Study of Potential Mohave Alternative/Complementary Generation Resources

Pursuant to CPUC Decision 04-12-016

Report Prepared for
Southern California Edison

SL-008587
February 2006

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Energy Economics, Inc.

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MOJAVE GENERATION ALTERNATIVES

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ACRONYMS AND ABBREVIATIONS

Term	Definition or Clarification
ACC	Arizona Corporation Commission
ACEEE	American Council for an Energy Efficient Economy
ADEQ	Arizona Department of Environmental Quality
ANA	Administration for Native Americans
APS	Arizona Public Service
ARI	Advanced Resources International, Inc.
ASU	Air separation unit
ATC	Available Transmission Capability
BACT	Best Available Control Technology
BAT	Business Activity Tax
bbl	Barrel
CAMR	Clean Air Mercury Rule
CCN	Certificate of Convenience and Necessity
CDD	Cooling degree days
CDE	Community development entity
CDFI	Community development financial institution
CEMS	Continuous emissions monitoring system
CGE	Computable general equilibrium
CPCN	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
CPV	Concentrating photovoltaic
CSEGR	Carbon sequestration with enhanced gas recovery
CSP	Concentrating solar power
DAQEM	Clark County Department of Air Quality and Environmental Management
DEP	Division of Environmental Protection
DEQ	Department of Environmental Quality

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
DNR	Department of Natural Resources
DOE	Department of Energy
DSIRE	Database of State Incentives for Renewable Energy
DSM/EE	Demand Side Management/Energy Efficiency
ECBM	Enhanced coal bed methane recovery using carbon dioxide
EDAWN	Economic Development Authority of Western Nevada
EIS	Environmental Impact Statement
EOR	Enhanced oil recovery
EPA	Environmental Protection Agency
EPACT	Energy Policy Act
EPC	Engineering, procurement, and construction
EPC	Emergency Planning Commission
EPRI	Electric Power Research Institute
EPS	Environmental Portfolio Standard
EWG	Exempt Wholesale Generator
FAA	Federal Aviation Administration
FERC	Federal Energy Regulatory Commission
FLM	Federal Land Managers
FMV	Fair market value
FTRs	Firm transmission rights
gpm	Gallon(s) per minute
GWh	Gigawatt-hour(s)
HHV	Higher heating value
hp	Horsepower
HRSG	Heat recovery steam generator
HTF	Heat transfer fluid

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
IECM	Integrated Environmental Control Model
IGCC	Integrated gasification combined-cycle
INEEL	Idaho National Engineering and Environmental Laboratory
inHgA	Inch(es) of mercury absolute
IOUs	Investor-owned utilities
IRP	Integrated resource planning
ISO	Independent system operator
kW	Kilowatts
kWh	Kilowatt-hour(s)
LAER	Lowest Achievable Emission Rate
LDWP	Los Angeles Department of Water and Power
LGTI	Louisiana Gasification Technology, Inc.
LLC	Limited liability company
LNB	Low-NO_X burners
MBtu	10^6 Btu (or mmBtu)
MCLs	Maximum contaminant levels
MD	Mechanical draft
mmBtu	10^6 Btu (or MBtu)
MOAs	Military operational areas
MW	Megawatt(s)
MWe	Megawatt(s) electric
MWh	Megawatt-hour
N.N.C.	Navaho Nation Code
NAAQS	National Ambient Air Quality Standards
NAICS	North American Industrial Classification System
NDOT	Navajo Department of Transportation

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
NEG	New Economic Geography
NEMA	National Electrical Manufacturers Association
NEPA	National Environmental Policy Act
NFPI	Navajo Forest Products Industries
NGCC	Natural gas combined-cycle
NN	Navajo Nation
NOI	Notice of Intent
NPDES	National Pollutant Discharge Elimination System
NPV	Net Present Value
NREL	U.S. Department of Energy – National Renewable Energy Laboratory
NSR	New Source Review
NST	Navajo Sales Tax
NTUA	Navajo Tribal Utility Authority
NV-DEP	Nevada Department of Conservation and Natural Resources – Division of Environmental Protection
NVP	Nevada Power Company
NYMEX	New York Mercantile Exchange, Inc.
O&M	Operating and maintenance
OASIS	Open Access Same-Time Information System
OC	Oxidation catalyst
OOIP	Original oil in place
PES	Portfolio Energy Standard
PIT	Possessory Interest Tax
PM	Particulate matter
PM_{10}	Particulate matter smaller than 10 µm
$PM_{2.5}$	Particulate matter smaller than 2.5 µm

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
PPA	Power purchase agreement
ppm	Parts per million
ppmvd	Parts per million, volumetric dry
PRB	Powder River Basin
PSD	Prevention of Significant Deterioration
psig	Pound(s) per square inch (gauge)
PTC	Production tax credit
PUCN	Public Utility Commission of Nevada
PV	Present value
REDYN	Regional Dynamics, Inc.
ROD	Record of decision
ROE	Return on Equity
ROIP	Remaining Oil in Place
ROR	Rate of return
ROW	Right-of-way
RPS	Renewable Portfolio Standard
RTO	Regional transmission organization
S&L	Sargent & Lundy LLC
SCE	Southern California Edison
SCORE	Service Corps of Retired Executives
SCR	Selective catalytic reduction
SEGS	Solar Electric Generating Station
SES	Stirling Engine Systems
SHPO	State Historical Preservation Officer(s)
SIP	State Implementation Plan
SNL	Sandia National Laboratories

ACRONYMS AND ABBREVIATIONS (cont.)

Term	Definition or Clarification
SOAPP	State-of-the-Art Power Plant (software program)
SPCC	Spill Prevention Control and Countermeasure (
SPP	Sierra Pacific Power
SRP	Salt River Project
SWEEP	Southwest Energy Efficiency Project
SWPPP	Storm water pollution prevention plan
Syngas	Synthesis gas
TBtu	10^{12} Btu
Tcf	10^{12} cubic feet
TDS	Total dissolved solids
TEP	Tucson Electric Power
tonne	Metric ton (1,000 kg)
tpy	Ton(s) per year
TRC	Total resource costs
UGS	Utah Geological Survey
UIC	Underground Injection Control (program)
USBM	United States Bureau of Mines
USFWS	U.S. Fish and Wildlife Service
USGS	U.S. Geological Survey
VAR	Volt-amperes reactive
WAPA	Western Area Power Administration
WTI	West Texas Intermediate (crude oil)
ZLD	Zero liquid discharge (system)

EXECUTIVE SUMMARY

The Mohave Generating Station is a two-unit 1,580 megawatt (MW) coal-fired power plant located in Laughlin, Nevada, built between 1967 and 1971. The station covers approximately 2,490 acres. The Mohave Generating Station is operated by Southern California Edison, the majority owner (56%) of the plant, corresponding to 885 MW of capacity. The Los Angeles Department of Water and Power (10%), Nevada Power Company (14%), and Salt River Project (20%) also own interests in the plant.

Integrated gasification combined-cycle (IGCC), concentrating solar power (CSP) technology, wind, natural gas combined-cycle (NGCC), other renewables, and energy efficiency were investigated as potential alternatives to replace or complement the share of the electrical capacity of the Mohave Generating Station owned by Southern California Edison.

The California Public Utilities Commission (CPUC) ordered Southern California Edison (SCE) to perform for them a study of alternatives for replacement or complement of its share of the Mohave Generating Station under Decision 04-12-016, issued on December 4, 2004. SCE chose Sargent & Lundy and Synapse Energy Economics to jointly perform this study.

Six categories of generation options were evaluated:

- **Integrated Gasification Combined-Cycle (IGCC).** Two different sites were studied: the existing Mohave site and a site near the Black Mesa mine.
- **Solar Technology.** Four different technologies were screened: trough, power tower, dish/Stirling engine, and concentrating photovoltaics.
- **Wind Technology.** Four sites were chosen based on wind resource availability and proximity to tribal lands.
- **Natural Gas Combined Cycle (NGCC).** NGCC at the existing Mohave site was studied.
- **Other Renewable Technologies.** A screening study of geothermal and biomass resource potential was performed for the area in and around tribal lands.
- **Demand Side Management/Energy Efficiency (DSM/EE).** DSM/EE frameworks were developed for purchase of resources made available in nearby states other than California by DSM/EE efforts in those states.

Sargent & Lundy performed the evaluations with respect to the first five options in the list above, and Synapse Energy Economics studied the final option.

Outputs of the study of the generation options include the following:

- Capital and O&M costs
- Water usage
- Land requirements
- Construction and operations labor requirements

All costs are presented in year 2006 dollars.

With respect to the generation resource options, Sargent & Lundy and Synapse Energy Economics collaborated in the study of the following elements:

- **CO_2 Sequestration.** The issues surrounding the economic viability of CO_2 sequestration through various means was studied. The geologic feasibility of such means was also studied and is included as an appendix.
- **Tribal Issues.** Tribal issues associated with royalties and taxes and other economic impacts, including impacts on employment, of the generation resource options were studied.
- **Financial Issues.** Financial issues including ownership structures of the prospective options and existing financial incentives were studied.
- **Generation and Demand Profiles.** The correspondence of the possible generation profiles with SCE demand was studied.
- **Transmission Issues.** Transmission issues including contractual issues of transmission availability and physical load flows were studied.

Fuel costs and emissions costs were also estimated on a per-unit basis by Synapse Energy Economics and are included as appendixes to this report.

ES.1 GENERATION TECHNOLOGY OPTIONS

ES.1.1 Project Sizes

Project sizes differed from the 885-MW capacity of the SCE share of the existing Mohave plant for various reasons. Those reasons are summarized as follows:

- **IGCC.** IGCC project sizes are limited by the size of the combustion turbine used as the primary heat source. Combustion turbine manufacturers have a limited number of turbine models with specific size ranges. IGCC project sizes, therefore, are determined by ambient conditions and whether one, two, three, four, or more combustion turbines are employed in the design. As a result, the projects have discrete sizes depending on the number of combustion turbines. The selection, in this study, of the 540-MW size range reflects the next increment in sizing above the sizes of recent demonstration plants that have all used one combustion turbine. We expect that both developers and constructors will desire to perfect this design configuration before moving on to larger sizes.

- **Solar.** In order to estimate reasonable unit sizes for the solar technologies, recent Renewable Portfolio Standards requirements in the area were evaluated. The amount of energy corresponding to the production of Mohave Station that must come from renewable sources was estimated. The unit sizes for each technology that could provide this energy were then estimated, based on estimated capacity factors for each technology. California retail sellers of electricity are required to increase their procurement of eligible renewable energy resources such that 20% of their retail sales (on a megawatt-hour basis) are procured from eligible renewable energy resources by 2017. An 885-MW plant at 72% capacity factor (equivalent to Mohave Generating Plant capacity factor) produces approximately 5,600,000 MWh of electricity per year. Twenty percent of this value results in 1,120,000 MWh, which will theoretically have to come from renewable energy resources by the year 2017. The parabolic-trough capacity factor capability, without thermal storage, is approximately 30%. In order to produce 1,120,000 MWh, a unit size of 425 MW is required.

  In order to reduce the plant size of a parabolic trough plant and eliminate the need for a conventional steam-Rankine power plant for backup, thermal storage of six hours can be considered in the parabolic-trough plant configuration. This is consistent with the design of other parabolic-trough plants. With six hours of thermal storage, the capacity factor capability is approximately 43%, which corresponds to 300 MW of installed power for 1,120,000 MWh.

  The dish/Stirling engine capacity factor capability, without thermal storage, is approximately 30%, which for 1,120,000 MWh (same generation as considered for the parabolic-trough technology) corresponds to 425 MW of power.

- **Wind.** Sites were identified that had Class 3 or better wind resources. The available wind resources have an implied annual capacity factor related to the maximum sustained wind speed and the profile of this wind resource over a year. This, combined with the associated land area over which installation of wind turbines is feasible, provides the major input for the estimate of available maximum capacity. The Department of Energy (DOE) has estimated that Gray Mountain has a total wind resource potential of up to 800 MW; however, this estimate may not take into account physical limitations, transmission capacity, economic resources versus technical resources, or other constraints at the site. An estimate to build out to 450 MW over a three-year phased development program of 150 MW per phase is reasonable, based on the available wind resources and engineering judgment, at this time. The Aubrey Cliffs initial potential is estimated to be 100 MW. Further capacity potential may exist and depends on the degree to which the wind resource drops off further from the mesa edge and the transmission capacity available on the targeted 230-kV transmission system where interconnection will occur south of Chino Point and Route 66 near Seligman. Clear Creek is initially being developed to a size of 75 MW. There does not appear to be sufficient planned transmission capacity at this site over the near and intermediate term to exceed 75 MW. The Sunshine Wind Park is being developed to a size of 60 MW to fully use available transmission capacity on the 69-kV APS line into which the project would interconnect.

- **NGCC.** The sizing criteria described for IGCC also apply to NGCC, resulting in capacities of approximately 500 MW for a two-combustion-turbine project and 1,000 MW for a four-combustion-turbine project.
- **Other Renewables.** Given the lack of available resources, the maximum potential unit size is approximately 2.5 to 5 MW. Therefore, other renewable energy sources are not feasible in size ranges resembling those of the other options and so were not considered.
- **DSM/EE.** Capacity ranges for available DSM/EE resources depend on the ability of the entities performing the demand-side management and energy efficiency activities to free up existing capacity. By 2010 it is possible that energy efficiency initiatives in Arizona and New Mexico could replace over 40% of the energy and capacity of SCE's share of the Mohave plant, provided satisfactory regulatory and commercial terms and conditions can be developed.

Approximate project sizes studied in this report are presented in the table below:

Table ES-1 — Approximate Project Sizes (MW)

IGCC	Solar	Wind	NGCC	Other Renewables	DSM/EE
500 - 600	425	60- 450	1000	2-5	N/A

ES.1.2 Integrated Gasification Combined Cycle

Gasification is a process that converts a variety of carbon-containing feed stocks like coal, petroleum coke, lignite, oil distillates, and residues into synthesis gas (syngas) consisting primarily of carbon monoxide (CO), hydrogen (H_2), and carbon dioxide (CO_2). Syngas from the gasifier is cleaned of particulate matter (PM), sulfur, and other contaminants before being combusted in a gas-fired combustion turbine. Heat from the turbine exhaust gas is extracted in a heat recovery steam generator (HRSG) and combined with steam produced in the gasification system to drive a steam turbine/generator.

- **No CO_2 removal.** This is technically feasible today with current technology.
- **CO_2 removal without shift conversion.** In this case, 90% of the carbon dioxide generated by the standard syngas production process is removed from the fuel gas. This is technically feasible today.
- **Maximum CO_2 removal.** This assumes that all of the carbon monoxide the syngas is converted to carbon dioxide using a shift reaction and 90% of this CO2 is removed from the fuel. The shift reaction is technically feasible today. However, a combustion turbine that can use the product syngas is not yet available.

Combined with the performance of the IGCC, the effects of CO_2 removal were analyzed for three separate cases:

- **No CO_2 Removal.** The base case performance assumed that carbon was not removed from the fuel. This is how current technology operates at this time.
- **CO_2 Removal without Shift Conversion.** This case assumed that syngas was produced using current gasifier technology and a standard selection of gasifier components, with no "shift reaction" to convert carbon monoxide in the syngas to CO_2. Some CO_2 is produced in the syngas nevertheless, and this was assumed to be removed. This is technically feasible today; however, the issue of where to put the removed CO_2 must still be addressed.
- **90% CO_2 Removal.** This case assumed that the syngas was further processed using a "shift" reaction to convert the carbon monoxide (CO) in the syngas to CO_2, and that 90% of the CO_2 in the resulting syngas was removed from the fuel. At the present time, a combustion turbine capable of burning the fuel that is the result of this process is not currently available, and technical research and development is still necessary.

Estimates of performance of the IGCC option at the two sites studied are as follows:

Table ES-2 — IGCC Plant Performance

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
Mohave				
Gross Output	MW	639.6	639.6	604.9
Net Output	MW	548.9	531.1	481.7
Heat Rate	Btu/kWh	9,909	10,402	11,730
Overall Efficiency	%	34.4	32.8	29.1
Heat Input	mmBtu/hr	5,439	5,525	5,650
Fuel Consumption	lb/hr	502,056	509,953	521,560
Fuel Consumption	tpy	2,199,007	2,233,595	2,284,432
Total Staffing	persons	145	155	155
Black Mesa				
Gross Output	MW	643.9	643.9	609.0
Net Output	MW	554.6	537.1	484.9
Heat Rate	Btu/kWh	9,927	10,421	11,751.3
Overall Efficiency	%	34.4%	32.7%	29.0%
Heat Input	mmBtu/hr	5,506	5,506	5,699

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
Fuel Consumption	lb/hr	508,191	508,191	526,020
Fuel Consumption	tpy	2,225,878	2,225,878	2,303,967
Total Staffing	persons	145	155	155

Capital costs for the various cases, as well as for the two sites, Mohave and Black Mesa, were developed with conventional cooling and dry cooling, respectively. These are summarized below.

Table ES-3 — IGCC Capital Costs

	No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal	
Net output, MW	548.9 (554.6)		531.1 (537.1)		481.7 (484.9)	
Capital Costs	M$	$/kW	M$	$/kW	M$	$/kW
Const. Cost w/ Wet Cooling (Mohave)	895	1,631	987	1,858	1,143	2,373
Const. Cost w/ Dry Cooling (Black Mesa)	910	1,641	1,002	1,866	1,158	2,388
EPC Fees (12.5%)*	113.76	205	125.20	236	144.81	301
Owner's Development Costs (6.5%)	59.16	107	65.10	123	75.30	156
Total Expected Costs w/Wet Cooling (Mohave)	1,065	1,940	1,174	2,210	1,361	2,825
Total Expected Costs w/Dry Cooling (Black Mesa)	1,083	1,973	1,192	2,219	1,379	2,844

*EPC fees include the profit of the EPC contractor plus allowances embedded by the EPC contractor in the contract price for—

- Process risk, including the cost of providing a performance guarantee
- Sub-contractors performance and completion risk, including items such as bankruptcy of the subcontractor or having to hire a new subcontractor if it is not performing its contract.
- Execution risk, including cost and schedule risk.

Water consumption was also estimated for the three cases of CO_2 removal and the two cases of cooling. These results are summarized below. Values shown are for 100% capacity factor and would vary proportionately with actual plant dispatch; these are maximum values.

Table ES-4 — IGCC Water Consumption

Based on 100% Capacity Factor	No CO_2 Removal		CO_2 Removal		With CO_2 Removal	
	gpm	acre-ft/yr	gpm	acre-ft/yr	gpm	acre-ft/yr
Total Plant Use (Mohave)	4,245	6,833	4,252	6,844	4,406	7,093
Total Plant Use (Black Mesa)	1,192	1,919	1,199	1,930	1,238	1,992

Notes: Boiler feedwater make-up is 1% of main steam flow rate.
Cooling tower make-up includes evaporation, drift and blowdown with four cycles of concentration.
Cooling towers used at Mohave with Colorado River water, Dry Cooling used at Black Mesa.
All water for coal slurry to either site is assumed to come from the "C-aquifer."

Land use was also estimated for this option, as summarized below.

Table ES-5 — IGCC Land Requirements

	Units	No CO_2 Removal		No Shift CO_2 Removal		Max. CO_2 Removal	
Cooling Type		Wet	Dry	Wet	Dry	Wet	Dry
Land Use	acres	300	300	300	300	300	300
	sq. mi.	0.469	0.469	0.469	0.469	0.469	0.469
Length of Side of Square with Same Area	mi.	0.69	0.69	0.69	0.69	0.69	0.69

ES.1.3 Solar

Four different solar power generation technologies were evaluated: parabolic trough, dish/Stirling engine, power tower, and concentrating photovoltaics. This review indicated that the parabolic-trough and dish/Stirling engine technologies were the only ones that could reasonably replace or complement a portion of the generation of the existing Mohave plant, forming a part of the generation required for compliance with emerging renewable portfolio standards. The power tower and concentrating photovoltaic technologies were not selected because, in the former case, the technology has proven inferior to the trough technology and has no commercial examples, while in the latter case, the technology is still in development and, also, has no commercial examples. The trough technology is in commercial operation. The dish/Stirling engine technology has been demonstrated on a small-scale, has a very high conversion efficiency, and has entered the commercial stage of its developed as witnessed by two agreements signed with major utilities that are designed to ultimately lead to formal power purchase agreements. A summary of the results of the analysis is provided in the table below.

Table ES-6 — Solar Technology Summary

		Parabolic-Trough	Dish/Stirling engine
Plant Size	MW	300	425
Number of Units		3	17,000
Unit Size	MW	100	0.025
Thermal Storage		Yes – 6 hours	No
Annual Capacity Factor		43%	30%
Annual Generation	MWh	1,120,000	1,120,000
Capital Cost	$/kW	$3,560	$1,400
Fixed O&M Cost	$/kW-yr	$33	$3
Variable O&M Cost	$/MWh	$30	$11
Land Use	acres	870 per unit (2,610 total)	2,125
	sq. mi.	1.359 per unit (4.078 total)	3.320
Length of Side of Square with Same Area	mi.	1.17 per unit (2.02 total)	1.82
Water Requirement	gal/yr	6,800,000 per unit (20,400,000 total)	2,856,000
	acre-ft/yr	20.87 per unit (62.61 total)	8.76
Total Staffing	persons	62 per unit (stand alone units) 88 total (combined units)	118

ES.1.4 Wind

Four sites with significant potential for power generation using wind technology were identified. These sites are summarized in the following table.

Table ES-7 — Wind Sites

Site	Gray Mountain	Aubrey Cliffs	Clear Creek	Sunshine
Wind Class at 80 m	4 to 7	4 to 5	3+ to 4	3
MW	450	100	75	60

Site	Gray Mountain	Aubrey Cliffs	Clear Creek	Sunshine
Expected Capacity Factor	40%	34%	32%	25%
Location	On the Navajo reservation near Cameron, Arizona and Moenkopi Substation	On Navajo fee and State Trust lands just northwest of Seligman, Arizona	On Hopi fee and State Trust lands southwest of Winslow	On Hopi fee and private ranch lands owned by two other landowners, located 35 miles east of Flagstaff on I-40 near the Meteor Crater and west of Winslow

Table ES-8 — Wind Sites Capital and O&M Cost Estimates

Project Size and Capital Costs	Gray Mountain-3 Phases	Gray Mountain-Phase 1	Aubrey Cliffs	Clear Creek	Sunshine
Net MW	450	150	100	75	60
Project Costs $2006	755,017,000	258,031,000	169,196,000	126,570,000	99,671,000
Project Costs per kW, $/kW	1,678	1,740	1,692	1,688	1,661
Fixed O&M, $/kW-yr	23.73	23.73	24.24	24.94	27.08
Variable O&M, $/MWh	0.195	0.195	0.223	0.244	0.279

Water requirements are negligible for the wind options. Staffing requirements are as follows:

Table ES-9 — Wind Sites Operating Staffing Requirements

Project	MW	Staff
Gray Mountain	450	14
Aubrey Cliffs	100	4
Clear Creek	100	4
Sunshine Wind Park	60	3

Land requirements for the wind options are as follows:

Table ES-10 — Wind Sites Land Requirements

		Gray Mountain-3 Phases	Gray Mountain-Phase 1	Aubrey Cliffs	Clear Creek	Sunshine
Land Use	acres	34,000	11,333	5,200	4,320	8,000
	sq. mi.	53.13	17.71	8.13	6.75	12.50
Length of Side of Square with Same Area	mi.	7.29	4.21	2.85	2.60	3.54

ES.1.5 Natural Gas Combined Cycle

Combined-cycle technology has been used to generate power for a number of years, utilizing a cycle containing both combustion turbines and steam turbines. The combination of the two types of turbines generally provides efficiencies in the range of 48% to 52% on a higher heating value (HHV) basis. Combined-cycle plants generally come in discrete sizes; the combined-cycle power plant size is primarily a function of the combustion turbine size, and these are available from manufacturers in a limited number of sizes.

The overall plant performance was estimated for the Mohave site for a 2 x 2 x 1 500-MW combined-cycle power block operating on the primary fuel (i.e., natural gas) at the site average ambient conditions. To obtain the total site performance estimate (i.e., nominal 1,000-MW facility), the performance estimate for the single 500-MW power block was doubled.

The full-load estimated plant performance while operating on natural gas with an air-cooled condenser is as follows:

Table ES-11 — Plant Performance Data with Dry Cooling

Ambient Temperature	20°F	67°F	108°F	125°F
Gross Generator Output, MW	1,063	1,017	902	880
HHV Heat Input, mmBtu/hr	7,412	7,028	6,478	6,404
Auxiliary Power Estimate, MW	23	23	22	21

Ambient Temperature	20°F	67°F	108°F	125°F
Net Generator Output, MW	1,040	994	880	859
Net Plant Heat Rate, Btu/kWh HHV	7,130	7,070	7,355	7,460

Note: Ambient temperatures shown correspond to the following:
20 ºF – site minimum design temperature
67 ºF – site average annual temperature
108 ºF– site summer design temperature
125 ºF – site maximum design temperature

As part of this study, CO_2 sequestration was evaluated. Based on information from the Department of Energy's Integrated Environmental Control Model (IECM) computer program, the performance of the combined-cycle facility is affected by the addition of CO_2 sequestration. From the program, the performance impact is approximately 15% less output and approximately 18% higher heat rate at the average ambient conditions.

Current capital cost estimates for the NGCC technology were developed using S&L's in-house database. A single 2 x 2 x 1 500-MW combined-cycle power block cost estimate was developed for each of two different cooling methods. The first case was for a plant with a mechanical draft (MD) cooling tower with a wet surface condenser. The second case was for a plant with an air cooled condenser. The capital cost estimates are as follows:

Table ES-12 — Capital Cost Estimates

Configuration	Estimated Capital Cost	Capital Cost per Installed kW*
Single 2x2x1 500-MW combined-cycle power block with MD cooling tower	$300,000,000	604
Two 2x2x1 500-MW combined-cycle power blocks with MD cooling tower	$540,000,000	544
Single 2x2x1 500-MW combined-cycle power block with air-cooled condenser	$306,000,000	616
Two 2x2x1 500-MW combined-cycle power blocks with air-cooled condenser	$551,000,000	555

* Based on net power at average ambient conditions

In addition to the costs that were developed for the two cooling methods, a cost estimate was developed for CO_2 sequestration. This estimate is based on the DOE IECM program data. The estimated capital cost for CO_2 sequestration is approximately $350/kW to $400/kW higher than the capital cost estimates provided above. Therefore, for a nominal 1,000-MW combined-cycle plant with mechanical draft cooling towers, the estimated capital cost with CO_2 sequestration is approximately $894/kW to $944/kW. Similarly, for a nominal 1,000-MW combined-cycle plant with air-cooled condensers, the estimated capital cost with CO_2 sequestration is approximately $905/kW to $955/kW.

Operations and maintenance (O&M) costs were also estimated. The fixed O&M costs are those spent regardless of how much the plant operates. The fixed O&M costs include costs for direct and indirect labor for operations and maintenance staff that are permanently employed at the plant site, as well as home office support costs allocable to the plant. In addition, the fixed costs include O&M contract services and materials and power purchased for in-house plant needs during plant outages. The variable O&M costs are those costs that change with the amount of power generated. The variable O&M costs include chemicals and consumables, catalyst replacement, and major maintenance of the combustion turbines, steam turbines, HRSG, and balance-of-plant.

The fixed and variable O&M costs for the NGCC power plant for each of the two cooling methods studied in this report are presented in the following table.

Table ES-13 — Estimated O&M Costs

Current $	MD Cooling Tower with Wet Surface Condenser	Air-Cooled Condenser
Fixed, $/kW-yr	$5.47	$5.47
Variable, $/MWh	$1.97	$1.77

CO_2 sequestration O&M costs were also estimated for this study. The fixed and variable O&M costs were estimated based on the DOE IECM program. The estimated fixed and variable O&M costs for the combined-cycle plant with mechanical draft cooling towers and with CO_2 sequestration are $6.45/kW-yr and $2.32/MWh, respectively. The estimated fixed and variable O&M costs for the combined-cycle plant with air-cooled condensers and with CO_2 sequestration are $6.45/kW-yr and $2.08/MWh, respectively.

Approximate plant land area requirements for the NGCC facility are presented in the following table. The table represents the estimated land requirements for two 500-MW combined-cycle power blocks. In addition, the table provides the approximate area required based on the method of cooling (i.e., mechanical draft cooling towers with wet surface condensers versus air-cooled condensers).

Table ES-14 — Approximate Land Area Required for 1,000-MW NGCC Facility

		MD Cooling Tower with Wet Surface Condenser	Air-Cooled Condenser
Without CO_2 Sequestration	acres	30	42
	sq. mi.	0.047	0.066

		MD Cooling Tower with Wet Surface Condenser	Air-Cooled Condenser
Length of Side of Square with Same Area	mi.	0.217	0.257
With CO_2 Sequestration	acres	34	46
	sq. mi.	0.053	0.072
Length of Side of Square with Same Area	mi.	0.230	0.268

Approximate water usage for the natural gas combined-cycle facility is provided in the following table.

Table ES-15 — Approximate Water Usage for 1,000-MW NGCC Facility

	MD Cooling Tower with Wet Surface Condenser		Air-Cooled Condenser	
	gpm	acre-ft/yr	gpm	acre-ft/yr
Cooling Tower Makeup Peak / Average	3,500 / 2,300	5,650 / 3,710	0 / 0	0 / 0
Cycle Makeup Peak / Average	66 / 44	110 / 70	66 / 44	110 / 70
Miscellaneous Peak / Average	76 / 76	120 / 120	76 / 76	120 / 120
Total Water Makeup Peak / Average	3,642 / 2,420	5,870 / 3,900	142 / 120	230 / 190

ES.1.6 Demand-Side Management / Energy Efficiency

As part of the study, potential DSM/EE resources available in the Western United States outside of California were reviewed. The specific technology option being analyzed involves SCE financing DSM implementation, coupled with power purchase arrangements under which the resultant available "freed up" power would be purchased by SCE.

This concept is based on the assumption that there are considerable low-cost efficiency resources in states neighboring California, and that SCE may be willing or directed to procure such resources (through DSM implementation coupled with a power purchase contract) depending on the overall costs in comparison to other alternatives. In doing so, SCE could create, for example, a 10-year power purchase agreement (PPA) with a neighboring utility at a price below its avoided costs, yet still high enough to entice the neighboring utility to implement the DSM. The DSM resource would be that available beyond what is already being pursued by the neighboring utility or state.

To assess the amount of energy efficiency potential in the region, the study by the Southwest Energy Efficiency Project of the economic potential for energy efficiency in the southwest (SWEEP 2002) was reviewed. As it turns out, Arizona and New Mexico have, by far, the largest potential for readily available utility efficiency savings; by 2010 there is estimated to be at least 2,394 GWh of energy per year and 408 MW of capacity available from these two states alone. To put this in perspective, SCE's share of the Mohave generation is roughly 5,700 GWh per year, and its share of the Mohave capacity is 885 MW. Thus, by 2010 energy efficiency from Arizona and New Mexico could replace over 40% of the energy and capacity from the Mohave plant. It is assumed that these savings can be achieved for a cost of $40/MWh or less. The analysis is conservative, because a relatively high estimate of cost of saved energy is assumed and because the raw efficiency potential documented in the SWEEP study is discounted.

A simple spreadsheet model was developed to gauge the effect of a DSM transfer. Based on the model, an illustrative example was created to assess the effect on each of the stakeholders (utility customers and shareholders) and the impact of peak load reduction benefits associated with the DSM procurement alternative or complement. After a consideration of the alternatives, a baseload "24 x 7" power purchase product coupled with DSM implementation was analyzed, in which the benefits associated with peak period load reductions were retained by the partnering utility while their utility customer rates were held constant. The results indicate that the economics of an interregional DSM resource transfer appear viable.

To investigate the feasibility and practicality of the DSM resource / power purchase option, PNM Resources of New Mexico was contacted. The aim of these conversations was to obtain feedback on the willingness of parties to participate in the DSM resource procurement and to determine the key issues facing potential utility partners considering a DSM/power purchase arrangement with SCE. In particular, Synapse sought to obtain information on the regulatory and institutional concerns or barriers that may exist and to determine the commercial factors that would influence the pricing arrangements that would accompany the DSM implementation / power purchase alternative. Another goal was to determine the likely range of prices or at least the driving factors in price determination; while the driving factors were discerned, no particular commercial bounds on pricing could be placed on the DSM alternative. To date, conversations indicate that regulatory reception in New Mexico remains a real concern, but it is safe to conclude that PNM Resources is interested in further discussing the concept.

The incentive for utilities to participate in agreements to implement energy efficiency programs in the states neighboring California in general, and to implement energy efficiency programs to enable power transfers to

SCE in particular, is, not surprisingly, directly related to the effect those programs are likely to have on corporate profits. Of the various methods open to utility regulators for reducing or eliminating any disincentive to pursue energy efficiency programs, the "decoupling" of utility profits from the level of sales is a concept that has been implemented or is under discussion in many states, including those in the southwest.

ES.1.7 Other Renewables

This study evaluated potential for electrical energy generation from two types of other renewable resources: biomass and geothermal.

In the case of biomass energy, the production of electricity in quantities sufficient to be considered as part of a replacement of or complement to the existing Mohave plant would require a feedstock of municipal solid waste and/or forestry residue.

Power generation from municipal solid waste requires a large source (population) and the ability to sort and provide combustible solid waste as a fuel source. The expansive area and lack of large population concentrations in tribal lands make this a difficult option. Moreover, municipal solid waste is not considered biomass. Biomass plants in the United States only use uncontaminated feedstock, which contains no toxic chemicals. Potentially hazardous materials (such as creosote-wood and batteries) would have to be removed from municipal solid waste at an additional cost to be considered true biomass.

Tribal lands have significant forest resources and the potential to support a forestry industry, but this is not a likely option in the near future. In the late 1950s, the Bureau of Indian Affairs and the Navajo Tribal Council created the Navajo Forest Products Industries (NFPI), which operated from 1962 to 1992, processing an average of 40 million board-feet of lumber each year. This program was carried out, however, with little concern for how these activities affected Navajo subsistence and spiritual use of the forests. In the early 1990s, conflict over the use of the forests developed. This conflict resulted in closure of the saw mill in 1995.

The potential, therefore, for developing feedstock for a biomass power plant on tribal lands within the next few years that would be large enough to play a significant role in replacing or complementing lost generation from the Mohave Project is extremely low.

Regarding geothermal resources, the available geological information indicates that the temperature of geothermal wells and springs within tribal lands range from 20°C (68°F) to 50°C (122°F) with the exception of two wells greater than 50°C (122°F). The water from thermal wells needs to be greater than 225°F (107°C) for generation of electricity. Given the relative lack of geothermal resources, it is estimated that the study area's geothermal resources could support a power plant of not more than 5 MW, and it is likely that no power plant is feasible in the study area.

Therefore, in both cases, the potentially viable unit size range (approximately 2.5 to 5 MW) is not meaningful in comparison to the nominal capacity of SCE's share of the Mohave power plant (885 MW), and therefore, these resources are not considered feasible as potential technology options for the replacement or complement for SCE's share of the existing Mohave plant.

ES.1.8 Generation Technology Summary Data

In order to provide a consistent set of data across all technology options studied, a common format for the data presented above was developed. Data in this format are provided below for all options studied. Summary data are not provided for the other renewable options because these technologies were not deemed viable for the size of generation desired from the technology options.

Table ES-16 — IGCC Summary Data

	Units	No CO_2 Removal		No Shift CO_2 Removal		Max. CO_2 Removal	
Cooling Type		Wet	Dry	Wet	Dry	Wet	Dry
Net Capability	MW	549	555	531	537	482	485
Capacity Factor*	%	100	100	100	100	100	100
Net Generation*	MWh/yr	4,808,364	4,858,296	4,652,653	4,704,996	4,219,692	4,248,061
Net Heat Rate	Btu/kWh	9,909	9,927	10,402	10,421	11,730	11,751
Capital Cost	$/kW	1,971	2,004	2,173	2,279	2,518	2,911
Fixed O&M Costs	$/kW-yr	49.59	49.59	67.45	67.45	80.98	80.98
Variable O&M Costs	$/MWh	1.59	1.26	1.66	1.32	2.00	1.62
Fuel Costs	$/mmBtu	1.15	1.15	1.15	1.15	1.15	1.15
Land Use	acres	300	300	300	300	300	300
Water Use	gpm	4,245	1,192	4,252	1,199	4,406	1,238
	acre-ft/yr	6,833	1,919	6,844	1,930	7,093	1,992
Total Staffing	persons	145	145	155	155	155	155
Transmission Direct Interconnection Costs**	$/kW	175.0	175.0	180.9	180.9	199.7	199.7
Transmission System Upgrade Costs***	$millions	173.0	173.0	173.0	173.0	173.0	173.0

	Units	No CO_2 Removal		No Shift CO_2 Removal		Max. CO_2 Removal	
Cooling Type		Wet	Dry	Wet	Dry	Wet	Dry
NO_X Emissions	lb/mmBtu	0.022	0.022	0.021	0.021	0.021	0.021
SO_2 Emissions	lb/mmBtu	0.13	0.13	0.02	0.02	0.02	0.02
CO_2 Emissions	lb/mmBtu	200	200	142	142	17	17

* 100% capacity factor is used as a reference; actual output will depend on dispatch conditions.

** It is assumed that direct interconnection costs and transmission upgrade costs for an IGCC plant at the existing Mohave site are zero, with the IGCC plant replacing the existing one. Costs shown are for the Black Mesa site.

*** Costs shown are for the Black Mesa site and without certain system upgrades that are already being contemplated for the near future. With those upgrades the cost is estimated at $48.0 million.

Table ES-17 — Solar Summary Data

	Units	Stirling	Trough*	
Cooling Type		N/A	Wet	Dry
Net Capability	MW	425	300	300
Capacity Factor	%	30	43	43
Net Generation	MWh/yr	1,120,000	1,120,000	1,120,000
Net Heat Rate	Btu/kWh	0	0	0
Capital Cost	$/kW	1,500	3,360	3,560
Fixed O&M Costs	$/kW-yr	3	33	33
Variable O&M Costs	$/MWh	11	30	30
Fuel Costs	$/mmBtu	0	0	0
Land Use	acres	2,125	2,610	2,610
Water Use	gpm	5.4	1,580	38.7
	acre-ft/yr	8.8	2,550	62.6
Total Staffing	persons	118	88	88
Transmission Direct Interconnection Costs (500 kV/230 kV)	$/kW	251.4/172.1	315.2/220.7	315.2/220.7
Transmission Upgrade Costs**	$000s	0	0	0
NO_X Emissions	lb/mmBtu	0	0	0
SO_2 Emissions	lb/mmBtu	0	0	0
CO_2 Emissions	lb/mmBtu	0	0	0

* Solar trough capital cost includes $600/kW for six hours of thermal storage.

** System upgrade costs are shown for Solar Site 2 as shown in the General Location Map in Appendix A.

Table ES-18 — Wind Summary Data

	Units	Gray Mountain - 3 Phases	Gray Mountain - Phase I	Aubrey Cliffs	Clear Creek	Sunshine
Cooling Type		N/A	N/A	N/A	N/A	N/A
Net Capability	MW	450	150	100	75	60
Capacity Factor	%	40	40	34	32	25
Net Generation	MWh/yr	1,566,640	522,213	304,624	204,790	146,937
Net Heat Rate	Btu/kWh	N/A	N/A	N/A	N/A	N/A
Capital Cost	$/kW	1,678	1,740	1,692	1,688	1,661
Fixed O&M Costs	$/kW-yr	23.73	23.73	24.24	24.94	27.08
Variable O&M Costs	$/MWh	0.195	0.195	0.223	0.244	0.279
Fuel Costs	$/mmBtu	N/A	N/A	N/A	N/A	N/A
Land Use	acres	34,000	11,333	5,200	4,320	8,000
Water Use	gpm	N/A	N/A	N/A	N/A	N/A
	acre-ft/yr	N/A	N/A	N/A	N/A	N/A
Total Staffing	persons	14	5	4	4	3
Transmission Direct Interconnection Costs	$/kW	83.3	85.2	126.2	91.9	96.7
Transmission Upgrade Costs	$000s	0	0	60.0	0	0
NO_X Emissions	lb/mmBtu	0	0	0	0	0
SO_2 Emissions	lb/mmBtu	0	0	0	0	0
CO_2 Emissions	lb/mmBtu	0	0	0	0	0

Table ES-19 — NGCC Summary Data

	Units	No CO_2 Removal		CO_2 Removal	
Cooling Type		Wet	Dry	Wet	Dry
Net Capability	MW	994.0	994.0	844.0	844.0
Capacity Factor	%	100	100	100	100
Net Generation	MWh/yr	8,707,440	8,707,440	8,707,440	8,707,440
Net Heat Rate	Btu/kWh	7,070	7,070	8,310	8,310
Capital Cost	$/kW	544	555	919	930

	Units	No CO_2 Removal		CO_2 Removal	
Cooling Type		Wet	Dry	Wet	Dry
Fixed O&M Costs	$/kW-yr	5.47	5.47	6.45	6.45
Variable O&M Costs	$/MWh	1.97	1.77	2.32	2.08
Fuel Costs	$/mmBtu	8.64	8.64	8.64	8.64
Land Use	acres	30	42	34	46
Water Use	gpm	2,420	120	2,500	200
	acre-ft/yr	3,900	190	4,030	320
Total Staffing	persons	60	60	75	75
Transmission Direct Interconnection Costs*	$/kW	0	0	0	0
Transmission Upgrade Costs*	$000s	0	0	0	0
NO_X Emissions	lb/mmBtu	0.0370	0.0370	0.0370	0.0370
SO_2 Emissions	lb/mmBtu	0.0	0.0	0.0	0.0
CO_2 Emissions	lb/mmBtu	114	114	11.4	11.4

* It is assumed that direct interconnection costs and transmission upgrade costs for an NGCC plant at the existing Mohave site are zero.

Other relevant parameters that may be used in an integrated resource plan process are shown in Appendix B.

ES.2 CARBON SEQUESTRATION

In this report, we examined the potential for capturing, transporting, and storing carbon dioxide that is produced by power generation facilities. Specifically, we explored five types of geologic carbon sequestration: enhanced oil recovery, enhanced gas recovery, sequestration in unminable coal seams, sequestration in deep saline aquifers, and sequestration in natural CO_2 domes. Of these, enhanced oil recovery at sites in California seems the most feasible use for carbon dioxide emissions produced by either an IGCC or NGCC facility located in Laughlin, Nevada. For the Black Mesa site, feasible locations for sequestration are discussed in Appendix C. Transportation of the carbon dioxide will require the construction of a pipeline and installation of compression equipment, which have significant costs.

The primary motivator for the advancement of sequestration technology is the expectation that anthropogenic carbon dioxide emissions will have to be controlled in order to mitigate global climate change. Despite the substantial, predicted worldwide capacity for storing carbon, a number of policy, economic, and technical barriers confront geologic sequestration. Therefore, any carbon dioxide producing power plant at the Mohave or Black Mesa sites would need to perform further economic analyses to justify the construction of a pipeline for transport.

ES.3 FINANCIAL AND ECONOMIC ISSUES

ES.3.1 Financial Incentives

Various financial incentives are available to owners and investors of electric generation facilities. The incentives are broken down into two general categories: (a) those incentives directed towards the commercialization of specific generation technologies of interest in this Study and (b) those incentives directed towards tribal activities or economic development activities for which tribes are likely to be eligible. For this study, the second category specifically focused on financial incentives directed towards tribal-owned generation facilities and those directed towards low-income communities.

Both categories of financial incentives generally come from the federal government or state governments in the form of tax advantages. These include income tax credits, exemptions and deductions for investments, sales tax exemptions on equipment purchases, variable property tax exemptions on the value of the generation system, production credits based on the quantity of energy produced, job creation credits, and accelerated or special depreciation allowances. Other non-tax incentives generally come in the form of federal, state, and private grants, loans with advantageous terms, or loan guarantee programs.

The results of our broad review indicate that there are many valuable sources of incentives that can be used to fund the development and construction of the various technologies being reviewed in this study. Many of the incentives were recently introduced through the enactment of the Energy Policy Act of 2005. Additional federal incentives are available through the Department of Agriculture, Department of Treasury, Department of Energy, and others. Furthermore, states offer many energy-related incentives, particularly with regard to renewable generation. Together, these technology-related incentives represent significant funding potential.

As an example, the federal production tax credit for wind generation is a very important assumption that must be considered in the economics of such projects. This credit, under Section 45 of the federal tax code, is set to expire on December 31, 2007. However it may be extended beyond that date. The credit amounts to a significant "after tax" benefit for each kilowatt-hour produced for the initial 10-year period of each project. Any integrated resource plan process that is considering renewable resources must take available production tax credits into account.

In addition, many incentives are available at the federal, state, and local levels to spur economic development, particularly for low-income communities, including tribes. These incentives can be significant, in terms of spawning new technologies on reservation lands.

ES.3.2 Business Structures

Depending on its ownership and specific attributes, a business organization may be defined as—

- A tribal enterprise that is owned and controlled by the tribe and subject to tribal law;
- A non-tribal enterprise that is either
  - — Subject to the laws of the tribe, and perhaps also to the laws of the state in which the enterprise operates; or
  - — Only subject to the laws of the state in which it operates.

Indian tribes are eligible to establish most forms of non-tribal business structures. Generally, non-tribal business structures are subject to federal and state taxes. Tribes and tribal members also can establish tribal-specific enterprises. Such businesses and organizations may offer their owners some discrete advantages, financially and socially. Tribal business structures can be subdivided into three major categories: (1) Tribal governments; (2) federally chartered tribal corporations under Section 17 of the Indian Reorganization Act of 1934; and (3) tribally chartered corporations.

The type of business classification chosen can have large consequences with regard to tax requirements, third-party funding potential, and immunity from nonconsented lawsuits. However, these are not the only considerations. Equally important are the type of business activity being considered, who has authority over day-to-day decisions, technology risks, job impacts, and other impacts of the business on the community and culture. The overall findings regarding recommended ownership structures for the technology options considered in this study are summarized below. However, it is premature to conclude that a particular technology is, or is not, suited to tribal ownership. Such decisions must, in the end, be made with full knowledge of the particular project and project financing options. However, the following points reflect reasonable *generic* conclusions that can be considered as starting points, subject to reconsideration when a specific project and its details are ready to examine.

- **IGCC.** Due to its high capital costs, business risks, and high potential for royalty income from non-tribal enterprises, it would likely be in the tribes' best interests if the proposed IGCC facility were owned and operated by a non-tribal entity formed under state law.

- **Wind and DSM/EE technologies.** For each of these, there are only moderate capital and operational costs, low technology risk, and a high potential to create future jobs for the tribes, both on and off reservation territories. In addition, the capital costs are incurred in small increments. As a result, wind and DSM technologies might be attractive as tribal business entities.

- **Solar Dish/Stirling Engine Technology.** Business risks associated with this technology probably fall somewhere between those of IGCC and wind. Dish/Stirling engines have moderate, but modular capital costs. The technology may be a source of expanded jobs for the tribes in the future. Given these consideration, solar dish/Stirling engines may be attractive to tribal businesses.

- **Solar Parabolic Trough Technology.** Solar parabolic troughs are usually very large projects: unlike solar dish/Stirling technology, parabolic troughs are not generally built in a modular fashion or to produce small amounts of energy. In addition, parabolic troughs have high capital costs. Given these factors, this technology may be more suited to non-tribal business structures.

- **NGCC.** At this time, no conclusions can be made with regard to a natural gas combined-cycle facility; the proposed location of the natural gas plant is on private land. Therefore, whether or not it would potentially be attractive as a tribal business is not relevant to this study.

- **Other Renewables.** No conclusions can be made at this time regarding biomass or geothermal technologies. Information on proposed project specifics, including proposed locations, job impacts, costs, and business risks, needed to make a solid conclusion regarding best business structure is still pending.

Finally, for the more modular technologies (wind, solar dish/Stirling, DSM/EE, and possibly, other renewables), it might make sense for the tribes to consider the option of having a diversity of business entities on their lands. For example, it is certainly feasible for one wind site to be owned and operated by a tribal government, while another is owned and operated by a non-tribal entity. Such a scenario would allow both types of owners to benefit from each other's experiences with the technology.

ES.3.3 Hypothetical Packages of Incentives Directed at Specific Technologies Owned by Specific Entities

While sections of this Study separately examine financial incentives and business structures, the Study also combines the two concepts and analyzes hypothetical packages of financial incentives that might apply to the capital costs of specific resources, owned by specific types of entities. The Study finds that, hypothetically, the packages of incentives, which include grants, sales tax deductions, tax incentives, depreciation incentives, and more, can be used to offset, on average, over 20% of capital costs for both supply- and demand-side options.

Loan guarantees and long-term contracts can further decrease project risks and costs. The Study concludes that there are a large variety of financial incentives that can potentially be used to offset the capital costs of new supply- and demand-side options both on and near tribal reservation land. Business owners, however, should not simply come to expect the realization of these incentives; many of them have strict requirements and many of them are competitive. Equally important, incentive availability changes over time; business owners should continually review available incentives to make sure they are aware of any changes or additions to offerings.

ES.3.4 Fuel Prices

Historic and future prices for electrical generation fuels in the Southwest were investigated. Costs for all fuels, except coal, have increased significantly over the last several years. Natural gas, once near half the price of oil, has moved dramatically upward, yet remains cheaper than oil. Coal prices, by comparison, have increased at less than the rate of inflation.

In terms of future fuel prices, natural gas prices (in real dollars) are likely to decline somewhat over the next several years (through 2010), but gradually rise thereafter, reaching current peaks only after 2025. The forecasted decline for the period 2006–2010 in natural gas prices is based on the rate of decline of prices for that period existing currently in the NYMEX Henry Hub futures market. On the other hand, coal prices, generally, are likely to increase gradually (in real dollars) from present time until 2025, but at a modest rate compared to that of natural gas[1]. Fuel price evaluations and data are provided in an appendix to this study.

ES.3.5 Emissions Valuation

The health and environmental effects of exposure to pollutants will impose costs on society. Through regulation, these social costs may be partially or wholly incorporated into the production costs of the polluter. An unregulated pollutant will impose a cost on society but not to the producer of the pollution. However, presently uncontrolled emissions have the potential to be regulated in the future and, therefore, represent risk. Regulation or legislation can shift an unpriced externality into a priced one, creating tangible costs and opportunities. A generator must consider, even anticipate, the possibility of new or changing regulations to be competitive over the long term.

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[1] The projection provided does not apply to Black Mesa, specifically, but to open market coal and mines that can ship to open markets, in general. Coal for the Mohave plant may be purchased at a fixed price for some period. It would be not be surprising, however, if a new coal contract were a long-term contract and were for a fixed price over that term or subject to a fixed price escalation schedule over that term. Note too that market expectations are still likely to have some influence on the negotiation of such contractual arrangements involving coal from the Black Mesa mine, and such a contract might contain provisions for re-openers or other price increases over time.

With this in mind, the assessment of emissions valuation considered the economic impacts and projected market prices of seven pollutants typically emitted by fossil fuel-fired power plants. The four considered most relevant in terms of current or near-future regulations are SO_2, NO_X, mercury, and CO_2.

Air emissions are generally regulated under both federal and state law and, in some instances, tribal law. EPA oversees implementation of the Clean Air Act, although Nevada (like most states) has authority to administer the federal laws within their borders. A polluter may be subject to regulations at different levels, and federal and state laws can overlap with each other.

A summary of the historical, current, and forward allowance prices for each pollutant is provided below.

- **SO_2.** SO_2 allowances have been traded for more than a decade. Allowance prices have escalated since 2000 and most dramatically from 2003 to present. The rise in natural gas prices pushed up the demand for coal-fired generation, and SO_2 allowance prices shot up to $700/ton in 2004. Recent movement in the SO_2 allowance market has followed the upward trend of the past two years. The rise in allowance prices may reflect an increase in the spread between high- and low-sulfur coal prices.

  As for the future, SO_2 forwards markets indicate a price rise in real dollars over the next four years, and then a significant decrease starting in 2009. The near-term price rise reflects the fact that states and counties will put pressure on sources to keep SO_2 emissions down to preserve $PM_{2.5}$ NAAQS attainment status. (SO_2 is a precursor to particulate matter.) In addition, tighter regulations on regional haze will tend to drive up SO_2 prices. The decrease starting in 2009 may reflect traders' views on future carbon regulations and their effect on operation of coal plants.

- **NO_X.** Most forward price data on NO_X is based on eastern markets, including NO_X SIP call. As with current and historic prices, these data are not adjusted for economic conditions in the southwest. That being said, generally, east-coast forwards show a slight decline in prices over the next couple of years.

  Nevada does not currently participate in NO_X trading programs. However, Nevada is under mandate to develop a state implementation plan (SIP) for the federal Regional Haze rule. However, in the unlikely case the Nevada regional haze plan involves a cap and trade mechanism, NO_X prices will tend to increase. The co-benefits of emissions control technology installed to comply with the Clean Air Mercury Rule (CAMR) could depress NO_X prices on this local market but would increase total cost of compliance for NO_X, SO_2, and mercury combined.

  Like SO_2, ambient NO_X is a precursor to PM. Pressure to reduce emissions will be most acute in Las Vegas, Nevada, which is not in attainment for PM_{10}, and surrounding upwind areas. Other areas in Clark County may also have an incentive to keep SO_2 emissions down to preserve $PM_{2.5}$ NAAQS attainment status.

  In addition, NO_X allowance prices are expected to correlate negatively with the cost of complying with carbon regulations. Carbon regulations would decrease operation of coal plants, thereby increasing the amount of NO_X allowances on the market and decreasing their price.

- **Mercury.** Because mercury has not been regulated via a cap-and-trade mechanism in the past, data on historical and current prices are not available. However, projections for mercury allowance prices do exist. These show an almost 2-fold increase in prices per pound between 2010 and 2020.

- **CO_2.** The United States does not currently regulate carbon dioxide emissions. However, there are some indications that this situation is likely to change sometime in the next decade. As an indicator of what prices might look like here in the states if CO_2 becomes regulated, the European Union's market for carbon dioxide allowances has ranged between 6 and 13 euros/ton CO_2 over the last couple of years. Closer to home, in December 2004, the California Public Utility Commission ruled that utilities must consider CO_2 regulation risk in all future plant investment decisions. Specifically, the Commission ruled to require California utilities to factor in an expected regulation cost of $8 to $25/ton (escalated by 5% annually) of CO_2 to any new fossil-fuel resources.

Details of the emissions evaluation are provided in Appendix D.

ES.4 TRIBAL ISSUES

The scope of work at the outset of the study included investigating the following areas:

- Employment impacts for certain technology options
- Estimates of royalties, taxes, and other costs assumed to be paid to the tribes in the course of implementing certain technology options
- Costs of land, water, and Black Mesa Mine coal
- Requirements and likelihood of permitting for generation plants, new or renewed coal mining operations, and right-of-way (ROW) permitting for power lines, roads and pipelines
- Acceptability of development on Hopi and Navajo lands for certain technology options

Employment impacts and estimates of tax liabilities for the various technology options were developed and are presented in this study. Due to their complexity and confidential nature, it was agreed by the stakeholders that issues of royalties; land, water, and coal costs; permitting; and acceptability were not to be developed further. After a brief review of land tenure and of approval issues, the study presents estimates of the taxes that would be payable to the Navajo Nation by technology options on tribal land and estimates of the direct and indirect employment benefits expected from the technology options studied.

Numerous financial benefits may be available to the owners of energy projects on tribal land and to the tribes involved. These include tax benefits and other financial incentives outlined in Chapter 10 of this report, and other advantages and simplifications, such as (1) ability to negotiate development leases with third parties without obtaining U.S. government approval and (2) preferential standing for purchases from certain businesses located on Indian reservations or owned by Native Americans. In addition, there can be substantial benefits to tribes that host energy projects. These include tax revenue; royalties; land lease revenue; direct, indirect, and induced employment; and social benefits to communities. Depending on the nature of the project, there may be other negative or positive impacts on the community, the environment, and/or the local economy, but the balancing of all these impacts is important in choosing which energy projects best suit tribes.

The review of land tenure and of approval issues offered in this study highlights a number of complexities and challenges to development on tribal land. However, this study does not intend to convey the impression that energy projects cannot or should not be developed on tribal lands; many such developments have occurred, and no doubt, more will occur. Indeed, numerous advantages, financial and otherwise, may ease the way for such developments, depending on the project's and site's qualifications. It is important to fully appreciate, however, the requirements that potential owners, developers, tribes, and other stakeholders might face.

ES.4.1 Taxes

Tribes have the authority to levy taxes on business activity conducted on tribal land in a manner analogous to the authority of states. Among the most significant benefits for development of the various technology options is their potential as tax revenue sources. The technology options under consideration would be subject to such taxes if conducted on tribal land.

The Hopi Tribe does not at present have a tax code. The Navajo Nation has enacted three taxes that would be applicable to businesses conducted on its tribal land:

- Possessory Interest Tax (PIT),
- Business Activity Tax (BAT), and
- Navajo Sales Tax (NST).

Table ES-18 shows estimates of the taxes that would be due for options on tribal land. For the Navajo Sales Tax, there is a separate estimate of the amount due as a result of initial investment activity and an estimate (in 2006 dollars) of the ongoing annual taxes due. The PIT, BAT, and NST (annual) estimates reflect the first-year values of items that would be expected to be ongoing taxable items. It is important to keep in mind that these tax revenues exclude any royalties for coal or water and any land lease payments. Also, certain Navajo Nation taxes may apply to projects that are outside the Reservation, but on Navajo fee land. If any of the above payments are shared with or made to another entity, such as, for example, the Hopi Tribe, the deductions available under the BAT Code would be reduced accordingly. The one-time sales tax amount for wind does not include sales tax on the wind turbines themselves, estimated to be $7,166,250.

Table ES-20 — Summary of Navajo Nation Taxes

Option	PIT	BAT	NST (Annual)	Total (Annual)	NST (One-Time)
IGCC at Black Mesa	$29,028,026	$4,364,662	$94,800	$33,487,488	$719,250
Parabolic Trough	$28,581,512	$1,949,038	$18,480	$30,549,031	$2,179,528
Solar Stirling Engine	$19,569,122	$1,848,782	$24,780	$21,442,685	$6,302,190
Wind (150 MW at Gray Mountain)	$19,062,820	$907,863	$47,941	$20,018,624	$1,580,706
DSM/EE on Reservation	$188	$9,010	$916	$10,113	$0
DSM/EE from Reservation	$1,877	$108,196	$9,156	$119,229	$0

ES.4.2 Employment Impacts

Eight alternative energy options that could be developed on or near the Navajo or Hopi reservations were characterized for the purpose of estimating the potential economic impacts associated with each. All the scenarios were based on the schedules and costs set out elsewhere in this report. Three additional information sources were used to develop the detailed expenditure patterns. The Stirling Engine/Dish scenario was based on a combination of expenditure and employment data from Sargent & Lundy and SES, while the detailed breakdown of capital expenditures for wind generation was taken from a study of the inputs to wind generation manufacturing and construction. The breakdown of DSM outlays was based Synapse's experience. Only the effect of the actual outlays for capital goods, labor, and O&M expenses were modeled. Taxes and royalties were not modeled. All of the economic impacts developed represent total employment impacts, including direct, indirect, and induced jobs.

- **Simulation 1: Integrated Gasification Combined Cycle (IGCC).** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are expected to total more than 330 jobs per year. Depending upon preferential hiring practices and job training provisions, at least 200 of these positions would be likely to be filled by Navajo or Hopi tribal members. Employment gains during the four-year plant construction period will total approximately 215 new jobs, with about two-thirds of these (approximately 140) expected to be among tribal members on the two reservations.

- **Simulation 1, Variant 1A: Integrated Gasification Combined Cycle (IGCC) with coal inputs from Navajo County.** Construction phase economic impacts for this variant are identical to those in Simulation 1. Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations, however, are expected to total 565 positions, as coal mining jobs in Navajo County to supply fuel for the plant are included. Assuming approximately 80% of the plant operation personnel and 90% of the incremental mining operation jobs are tribal members, about 280 of these positions are estimated to be Navajo nation members, with about 40 positions to be held by Hopi tribal members.

- **Simulation 2: Solar Parabolic Trough.** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 180 positions, with average annual employment during the two-year construction period exceeding 725 jobs. The magnitude of this project, its compressed construction schedule, and significant on-site assembly work is estimated to result in the largest single-year construction impacts of any of the contemplated projects. Tribal employment during the two-year construction phase is estimated to total about 530 annual jobs, with about 495 of these estimated to be filled by Navajo tribal members and about 40 by Hopi tribal members.

- **Simulation 3: Stirling Engine/Dish.** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to exceed 240 jobs per year, with average annual construction employment during the three-year construction period of about 475 jobs in the same six counties. This project is estimated have significant on-site assembly work and related employment opportunities for tribal members, representing more than 210 jobs per year during the construction period. During operation, this facility is estimated to generate nearly 110 jobs for tribal members in the six counties encompassing the Navajo and Hopi reservations, most of which will be in Navajo County, where the plant would be located.

- **Simulation 4: Wind Turbines, Gray Mountain.** Although construction-related employment associated with this project is estimated to exceed 350 jobs per year during the two-year construction period, total permanent employment impacts following completion of this wind turbine facility in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 21 jobs per year. About two-thirds of these permanent jobs are estimated to accrue to tribal members.

- **Simulation 5: Wind Turbines, Aubrey Cliffs.** Tribal employment growth during the one year construction phase of the Aubrey Cliff wind turbines is estimated to total about 65 jobs, with permanent tribal job growth of about 4 positions. Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to total 6 jobs.

- **Simulation 6: Wind Turbines, Clear Creek.** Total construction-related job growth in the six counties encompassing the Navajo and Hopi reservations during the one-year construction of the Clear Creek wind turbines is estimated to total approximately 115 jobs, with about 50 of these likely to be among tribal members. Permanent employment gains associated with this facility is estimated to total about 17 in the entire New Mexico/Arizona/Utah region, with about 6 of these in the six-county reservation area.

- **Simulation 7: Wind Turbines, Sunshine.** Employment impacts associated with the Sunshine wind turbine facility are estimated to be the lowest among the nine scenarios contemplated. With a total investment value of about $91 million, this facility is estimated to result in about 90 new jobs in the six counties encompassing the Navajo and Hopi reservations during the one-year construction phase. Total permanent employment impact in the Arizona/New Mexico/Utah region following completion of the plant is estimated to be about 12 new jobs, with approximately 4 of these in the six-county reservation area. With the facility located on Hopi fee land, it is anticipated that a higher percentage of both construction and operational positions would accrue to Hopi tribal members.
- **Simulation 8: Energy Efficiency Program.** Total employment impacts over the five-year life of the program in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 205 net new annual jobs throughout Arizona and New Mexico, with the most significant job impacts in the balance of Arizona and New Mexico regions. Because the program distribution center and installation crews are assumed for the sake of this simulation to be based in Apache County, on the Arizona/New Mexico border, most of the tribal job growth is estimated to be among Navajo Nation members. About 40 full-time jobs per year during the five-year life of the program are estimated to result from this investment among Navajo tribal members.

ES.5 LOAD AND GENERATION PROFILES

One of the study's goals was to evaluate the correlation between various potential Mohave alternatives and complements and SCE load and costs. For the demand profiles, hourly load and price data for SCE were collected for the year 2002 and for the more recent 12 months of October 2004 through September 2005. The data indicate that nighttime and evening loads are fairly consistent throughout the year. The big difference occurs in afternoon loads, which are much higher during July, August, and September. The data also indicate that a portion of the peak daily loads are related to air conditioning use. Based on this information, resources that preferentially provide more energy during afternoon and evening hours and during summer days would correlate best with SCE loads and costs.

As it is a baseload generation facility, the daily generation profile for the existing Mohave Station is very flat. Thus, its most direct replacement would be another baseload generation resource, such as an IGCC or NGCC plant. Solar resources, on the other hand, provide a good match specifically with the daytime peak. However, solar output peaks earlier than the SCE load does and falls off rapidly in the early evening. Of some of the designs being considered, a dish/Stirling engine would best be able to provide power throughout the entire solar day. Systems with parabolic troughs would have lesser, but still good technical performance. Such a system with storage could shift the generation to later in the day and provide a better match with the SCE load.

As with solar, wind energy is high in summer, as are SCE loads. The daily wind pattern shows greater availability in the late afternoon and evening hours, which is a good complement to the solar option.

As for the resource output of the DSM alternative or complement to Mohave, it cannot be described in the same terms as the resource output of the supply options. The hourly profile of energy and/or capacity savings resulting from a portfolio of installed DSM measures will depend on the set of measures installed, which are yet to be determined with any specificity. As the DSM options being studied are in the Southwest, the available end uses would be, to some extent, similar to SCE's, and available savings would have a profile quite similar to SCE's, depending on the programs chosen. However, the commercial terms for such an exchange of DSM for power could shape the power provided in various ways to suit SCE loads.

ES.6 TRANSMISSION ISSUES

This study sought to determine transmission availability from Arizona and Nevada to the physical interchange points at the California independent system operator (ISO) border. It used both flow-based and contract-path based methods of analysis: power flow studies and assessments of ultimate "into-CA" transmission depend on flow-based analyses, while the OASIS-based assessment of existing transmission availability is based in large part on a contract-path based regime. From the California ISO border, the major transit paths into SCE's service territory include the Palo Verde-to-Southern California route and the set of 500-kV and 230-kV transmission lines emanating from the southern Nevada area at the McCullough, Marketplace, Eldorado, Mohave, and Mead substations. No advance transmission reservations are needed into SCE's territory once the power is transmitted to the California ISO border; thus, transmission availability to that border was scrutinized.

WesTTrans's Open Access Same-Time Information System (OASIS) data were reviewed, examining source points from the Study Area and sink points at the California ISO physical interchange tie points. Source points closest to the Mohave options, located primarily on the Arizona Public Service transmission system in northeastern and central northern Arizona were scrutinized.

The analysis demonstrates that shorter-term firm or non-firm service is available from most source points examined, but not necessarily during all periods.[2] Thus, technology options located in the Study Area connecting to the grid in the near-term might need to rely on shorter term transmission availability. It is

[2] Shorter-term transmission service generally implies hourly and/or daily capability, as opposed to monthly or yearly capability. For example, daily and hourly service for up to 329 MW was available on the Moenkopi-to-Palo Verde 500-kV path for a few days and hours in September 2005.

important to keep in mind, however, that the value of OASIS information is limited because of its time frame; it is not predictive beyond the near-term time periods, at most a few years out.

The transmission load flow evaluation analyzed the feasibility of adding generation at a number of sites in terms of upgrades required for transmission service. The interconnection cost is based on transmission upgrades required to relieve any overloaded facility that would prohibit the evacuation of power from the generation area. Upgrades required for interconnection allow the generator to inject power into the transmission system. However, this does not necessarily grant transmission service that would be need to allow the generator to transfer power to the California border.

Load flow analyses of the impact of injecting power into the transmission network in 10 different generation scenarios were performed. The 10 scenarios include 5 single-plant cases and 5 multiple-plant cases. Locations of generation sites studied are provided in the map in Appendix A. Each of the 10 cases was then run two ways—first with existing transmission only and then again with two transmission projects that are scheduled for completion by 2010 for comparison (denoted “Path 49 Upgrades”). The first of the “Path 49 Upgrades” projects are the “East of Colorado River Path 49 Short Term Upgrades,” which includes installation of capacitors, phase-angle regulating transformers, and static VAR compensators on lines and substations in Arizona, California, and Nevada. The second project is the installation of a second 500-kV transmission line between the Devers substation in California and the Harquahala substation in Arizona, just southwest of the Palo Verde Power Plant.

The results of the load flow studies indicate that longer-term[3] firm transmission service is available in some cases without additional transmission system upgrades but is not available in others without system upgrades. Results of the load flow analyses are provided in the table below.

Table ES-21 — Interconnection Cost Estimates

Case Number	Case Description	Estimated Cost *without* Path 49 Upgrades ($ in Millions)	Estimated Cost *with* Path 49 Upgrades ($ in Millions)
1	Black Mesa IGCC (500 MW)	$173.0	$48.0
2	Gray Mountain Wind (450 MW)	$0.0	$0.0

[3] Longer-term transmission service generally implies service of at least a years’ duration. For example, Tucson Electric Power offered 125 MW of yearly transmission service for 2006, 2007, and 2008 on its rights to the Moenkopi–Palo Verde 500-kV path. Longer-term service can also imply transmission service available for many years into the future. Data on availability of such long-term transmission are not readily provided through the OASIS system. However, some of the utility documents available through the OASIS system indicated ongoing availability of longer-term transmission over specific, limited segments of the Arizona Public Service system.

Case Number	Case Description	Estimated Cost *without* Path 49 Upgrades ($ in Millions)	Estimated Cost *with* Path 49 Upgrades ($ in Millions)
3	Solar Site 2 (425 MW)	$0.0	$0.0
4	Aubrey Cliffs (100 MW)	$60.0	$130.0
5	Clear Creek & Sunshine (135 MW)	$0.0	$0.0
6	Black Mesa IGCC & Solar Site 1 (925 MW)	$216.9	$158.7
7	Black Mesa IGCC & Gray Mountain Wind & Aubrey Cliffs (1050 MW)	$170.0	$195.0
8	Solar Site 2 & Gray Mountain Wind & Aubrey Cliffs (975 MW)	$272.5	$117.4
9	Solar Sites 1 & 2 (850 MW)	$214.5	$46.6
10	Gray Mountain Wind & Aubrey Cliffs & Clear Creek & Sunshine (685 MW)	$162.5	$70.0

The installation of the "Path 49 Upgrades" does not completely eliminate the need for transmission system upgrades in those cases where they were necessary in the case run without the "Path 49 Upgrades." However, in most cases, the associated scope and cost of upgrades is significantly reduced. The exceptions are Cases 4 and 7 above. These results occurred because of a particular situation:

- **Overloaded Lines in Base Case.** In the Base Case, that is, without any upgrades and without any new generation, certain lines had already been overloaded.
- **Overloads Remain without "Path 49 Upgrades," but with New Generation.** Since the overloaded lines already existed, however, the new generation of Cases 4 and 7 was not reason for the overload, and no cost was assigned.
- **Relief of Overload by "Path 49 Upgrades."** With the "Path 49 Upgrades" installed but without the new generation of Cases 4 or 7 added, those certain lines that had been overloaded were no longer overloaded.
- **Overload Caused by New Generation with "Path 49 Upgrades" Installed.** Now, since the overloads of the base case had been mitigated by the "Path 49 Upgrades," renewed overloads in certain lines required further upgrades and costs were assigned.

In addition it is important to consider that other new transmission line proposals or works in progress add significant capacity to into-California (and likely intra-Arizona) transaction paths. To the extent these lines are built, it is possible that Mohave technology options could secure firmer access to import into SCE territory.

The following conclusions can be drawn from the transmission analyses:

- **Long-Term Firm Service.** Existing conditions appear to limit the availability of long-term (i.e., one or more years) firm service from Arizona supply sources, without new transmission upgrades. Shorter-term service of more limited duration is available for some source-sink path combinations.

- **Short-Term Non-Firm Service.** Based on OASIS data, shorter-term firm or non-firm service is available from most source points examined, but not necessarily during all periods. Thus, technology options located in the Study Area connecting up to the grid in the near-term might need to rely on shorter-term transmission availability. Note that SCE's ownership of rights for transmission service from their Four Corners generation share ownership was not considered as a possible source of transmission access for any of the Mohave technology options.

- **Tradeoffs between Increased Capacity for New Supply and Use of Existing Capabilities**. The transmission interconnection requirements identified for most of the supply-side technology options are based on provision of effectively firm transmission service during peak periods. Use of existing grid capacity could be considered if curtailing output for some periods proved economically viable, and/or if short-term transmission use in additional to what is transparently available through OASIS could be secured through negotiations with existing users who have rights to use the grid during peak periods.

- **OASIS Information.** The value of OASIS information is limited because of its time frame; it is not predictive beyond the near-term time periods, at most a few years out.

- **Proposed New Transmission Upgrades.** New transmission line proposals or works in progress add significant capacity to into-California (and likely intra-Arizona) transaction paths. To the extent these lines are built, it is possible that most supply technology options could secure access to import into SCE territory.

- **Alternative Locations of Options.** Any technology options that source power from the existing Mohave site, or from the Palo Verde hub (e.g., the DSM alternative) will not face the transmission limitations identified in our review, which are generally in the northeastern and north central Arizona regions. Transmitting alternative power from the Palo Verde hub could lead to increased congestion charges into California, but such congestion does not preclude the use of Palo Verde hub resources, it just changes the total costs to import into California.

- **Effect of New Institutional Constructs.** This review did not assess the transmission availability under any new institutional constructs. If a West Connect Regional Transmission Organization (RTO) or similar regional transmission entity established coordinated transmission operations in the desert southwest area, the paradigm for transmission access and Available Transmission Capability (ATC) computation could change. One possible outcome of such arrangements is a lesser dependence on the need for source-to-sink physical transmission reservations in order to use the desert southwest grid to secure power flows into California from source points in the Study Area.

- **Wheeling Capability under Current Transmission Capacity**. The DSM and Mohave combined-cycle technology options could each move Mohave-equivalent power into the SCE territory based on existing conditions. The California border location for these options allows such transfer to occur during most if not all hours, although some congestion cost allocation from the California ISO would likely apply in some hours. The remaining Arizona area supply options would all be able to move power into the SCE territory for some hours of the year, based on securing available shorter-term firm or non-firm transmission, but it is unlikely they would be able to secure transmission for all hours, especially during peak periods, based on an examination of the OASIS data and results of the load flow studies.

- **Wheeling Capability with Reasonably Certain New Transmission Upgrades**. Most of the proposed new transmission projects that have a high likelihood of being built will result in increased transfer capability from western Arizona or southern Nevada into California, but they will not substantially affect the transfer capability from northeastern Arizona to western Arizona. There are numerous Arizona transmission upgrades proposed for the heavier load centers, such as Phoenix; these upgrades will not necessarily increase transfer capability over the major paths out of northeastern and north-central Arizona. Thus, even with implementation of certain new projects, it is not assured that the increased capacity will allow for Study Area technology options to secure firm, longer-term transmission service into the California border area. However, if intra-Arizona upgrades on the 500-kV system in the north and the northeast are realistically considered, then the increase in transfer capability from the Study Area to the California border would likely be on the order of the output associated with SCE's share of Mohave.
- **Wheeling Capability with Uncertain New Transmission Upgrades.** It is difficult to state with any certainty what the wheeling capability with new transmission upgrades might look like without conducting additional load flow studies and accounting for the location of new supply sources that might be considered if new transmission is built. This is beyond the scope of this study. For example, even if the Navajo Transmission Project is built, the potential for new generation in the northeastern Arizona region must be considered when assessing whether such new capacity might be available for the Mohave technology options. However, if any of the major northeastern/north central Arizona to southwestern/northwestern Arizona paths are upgraded, the potential for transmission capacity increases on the order of SCE's share of Mohave output is likely.

ES.7 SUMMARY

This study has estimated capital and operating costs, resource usage, and economic impacts of several different technology options that might be used as replacements for or compliments to the existing Mohave Generating Station.

The parameters of the options considered can be summarized as follows:

Table ES-22 — Technology Option Comparison

		IGCC (2)(3)	Solar Dish	Solar Trough	Wind (4)	DSM(5)	NGCC (2)(3)
Capital Cost (1)	2006 $/kW	2,004	1,500	3,560	1,702	N/A	555
Fixed Operating Costs	2006 $/kW-yr	49.59	0.00	33.00	45.96	0	5.47
Variable Operating Costs	2006 $/MWh	12.68	11.00	30.00	0.21	0	62.85
Total Operating Costs (6)	2006 $/MWh	20.54	11.00	38.76	14.41	N/A	63.72
Land Use/MW	acre/MW	0.541	5.000	8.700	75.21	0.000	0.042
Water Use/GWh	acre-ft/GWh	0.395	0.008	0.019	0.000	0.000	0.022
Operations Staffing	Employees/MW	0.26	0.28	0.29	0.04	N/A	0.06
Capacity Factor Assumed for Operating Cost Calc.	%	72.0	30.0	43.0	36.9	N/A	72.0
Approximate Construction Period	months	48	36	45	9-12	N/A	24

Notes:

1. Capital costs shown do not include the costs of direct transmission access or transmission system upgrade costs.
2. IGCC and NGCC plants are assumed to use dry cooling. IGCC plant is assumed to be at the Black Mesa site. No carbon sequestration-related costs are included in values used for comparison above.
3. Capacity factor assumptions for IGCC and NGCC are assumed to be comparable to the existing Mohave plant's average capacity factor. Such an assumption may not be true, especially for the natural gas-fired option, and depends on the dispatch and outage schedules of the respective options.
4. Wind values are weighted averages for the four sites identified.
5. The DSM technology option differs considerably from the supply options and thus cannot be characterized in the same way. See the text below.
6. Total operating costs =variable operating costs + (fixed operating costs/kW-yr)*(1yr/8760hrs)*(1/assumed capacity factor)*(1000kW/MW)

No definitive choices regarding technology options can be made strictly from the data provided above. This choice is properly made within the scope of an integrated resource plan process. However, certain conclusions can be drawn simply from looking at the capital and operating costs:

- It can be seen that the solar dish and wind options have relatively low capital and operating costs, potentially making them an economically attractive alternative.
- The DSM option includes installed demand-side technologies and a coupled power purchase contract. It does not have the same cost structure as the supply options. The alternative's cost structure (as analyzed in this study) includes not just the installed DSM costs, but also effective premiums that may be required to address lost revenue or related institutional risks. In its simplest form, the DSM option looks like an all-in power purchase contract, whose price is subject to negotiation, and the study posits a baseload resource profile for this contract (although flowing DSM peaking benefits directly to SCE is possible). What is known is that the underlying DSM resource costs are relatively low ($40/MWh based on total resource costs);

that it provides peaking benefits in the partnering utility service territory; that the resource may be shaped to provide SCE with a resource shape that is baseloaded, peaking, or in between; and that the ultimate negotiated price will rest heavily on these factors. There are also institutional issues that will affect the partnering utility's perception of risk and thus of the minimum negotiated price at which it would be willing to transact. However, the study shows that this should continue to be considered a viable option for replacing and/or complementing Mohave.

- The NGCC option has a relatively low capital cost; however, the variable cost associated with fuel makes its operating costs very high. As such, it is unlikely to be dispatched at the level assumed here.
- The IGCC option has a higher capital cost than most options, but its operating costs are slightly lower than many options.
- Operating labor requirements for the IGCC, solar dish, and solar trough options, on a per-MW basis, are similar. The wind and NGCC options have much lower operating labor requirements. The DSM option is not directly comparable in terms of labor requirements. Each year's increment of DSM resource acquisition is relatively labor intensive, but once an increment of DSM resource has been acquired, there is little, if any, ongoing labor requirement.

From the above, one may further conclude that, if SCE's need for generation resources arises from a need for peaking power, then the solar and wind options may be more attractive than the other options. However, it must be pointed out that, since these options cannot be dispatched, their generation would not necessarily have perfect correlation with SCE's peak load or its load demand profile. Therefore, gaps might have to be filled by other generation resources. It may be possible to configure DSM resources with a delivered resource shape to suit SCE's needs by varying the commercial terms, depending on the commercial and regulatory terms developed.

On the other hand, if the need for generation resources arises from an overall increase in load demand, then resources that can provide baseload would be more attractive. The solar trough resource with thermal storage can store energy for use during off-peak hours; however, its capital costs are extremely high. These costs, in fact, tend to eliminate it as an option. The NGCC option, on the other hand, has the potential to operate as a baseload resource. However, since the largest part of its variable operating costs depends on the price of natural gas, it is unlikely that it would be dispatched as a baseload resource if natural gas prices continue to rise. The IGCC or DSM options, therefore, remain the most attractive option for a baseload resource.

In general, however, the capital and operating costs should be analyzed over a particular project life span and a levelized cost of generation developed. For example, while wind and certain solar options may have low capital and operating costs, their expected energy output is low relative to the size of the units contemplated. This will tend to drive up the levelized cost of energy. Contrastingly, the DSM technologies have low total resource costs, helping to make the levelized cost of the resource, including the purchase power component, particularly attractive.

The calculation of the levelized cost of energy requires inputs that include the values shown above along with economic parameters, such as discount and escalation rates, and energy output during the project life span. The energy output requires detailed assumptions regarding availability and fuel cost. The analysis of these costs over the life time of the project is beyond the scope of this study and is rightfully to be performed as part of the integrated resource planning process. Furthermore, if the options are developed by the tribes or a private developer, then the feasibility of a technology option also depends on the terms of the power purchase agreement. While, from a levelized cost of energy or revenue requirements viewpoint, a particular technology option may be viable, it must also be viable financially to the project developer on a discounted cash flow basis. Neither the levelized cost of energy calculation nor the discounted cash flow analysis is within the scope of this study.

In addition, capital and operating costs should not be the only variables to consider when comparing options. Use of land and water and compliance with current and future environmental regulations are equally important, as discussed below.

Operating labor requirements for the IGCC, solar dish, and solar trough options, on a per-MW basis, are similar. The wind and NGCC options have much lower operating labor requirements. The DSM option is not directly comparable in terms of labor requirements. Each year's increment of DSM resource acquisition is relatively labor intensive, but once an increment of DSM resource has been acquired, there is little if any ongoing labor requirement.

Of course, capital and operating costs should not be the only variables to consider when comparing options. Use of land and water and compliance with current and future environmental regulations are equally important, as discussed below.

Use of land for the NGCC option is relatively low. The IGCC option uses 10 times the land on a per-MW basis. The solar options use approximately 100 times the land of the NGCC option on a per-MW basis. The wind option land use is 1,500 times that of the NGCC option, again on a per-MW basis. Finally, the DSM option requires minimal land only for office space, some warehousing, and miscellaneous other small land usages.

Water use for the solar dish option is lower than all options except DSM and wind, which have negligible water use. Solar trough water use is slightly greater than twice the use of the solar dish option on a per-MWh basis. NGCC water use is slightly less than three times the solar dish option's water use on a per MWh basis. The IGCC option uses the greatest amount of water on a per-MWh basis, at 50 times the usage of the solar dish option.

The foregoing summary has ignored the costs associated with environmental compliance, including the costs of CO_2 removal and sequestration. Such costs do not apply to wind, solar, and DSM options. They have, however, an extremely large negative impact upon the IGCC and NGCC options. Capital cost increments for the various levels of CO_2 removal in $/kW are given in the table below:

Table ES-23 — Capital Cost Increments for CO_2 Removal and Transport

	IGCC CO_2 Removal without Shift Conversion	IGCC 90% CO_2 Removal	NGCC 90% CO_2 Removal
Direct Plant Increase in Capital Cost, $/kW	275	632	375
Pipeline and Compression Cost, $/kW	92	179	877

Pipeline and compression costs vary due to the location of CO_2 storage. The values shown for IGCC, like the previous values, are for the Black Mesa site, for which a geological formation was found in relatively close proximity. For the NGCC option, these costs are associated with a pipeline from the existing Mohave site to Bakersfield, California, utilizing the Interstate 40 corridor, for use of the CO_2 in enhanced oil recovery operations. Values for pipeline and compression costs would be very roughly similar for IGCC located at the same site. It may be concluded from the values shown that IGCC with CO_2 removal that does not employ any shift conversion, removing between approximately 18% and 30% of the carbon present, depending on gasifier technology and coal constituents, may be feasible, but the costs for large-scale CO_2 removal, at the level of 90% removal of carbon present, are extremely high and possibly prohibitive with current technologies.

The outcome of a process of selection between the various options considered here cannot be made without a full integrated resource planning process. If land, water, and CO_2 sequestration issues were ignored, it may be possible to conclude that the solar dish, wind, or DSM options may be more attractive in the case that energy requirements are of a peaking nature, while if such requirements are of an across-the-board baseload nature, then the IGCC or the DSM option may be more attractive. However, this simple conclusion fails to take into account the other resources that are displaced by any of these options and the associated costs and benefits of such displacement. It also ignores the difference in volume of energy generation between the two energy requirements. A baseload resource will ultimately have more megawatt-hours over which to spread its capital and fixed costs in the calculation of a levelized cost of energy.

Furthermore, land, water, and CO_2 sequestration issues cannot be completely ignored. The quantity of land required for the solar and wind options must be considered for each site identified. CO_2 sequestration issues do not affect solar dish, wind, and DSM options, since no CO_2 is emitted, but may be significant for the IGCC and NGCC options. Water requirements for the IGCC, NGCC, and, to a lesser extent, the solar options must be considered. Certain options would eliminate the use of water used to create the coal slurry that is the medium by which fuel is shipped to the existing site. This may accrue certain benefits to the owners of the water rights through alternative uses for that water.

In summary, this study has compiled data necessary for input into an integrated resource plan, its primary objective. It has also made certain qualitative comparisons and conclusions. Among these, it has been concluded that

- Other renewable resources, specifically biomass and geothermal energy, are not present in the area to a sufficient extent to enable construction of plant of a size that is meaningful in comparison to the size of SCE's share of the existing Mohave plant.
- Solar trough technology is, in all likelihood, too costly for implementation, especially if thermal storage is considered.
- Some of the options are particularly suitable for tribal ownership, although project specifics will determine the ideal ownership structure.
- Total environmental compliance costs for fossil fuel plants are likely to rise whether or not the US implements a carbon policy.

The other technology options all have their associated costs and benefits. It is not within the scope of this effort to weigh these costs and benefits in a quantitative way to develop priorities or groupings of preferred generation resources. Rather, considerations that must be addressed in an integrated resource plan study have been identified.

Last page of Executive Summary.

1. INTRODUCTION

1.1 EXISTING PLANT

The Mohave Generating Station is a two-unit 1,580-megawatt (MW) coal-fired power plant located in Laughlin, Nevada, built between 1967 and 1971. The station covers approximately 2,490 acres. The Mohave Generating Station is operated by Southern California Edison (SCE), the majority owner (56%) of the plant. The Los Angeles Department of Water and Power (10%), Nevada Power Company (14%), and Salt River Project (20%) also own interests in the plant.

1.2 STUDY PLAN

Southern California Edison was ordered to perform a study of alternatives for replacement or complement of its share of the Mohave Generating Station by the California Public Utilities Commission (CPUC) under Decision 04-12-016, issued on December 4, 2004. The relevant part of the decision stated:

> Edison is hereby directed to undertake a feasibility study of the options for replacing its share of Mohave's output if Mohave closes, or to be used in conjunction with Mohave if it returns to service, from sources that will provide the fullest possible benefit to the Hopi and Navajo while protecting the interests of Edison's ratepayers. Edison is to involve any interested party in this proceeding work together with those parties to design this study and to jointly determine the independent consultants, contractors and supervisors on the study. One aspect of this study should consider the IGCC options at the Black Mesa Mine, including water use issues and an assessment of the feasibility and cost associated with the sequestration of carbon emitted from the plant. Cost assessments should include an analysis of federal funds available for IGCC development. Edison should also analyze the feasibility of renewable energy projects on reservation land, including but not limited to the proposed solar thermal facilities identified by WEC.
>
> Both the IGCC and renewable energy projects should include consideration of any enhancements to the transmission system that may be necessary to bring power into California. The final plan should be sufficiently detailed, including cost components, proposed counterparties and generation on-line dates, to allow this Commission to affirm a specific resource plan during Edison's next long-term planning process. Ownership arrangements involving the Hopi and Navajo should be given consideration in the feasibility study.

Pursuant to this scope, concentrating solar power (CSP) technology, wind technology, integrated gasification combined-cycle (IGCC), natural gas combined-cycle (NGCC), other renewables, and energy efficiency were investigated as potential alternatives to replace or complement the electrical generation of the Mohave Generating Station.

Stakeholders were involved throughout the study process. Their comments on draft versions of this report and S&L's responses are provided in Appendix E.

1.3 METHODOLOGY

The methodology for evaluating the technological, financial, economic, and social issues associated with this study is discussed below.

1.3.1 Integrated Gasification Combined Cycle

To develop the overall capital and operating costs associated with an IGCC power plant, Sargent & Lundy (S&L) planned to use data from technology developers and compare this information with published studies and other internal sources. Although four suppliers/technology developers provided a willingness to provide data for this study, no data has been received at the time of this writing. As a result of the lack of vendor-provided data, S&L determined that the best approach for developing the costs and performance for a gasification facility designed for Black Mesa coal would be to use the Department of Energy's (DOE) Integrated Environmental Control Model (IECM) and adjust the outputs as necessary to compensate for the specific application addressed in this study.

This model was selected because it can be used to directly compare the effects on the facility's design when considering either with or without carbon sequestration.

Adjustments S&L performed on the results included the following:

- Assumed that the cost and relative performance of the gasification system when using Black Mesa coal would be the same as for Illinois #6 coal.
- Assumed that the cost and relative performance of the sulfur removal system when using Black Mesa coal would be the same as for Wyoming Powder River Basin (PRB) coal.
- Adjusted the combustion turbine output for site conditions.
- Adjusted the capital costs for dry cooling where necessary.
- Added emission control costs for NO_X (selective catalytic reduction [SCR]) and mercury removal.
- Adjusted coal handling cost estimates for slurry delivery by crediting the cost for coal rail unloading, slurry preparation, and so forth.
- Compared costs of power delivery systems to S&L data base costs as appropriate.

The capital costs were obtained from the IECM model. S&L also added owner's costs and EPC contractor profit to the values computed that are not included in the IECM estimate. The resulting capital cost values are in the same range as values computed for other projects.

For this study, S&L used the consumable costs calculated for each subsystem the IECM model. Water costs were calculated separately. Ash (slag) and sulfur disposal and/or byproduct credits were developed separately. Fixed operating labor was estimated separately using the IECM shift labor requirements as a guideline. Fixed and variable labor was based on model inputs subtracting the in-plant estimate of the labor force from the maintenance labor requirements.

1.3.2 Solar Technology

In addition to parabolic trough and power tower technologies, solar dish engines and concentrating photovoltaics were evaluated. The existing technical data available on these technologies were collected, organized, and reviewed. Based on the review, potential power plant configurations were developed that are considered to be feasible based on the maturity of the technology, technical risks and expected reliability, capital costs, O&M costs, levelized energy costs, and dispatch constraints.

Specific solar technology information was integrated into an overall evaluation of the technical parameters that need to be considered for an electric power plant project. These additional parameters include, but are not limited to, balance-of-plant design considerations; site arrangement considerations for construction, operations, and major maintenance activities; geotechnical considerations; environmental and permitting considerations; power transmission considerations; and cost considerations for construction and O&M.

The technology assessment identified possible combinations of solar power technologies and associated capital and O&M costs that are considered to be the most promising for future development. A key consideration was to identify technologies that are reasonable candidates for near-term large-scale deployment as differentiated from technologies that still require significant development.

1.3.3 Wind Technology

Four candidate sites were identified based on the wind characteristics of each potential site as shown on NREL wind maps. Site walkdowns were performed during which available infrastructure and conflicts (such as public roads, barns, telephone transmission wires, available setback for falldown radius of turbines, and topography to capture the highest elevations) were reviewed. Land requirements were estimated. Township, county, or tribal zoning processes and local codes and regulations for each site were evaluated. Local, state, and federal permit requirements were evaluated to determine fatal flaws at any of the sites. Transmission access issues were reviewed. Capital and O&M costs based on a database of other projects were estimated.

An evaluation was made of the wind farm size for each potential site based on available land, capital costs, O&M costs, and estimated performance. Performance, including output and capacity factor, based on location and wind characteristics were estimated.

1.3.4 Natural Gas Combined Cycle

Capital costs were obtained from a database of recent projects. Fixed O&M costs were estimated including costs for direct and indirect labor for operations and maintenance staff that are permanently employed at the plant site, as well as home office support costs allocable to the plant. In addition, the fixed costs include O&M contract services and materials and power purchased for in-house plant needs during plant outages. Variable O&M costs include chemicals and consumables, catalyst replacement and major maintenance of the combustion turbines, steam turbines, HRSG, and balance-of-plant. The estimate was derived on the basis of an 80% capacity factor and approximately 50 starts per year. On the basis of this duty cycle, the combustion turbines will require a combustion inspection every year, a hot gas path inspection every three years, and a major inspection every six years. Performance and emissions data were obtained from the Electric Power Research Institute's (EPRI's) State of the Art Power Plant (SOAPP) program.

1.3.5 Energy Efficiency/Demand-Side Management

The states and utilities in the region that would be appropriate sellers of energy efficiency resources were identified, and an estimate of the technical and economic potential for energy efficiency resources from the candidate states was developed. The conceptual mechanism for purchasing energy efficiency resources from other states and other utilities was studied. In addition, an estimate of the amount of economic potential for energy efficiency in the neighboring states that could be sold to SCE through power purchase arrangements was developed, including consideration of the extent to which energy efficiency in the neighboring states is being developed for internal purposes. The economics of the mechanism for purchasing energy efficiency resources from other states and other utilities were also assessed. The contractual arrangements necessary for purchasing energy efficiency resources from other states and other utilities were studied with likely durations and terms and conditions assessed. The institutional challenges for purchasing energy efficiency resources from other states and other utilities were also assessed. Finally, the above assessments were used to develop a recommendation for the extent to which this sort of energy efficiency purchase can represent an alternative (or partial alternative) to Mohave.

1.3.6 Other Renewable Technology

The feasibility of other renewable energy sources, including biomass and geothermal energy, was evaluated with the following purposes:

- To determine the feasibility of the technology for the various Mohave scenarios
- To determine the megawatt scale at which the technology would be feasible
- To perform an initial economic screening to assess whether the technology can compete with the other five technologies studied as a viable option

Biomass and geothermal energy sources were evaluated on a general basis for the following:

- Commercial availability
- Expected performance in the geographical area
- Land, water, and other resource requirements
- Capital and O&M cost estimates based on published data

1.3.7 CO_2 Sequestration

The evaluation of geologic CO_2 sequestration involved the following tasks:

- **Overview.** Four types of geologic sequestration were examined: enhanced oil recovery, enhanced gas recovery, sequestration in unminable coal seams, and sequestration in deep saline aquifers.
- **Evaluation of Feasibility.** The various possible liabilities associated with geologic sequestration, including operational liability, climate liability, and in situ liability were analyzed. Furthermore, a study was performed regarding suitable options for sequestration in the vicinities of the Mohave and Black Mesa sites by URS, Inc., provided as Appendix C to this report.
- **Economics.** The market for CO_2 was evaluated for its size and prospective pricing.
- **Capital Costs.** The capital costs of compression and pipeline equipment for transport of CO_2 were estimated. The Mohave-to-Bakersfield compression and pipeline cost was estimated, as well as the cost for a representative pipeline to the Cortez, Colorado, area.

1.3.8 Tribal Issues

Acceptance by the tribes was evaluated, encompassing the following items:

- Identification of relevant tribal lands
- Identification of the relevant policies, issues, trends and disputes
- Development of relevant factors (pros and cons) for each tribe
- Analysis of each technology on relevant factors
- Identification of approaches that could make each technology more attractive to the tribes

Progress in this area has proceeded in general terms only. Tribal governance policies and opinions are closely held.

1.3.9 Financial and Economic Issues

Financial and economic issues in five areas were reviewed:

- **Financial Incentives.** The various state and federal incentives that are possibly available for generation projects with tribal involvement were compiled.
- **Business Classifications.** Businesses that are owned by Indian tribes and by tribal members can operate under a variety of legal structures. The costs and benefits of the various classification were enumerated with respect to—
  - Federal and state tax status
  - Ability to attract investment monies
  - Business strategy and day-to-day operational authority
  - Liabilities
  - Law and government
- **Job Impacts.** The construction, operation, and other economic impacts of the various generation projects were evaluated using macroeconomic models. Construction of the macroeconomic models is underway, but has not yet been completed.
- **Fuel Prices.** Fuel prices were developed and are included in Appendix F.
- **Emissions Costs.** A summary of emissions costs were developed and are included in Appendix D.

1.3.10 Generation and Load Profiles

The evaluation of the correspondence between the load profile of SCE and the various technological alternatives involved collection of information about SCE load profiles by location, time, weather, and customer class. Data for each resource type were then analyzed and converted into comparable formats.

1.3.11 Transmission Issues

The methodology used focused on three specific tasks:

- **Existing Available Transmission Capability (ATC) Evaluation.** OASIS data were used to determine existing available transmission capability.
- **Utility Study Review.** Existing California ISO and desert southwest utility studies were reviewed. An overview of future changes to the transmission system, focusing on the impact that major transmission upgrade proposals would have on changing (increasing) the level of transmission capacity available for transactions between the desert southwest and California, was developed.
- **Load Flow Studies.** Load flow studies were carried out using various cases involving the technological alternatives in combinations that were roughly equivalent to the capacity to be replaced at the existing Mohave plant.

Last page of Section 1.

2. INTEGRATED GASIFICATION COMBINED CYCLE TECHNOLOGY

Gasification is a process that converts a variety of carbon-containing feed stocks like coal, petroleum coke, lignite, oil distillates, and residues into synthesis gas (syngas) consisting primarily of carbon monoxide (CO), hydrogen (H_2), and carbon dioxide (CO_2). The technology of gasification dates back to the 18th century with the production of water-gas for lighting and cooking before the advent of electricity use. This technology was largely phased out with the expansion of electricity and natural gas usage in the mid-20th century. Recent commercial use has expanded over the past 50 years and is an important process in the chemical and refining industries. Interest in gasification for the power generation began in the 1970s and was demonstrated as technically viable with the construction and operation of the Cool Water facility in California that was funded by Southern California Edison, EPRI, and DOE. This facility used the Texaco gasifier for producing the syngas used to fuel GE combustion turbines. Starting in the 1980s Shell, Texaco (GE Energy), Dow (ConocoPhillips) and Lurgi scaled up the size of gasifiers to produce the quantities of gas needed for large gas turbines. The use of gasification for both power and as a chemical feedstock increased as facilities around the world adopted gasification as an alternative to use of premium fuels, see Figure 2-1. During the 1990s, world gasification capacity grew by almost 50%, largely for the production of chemicals, as shown on Figure 2-2.

Figure 2-1 — Growth of Syngas Production Worldwide

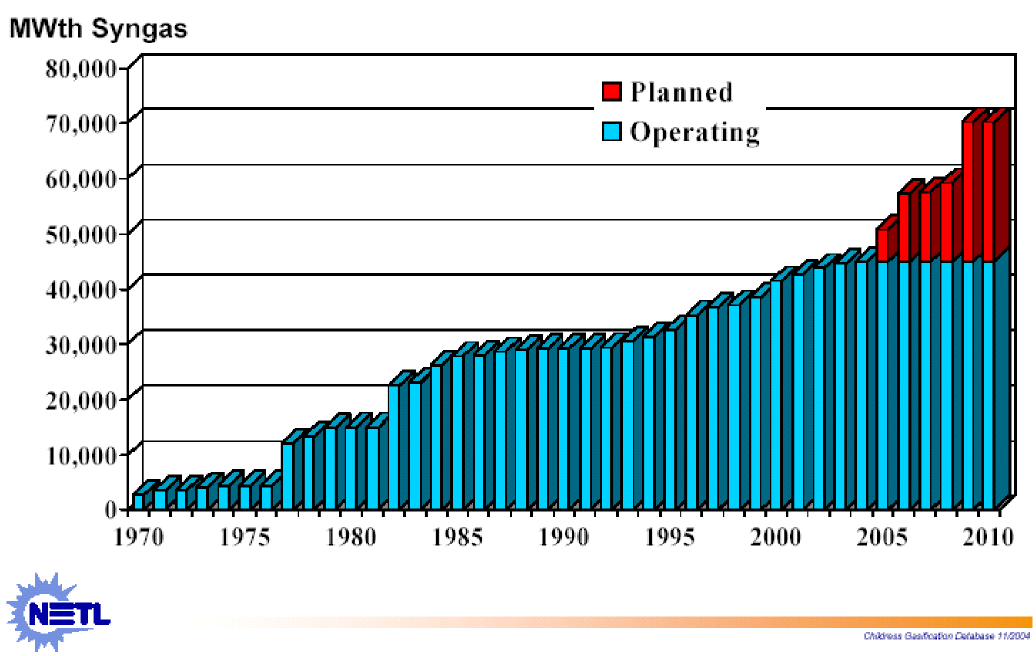
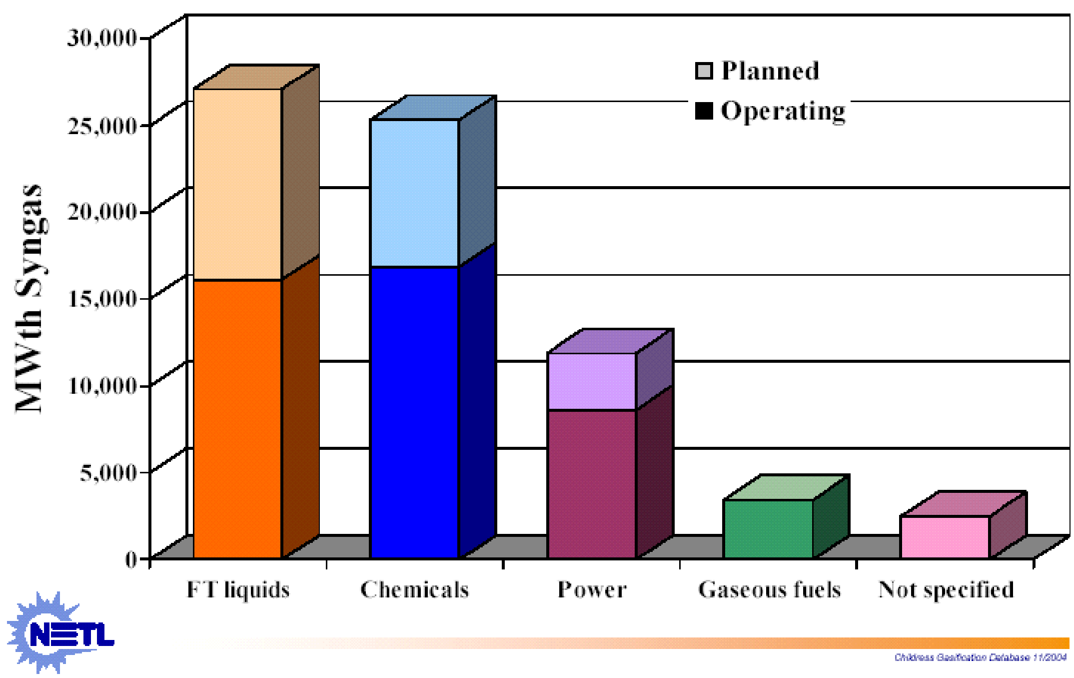


Figure 2-2 — Quantities of Syngas Product Distributed



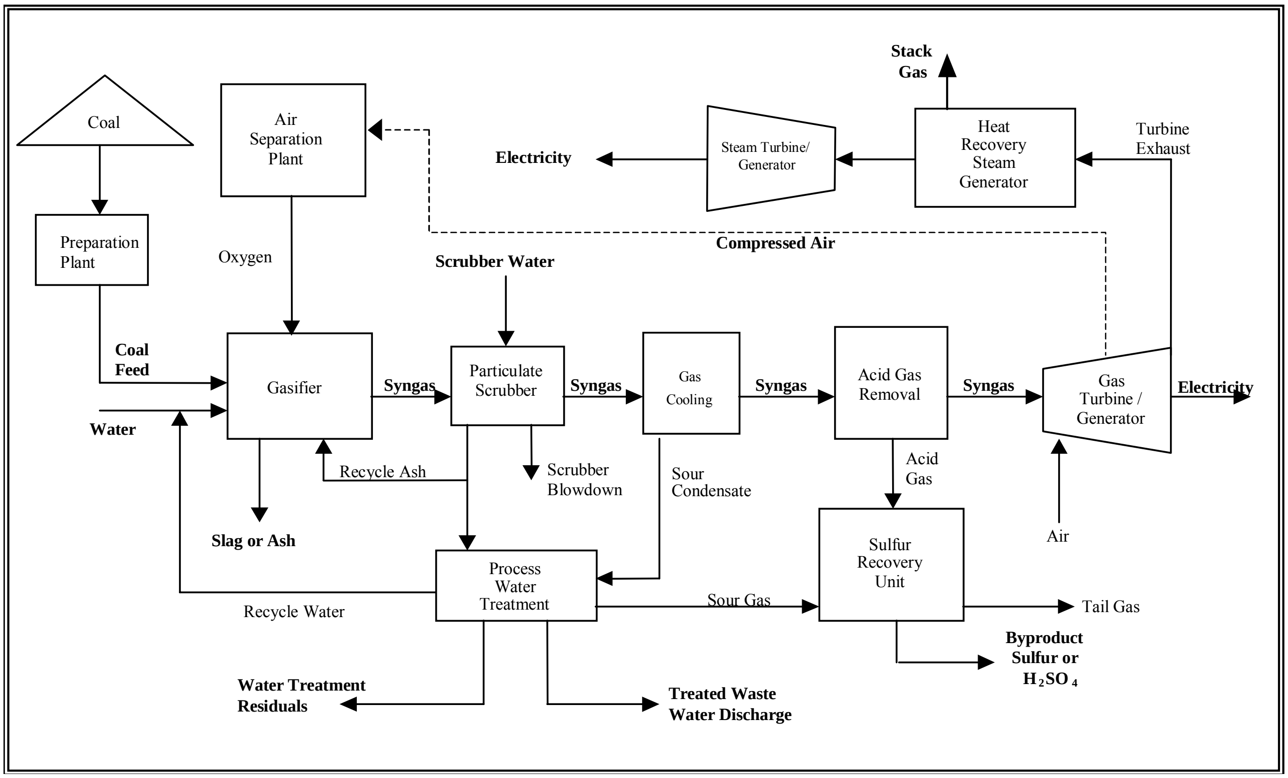
Syngas from the gasifier is cleaned of particulates, sulfur, and other contaminants before being combusted in a gas-fired combustion turbine. Heat from the turbine exhaust gas is extracted in a heat recovery steam generator (HRSG) and combined with steam produced in the gasification system to drive a steam turbine/generator.

Each gasification technology supplier applies its own unique methods of feeding coal to their reactor. In general, coal can be fed to the gasifier using either wet (slurry) or dry feed systems. The gasifier reactor is typically classified as one of three types: fixed-bed, fluid-bed, or entrained-flow type. This report focuses on the entrained-flow type, as this is the technology considered most cost-effective for power generation and sufficiently technically proven by industry experts to warrant deployment at this time. It should be noted that, in general, gasification systems may use either air or oxygen as the oxidant during gasification; currently offered entrained-bed systems only use oxygen.

The gasification process produces the syngas at high temperature (varies by technology), which must be cooled to the temperatures required by the downstream cleanup systems. This heat can be captured by generating steam and by heating boiler feedwater and will increase overall energy efficiency of the power plant when integrated with the power island. Additional integration and efficiency can be achieved by integrating the combustion turbine with the air separation plant used to produce oxygen for feeding the gasifier. This involves supplying all or part of the compressed air required in the air separation unit (ASU) from the combustion turbine compressor and returning nitrogen from the ASU to the turbine combustor.

The major components of coal-fueled IGCC power plants include coal handling and preparation equipment, gasifier, air separation unit, gas cooling and clean-up processes, and combined-cycle power block. Figure 2-3 is a simplified schematic diagram of a typical IGCC plant.

Figure 2-3 — IGCC Schematic of Generic IGCC Power Plant



The use of IGCC systems has had limited market penetration to date. There have been four IGCC demonstration facilities constructed in the United States that use coal as a feedstock and two in Europe. Table 2-1 is a listing of these early IGCC demonstration units indicating technology suppliers for the gasifier and combustion turbine facilities. The Cool Water facility was discontinued after the demonstration was completed because its production costs were not competitive with other sources of electricity. The Louisiana Gasification Technology, Inc. (LGTI) facility installed by Dow at their chemical plant in Plaquemine, Louisiana, demonstrated the viability of the technology but became uneconomic when gas prices dropped significantly in the 1990s, and the facility use was discontinued. The Pinion Pine facility had extensive operating difficulties and was never successfully operated. The Pinion Pine IGCC facility never operated successfully on coal and only operates on natural gas. The failure of this facility indicates that the risks associated with IGCC deployment are real.

Table 2-1 — IGCC Demonstration Plants

Plant Name	Owner	Output (MW)	Feedstock	Gasifier Type	Combustion Turbine	Years of Operation
Facilities in USA						
Cool Water	SoCal Edison	125	Bit Coal	Texaco	GE-7FE	1984-1988
LGTI	Dow Chemical	160	Sub Bit Coal	Dow (E-Gas)	W - 501	1987-1995
Polk County	Tampa Electric	250	Bit Coal	GE (Texaco)	GE-7FA	1996-Current
Wabash River	Destec / PSI Energy	262	Bit Coal & Pet Coke	E-Gas	GE-7FA	1995-Current
Pinion Pine	Sierra Pacific	100	Bit Coal	KRW	Siemens V94.2	1994-Current
Facilities in Europe						
Willem-Alexander	Nuon	253	Bit Coal	Shell	GE-6FA	1998
Puertollano	Elcogas	298	Bit Coal & Pet Coke	Prenflo (Shell)	Siemens V94.3	1998-Current

The operation of these plants has provided a basis for the design of future IGCC facilities and has contributed to the confidence expressed by technology suppliers that they can provide large commercial power plants sized greater than 500 MW. Suppliers GE (Texaco), ConocoPhillips (E-Gas), and Shell all are currently offering commercial facilities with warranties and guarantees.

The use of gasification technology is not limited to IGCC from coal. Gasification technology has been successfully used to provide syngas to a variety of chemical processes and to provide power at refineries using petcoke or heavy oil as the feedstock. A listing of the plants using gasification in the United States is provided in Table 2-2. The operation of these plants provides greater confidence in the use of gasification technology and in the ability of vendors to provide designs for the gasifier and downstream systems. The Dakota Gasification plant is the largest operating gasification plant in the United States. The Lurgi technology employed by this facility to produce substitute natural gas is not considered cost effective for IGCC facilities. The use of gasification technology for non-IGCC purposes does not fully reduce the risks associated with early deployment of this technology. There are many facets to IGCC operation in a power industry setting using coal that must still be addressed as a cutting-edge technology.

Table 2-2 — Other Gasification Facilities in the United States (non-coal IGCC)

Plant Name	Tech Name	Year Start	Gasifier Status	Total Gasifiers	SGCap Nm3d	MWth Out	Fuel Feed	Products
Kingsport Integrated Coal Gasification Facility	GE	1983	Operating	2	1,600,000	218.7	Bit. coal	Acetic anhydride & Methanol
El Dorado Gasification Power Plant	GE	1996	Operating	1	80,559	11.0	Petcoke, Ref. waste & Natural gas	Electricity & HP steam
Delaware Clean Energy Cogeneration Project	GE	2002	Operating	2	3,800,000	519.5	Fluid petcoke	Electricity & Steam
Coffeyville Syngas Plant	GE	2000	Operating	2	2,141,200	292.7	Petcoke	Ammonia & UAN
Convent H2 Plant	GE	1984	Operating	2	1,880,000	257.0	H-Oil bottoms	H2
Oxochemicals Plant	GE	1979	Operating	2	500,000	68.4	Naphtha & fuel oil	Oxochemicals
Baytown Syngas Plant	GE	2000	Operating	2	2,540,000	347.2	Deasphalter pitch	Syngas
Great Plains Synfuels Plant (formerly Dakota Gasification)	Sasol Lurgi Dry Ash	1984	Operating	14	13,900,000	1,900.3	Lignite & Ref. residue	SNG & CO2
Baton Rouge Oxochemicals Plant	Shell	1978	Operating	3	570,000	77.9	Heavy fuel oil	Oxochemicals

An important issue in designing IGCC power plants for commercial operation is ensuring that they operate with high availability. To be viewed as a viable technology for commercial electricity generation, power plant technologies generally need to achieve availabilities around 90%. The early demonstration facilities each started out with relatively poor availability. Performance improved with experience, and the plants currently operating are now achieving about 80% availability. This low level of availability can be attributed in part to fact that these facilities are all of a single train design. This means that there is only one gasifier feeding one cleanup system feeding a single train power block. This arrangement provides little redundancy and the forced outage of any component brings the entire plant off-line.

Achieving a high level of availability with current gasification technologies is generally believed to require redundant gasifier capacity, which increases the cost of IGCC facilities, otherwise a back-up fuel supply such as natural gas or fuel oil must be used during syngas outages. The impact on the cost of the application of redundant systems can be minimized in larger power plants. A single redundant gasifier is typically all that is required for plants ranging from 500 to 1,000 MW. The application of a redundant gasifier at the Eastman Chemicals gasification facility in Kingsport, Tennessee, results in a 98% availability for methanol production from syngas. Shell claims that its technology does not require extended, planned outages for refractory replacement and, therefore, may be able to achieve over 90% availability without spare gasifier capacity.

Texaco and E-Gas technologies use refractory-lined gasifiers. In the case of Texaco technology, “burner replacement” is needed every of 25 to 60 days and complete refractory replacement every 2 to 3 years. These tasks can be scheduled to minimize the impact on plant dispatch. If a 90% overall IGCC equivalent availability is required, then, based on experience and lessons learned at the commercial demonstration plants, a spare gasifier would be required. The spare reduces the scheduled outage time and some of the forced outage time.

Shell gasifiers do not need such extended outages and have had a higher availability. However, Shell would likely also need a spare gasifier if 90% availability were required without use of a backup fuel.

In a paper presented by E-Gas at a 2002 conference, a case for having no spare gasifier was made for those instances where spring and fall power demand is lower, so that planned outages could be taken to replace refractory on one train while the others continue to operate.

The costs associated with providing a spare gasifier can vary from 3% to 15% of total capital cost depending on the technology selected and the amount of downstream equipment included in the spare train. Careful consideration of the needed IGCC plant equivalent availability, annual power demand profile, and feasibility of utilizing the secondary fuel as a backup must be made in order to decide on the level of redundancy required.

With all these issues taken together, S&L believes that the added cost for a spare gasifier is the prudent recommendation for clients pursuing IGCC at its present level of technology development.

2.1 STUDY METHODOLOGY

To develop the overall capital and operating costs associated with an IGCC power plant, S&L planned to use data from technology developers and compare this information with published studies and other internal sources. S&L contacted the companies listed in Table 2-3. The response from these companies is listed.

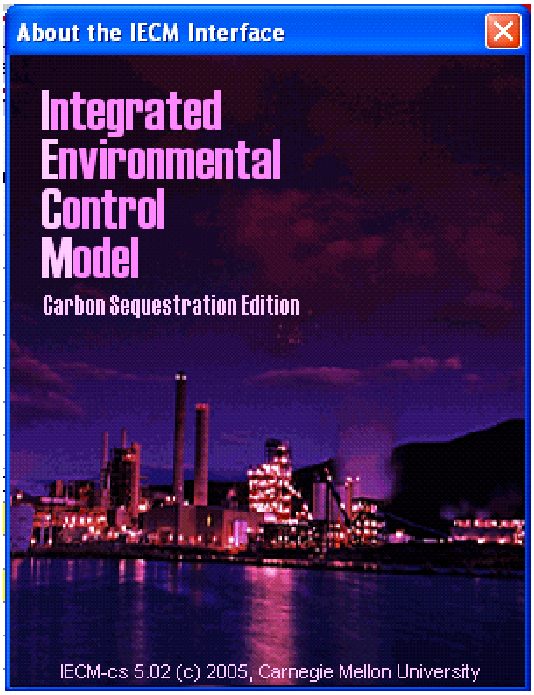
Although four suppliers/technology developers provided a willingness to provide data for this study, no data has been received at the time of this writing.

Table 2-3 — Gasification Suppliers Response to Study

Supplier/Developer	Response	Date Data Received
GE (Texaco)	Yes	None
ConocoPhillips (E-Gas)	Yes	None
Shell	Yes	None
Lurgi	None	
GTI (U-GAS)	None	
Process Energy (developer)	Yes	None
Future Energy (Schwartze Pumpe)	None	

As a result of the lack of vendor-provided data, S&L determined that the best approach for developing the costs and performance for a gasification facility designed for Black Mesa coal would be to use the DOE's Integrated Environmental Control Model (IECM) and adjust the outputs as necessary to compensate for the specific application addressed in this study. The IECM model can be downloaded from the web site: http://www.iecm-online.com/cees_download.htm (Figure 2-4). These results were compared with other studies published in the open literature and with in-house data available to S&L.

Figure 2-4 — IECM Model Opening Screen



This model was selected because it can be used to directly compare the impacts on the design of a facility when considering either with or without carbon sequestration.

The IECM model has several advantages for such a study.

- It is relatively simple to use.
- It is easy to adjust for basic data.
- Ambient conditions can be adjusted to fit site conditions.
- HRSG exhaust temperature can be adjusted to fit criteria.
- Combustion turbine NO_X emissions can be set to meet vendor guarantees.
- CO_2 compression requirements can be adjusted to meet pipeline transportation needs.
- Final capital cost and power values are generally in the range of published studies.

After exercising the model to develop the cost estimates, S&L determined that there are currently several limitations that need to be recognized when using the study for anything beyond a preliminary screening tool. These limitations include the following:

- Only one gasifier technology is available (GE [Texaco] Quench)
- Only one combustion turbine is available (GE 7FA)
- Only the Selexol + Claus + Stretford combination can be considered among cleanup system technologies.
- Only three fuel options are available:
  - Pittsburgh Seam coal
  - Illinois Seam coal
  - Powder River Basin coal
- No mercury removal is considered at this time.
- Air cooling for the condenser is not an option.
- Water usage results do not match published data (which is limited for many technologies).
- Combustion turbine model has several limitations:
  - Uses water dilution for NO_X control only
  - Does not consider nitrogen dilution
  - Does not integrate air separation unit with CT
  - Does not consider SCR
  - Result: lower efficiency, lower capital cost
- Steam turbine system model has several limitations:
  - Limited plant integration and no export steam
  - Result: lower efficiency, lower capital cost than might be expected otherwise

Although these limitations seem extensive, the results could be adjusted to meet the needs of the study. Adjustments S&L performed on the results included the following:

- Assumed that the cost and relative performance of the gasification system when using Black Mesa coal would be the same as for Illinois #6 coal.
- Assumed that the cost and relative performance of the sulfur removal system when using Black Mesa coal would be the same as for Wyoming PRB coal.
- Adjusted the combustion turbine output for site conditions.
- Adjust the capital costs for dry cooling where necessary.
- Added emission control costs for NO_X (SCR) and mercury removal
- Adjusted coal handling cost estimates for slurry delivery by crediting the cost for coal rail unloading, slurry preparation, and so forth.

- Compared costs of power delivery systems to S&L data base costs as appropriate
- The capital costs from the IECM study were computed in 2002 dollars. These values were escalated at 3% per year to 2006 dollars.[1] S&L also added owner's costs and EPC contractor profit to the values computed that are not included in the IECM estimate. The resulting capital cost values are in the same range as values computed for other projects. Screening studies of the nature preformed by S&L for this project, whether using the IECM model or other techniques, are typically considered accurate to a -20% to +30% range. To achieve a higher degree of accuracy (e.g. ±10% to 15%) for a technology requires extensive data on past installation as is common with pulverized coal fired plants. For a new IGCC facility to have this level of accuracy requires—
    - Complete process and instrument flow diagrams for all systems in the plant,
    - Detailed sizing of all major equipment and quotations from vendors for that equipment,
    - Design of foundations and buildings, and
    - Environmental Permits in place to allow detailed engineering and construction to proceed.

  This level of detail is typically provided after completion of a significant level of engineering (typically ~ $4 to $7 million level of effort). There are several IGCC projects currently under development across the country that have initiated this level of effort, but there are no reported costs from these projects yet published.

The operating and maintenance (O&M) costs computed by the IECM are not calculated in the same manner as is typically performed by a utility. An example is that IECM allocates an internal cost for auxiliary power (electricity use) to each section of the power plant. This is in addition to the tabulation of internal power use associated by the difference between gross and net generation. This allocation would normally be considered double counting. For this study, S&L used the consumable costs calculated for each subsystem. Water costs were calculated separately. Ash (slag) and sulfur disposal and/or byproduct credits were developed separately. Fixed operating labor was estimated separately using the IECM shift labor requirements as a guideline. Fixed and variable labor was based on model inputs subtracting the in-plant estimate of the labor force from the maintenance labor requirements.

[1] Inflation in the utility industry is trended by the "Handy Whitman" Index. The index has a table for Power Generation Construction in the Pacific Region. The index values for the period varied substantially over each year of this period. Inflation was over 8% in 2004. Only estimates may be applied for 2005 since economic data are not available. The 6-year average inflation rate from 1999 to 2005 was 3.7%, while the 4-year average rate from 1999 to 2004 was 2.7%. Since we were uncertain how inflation would fare during 2005 to 2006, a compromise rate of 3% was used for the study to compare the various project cost estimates reviewed in the literature and for the IECM results.

2.2 TECHNICAL FEASIBILITY AND MAXIMUM CAPACITY

2.2.1 Design Basis Technical Assumptions

The study requested by the California Energy Commission specified that a gasification plant be considered at either the Mohave or Black Mesa Mine sites. It also specified that the plant be considered both with and without carbon dioxide removal and sequestration.

S&L determined that this study must focus on a facility that is currently both technically and commercially viable for installation with the most rapid schedule practical to replace power that will be lost if Mohave Generating Station is retired. The following considerations were therefore developed as the basis for the study:

- Develop IGCC plant costs for commercial scale IGCC plant at two sites, operation by 2011 if possible:
  - Mohave Generating Station
  - Black Mesa Coal Mine
- Consider aspects associated both with and without CO_2 removal and sequestration:
  - Limited CO_2 removal without shift conversion
  - High degree of CO_2 removal with shift conversion
- Develop costs for a CO_2 pipeline from Mohave to Bakersfield for use as enhanced oil recovery (EOR) sequestration.
- Develop costs for a CO_2 pipeline from Black Mesa to McElmo Dome Natural CO_2 Reservoir near Cortez, Colorado.
- Minimize water consumption in the plant design.

From this basis, the study developed a conceptual plant basis for design. This basis is summarized in Table 2-4.

Table 2-4 — IGCC Facility Design Basis

	No CO_2 Removal	With CO_2 Removal
Number of Gasifiers	2 + 1 Spare	2 + 1 Spare
Combustion Turbine	2 “F” technology CTs	2 “F” technology CT’s
Steam Generator	2 HRSGs	2 HRSGs
Turbine Generator	1	1
Boiler Feedpumps	Motor Driven	Motor Driven
Condensing Equipment	Dry Cooling	Dry Cooling

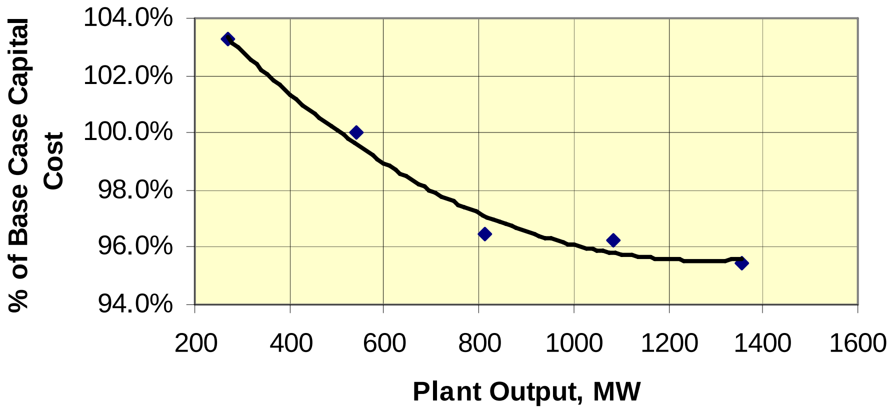
	No CO_2 Removal	With CO_2 Removal
Sulfur Removal	Selexol 1-Stage + Claus + Stretford	Selexol 1-Stage + Claus + Stretford
NO_X Control	Syngas Modified Burners + Water Diluent	Syngas Modified Burners + Water Diluent
CO_2 Removal	None	Selexol 2-Stage Process
Particulate	N/A	N/A

2.2.2 Feasible Capacity Ranges

The study requested by the California Energy Commission specified that a gasification plant of approximately 250 MW capacity be considered at either the Mohave or Black Mesa Mine sites. It also specified that the plant be considered both with and without carbon dioxide removal and sequestration.

S&L considered this scale to be impractical from a commercial point of view. Most companies considering commercial gasification plants are currently considering facilities with multiple trains that provide for higher reliability, availability, and improved costs of scale. A two-train facility at ISO standard conditions would provide about 540 MW, a three-train system would provide 825 MW, and a four-train would provide 1,100 MW of capacity. S&L determined that developing the cost basis for a nominal 550-MW plant would provide the best data for a replacement facility based on the current state of technology development because most of the studies conducted for new IGCC facilities being considered today are of this size. As a result, vendors would most likely be able to use existing information to readily develop estimates for use in this study. Facilities larger than 550 MW would benefit from "cost of scale" efficiencies, which can be estimated based on shared spare equipment savings and other factors. The IECM model was exercised to determine the relative cost of scale for capital costs of plants ranging in output from 265 to 1,355 MW (no carbon capture). Based on the data obtained, the curve in Figure 2-5 was constructed, which can be used to adjust the estimates from the 100% basis to alternative costs for either larger or smaller plants. As can be seen from this curve, the single train facility would likely cost about 3% more per kilowatt than a two-train facility. Similarly a three-train facility indicates a 3% cost savings compared to the two-train design. As the facility increases in size beyond the three-train size, the relative benefit decreases. The decision to construct a two- or a three-train gasification plant is dependent on the results of the integrated resource plan to be prepared by Southern California Edison.

Figure 2-5 — Cost of Scale for Typical IGCC Plants
(540 MW = 100%)



2.2.3 Fuel Requirements

The design fuel for the study is Black Mesa coal. The coal is currently delivered to the Mohave Generating Station via a pipeline as a slurry. The slurry is delivered to the mine at a typical coal/water concentration of approximately 50%. Two of the leading gasification technologies (i.e., GE and E-Gas) use coal water slurry as the means by which coal is fed to the gasifier. They typically provide their feed to the gasifier at higher coal slurry concentrations, typically 65%. For this study, S&L assumed that the existing delivered slurry meets the size criteria for these gasifiers and that the existing dewatering systems will be able to be modified to provide the desired slurry concentration. The size distribution of the coal is summarized in Table 2-5.

Table 2-5 — Black Mesa Coal Water Slurry Size Distribution

Method	Laser Diffraction Analysis					Wet Screen Analysis			Minus	Plus
Size No.	1	2	3	4	5	6	7	8	10.78	600
Sieve No.					325	100	50	30	µm	µm
Size, µm	1.18	1.67	4.24	10.78	45	150	300	600	Sizes	Sizes
Quantity	3.37	2.56	4.02	17.92	17.70	21.90	22.30	10.23	9.95	10.23
	Fines			Optimum				Coarse	Fines	Coarse

The Black Mesa fuel is considered a subbituminous coal (ref: USGS sample data base and U.S. Bureau of Mines). The analysis of the fuel was developed from data provided by Southern California Edison and supplemented with data from the U.S. Geological Survey. Unlike subbituminous coals mined in Wyoming and Montana, which have high moisture contents of about 25% to 35%, this fuel has a moisture content (as mined) of about 10.5% to 12.5%. This moisture yields a coal with a higher heating value of 10,834 Btu/lb, which is similar to Illinois coals (typically 10,500 to 11,500 Btu/lb). The sulfur content of the fuel is relatively low at about 0.42%. The analysis of the fuel is summarized in Table 2-6. The ash fusion temperature of the coal is important for gasification processes that produce molten slag: the gasifier must operate at a temperature sufficient to melt the ash. This may require additives to “flux” the ash. Gasifiers that produce a “dry” ash, on the other hand, must operate below the ash fusion temperature to avoid slagging conditions.

Table 2-6 — Black Mesa Coal Analysis

As Received	
Proximate Analysis	**%**
Moisture	10.36
Volatile Matter	38.68
Fixed Carbon	43.50
Ash	7.45
Total	100.00

Ultimate Analysis	**%**
StdAsh	6.68
Moisture	10.36
Hydrogen	5.11
Carbon	56.71
Nitrogen	1.01
Oxygen	19.72
Sulfur	0.42
	100
Btu/lb	10,834

Hg, ppm	0.05

Ash Fusion Temperature deg F	
Initial Deformation	2,184
Softening	2,245
Fluid	2,307
T-250	2,686

Ash Mineral Analysis	**wt %**
SiO_2	54.15
Al_2O_3	21.19
TiO_2	0.96
Fe_2O_3	4.64
CaO	7.94
MgO	2.00
K_2O	0.87
Na_2O	2.04
SO_3	5.41
P_2O_5	0.22
SrO	0.10
BaO	0.44

Total feed to the gasifier for the base case nominal 550-MW plant is about 6,000 ton/day of coal.

2.2.4 Water Requirements

Determining the quantity of water required for the facility is a critical element of the study. Currently, Mohave Station receives water from the Colorado River to run the power generating plant. Fuel is delivered as a slurry with water from the N-Aquifer. The N-Aquifer water will become unavailable as of January 1, 2006. SCE is participating in negotiations to make C-Aquifer water available to replace the water from the N-Aquifer. For this study, water was assumed to cost $200 per acre-ft from the Colorado River and $1,000 per acre-ft from the C-Aquifer. It is assumed that these prices are sufficient to recovery all pumping and transportation costs, including capital costs, over time. There are essentially three primary scenarios for water use:

- The IGCC facility is located at the Mohave Site; C-Aquifer water is used for slurry delivery of coal and Colorado River water is used for process and cooling water purposes.
- The IGCC facility is located at the Black Mesa Site; C-Aquifer water is used for slurry delivery of coal and for process purposes. Cooling is provided by an air-cooled condenser to minimize water use.
- The IGCC facility is located at the Black Mesa Site; Dry coal feed gasification (Shell) technology is selected to minimize the water requirements from the C-Aquifer water for process purposes only. Cooling is provided by an air-cooled condenser to minimize water use.

Each of these scenarios was considered for the three carbon removal cases studied, that is, no CO_2 removal, CO_2 removal without shift conversion, and maximum CO_2 removal. The results of the study are summarized in Table 2-7. The data lists the flow rate in gallons per minute (gpm) and acre-ft/yr of instantaneous demand and in acre-ft per year assuming a 100% capacity factor to ascertain maximum water demand.

Table 2-7 — Water Demand for IGCC at Mohave and at the Black Mesa Mine

Based on 100% Capacity Factor	No CO_2 Removal		CO_2 Removal without Shift Conversion		With CO_2 Removal	
	gpm	acre-ft/yr	gpm	acre-ft/yr	gpm	acre-ft/yr
Boiler Feedwater Make-up (1)	175	282	175	282	182	292
Coal Feed Slurry @ Mohave	*1,095*	*1,762*	*1,095*	*1,762*	*1,137*	*1,829*
Coal Feed Slurry @ Black Mesa	*842*	*1,356*	*842*	*1,356*	*874*	*1,407*
Miscellaneous Plant Uses	175	282	182	292	182	292
Cooling Tower Make-up (2)	2,800	4,507	2,800	4,507	2,906	4,678
Total Plant Use Mohave (3)	4,245	6,833	4,252	6,844	4,406	7,093

Based on 100% Capacity Factor	No CO_2 Removal		CO_2 Removal without Shift Conversion		With CO_2 Removal	
	gpm	acre-ft/yr	gpm	acre-ft/yr	gpm	acre-ft/yr
Total Plant Use Black Mesa (3)	*1,192*	*1,919*	*1,199*	*1,930*	*1,238*	*1,992*
Total Plant Use Black Mesa (Shell gasifier)	*350*	*563*	*357*	*574*	*363*	*585*

1. Boiler feedwater make-up is assumed to be 1% of main steam flow rate.
2. Cooling tower make-up includes evaporation, drift, and blowdown with four cycles of concentration.
3. Cooling towers used at Mohave; dry cooling used at Black Mesa.

Water use from C-Aquifer in italics.

The feeding of coal as a slurry from the Black Mesa Mine to the Mohave Generating Station typically requires a slurry of about 50% coal in water. This implies that for each pound of coal, a pound of water is required. Gasification prefers that a slurry minimize the amount of water fed to the gasifier to improve efficiency. Slurry concentrations of about 65% to 70% are desired. S&L assumed that slurry will be fed to the gasifier with a slurry concentration of 65% (in the absence of vendor data). This means that for slurry feed to the gasifier, there is 0.53 pound of water for each pound of coal, yielding 1.53 pounds of slurry. For a plant located at Mohave, excess water must be removed before feeding to the gasifier. If a plant is located at the Black Mesa site, slurry could be prepared to meet the gasifier requirements, since pipeline transportation of the fuel is not required. For dry feeding of coal, no slurry water is required.

The quality of the water from the C-Aquifer is unknown at this time. Estimates performed for the gasification plant include a factor for typical water treatment (softening) and for boiler water treatment (demineralization). S&L assumed that this level of treatment imbedded in the cost models is sufficient for the IGCC cost estimate.

Data are provided with capital and operating costs for an IGCC plant at Mohave Station that uses either wet or dry cooling. An analysis of the long-term availability of Colorado River water is beyond S&L's scope for this report. S&L assumes that SCE will evaluate the effect of water availability on the cost and performance of the IGCC facility when they perform their integrated resource plan modeling.

2.2.5 Land Requirements

The land requirements reported in the literature to construct a 550-MW IGCC facility varies from 125 acres to 300 acres. The actual requirements depend on several factors:

- Land required for the process equipment

- Land required for coal unloading, storage, and preparation and duration of storage desired (e.g., 30 days or 6 months.
- Land requirements for ash disposal

Technology developers have indicated in past studies by S&L that the land required for the process equipment is about 100 acres. The area required for coal handling and unloading is typically also about 100 acres. The area required for ash disposal is similarly about 100 acres. The smaller value is the minimum required for minimal coal storage and no ash disposal on site. The larger value accommodates more traditional power plant requirements. S&L has worked on site development projects with about 175 acres that use a minimal storage of coal and very limited storage for ash. For this study, a 200-acre site should be adequate if limited ash storage is required, since a complete coal unloading system is not required at either Mohave or Black Mesa. However, a 300-acre site would provide sufficient space for the plant plus ash storage.

2.2.6 IGCC Performance

The IECM model was used to determine the performance of the IGCC Facility as stated above. The overall output of the plant is reduced with CO_2 removal and compression to deliver gas to sequestration sites via pipeline, and thus, the efficiency is diminished. The key performance parameters are listed in Table 2-8. The initial plant efficiency is somewhat lower than might be expected for a typical IGCC facility. This may be because the IECM model does not capture the full measure of thermal integration that is commonly associated with production of steam and electricity associated with cooling the syngas from the exit of the gasifier down to the sulfur removal cleanup system temperatures. This efficiency is typically about 2%. Also, the IECM does not take into account the benefit of integration of the combustion turbine with the air separation unit (ASU), which can also improve efficiency by reducing the compression power required by the ASU. Typical quoted efficiencies reported for the GE (Texaco)-based IGCC facilities at this scale is about 37%. S&L originally hoped to received vendor data for plant efficiencies to reflect their current design philosophy as applied to Black Mesa coal. Since we did not receive vendor input, the values from the IECM model were not adjusted to maintain the consistent nature of the estimate; however, these adjustments can be made when considering parametric analysis of the results.

Table 2-8 — Study-Predicted IGCC Performance Based on IECM Model

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal	
		Mohave	Black Mesa	Mohave	Black Mesa	Mohave	Black Mesa
Gross Output	MW	639.6	643.9	639.6	643.9	604.9	608.2
Net output	MW	548.9	554.6	531.1	537.1	481.7	483.9
Heat Rate	Btu/kWh	9,909	9,927	10,402	10,259	11,730	11,758
Overall Efficiency	%	34.4	34.4	32.8	33.3	29.1	29.0
Heat Input	mmBtu/hr	5,439	5,506	5,525	5,506	5,650	5,690
Fuel Consumption	lb/hr	502,056	508,191	509,953	508,191	521,560	525,177
Fuel Consumption	tpy	2,199,007	2,225,878	2,233,595	2,225,878	2,284,432	2,300,277

Assumptions: Mohave: Site elevation approximately 710 ft; average ambient temperature 67°F.
Black Mesa: Site elevation approximately 5,500 ft; average ambient temperature 59°F.

Parametric studies were conducted to determine the relative performance of the IGCC facility at varying temperatures to assist SCE with their resource planning. Figure 2-6 identifies the level of plant output variation and net heat rate associated with ambient temperature predicted by the IECM model at the Mohave Site. The performance of the plant at 108°F is reduced significantly from average conditions. Net output for the three scenarios is: 514, 505, and 448 MW (base case/no-regrets/max CO_2 removal). The heat rate at 108°F increases slightly to: 9,930, 10,421, and 11,781 Btu/kWh.

For the Black Mesa site, three curves were prepared (elevation assumed for the Black Mesa Site is 5,500 feet which is the limit of capability for the IECM model). One provides a similar view of the impact of temperature on net heat rate and output at 5,500 feet elevation, Figure 2-7. Figure 2-8 compares the effect of elevation (if an alternative site is considered at an elevation above 5,500 feet, which is very likely) on net output for two ambient temperatures. Figure 2-9 compares the effect of elevation on the net heat rate for two ambient temperatures. All cost and performance data presented in this report were calculated for the Black Mesa design at 5,500 feet elevation.

Figure 2-6 — Mohave Site Net Output and Heat Rate as a Function of Site Temperature

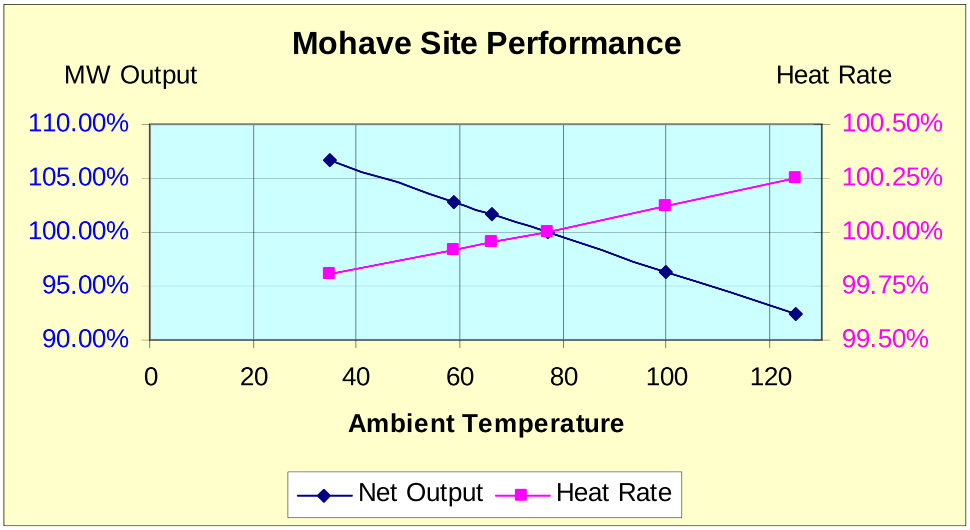


Figure 2-7 — Black Mesa Site Net Output and Heat Rate as a Function of Site Temperature

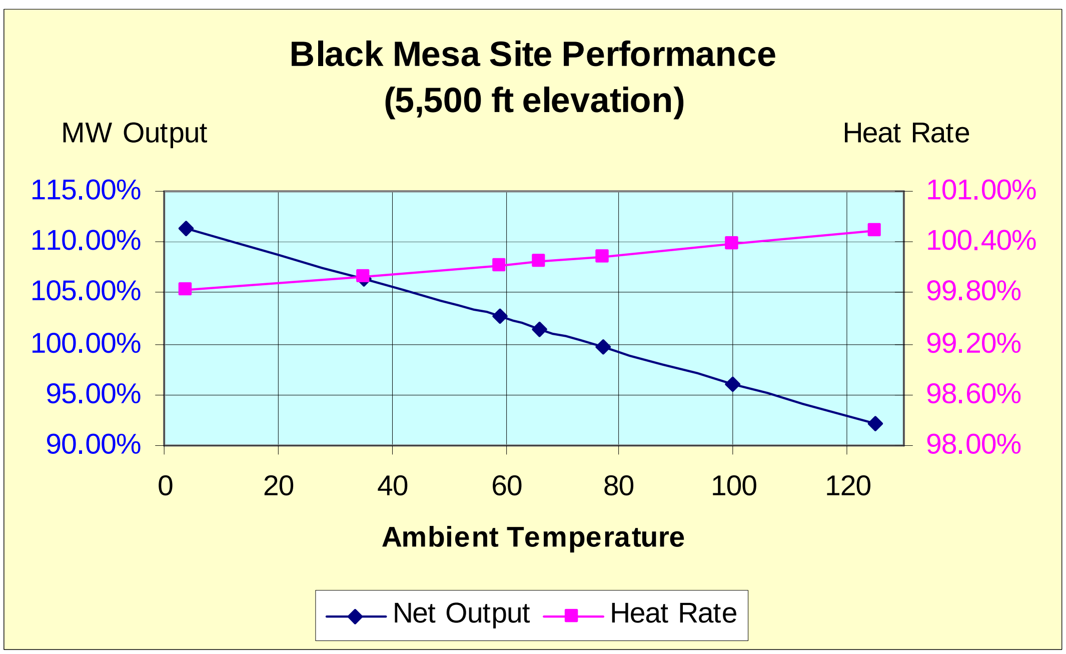


Figure 2-8 — Black Mesa Site Net Output as a Function of Site Elevation

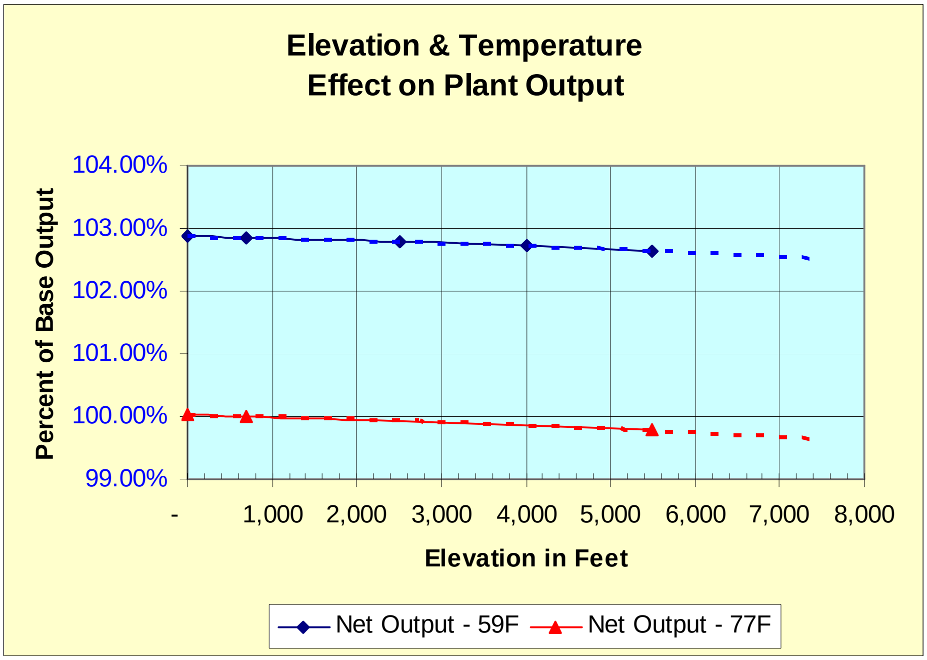
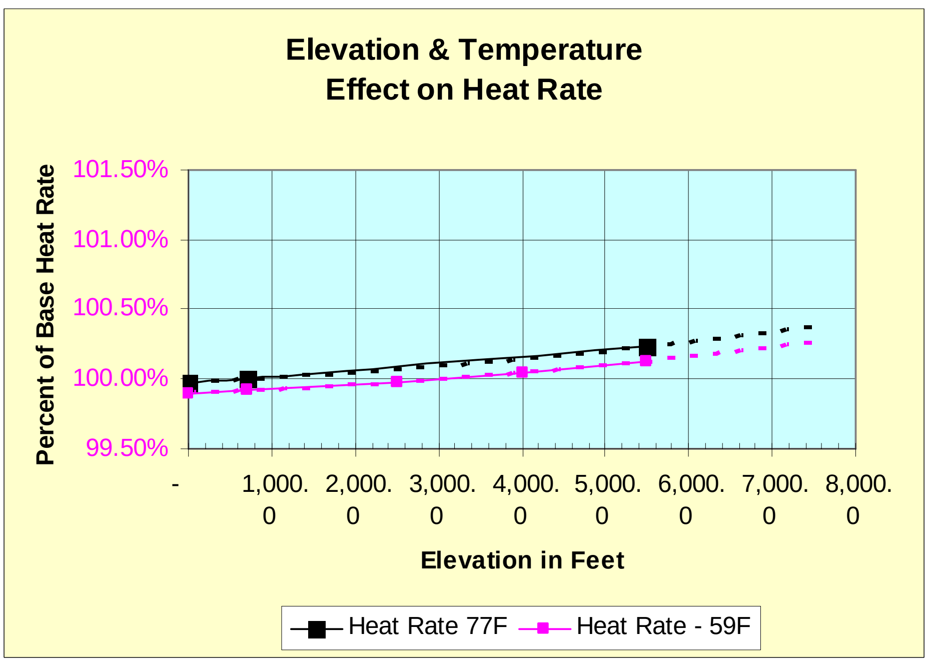
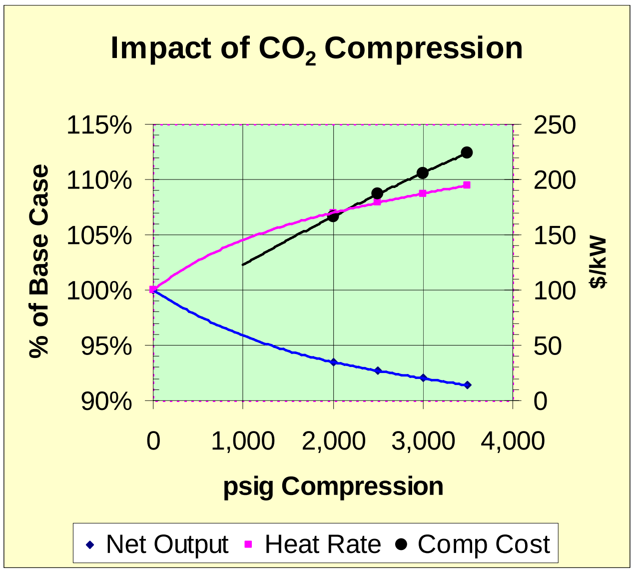


Figure 2-9 — Black Mesa Site Net Heat Rate as a Function of Site Elevation



Examination of the data shows the significant output and heat rate penalty associated with CO_2 recovery and sequestration. A key aspect of sequestration is the compression requirements needed to transport and deliver high-pressure CO_2. This value is highly dependant on distance. S&L exercised the IECM model to ascertain the cost and performance sensitivity of the compression requirements for CO_2 for the maximum removal case facility. This is summarized in Figure 2-10.

Figure 2-10 — Impact of CO_2 Compression on Plant Cost and Performance



2.3 SITE SCREENING

S&L assumed two site locations for this study: the existing Mohave Generating Station and a site near the Black Mesa Coal Mine.

2.3.1 Mohave Generating Station Site

The Mohave Generating Station is located in Laughlin, Nevada. The site elevation is 714 feet above sea level. The area is typical of dry arid desert conditions. Maximum ambient conditions are 125°F with a 79°F wet bulb. The 1% maximum temperature is at 108°F. Minimum ambient temperatures are 20°F. Average conditions considered for the study were 67°F to account for average day-time temperatures during the entire year. The site contains more than sufficient acreage for installation of the facility and for expansion to increase the output from the site if that is desired.

The Mohave Generating Station sits near the Colorado River and uses water from the river for cooling and plant uses. This study assumed that Colorado River water will be used for cooling tower makeup and for process uses. Alternative costs for a dry cooling system were developed in case a reduction in Colorado River water use is considered.

Water from the C-Aquifer will be required for delivering the coal from the Black Mesa mine to Mohave.

The coal will be delivered to the station as a coal-water slurry. It is recommended that slurry-fed gasification technologies provided by either GE (Texaco gasifier) or ConocoPhillips (E-Gas) be considered. The slurry will need to be concentrated from the delivery concentration of about 50% coal to approximately 65% coal before feeding. S&L has assumed that the existing centrifuges would be able to facilitate this. The cost study has credited the installation at the site by reducing the coal handling equipment requirement for rail facilities, coal unloading, and coal storage and reclaim piles.

In case carbon dioxide is removed from the syngas for sequestration, a pipeline of approximately 230 miles to the Bakersfield area was considered.

Since the Mohave site has existing electrical switch yard and transmission access, extension or enhancements of these assets are not required.

2.3.2 Black Mesa Site

The Black Mesa Mine is located on the Navajo Reservation in northern Arizona. The closest town to the site is Kayenta, Arizona. There are vast open areas available for development near the mine, and a specific location was not selected. It is assumed that a suitable location can be identified in case a further, in depth, study is considered. The elevation in the area of the mine varies from about 5,500 to 7,000 feet. For the study, a mine site elevation of 5,500 feet was assumed in the model because that is the limit of altitude adjustment possible. Average ambient temperatures at the site were assumed to be approximately 59°F.

All water for the gasification process was assumed to be derived from the C-Aquifer. For this reason, only dry cooling was considered in the capital cost for this location. In case slurry feed systems are used, it is assumed that the slurry can be prepared with the existing equipment at the mine at the 65% concentration required for feeding the gasifiers. Less water use can be realized if a dry fed gasifier (Shell) is used; however, a higher capital cost to provide for dry grinding and drying of the coal feed would then be needed.

In case carbon dioxide is removed from the syngas for sequestration, a pipeline of approximately 130 miles to the Cortez, Colorado, area was considered.

2.4 ENVIRONMENTAL EMISSIONS ISSUES

The plant emissions are estimated by the IECM model. Additional NO_X removal is calculated to reduce the levels from the CT exhaust to below the anticipated BACT limit. The primary emissions are summarized in Table 2-9. Mercury emissions are not estimated as a part of the IECM model for IGCC facilities. S&L assumed a 90% reduction in mercury, as is predicted by most experts, with the use of activated carbon filters on IGCC plants.

The level of sulfur emissions is significantly reduced on plants that use a two-stage Selexol process for CO_2 removal. This low level is due to the higher degree of H_2S removal that occurs along with the capture of CO_2 from the syngas.

Mercury emissions are shown based on gross generation, to reflect the requirements of the Clean Air Mercury Rule (CAMR) issued in March 2005.

Table 2-9 — Summary of Primary Emissions

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal	Comments
Emissions		**IECM Predicted Performance**			
SO_2	lb/mmBtu	0.13	0.02	0.02	0.15 (Anticipated BACT Limit)
	lb/n-MWh*	1.25	0.21	0.24	
	tpy	2,952	477	495	
NO_X	lb/mmBtu	0.0217	0.0217	0.0214	0.03 (Anticipated BACT Limit)
	lb/n-MWh	0.22	0.22	0.25	
	tpy	510	510	522	
CO_2	lb/mmBtu	200	142	17	
	lb/n-MWh	1,978.16	1,457.45	197.85	
	tpy	4,682,220	3,337,998	410,406	

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal	Comments
Emissions		IECM Predicted Performance			
Particulate	lb/mmBtu	0.012	0.012	0.012	0.012 (Anticipated BACT Limit)
	lb/n-MWh	0.12	0.12	0.14	No IECM Particulate Data
	tpy	282	282	292	
Mercury	lb/TBtu	0.46	0.46	0.46	
	10^{-6} lb/g-MWh*	3.90	3.90	4.28	No IECM Mercury Data; CAMR rule is based on gross output
	oz/yr	344.4	344.4	357.4	

* n-MWh = net megawatt-hour; g-MWh = gross megawatt-hour.

2.5 CARBON SEQUESTRATION

S&L developed the quantities of CO_2 that could be separated from the syngas as characterized by three scenarios. The amount of CO_2 removed for sequestration is listed in Table 2-10. The three scenarios are as follows:

- **No CO_2 removal.** This is technically feasible today with current technology.
- **CO_2 removal without shift conversion.** In this case, 90% of the carbon dioxide generated by the standard syngas production process is removed from the fuel gas. This is technically feasible today.
- **Maximum CO_2 removal.** This assumes that all of the carbon monoxide the syngas is converted to carbon dioxide using a shift reaction and 90% of this CO_2 is removed from the fuel. The shift reaction is technically feasible today. However, a combustion turbine that can use the product syngas is not yet available.

Note that although it is technically possible to remove a high degree of CO_2 from the syngas, it is not likely that such a plant will be technically viable until about the 2020 time frame. This is due to the need to develop a hydrogen-fueled combustion turbine that can reliably generate power and be guaranteed by the turbine vendors.

Burning hydrogen-rich fuels is currently practiced in syngas combustion and in the combustion of assorted waste gases. To meet stringent NO_X emissions, the syngas is diluted with either nitrogen or water to lower peak flame temperatures and also increase the output of the turbine. However, vendors have reported that if burning a fuel where hydrogen is the only fuel component, there are additional issues in design needed to prevent flashback and to ensure proper safeguards. These issues entail extensive design and testing of construction materials and combustion firing configurations. Without such tests, there is considerable risk to both the engine supplier and the power generation company in the deployment of the first such unit.

The U.S. Department of Energy is actively conducting research for development of advanced turbines that will use hydrogen-rich fuels with several turbine vendors. DOE recently awarded a contract to GE for $45.6 million dollars to develop the hydrogen fueled turbine design for an engine that will be tested in the FutureGen project. This is likely to be the first demonstration of a hydrogen-rich fueled engine. Many power generation companies have offered to participate in this project with DOE to ensure its completion. The hydrogen turbine is critical to the ability to commercial CO_2 sequestration moving forward.

Table 2-10 — CO_2 Byproducts for Sequestration

		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
CO_2	lb/mmBtu	—	57.52	175.41
	lb/n-MWh	—	589.23	2,059.33
	tpy	—	1,349,509	4,271,814

2.6 TRANSMISSION REQUIREMENTS

Direct transmission access costs include the costs of the connection at the plant site, the plant transmission line, and any substation required at the interconnection with the trunk transmission line. For an IGCC plant at the existing site, these costs are assumed to be negligible because the IGCC plant would replace the existing plant if it were built there. At the Black Mesa site, connection of the plant requires a plant switchyard, an approximately 85-mile long transmission line at 500 kV, and interconnection equipment to connect to the existing 500-kV trunk transmission line. These costs are estimated to be approximately $94.6 million.

Direct transmission access costs described here do not include the costs of upgrades to the transmission system that may be required to alleviate congestion or single contingency concerns that result from load flow analyses. Those costs are estimated in Section 12.

2.7 O&M AND CAPITAL COST ESTIMATES

2.7.1 Economic Assumptions

The capital costs for the study assume overnight construction in 2006 dollars. The IECM capital cost data were used as the basis for the plant with adjustments as described in Section 2.1 to meet site requirements and to account for escalation from 2002 at 3%/yr. These values were compared to published capital cost estimates in the literature for reasonableness. The cost of reagents and consumption rates were based on IECM model inputs, except for water costs and for materials not considered in IECM, such as mercury removal and SCR operation.

The costs are shown with the construction labor based on the internal factors assumed within IECM. Productivity adjustments that may be suggested for local conditions in the Laughlin, Nevada, or Black Mesa area are indicated, but are not included in the totals. Sales and property taxes and land lease costs are not included in the cost estimates presented.

2.7.2 Capital Costs

The capital costs determined by the IECM model were developed for the three cases. Costs are shown in total dollars and on a normalized $/kW basis for each case. Costs are shown for both the Mohave Generating Station site (Table 2-11) and the Black Mesa site (Table 2-13). The capital costs for the plant at either site are essentially the same except for specific design differences such as wet or dry cooling or coal slurry feed or dry feed. The normalized costs reported in $/kW will vary based on the changes in net output of the plant due to differences in average ambient temperature and site elevation. There are also differences in performance (heat rate) that affect the operating costs that are site specific due to temperature and elevation. Also, the cost per kilowatt is significantly affected for the cases where carbon dioxide is removed and sequestered. This is the result of the reduced power output from the plant (due to compression requirements to transport CO_2). Thus there are fewer kilowatts for sale and thus the cost per net kilowatt is much higher.

It is assumed that water from the Colorado River will be used for cooling at the Mohave site. If this is not desired, adjustment to the cost for the addition of dry cooling is provided. It is assumed that dry cooling will be necessary at the Black Mesa site to conserve water resources.

The level of emissions, specifically CO_2 emissions, is expected to be about the same for both the Black Mesa and the Mohave sites.

Table 2-11 — Capital Cost Estimate for IGCC Using Black Mesa Coal at Mohave

	No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal		Comments
Net Output, MW	548.9		531.1		481.7		
Capital Costs	M$	$/kW	M$	$/kW	M$	$/kW	
Costs in Year 2006 Dollars							
Air Separation Unit	199	363	199	375	206	427	
Gasifier Area	295	537	295	555	305	634	Base Cost reduced for Existing Slurry
Sulfur Control	53	97	53	100	53	111	
Mercury Control	4	7	4	8	4	8	
CO_2 Capture	—	—	92	172	233	484	
Power Block	339	617	339	638	337	699	
Dry Cooling Additional Cost	15	27	15	28	15	31	If added for dry cooling reduce makeup water
Post-Combustion NO_X Control	5	10	5	10	5	11	
Total Cost with Wet Cooling	895	1,631	987	1,858	1,143	2,374	
Total Cost with Dry Cooling	910	1,658	1,002	1,886	1,158	2,405	
OT Inefficiency & Premium Pay & Location Adjustment (not included above)							
Owner's Cost							
Owner's Development Costs (6.5%)	59.16	108	65.10	123	75.30	156	Shown for dry cooling
EPC Fees (12.5%)	113.76	207	125.20	236	144.81	301	Shown for dry cooling
Total Expected Costs with Wet Cooling	1,065	1,941	1,174	2,139	1,361	2,479	
Total Expected Costs with Dry Cooling	1,083	2,004	1,192	2,279	1,379	2,911	

Table 2-12 — Capital Cost Estimate for IGCC Using Black Mesa Coal at Black Mesa Site

	No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal		Comments
Net Output, MW	554.6		537.1		484.9		
Capital Costs	M$	$/kW	M$	$/kW	M$	$/kW	
Costs in Year 2006 Dollars							
Air Separation Unit	199	359	199	371	206	424	
Gasifier Area	295	531	295	549	305	629	Base Cost reduced for Existing Slurry
Sulfur Control	53	96	53	99	53	110	
Mercury Control	4	7	4	7	4	8	
CO_2 Capture	-	-	92	170	233	481	
Power Block	339	611	339	631	337	694	
Dry Cooling Additional Cost	15	27	15	28	15	31	If added for dry cooling reduce makeup water
Post-Combustion NO_X Control	5	10	5	10	5	11	
Total Cost with Wet Cooling	895	1,614	987	1,837	1,143	2,358	
Total Cost with Dry Cooling	910	1,641	1,002	1,865	1,158	2,389	
OT Inefficiency & Premium Pay & Location Adjustment (not included above)							
Owner's Cost							
Owner's Development Costs (6.5%)	59.16	107	65.10	121	75.30	155	Shown for dry cooling
EPC Fees (12.5%)	113.76	205	125.20	233	144.81	299	Shown for dry cooling
Total Expected Costs with Wet Cooling	1,065	1,921	1,174	2,117	1,361	2,454	
Total Expected Costs with Dry Cooling	1,083	1,953	1,192	2,219	1,379	2,843	

2.7.3 Operating and Maintenance Costs

O&M costs are separated into fixed and variable cost categories. Fixed costs include labor and maintenance. Variable costs include chemicals, catalysts, water use, waste disposal and other costs that vary as a function of the annual total production from the plant. A 100% capacity factor was assumed for this study to provide the maximum values for consideration. Adjustments can be performed to the variable cost values for alterative capacity factors. Table 2-13 provides the total O&M cost estimates for the facilities at Mohave. Costs for chemicals, catalyst, etc. are generally developed within IECM, and additional costs not covered by IECM (e.g., activated carbon for mercury control) are added. Water costs were provided, segregated between waters required from the C Aquifer for each site and from the Colorado River, which can be used at the Mohave site. Operating costs for the Black Mesa Site are listed in Table 2-14.

Table 2-13 — Operating and Maintenance Cost Estimate at Mohave

	No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal	
Net Output, MW	548.9		531.1		481.7	
O&M Costs	M$/yr	$/kW-yr	M$/yr	$/kW-yr	M$/yr	$/kW-yr
Fixed O&M						
Total Plant Labor	14.42	26.27	16.52	31.10	16.52	34.30
Total Maintenance Contract Labor	3.16	5.75	6.56	12.35	6.56	13.62
Total Plant Maintenance Materials	9.22	16.80	12.19	22.95	15.27	31.70
Total Fixed O&M	26.80	48.83	35.27	66.40	38.35	79.62
Variable O&M	M$/yr	$/MWh	M$/yr	$/MWh	M$/yr	$/MWh
Consumable Materials	4.67	0.97	4.73	1.02	5.35	1.27
Process Water from Colorado River	0.33	0.07	0.33	0.07	0.34	0.08
Cooling Water from Colorado River	0.90	0.19	0.90	0.19	0.94	0.22
Slurry Water from C Aquifer	1.76	0.37	1.76	0.38	1.83	0.43
	M$/yr	$/MWh	M$/yr	$/MWh	M$/yr	$/MWh
Mohave Variable O&M with Slurry	7.66	1.59	7.73	1.66	8.46	2.00

Table 2-14 — Operating and Maintenance Cost Estimate at Black Mesa

	No CO_2 Removal		CO_2 Removal without Shift Conversion		90% CO_2 Removal	
Net Output, MW	554.6		537.1		484.9	
O&M Costs	M$/yr	$/kW-yr	M$/yr	$/kW-yr	M$/yr	$/kW-yr
Fixed O&M						
Total Plant Labor	14.42	26.00	16.52	30.76	16.52	34.07
Total Maintenance Contract Labor	3.16	5.70	6.56	12.22	6.56	13.53
Total Plant Maintenance Materials	9.22	16.63	12.19	22.69	15.27	31.49
Total Fixed O&M	26.80	48.33	35.27	65.66	38.35	79.09
Variable O&M	M$/yr	$/MWh	M$/yr	$/MWh	M$/yr	$/MWh
Consumable Materials	4.67	0.96	4.73	1.01	5.35	1.26
	M$/yr	$/MWh	M$/yr	$/MWh	M$/yr	$/MWh
Black Mesa Variable O&M with Slurry	6.14	1.26	6.20	1.32	6.87	1.62

2.7.4 Byproduct Sulfur Production and Operating Credits

Sulfur is a commodity that is widely used for a variety of industrial purposes. One of its primary purposes is the production of sulfuric acid. If a market exists near the IGCC facility for sulfuric acid, capital and operating costs for the facility can be reduced by producing sulfuric acid rather than elemental sulfur. This is done at the Polk County gasification plant in Florida, where the acid is used in fertilizer manufacturing.

For this study, elemental sulfur is produced because it is safer to handle, transport, and store and there are no known larger users of sulfuric acid in the area of the plant sites. Production is shown at a 100% capacity factor basis, and adjustments can be determined for smaller production ratios.

Table 2-15 — IGCC Sulfur Production Estimate for Black Mesa Coal

Values at 100% Load and 100% Capacity Factor		No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
Sulfur	lb/mmBtu	0.34	0.38	0.38
	lb/n-MWh	3.34	3.92	4.49
	tpy	7,913	8,973	9,321
Ash (Slag)	lb/mmBtu	6.17	6.17	6.17
	lb/n-MWh	61.1	63.2	72.4
	tpy	144,709	144,709	150,210
	acres for 30 years (40 ft high)	124		

2.8 PERMITTING ISSUES

The construction of an IGCC plant at the existing Mohave site near Laughlin, Nevada or the Black Mesa mine site will entail a number of permits and approvals before the start of construction. Some permits should be obtained once construction begins, and others should be obtained during commissioning of the plant. The importance of establishing a strict permitting schedule cannot be overstated, as certain procedures (i.e., ambient air quality monitoring and modeling) will require up to two years of lead time. With an adequate knowledge of the applicable regulations and the information required in the various permit applications, SCE can implement an effective permit strategy.

The State of Arizona Department of Environmental Quality (ADEQ) and the U.S. EPA Region IX have designated authority over environmental permitting in Navajo tribal lands to the Navajo Nation EPA (Delegation Agreement #00-0024). This designation affects all air, water, and solid waste permitting issues. There have been some historical disputes between the Navajo Nation and the Hopi Nation over tribal boundaries and control of activities at the Black Mesa Mine; it is not known how these disputes would affect the ability to develop an IGCC plant at the site.

- **Air Quality Construction Permits.** A New Source Review (NSR) / Prevention of Significant Deterioration (PSD) air quality construction permit is the primary approval necessary for the construction of a power plant. The U.S. Environmental Protection Agency (EPA) has delegated authority for the implementation and enforcement of the NSR/PSD regulations to the Nevada Department of Conservation and Natural Resources – Division of Environmental Protection (NV-DEP).

Under NSR, new major stationary sources with the potential to emit "significant" amounts of air pollution are required to obtain approval before commencing construction. Table 2-16 gives the major stationary source thresholds for coal and natural gas-fired power plants. An IGCC plant utilizes coal to great a syngas for running a combustion turbine, so it is not clear which unit configuration in Table 2-16 would apply. Whatever the definition, a 500-MW IGCC plant at either of the two sites would surely be designated as a major stationary source.

Table 2-16 — Definition of Major Stationary Source

Unit Configuration	Is Unit Configuration Included in One of the 28 Source Categories?	Unit is Classified as a Major Stationary Source if it has the Potential to Emit Greater Than….
Coal-Fired Plant with Heat Input >250 mmBtu/hr	Yes	100 tpy
Coal-Fired Plant with Heat Input < 240 mmBtu/hr	No	250 tpy
Natural Gas-Fired Combined-Cycle Plant with HRSG and Heat Input >250 mmBtu/hr	Yes	100 tpy
Natural Gas-Fired Combined-Cycle Plant with HRSG and Heat Input <250 mmBtu/hr	No	250 tpy
Natural Gas-Fired Simple-Cycle Combustion Turbine – any size	No	250 tpy

Construction of a new major stationary source will be subject to NSR review if potential emissions from the new source are "significant." Significant emissions thresholds are defined in terms of annual emissions rates in tons per year (tpy). Table 2-17 lists the pollutants for which significant emission rates have been established.

Table 2-17 — PSD Significant Emission Rates

Pollutant	Significant Emissions Rate (tpy)
CO	100
NO_X	40
SO_2	40
PM_{10}	15
VOC	40
H_2SO_4 mist	7

Source: 40 CFR 52.21 (b) (23)

Major new stationary sources in Nevada are required to submit an Air Use Permit application to the NV-DEP before starting construction. A new source in Navajo County would be required to submit a permit application to the Navajo Nation EPA – Air Quality Control Program. The Air

Use Permit application is used to identify all applicable federal and state regulations. The permit application requires a comprehensive description of the proposed project including—

- Process description
- Regulatory discussion describing all federal, state, and local air pollution control regulations and a discussion of how the proposed process unit complies with each regulation
- Best Available Control Technology analysis
- Emissions summary and calculations
- Stack/vent parameters
- Site description and process equipment location drawings
- Additional supporting information for specific processes and equipment

The Mohave site is located in Clark County, Nevada. Portions of Clark County (the greater Las Vegas metropolitan area) are currently designated as non-attainment for Carbon Monoxide (CO), 8-hour Ozone (O_3), and Particulate Matter less than 10 microns (PM_{10}). Although the Mohave site is not located in the non-attainment area, its close proximity would require that the owners of the proposed plant evaluate its impact on the non-attainment area.

The Black Mesa site is located in Navajo County, Arizona, which is currently in attainment for all criteria pollutants. There are no non-attainment counties near the site that would require an impact assessment or further emissions reductions.

It can take up to two years to obtain a Final Air Quality Construction permit: six to nine months to conduct modeling and prepare the permit application material; one year for the state to review the material and issue a draft permit; and three months for public comment and revisions before issuing the final permit.

- **Ambient Air Monitoring.** The NV-DEP and Arizona DEQ maintain systems of ambient air quality monitors throughout the state. Continuous data is collected for O_3, SO_2, NO_X, CO, PM_{10}, $PM_{2.5}$, and meteorological data. An automated data acquisition system is used to retrieve the data from all monitoring locations onto a central data management system. There are many ambient monitors in Clark County, primarily because of the Las Vegas non-attainment area and the operation of large stationary sources such as the existing Mohave station. The NV-DEP and Arizona DEQ conduct routine maintenance and calibration of these monitors for quality assurance.

  Data from the ambient air quality monitors are used to determine compliance with the National Ambient Air Quality Standards (NAAQS), shown in Table 2-18. The data are used to chart long-term trends in air quality and establish goals. Furthermore, the ambient air quality data are a necessary input for air quality modeling that is used for determining the impact of a proposed power plant.

Table 2-18 — National Ambient Air Quality Standards

Pollutant	Primary Standard 1	Primary Standard 2
PM_{10}	50 µg/m3 (annual mean)	150 µg/m3 (24-hour - 99th percentile)
$PM_{2.5}$	15 µg/m3 (annual mean)	65 µg/m3 (24-hour – 98th percentile)
SO_2	0.03 ppm (annual mean)	0.14 ppm (2nd highest 24-hour)
O_3	0.12 ppm (2nd highest 1-hour)	0.08 ppm (4th highest 8-hour)
CO	9 ppm (8-hour average)	35 ppm (1-hour average)
NO_X	100 µg/m3 (annual mean)	--
Pb	1.5 µg/m3 (quarterly average)	--

- **Air Quality Modeling.** Air quality modeling is used to estimate impacts to ambient air to determine whether the proposed power plant will result in pollutant concentration levels that exceed the applicable ambient air standards. Models allow one to forecast future air quality levels from sources that have not been constructed. Federal law requires that the NV-DEP and Navajo Nation EPA have legally enforceable procedures in place to prevent construction or modification of any source where the emissions from the projected activity would interfere with the attainment and maintenance of the National Ambient Air Quality Standards (NAAQS).

  The primary U.S. EPA modeling guidelines are discussed in *40 CFR Part 51, Appendix W – Guideline on Air Quality Models*. There are two levels of sophistication for air quality models. The first level consists of relatively simple estimation techniques that generally use preset, worst-case meteorological conditions to provide conservative estimates of the air quality impact of a specific source. These are called screening techniques or screening models. The purpose of such techniques is to eliminate the need of more detailed modeling for those sources that clearly will not cause or contribute to ambient concentrations in excess of either the NAAQS or the allowable PSD concentration increments. If a screening technique indicates that the concentration contributed by the source exceeds the PSD increment or the increment remaining to just meet the NAAQS, then the second level of more sophisticated models should be applied.

  The second level consists of those analytical techniques that provide more detailed treatment of physical and chemical atmospheric processes, require more detailed and precise input data, and provide more specialized concentration estimates. As a result, they provide a more refined and, at least theoretically, a more accurate estimate of source impact and the effectiveness of control strategies. These are referred to as refined models.

  The U.S. EPA lists a number of recommended and alternative air quality modeling software. Regardless of the sophistication of the software, the utility of the model largely depends on the availability of good meteorological and ambient air quality data. An applicant for an air quality construction permit in Nevada will need to adequately satisfy the NV-DEP that the air quality in the Las Vegas metropolitan non-attainment area will not be negatively impacted by the project. An applicant for a air quality construction permit in Arizona will need to adequately satisfy the Navajo Nation EPA that the air quality of all neighboring counties remain in attainment with the NAAQS.

- **BACT/LAER Analysis.** The developer of the new plant will need to demonstrate that their planned IGCC plant will be employ the Best Available Control Technology (BACT) for all criteria pollutants. BACT is defined as an emissions limitation based on the maximum degree of reduction which, on a case-by-case basis, is determined to be achievable taking into account energy, environmental, and economic impacts and other costs. Since IGCC power plants are just beginning to be permitted in the U.S., it is unknown whether a SCR system will be required. The close proximity of the Las Vegas 8-hour non-attainment area to the Mohave site may necessitate the use of an SCR to further reduce NO_X emissions. Low-NO_X burners (LNB) are standard for most new combustion turbines; with syngas firing, typical NO_X emission rates will be on the order of 25 ppmvd (at 15% O_2). Recent BACT determinations have required CO emission limits in the 9.0 to 25.0 ppmvd range. Because of the close proximity to the CO non-attainment area in Las Vegas, an oxidation catalyst (OC) may be required to reduce emissions by an additional 70% to 90%. The gasification process will remove most PM_{10}, SO_2 and H_2SO_4 from the syngas, and would be considered BACT.

- **Class I Area Impact Review.** The Clean Air Act Amendments of 1977 gave Federal Land Managers (FLM) an affirmative responsibility to protect the natural and cultural resources of Class I areas from the adverse impacts of air pollution. Class I areas include certain national parks and wilderness areas. FLM responsibilities include the review of air quality permit applications from proposed new major sources near Class I areas. If the FLM determines that emissions from a proposed source will contribute to adverse impacts on the air quality or visibility of a Class I area, then he may recommend to the NV-DEP that the permit be denied, unless the impacts can be mitigated.

  All new emission sources that have the potential to impact visibility in a Class I area will be subject to pre-construction review by the FLM. Visibility impacts are predicted using computer modeling (e.g., CalPUFF), and are generally a function of emissions of SO_2, SO_3, NO_X, PM_{10}, and ammonia. Sources located near a Class I area will be subject to more rigorous review, and if visibility impacts are predicted by the model, the permitting agency may impose more stringent emission requirements.

  The Mohave site is located near numerous Class I areas in California, Utah, and Arizona. Table 2-19 lists the distances between these Class I areas and Laughlin, Nevada.

Table 2-19 — Distances from Laughlin, Nevada, to Class I Areas

Class I Area	Distance (miles)
Domeland Wilderness Area (CA)	202
San Gabriel Wilderness Area (CA)	179

Class I Area	Distance (miles)
Cucamonga Wilderness Area (CA)	184
San Gorgonio Wilderness Area (CA)	139
San Jacinta Wilderness Area (CA)	144
Joshua Tree Wilderness Area (CA)	119
Grand Canyon National Park (AZ)	152
Sycamore Canyon Wilderness Area (AZ)	145
Pine Mountain Wilderness Area (AZ)	174
Mazatzal Wilderness Area (AZ)	195
Zion National Park (UT)	162

The Black Mesa site is located near numerous Class I areas in Arizona, Utah, Colorado, and New Mexico. Table 2-20 lists the distances between these Class I areas and Kayenta, Arizona.

Table 2-20 — Distances from Black Mesa Mine (Kayenta, Arizona) to Class I Areas

Class I Area	Distance (miles)
Grand Canyon National Park (AZ)	116
Sycamore Canyon Wilderness Area (AZ)	141
Pine Mountain Wilderness Area (AZ)	190
Mazatzal Wilderness Area (AZ)	181
Sierra Ancha Wilderness Area (AZ)	205
Petrified Forest National Park (AZ)	122
Zion National Park (UT)	158
Bryce Canyon National Park (UT)	119
Canyonlands National Park (UT)	99
Mesa Verde National Park (CO)	104
Weminuche Wilderness Area (CO)	160
San Pedro Parks Wilderness Area (NM)	188

- **Local Air Quality Permits.** The Clark County Department of Air Quality and Environmental Management (DAQEM) issues permits for all boilers and steam generators in the county. This permit would be applicable to the heat recovery steam generator (HRSG) that is a component of an IGCC plant. The permit application requests basic information, such as the manufacturer name, serial number, boiler rating (in hp), minimum and maximum rating per burner (in ft^3/hr or gal/hr), stack height and diameter, exhaust velocity and temperature, and capacity factor.

The Clark County DAQEM also issues permits for cooling towers. This permit application requests basic information, such as manufacturer name, serial number, circulation rate (in gal/min), maximum TDS (in ppm or mg/L) before purging, drift eliminators and drift loss percentage, and maximum hours of operation per day and per year.

- **Wastewater Discharge Permits.** The existing coal fired power plant (2 x 790 MW) sends its cooling tower blowdown and other plant discharges to a series of lined evaporation ponds. Domestic wastewater from the plant is also treated and sent to evaporation ponds. No plant effluent is discharged to any surface or ground waters of the United States. New IGCC plants at the Mohave or Black Mesa sites would likely use a zero liquid discharge (ZLD) system.

The liquid effluent from a new IGCC plant at the Mohave site would be considerably greater than an NGCC plant, especially if slurry coal were to be used in the gasifier. It is not known whether the existing evaporation ponds could accommodate the additional load or a new evaporation pond will be needed.

Although a traditional National Pollutant Discharge Elimination System (NPDES) permit would not be required, the ZLD system would still require permitting approval from the NV-DEP. The existing permit for Mohave Station (permit #NEV30007) requires leak detection systems for the ponds at the site. Such methods include geophysical survey equipment, visual sump inspections, visual liner inspections, and monitoring wells. There are no flow limitations in the permit, except for the package sewage treatment plant design capacity of 36,000 gallons per day.

There are currently areas of groundwater contamination (high mineral content) on the site from leaking ponds that occurred in the early years of the plant. The existing permit requires an on-going remediation program to bring the groundwater quality to an electrical conductivity below 1,000 microsiemens. The site groundwater is expected to be completely remediated by July 2007.

A new IGCC plant at Mohave would use the existing ZLD system at the site, or it would require the construction of new ponds to accommodate plant effluent. In either case, the permit with the NV-DEP would need to be revised. This revision would require a public comment period and a public hearing before final issuance of the permit. The total time required for this permit revision could range from 6 months to 1 year.

A ZLD system at the Black Mesa site would require permitting approval from the Navajo Nation EPA – Surface and Groundwater Protection Department. The historic mining and water withdrawals (to operate the coal slurry pipeline) at the site have affected the groundwater quality, so any new discharges to the surface or groundwater would require substantial impact modeling. The Navajo Nation EPA issues NPDES permits for discharges to the surface water bodies, and Underground Injection Control permits for discharges into deep wells. The maximum contaminant levels (MCLs) for drinking water must not be exceeded if the IGCC plant discharged to the surface or groundwater.

During construction, the site would require a General Number 2 NPDES permit (storm water discharges from construction activities) from the Nevada DEP or the Navajo Nation EPA. As part of this permit, the construction contractor would need to create a Storm Water Pollution

Prevention Plan (SWPPP), which details the measures for preventing debris from entering local streams. A SWPPP typically performs the following functions:

— Identifies all potential sources of pollution which may reasonably be expected to affect the quality of storm water discharges from the construction site
— Describes practice to reduce and sequester pollutants in the storm water discharges
— Assures compliance with the terms and conditions of the General Number 2 NPDES permit

- **U.S. Army Corps of Engineers Permits.** It is unlikely that there are any jurisdictional wetlands in this arid region of the United States, requiring a permit from the U.S. Army Corps of Engineers. However, if a new natural gas pipeline connection to the site crossed any "waters of the United States," including dry creek beds, then a Nationwide Permit #12 (Utility Line Activities) would be required. This general permit allows installation of a pipeline underneath the river or creek, but requires that the water body be returned to its original condition.

- **Solid Waste Disposal Permits.** At an IGCC plant, the gasification process results in a vitreous coal waste. There may be some recycling options for this waste, although an on-site landfill will be the most likely fate.

  The existing coal-ash landfill at the Mohave site may be able to accommodate the additional load from a new IGCC plant. However, if the landfill would need expansion, then a permit from the Clark County Health District – Office of Solid Waste & Compliance would be required. The height and slope limits of the landfill will be set by the County.

  At the Black Mesa site, the coal waste could potentially be disposed in areas of prior mining, as part of an overall land reclamation process. The permitting of a coal waste landfill is under the auspices of the Navajo Nation Division of Community Development – Solid Waste Management Program. The landfill design would need the appropriate clay and geo-membrane liners, leachate collection systems, groundwater monitoring wells, and other typical requirements. The height and slope limits of the landfill will be set by the Navajo Nation.

  The permit application will request information such as the engineering specifications, environmental monitoring plan, closure plans, and financial assurance documentation. The total time required for a new solid waste landfill permit could range from 6 months to 1 year.

  During construction, hazardous and non-hazardous wastes would be disposed of off-site using a licensed commercial hauler. The plant should make a concerted effort to reuse or recycle construction debris and excavated material.

- **Public Utility Commission of Nevada (PUCN).** Any new power generation facility in the State of Nevada will require a Certificate of Public Convenience and Necessity (CPCN) from the PUCN. To obtain a CPCN, an applicant must demonstrate that there is a public need for a new facility and that the proposed utility is willing to serve and able to fulfill the public need.

- **Arizona Corporation Commission.** The Arizona Corporation Commission (ACC) typically regulates providers of electric service in Arizona and approves the siting of new power plants. They issue Public Convenience and Necessity (CPCN) determinations for investor-owned and cooperative utilities. However, the ACC does not have authority over power plant siting in tribal lands. A new IGCC plant at the Black Mesa Mine site would not require ACC approval.

Any new transmission lines or natural gas pipelines that exit Navajo County may be subject to the ACC regulations.

- **Zoning / Land Use Permits.** The Mohave site is currently zoned for power plant use. It is assumed that a new IGCC power plant could be located entirely within the existing site. While there is no need to obtain a zoning change, the project developers will still need to submit a "Major Project Application: Specific Plan or Land Use & Development Guide" with the Clark County Department of Development Services. This guide costs $1,000 plus $4 per acre (for all acres over 300 acres). The applicant needs only to submit a description of the project and the location of the property (parcel numbers).

  It is possible that some of the landscaping, parking, and fencing requirements have changed since the original plant was built. The Clark County Department of Development Services maintains an Industrial Development Checklist with all of the applicable conditions.

  The Black Mesa Mine site is currently zoned for mining. A new IGCC power plant at the site would require a zoning change from the Navajo Nation Division of Community Development.

- **Building Permits.** For the Mohave site, the Clark County Department of Development Services issues all building and civil design permits. For the Black Mesa site, the Navajo Nation Division of Community Development – Design and Engineering Services issues all building permits. These permits are typically obtained throughout construction, and the applications are submitted in phases. The first permits are for grubbing, grading, and other necessary earthwork. Next are the foundation permits for all buildings, warehouses, equipment skids, cooling towers, and so forth. Structural permits come next, as the building fabrications begin. These are followed by plumbing, mechanical (i.e., HVAC), electrical, and fire protection permits for all occupied buildings. The offices, control room, restrooms, and showers will need to be handicap accessible. There will likely be periodic inspections of the construction site by building inspectors and fire officials.

  Obtaining building permits for a major project, such as a power plant, will require continuous interaction with Clark County or Navajo Nation staff. It is recommended that the project team meet with the appropriate Development Services personnel to establish a submittal schedule and determine how drawings and calculations will be submitted. In some instances a local permit expediter may need to be hired in order to accelerate the permitting process.

- **Other Permits.** A number of minor permits will be required for construction of an IGCC power plant at the Mohave or Black Mesa sites. The delivery of plant equipment in overweight or oversized trucks would require a special use permit from the Nevada Department of Transportation or Arizona Department of Transportation for state highways, or the Navajo Department of Transportation (NDOT) for tribal roads. NDOT also grants archeological clearance for major projects. The construction of a tall stack would require an Obstruction Hazard Determination from the Federal Aviation Administration.

  An IGCC power plant could potentially use fuel oil for startup operations, fire pumps, and emergency generators. Any large petroleum storage tank at the site (>1,100 gallons aboveground, any size below ground) would require a permit from the Clark County Fire Marshall. In addition, the site would need to update its Spill Prevention Control and

Countermeasure (SPCC) plan to account for the new tanks. The SPCC plan (spelled out in 40 CFR Part 112) details how potential spills of petroleum products would be contained.

2.9 CONCEPTUAL PROJECT CONSTRUCTION SCHEDULE

The amount of time required to complete an IGCC facility is about 5 to 6 years from the decision to begin. Actual construction can be accomplished in about 3½ years, which will be followed by a period of about 6 months for startup and commissioning of the plant equipment. The more critical timing aspect is in the front-end decision process and selection of a technology and in the amount of time required to receive permitting and all approvals necessary to begin construction. These periods are shown in the typical schedule shown in Appendix G.

2.10 GENERATION PROFILE AND LOAD DEMAND

The output of the IGCC facility is typical of a baseloaded combined-cycle combustion turbine. The output from the plant will be influenced by the ambient temperatures. In general, power output will improve with decreasing temperatures and decrease with increasing temperatures. The graphs in Section 2.2.6 (Figure 2-6 through Figure 2-10) can be used to assess the variation in output with temperature.

The overall output from the plant is a function of the configuration, that is, a 2 x 2 x 1 combustion turbine, HRSG, and steam turbine of 540 MW in the base case. Lower outputs depend on the extent of carbon dioxide capture desired. The plant can be adjusted in scale by changing the number of combustion turbines installed at the site. The combinations of plant configurations possible and the outputs possible are listed in Table 2-21. It is not possible to select a specific output for an IGCC facility (e.g., 700 MW) since the combustion turbine equipment and associated steam turbine output and auxiliary power demand determine the plant capacity for each configuration.

Table 2-21 — Output for Alternative IGCC Facility Configurations

Configuration	Net output, MW		
	No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
1x1x1	269	260	228
2x2x1	**549**	**531**	**482**
3x3x1	812	786	689

Configuration	Net output, MW		
	No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
4x4x2	1,084	1,049	919
5x5x2	1,356	1,312	1,150

2.11 EMPLOYMENT CHARACTERISTICS

2.11.1 Construction Labor

Table 2-22 provides the anticipated craft labor estimate for the types and duration of skilled workers needed to construct an IGCC facility. The estimated total is 4,110 man-months. Peak work force on site is anticipated to average 120 craft labor workers over about two years. Additional construction supervision, engineering, and site support is required, but was not directly estimated.

Table 2-22 — Construction Labor Estimate

Craft	Man-Months
Insulation Workers	220
Boilermakers	650
Cement Finishers	50
Carpenters	380
Electricians	860
Ironworkers	450
Laborers	390
Millwrights	140
Operating Engineers	200
Painters	80
Pipe Fitters	430
Sheet Metal Workers	100
Surveyors	90
Teamsters	70
Total	4,110
Peak Labor	120

2.11.2 Operations and Maintenance Labor

The labor force required to operate the facility assumes a labor force necessary for performance of all functions of the facility with minimal subcontracting for routine services (such as coal analysis). Assumed total operating staff is based on five shifts. It is assumed that routine labor costs approximately 1/3 of total maintenance cost and is performed by technicians on site because of the relatively remote nature of both sites from areas where industrial trades can be readily called upon to service the plant equipment. Contract labor is assumed for a percentage of maintenance costs that cannot be accommodated by the plant staff. Maintenance material is a percentage of capital equipment, using the IECM factors.

Administration and other staff include shift supervision, engineering, laboratory staff, plant management, and clerical support.

Labor costs are assumed to be $70,000 per year per person averaged across the entire work force. S&L has found that this is a reasonable assumption when estimating aggregate power generation plant budgets for total labor for all persons at the plant in all job categories. For this level of study, it is not necessary to perform a detailed cost analysis for each job description.

The staffing and maintenance costs are summarized in Table 2-23.

Table 2-23 — Labor and Maintenance Cost Estimate for IGCC

	No CO_2 Removal	CO_2 Removal without Shift Conversion	90% CO_2 Removal
Operating Labor Staff	145	155	155
Onsite Maintenance Staff (1/3 of Maintenance Labor)	20	30	40
Administration and Eng. Other Staff	41	41	41
Total Labor Staff	206	236	236
Total Cost of Labor, M$/yr	$ 14.42	$ 16.52	$ 16.52
Contract Labor, M$/yr	$ 3.16	$ 6.56	$ 6.56
Maintenance Material Costs, M$/yr	$ 9.22	$ 12.19	$ 15.27
Maintenance Labor Costs, M$/yr	$ 4.56	$ 6.54	$ 9.36

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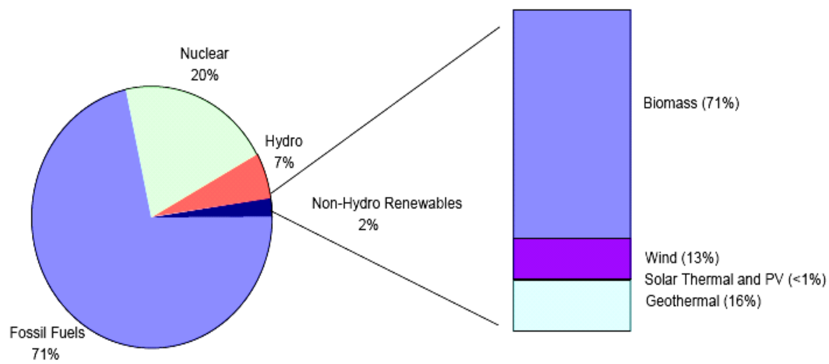
3. SOLAR TECHNOLOGY

In 2003, the United States generated 3,883 billion kilowatt-hours of electricity (Energy Information Administration, *Electric Power Annual*, December 2004). About 71% of United States electricity was generated from fossil fuels, about 20% from nuclear power, another 7% from hydroelectric facilities, and the remaining 2% from other renewables (Figure 3-1). Biomass (71%) was the predominant non-hydro renewable fuel for electricity generation in 2003, followed by geothermal and wind. Solar thermal and photovoltaics together accounted for less than 1% of U.S. non-hydro renewable generation.

Figure 3-1 — United States Electricity Generation, 2003



Source: Energy Information Administration, *Electric Power Annual 2003*, December 2004 and *Electric Power Monthly*, November 2004

The most important law promoting renewable energy in the 1990s was the Energy Policy Act (EPACT) of 1992. EPACT established a 10-year inflation-adjusted production tax credit (PTC) of 1.5 cents per kWh for tax-paying privately and investor-owned wind projects and closed-loop biomass plants brought online between 1994 and 1999. The incentive expired in 1999, but had been renewed twice, in 1999 and 2001, before its expiration at the end of 2003. Late in 2004, it was extended again through 2005. This latest extension increased the number of renewable technologies that are covered by the incentive. While EPACT significantly improved the economics of wind power, another U.S. policy, implemented thus far at a state level, has been more beneficial to the installation of solar photovoltaic generation. This policy is net metering, which allows small producers of renewable energy from selected sources to sell their power back to the grid. The buyback rate is determined by law and is frequently equal to the retail electricity rates, or sometimes slightly less than retail rates. Net metering programs are designed for small electricity customers (residential or small commercial) who produce their own power to bank power on the grid in times of surplus and draw down from the grid in times of need. As of September 2004, net metering was available in 32 states and the District of Columbia (DSIRE, “Rules Regulations and Policies,” http://www.dsireusa.org/summarytables/reg1.cfm). Most states set size limits on systems for net metering eligibility with many states having capacity limits of around 25 kW, though limits vary from 10 kW in New Mexico to 1,000 kW in California (DSIRE, “Net Metering Programs,” http://www.dsireusa.org/library/docs/ NetMetering_Map.doc).

The limited generation provided by solar thermal and photovoltaics is primarily due to high capital cost, which is partially, but not entirely, offset by lower O&M costs. Dispatchability is another important issue. Besides being more costly than conventional generating sources, concentrating solar power (CSP) electricity generation is also more costly than certain other renewable power generating technologies (notably wind) due primarily to CSP’s higher capital cost. CSP cost-competitiveness relative to other renewables is important because CSP will be compared with other renewable technologies in states that have adopted renewable portfolio standards.

3.1 CONCENTRATING SOLAR POWER TECHNOLOGIES

Two types of CSP applications were investigated: dispatchable power systems and distributed power systems. Dispatchable power systems are capable of providing dispatchable intermediate-load generation in the wholesale bulk-power market, such as the Mohave Generating Station. Distributed power systems provide distributed generation, grid support, remote, and village power markets. Distributed energy resources are parallel and stand-alone electric generation units located within the electric distribution system at or near the end user.

There are four CSP technologies being promoted internationally:

- Parabolic trough
- Dish/Stirling engine
- Power tower
- Photovoltaics

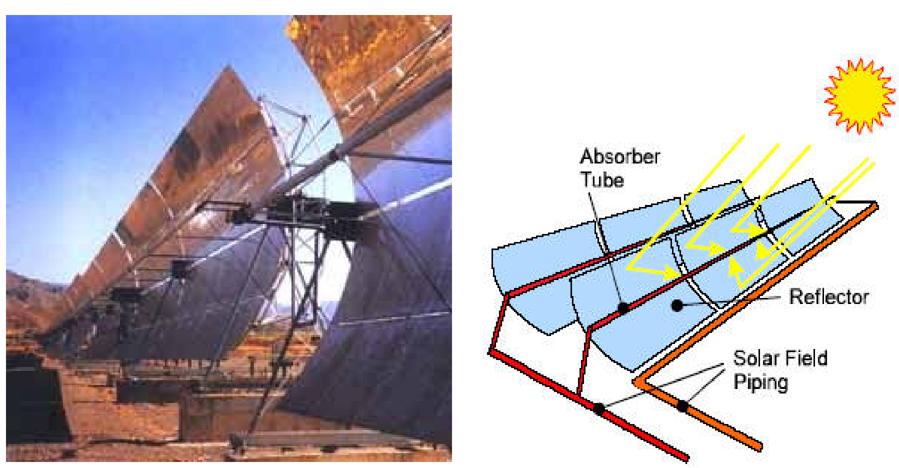
For each of these, there exist several design variations or different configurations. The amount of power generated by a CSP plant depends on the amount of direct sunlight. These technologies use only direct-beam sunlight, rather than diffuse solar radiation.

3.1.1 Parabolic Trough

Parabolic-trough systems concentrate the sun's energy through long rectangular, curved (U-shaped) mirrors. The solar field is modular and is composed of many parallel rows of solar collectors aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector that focuses the sun's direct beam radiation on a linear receiver located at the focus of the parabola. The collectors track the sun from east to west during the day to ensure that the sun is continuously focused on the linear receiver. A heat transfer fluid (HTF) is heated as it circulates through the receiver and returns to a series of heat exchangers in the power block where the fluid is used to generate high-pressure superheated steam. The superheated steam is then fed to a conventional reheat steam turbine-generator to produce electricity. The spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers via condensate and feedwater pumps to be transformed back into steam. After passing through the HTF side of the solar heat exchangers, the cooled HTF is recirculated through the solar field.

Parabolic trough technology is currently the most proven solar thermal electric technology. This experience is primarily the result of the nine commercial-scale Solar Electric Generating Station (SEGS) solar power plants, the first of which has been operating in the California Mojave Desert since 1984. These plants, which continue to operate daily, range in size from 14 to 80 MW and represent a total of 354 MW of installed electric generating capacity.

Figure 3-2 — Parabolic Trough Concept



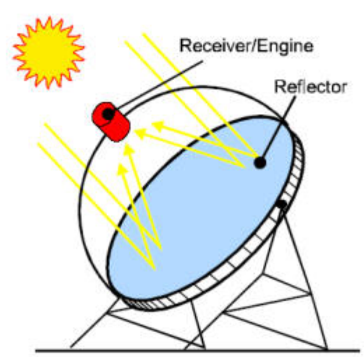
3.1.2 Dish/Stirling engine

A dish/engine system uses a mirrored dish (similar to a very large satellite dish). The dish-shaped surface collects and concentrates the sun's heat onto a receiver, which absorbs the heat and transfers it to a working gas within the engine. The heat causes the gas to expand against a piston or turbine to produce mechanical power. The mechanical power is then used to run a generator or alternator to produce electricity.

Dish/engine systems are characterized by high efficiency, modularity, and autonomous operation. Of all solar technologies, dish/engine systems have demonstrated the highest solar-to-electric conversion efficiency (29.4%) and, therefore, have the potential to become one of the least expensive sources of renewable energy. The modularity of dish/engine systems allows them to be deployed individually for remote applications, or grouped together for small-grid or end-of-line utility applications.

There are no commercial dish-Stirling power plants operating today. Current development in the United States is focused on prototype system of 10 units in active development and testing at Sandia National Laboratories (SNL) under a joint agreement between Stirling Engine Systems (SES) (Phoenix) and Sandia. In early August 2005, Southern California Edison publicly announced the completion of negotiations on a 20-year power purchase agreement with SES for between 500 MW and 850 MW of capacity (producing 1,182 to 2,010 GWh/yr) from the first commercial deployment of this new solar thermal generating technology. SES also signed an agreement for between 300 and 900 MW with San Diego Gas and Electric in September 2005.

Figure 3-3 — Dish/Stirling Engine Concept



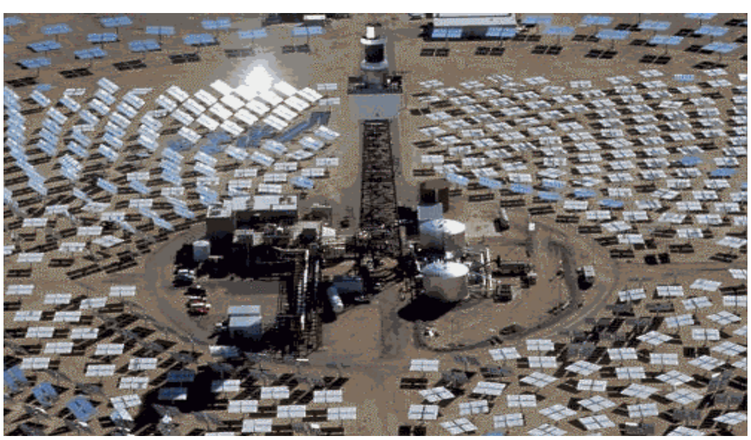
3.1.3 Power Tower

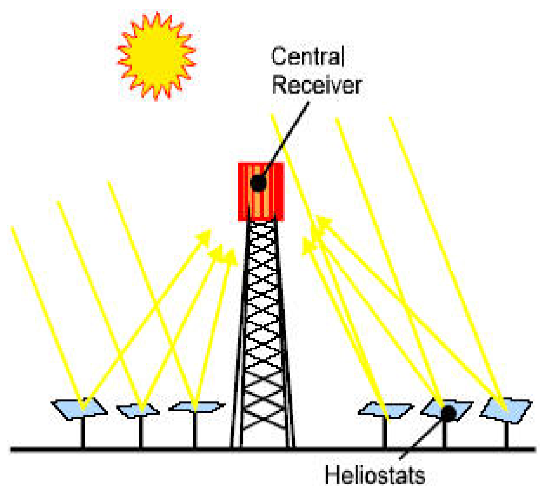
Solar power towers generate electric power from sunlight by focusing concentrated solar radiation on a tower-mounted heat exchanger (receiver). The system uses hundreds to thousands of sun-tracking mirrors called heliostats to reflect the incident sunlight onto the receiver.

In a molten-salt solar power tower, liquid salt at 290ºC (554ºF) is pumped from a ‘cold’ storage tank through the receiver where it is heated to 565ºC (1,049ºF) and then on to a ‘hot’ tank for storage. When power is needed from the plant, hot salt is pumped to a steam generating system that produces superheated steam for a conventional Rankine cycle turbine-generator system, similar to that used in the parabolic-trough system. From the steam generator, the salt is returned to the cold tank where it is stored and eventually reheated in the receiver.

Power tower plants are commercially less mature than parabolic-trough systems, are not modular, and cannot be built in the smaller sizes of dish/Stirling or trough-electric plants and be economically competitive. There are currently no commercial power tower plants in operation. Experimental and prototype systems have been placed in operation in Spain, France, Israel, and the United States, the largest of which were the two 10-MW Solar One and Solar Two plants near Barstow, California.

Figure 3-4 — Power Tower Concept





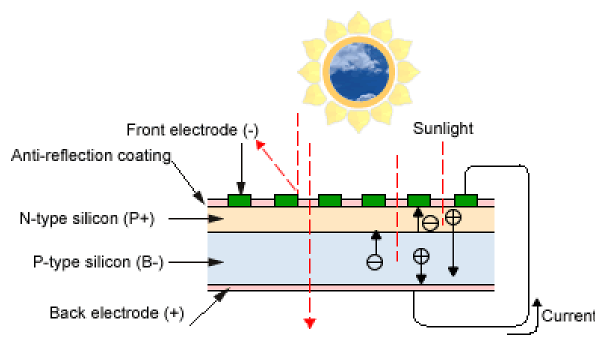
3.1.4 Photovoltaics

Concentrating photovoltaic (CPV) systems use lenses or mirrors to concentrate sunlight onto high-efficiency solar cells. These solar cells are typically more expensive than conventional cells used for flat-plate photovoltaic systems. However, the concentration decreases the required cell area while increasing the cell efficiency.

Photovoltaic output is dc voltage and an inverter is required to convert to ac voltage.

There are no commercial CPV power plants in operation. A series of pre-commercial development systems totaling 500 kW are operating in Arizona under the auspices of Arizona Public Service (APS), and a 200+ kW system is in operation in Australia. Planned deployments in the near future include 5 MW by APS, several megawatts in Australia, and an undetermined level in Europe.

Figure 3-5 — Photovoltaic Concept



3.2 SOLAR RESOURCE

The total amount of convertible solar energy (direct normal insolation) is measured in kilowatt-hours per square meter per day (kWh/m^2/day). At high noon on a clear day, with the sun directly overhead, each square meter receives 1 kilowatt of sun power. If the solar resource in an area is 6 kWh/m^2/day that means the actual power realized in a day is equal to 6 hours of full sun. Insolation values of 8 to 9 kWh/m^2/day are considered premium; values of 7 to 8 kWh/m^2/day, very good; and values of 6 to 7 kWh/m^2/day, good.

An insolation map developed by the U.S. Department of Energy – National Renewable Energy Laboratory (NREL) is provided in Figure 3-6. The majority of the Navajo/Hopi reservations area is shown to have a very good insolation value of 7 to 8 kWh/m^2/day.

Figure 3-6 — CSP Resource Potential

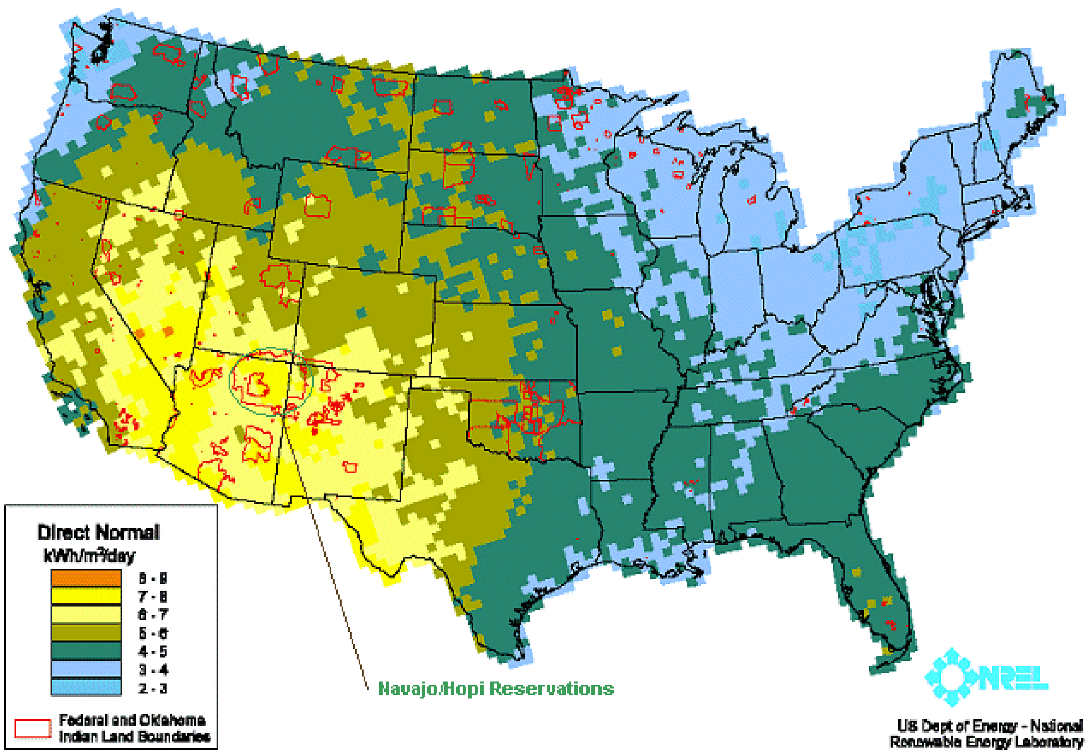
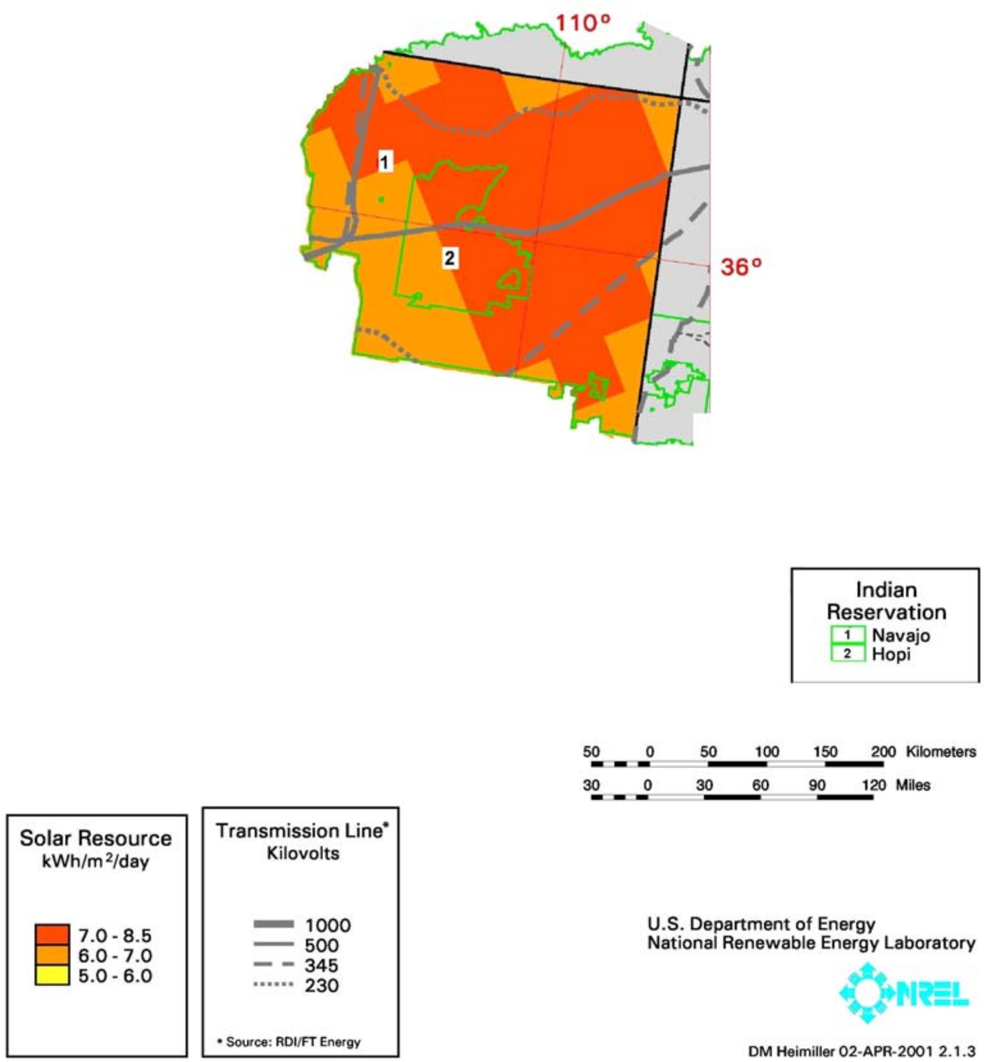


Figure 3-7 presents the NREL CSP resource map for the Arizona reservations area. The majority of the Navajo/Hopi reservations reside in Arizona. Figure 3-7 also indicates that two 1,000-kV, two 345-kV, and one 230-kV transmission lines are within the 7 to 8 kWh/m^2/day insolation area. For dispatchable power systems, location near existing high-voltage transmission lines is desirable to reduce cost. Construction of a transmission line, excluding the electrical substation, can cost between $500,000 and $1,500,000 per mile, depending on voltage, terrain, access, and any required upgrades to the grid.

Figure 3-7 — Arizona CSP Resource Map



3.3 CSP TECHNOLOGY COMPARISON

In this subsection, the four CSP technologies—parabolic trough, dish/Stirling engine, power tower, and concentrating photovoltaics—are compared with respect to the following characteristics:

- Current technology status
- Load profile compatibility
- Capital costs

- O&M costs
- Land area requirements
- Water usage

3.3.1 Current Technology Status

3.3.1.1 Parabolic Trough

Parabolic trough technology is currently the most proven solar thermal electric technology. Nine commercial-scale SEGS solar power plants are operating in the California Mojave Desert, with the first unit operating since 1984. These plants range in size from 14 to 80 MW electric (MWe) and represent a total of 354 MWe of installed electric generating capacity. The primary developers of this technology include Solargenix Energy (USA), Solel Solar Systems (Israel), and Solar Millennium (Germany). Suppliers of components for trough systems include reflector supplier Flabeg (Germany) and receiver suppliers Schott Glass (Germany) and Solel Solar Systems. New commercial projects are either in the planning or active project development stage. At present, there are four new active projects: 50-MW project in Nevada, 1-MW project in Arizona, and two 50-MW projects to be developed in two stages in Spain.

3.3.1.2 Dish/Stirling engine

Solar dish/engine systems are being developed for use in emerging global markets for distributed generation, remote power, and grid-connected applications. Individual units, ranging in size from 10 to 25 kW, can operate independently of power grids. There are no commercial dish/Stirling power plants operating today. Current development in the United States is focused on prototype system of 10 units in active development and testing at Sandia National Laboratories under a joint agreement between Stirling Engine Systems, Phoenix, Arizona, and SNL. Additional prototype systems are planned before implementation of large-scale grid-connected systems. Contracted deployments are as follows:

- SES 25-kW demonstration dish, Eskom, South Africa.
- 10-kW Schlaich Bergermann und Partner (SBP) dish providing power to grid in Spain.

In early August 2005, SCE publicly announced the completion of negotiations on a 20-year power purchase agreement with Stirling Energy Systems for between 500 and 850 MW of capacity (producing 1,182 to 2,010 GWh/year) from the first commercial deployment of a new solar thermal generating technology. According to SES, the commercial, grid-connected dish/engine (Stirling) plant is to begin construction in 2008.

The plant will be located in the Mojave Desert and consist of 20,000 dish/engines. SES also signed an agreement for between 300 and 900 MW with San Diego Gas and Electric in September 2005.

3.3.1.3 Power Tower

Power towers are commercially less mature than parabolic trough systems. The largest power towers built to date are the 10-MWe Solar One and Solar Two demonstration plants in southern California, neither of which is operating at present. The Solar One pilot plant operated from 1982 to 1988. The Solar Two plant was a retrofit of Solar One to demonstrate the advantages of molten salt for heat transfer and thermal storage. Experimental and prototype systems have been placed in operation in Spain, France, Israel, and the United States, the largest of which were the Solar One and Solar Two demonstration plants previously described. There are no definitive power tower projects either contracted or confirmed.

3.3.1.4 Concentrating Photovoltaics

Current technology is characterized by the following:

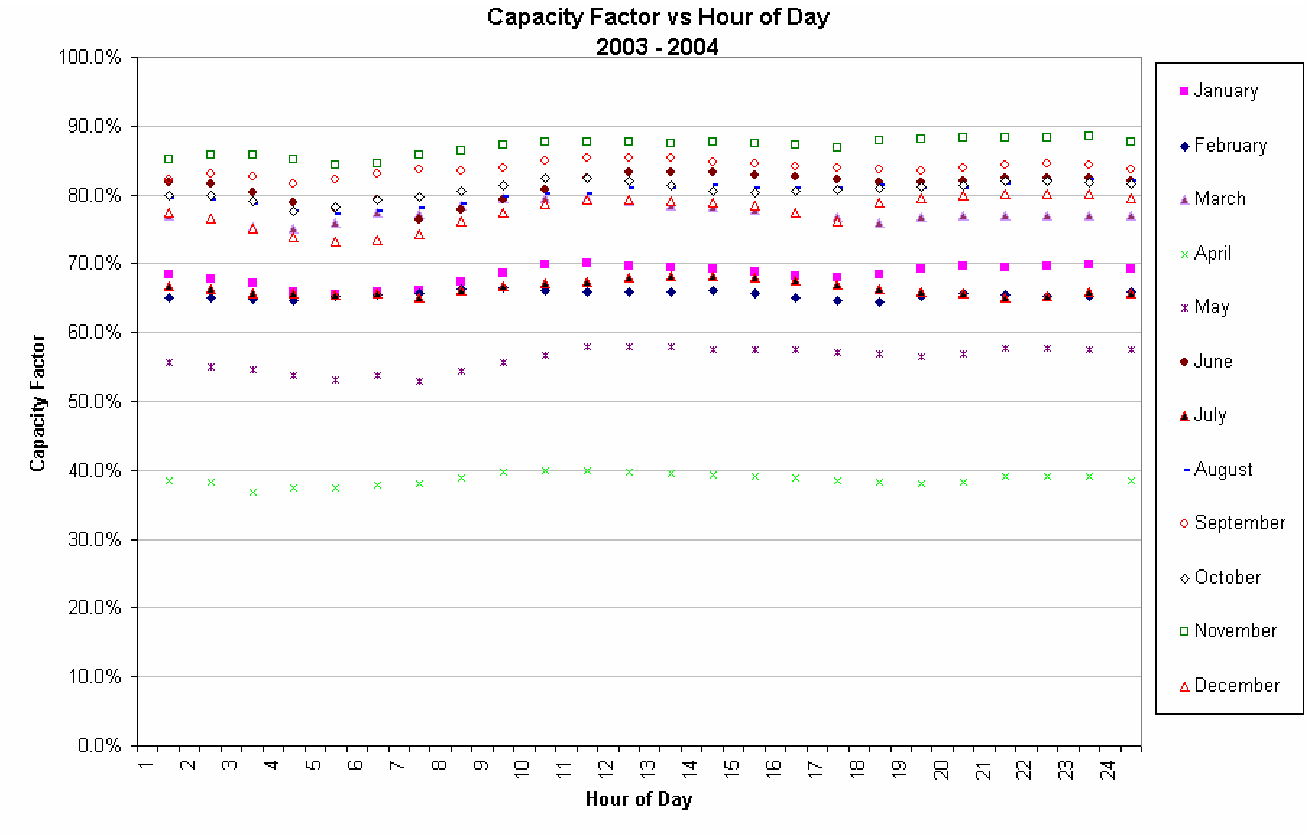
- 25- to 35-kW CPV systems.
- Two-axis tracking structure.
- 350-square-meter concentrator.
- 3M acrylic lens concentrator at 250 times, or parabolic dish with photovoltaics at the focal point.
- Receiver using inexpensive silicon solar cells, or advanced cell multi-junction technology.

There are no commercial CPV power plants in operation. A series of pre-commercial development systems totaling 500 kW are operating in Arizona under the auspices of APS, and a 200+ kW system is in operation in Australia. Planned deployments in the near future include 5 MW by APS, several megawatts in Australia, and an undetermined level in Europe.

3.3.2 Load Profile Compatibility

The load profile, that is, the capacity factor versus hour of the day for a 12-month period, of the Mohave Generating Plant for 2003–2004 is depicted in Figure 3-8. The load profile indicates the Mojave Generating Plant operates in a baseload mode with a relatively constant capacity factor over a 24-hour period for any particular month, with operation at a 60% or greater capacity every month except April (approximately 40%) and May (approximately 55%).

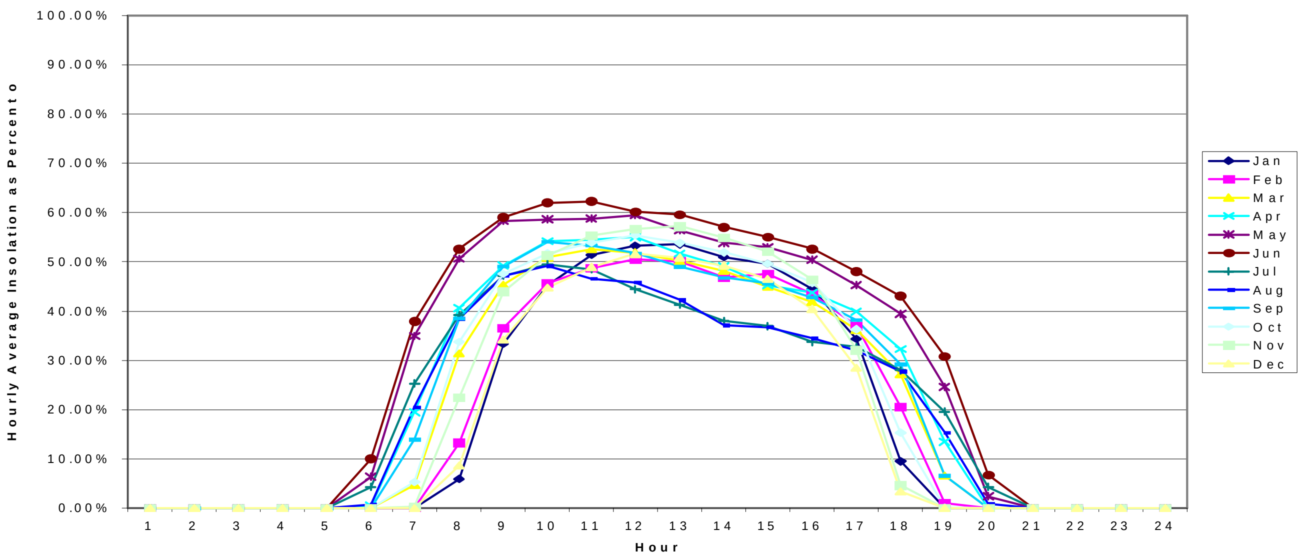
Figure 3-8 — Load Profile for Mojave Generating Plant



NREL data for normal solar insolation at ground level for the period 1981–1990 in the vicinity of Flagstaff, Arizona,[1] were obtained. In order to estimate the output of a solar plant, this information was averaged for each hour of the day for each month of the year. The data were normalized to the maximum insolation value during the 10-year period so that this maximum value of insolation represents 100% output. Results are shown in the following figure.

[1] Data available at http://rredc.nrel.gov/solar/old_data/nsrdb/hourly/

Figure 3-9 — Monthly Average Expected Hourly Output from Solar Technology without Energy Storage



Since all CSP technologies require sunlight to produce power, thermal storage or a hybrid configuration would be necessary to match the existing Mohave Generating Plant load profile.

3.3.2.1 Thermal Storage

Thermal storage stores solar-generated thermal energy for use during non-sunlight periods. As previously noted, the annual average insolation value for the majority of the Navajo/Hopi reservations area is 7 to 8 kWh/m^2/day, equivalent to 7 to 8 hours of full sun. To match the highest capacity factor of approximately 88% of the existing Mohave Generating Plant, the load profile would require approximately 15 to 16 hours of storage.

The first commercial SEGS 14-MWe parabolic-trough CSP plant (1984 vintage) included 3 hours of thermal storage, a simple two-tank storage system that used the plant's HTF for a storage medium. However, the later SEGS plants operated at higher temperatures that precluded the same method due to the higher vapor pressure and high cost of the HTF. No thermal storage technology has been commercially demonstrated for the higher solar field operating temperatures (approximately 400°C) required for the more efficient steam cycles in the later SEGS plants.

The Solar Two power tower CSP plant produced 10 MW of electricity with enough thermal storage, using a two-tank molten-salt storage system, to continue to operate the steam turbine at full capacity for 3 hours after the sun had set. However, the Solar Two 1988 demonstration was only one week of continuous operation.

For parabolic-trough and power-tower CSP technologies, thermal storage costs range from $35 to $70 per kWh. The capital cost for each hour of 885-MW storage ranges from $28,000,000 to $60,000,000. In addition to the cost of storage, the solar field capital cost increases since the solar field has to be larger to provide the heat input to the storage system. For 15 to 16 hours of storage, the solar field would be approximately 4 times larger than without storage. Thus, it is not practical for 15 to 16 hours of 885-MW storage due to the high cost.

Since dish/Stirling engine units are self-contained modules without a circulating medium to transfer heat to a storage system, thermal storage is not considered realistic. The same is true for concentrating photovoltaics; although battery energy storage could be considered, it would be prohibitively expensive and massive.

3.3.2.2 Hybrid Configuration

CSP-fossil hybrid options are possible with a natural gas combined-cycle and coal-fired or oil-fired conventional steam-Rankine power cycle, which would use fossil fuel to supplement the solar output during periods of low solar radiation. All of the SEGS parabolic-trough plants are "hybrids," utilizing natural gas-fired boilers to generate electricity during low-insolation periods. The SEGS plants are limited, however, to a maximum usage of 25% natural gas on a total heat input basis.

Currently, there are no commercial or prototype hybrid power tower, dish/Stirling engine, or concentrating photovoltaics systems.

To match the existing Mohave Generating Plant load profile, a CSP-fossil hybrid plant would require a 885-MW natural gas combined-cycle, coal-fired or oil-fired conventional steam-Rankine power plant, which defeats the objective of replacing the fossil-fueled plant.

3.4 CAPITAL COSTS

Current capital cost estimates for the CSP technologies are highly speculative since the last commercial-scale CSP plant was built in 1990 (the SEGS IX parabolic-trough plant) and the current dish/engine (Stirling) and concentrating photovoltaics plants are small demonstration plants. The current capital cost estimates presented here are based primarily on NREL data and publicly available CSP technical information. The costs presented below do not include thermal storage for any of the technologies for comparative purposes.

Table 3-1 — Estimated Current Capital Costs for CSP Technologies

2005$	Parabolic-trough	Power Tower	Dish/ Stirling Engine	Concentrating Photovoltaics
Direct Cost, $/kW	$2,500*	$2,800*	$3,000**	$8,000

* 100 MW plant without storage

**Based on Stirling Engine Systems information for first 50 MW deployment

The capital costs for the CSP technologies are notably higher than for a conventional coal-fired plant ($1,600–$1800/kW) or a combined-cycle plant ($600–$800/kW).

3.5 OPERATING AND MAINTENANCE COSTS

Similar to the capital cost estimates, O&M costs for the power tower, dish/Stirling engine, and concentrating photovoltaics plants are highly speculative since current plants are small demonstration plants. The O&M cost estimates presented here for these technologies are based primarily on NREL data. O&M costs for the parabolic-trough plant are based on actual data from the existing SEGS plants. The estimated costs are presented below.

Table 3-2 — Estimated O&M Costs for CSP Technologies

2005$	Parabolic Trough	Power Tower	Dish/Stirling Engine	Concentrating Photovoltaics
Fixed, $/kW-yr	$33	$30	$3	$3
Variable, $/MWh	$30	$30	$11	$5

The higher fixed O&M costs for parabolic trough and power tower reflect the staffing requirements, mainly due to the Rankine-cycle portion of the plant.

3.6 LAND AREA REQUIREMENTS

Approximate plant area requirements for each CSP technology is provided below.

Table 3-3 — Approximate Area Required for CSP Technologies

	Parabolic Trough	Power Tower	Dish/Stirling engine	Concentrating Photovoltaics
Acres per MW	6	5	4	10
For 885 MW				
Acres	5,310	4,425	3,540	8,850
Square Miles	8.3	7.0	5.5	14.0

For comparison, the 1,580-MW Mohave Generating Plant occupies approximately 2,490 acres (1.6 acres per megawatt).

As previously noted, thermal storage will increase the area requirements. For 15 to 16 hours of thermal storage for parabolic trough or power tower, the solar field is approximately 4 times larger than shown in Table 3-3.

3.7 WATER USAGE

Approximate water usage is tabulated in Table 3-4.

Table 3-4 — Approximate Water Usage for CSP Technologies

	Parabolic Trough	Power Tower	Dish/Stirling Engine	Concentrating Photovoltaics
Cooling Tower Makeup (gal/MWh)	700	700	0	0
Rankine-Cycle Makeup (gal/MWh)	16	16	0	0
Mirror Washing (gal/MWh)	2	2	1	1*
Total Gallons per MWh	718	718	1	1

* Based on dish/Stirling engine value.

For an 885-MW plant at 72% capacity factor (equivalent to the Mohave Generating Plant's capacity factor), the estimated water usage per year is shown in Table 3-5.

Table 3-5 — Approximate Water Usage for 885-MW Plant at 72% Capacity Factor

	Parabolic Trough	Power Tower	Dish/Stirling Engine	Concentrating Photovoltaics
Cooling Tower Makeup, (gal/yr)	4,000,000,000 or 0 (with dry cooling)	4,000,000,000 or 0 (with dry cooling)	0	0
Rankine-cycle Makeup, (gal/yr)	90,000,000	90,000,000	0	0
Mirror Washing, (gal/yr)	11,000,000	11,000,000	6,000,000	6,000,000*
Total (gal/yr)	4,101,000,000 or 101,000,000 (with dry cooling)	4,101,000,000 or 101,000,000 (with dry cooling)	6,000,000	6,000,000
Total (acre-ft/yr)	12,585.5 or 310 (with dry cooling)	12,585.5 or 310 (with dry cooling)	18.4	18.4

* Based on dish/Stirling engine value.

For the parabolic trough and power tower Rankine-cycle portion, cooling systems are required to condense the steam at the turbine exhaust and to maintain the design turbine back pressure. The water requirement for the cooling tower is the result of evaporative cooling. This large water usage can be reduced with an air-cooled system. There are two types of air-cooled systems: direct and indirect. Direct systems duct the steam to air-cooled condensers that can be either mechanical or natural draft units. Indirect systems condense the steam in water-cooled surface condensers. The heated water is then pumped to air-cooled heat exchangers, where it is cooled and then re-circulated to the steam condenser. Both systems are commercially available for utility-sized power plants. Air-cooled systems reduce water use at a plant by eliminating the use of water for steam condensation. With an air-cooled system, the capital cost of the plant will increase by approximately 4% to 8%, and power output will be reduced by approximately 5% to 10%. The parabolic-trough and power-tower water requirement would be approximately 101,000,000 gallons per year (18 gallons per MWh, 310 acre-ft per year) for an 88-MW plant at 72% capacity factor with an air-cooled condenser. Since the project is to be located on or near tribal lands, project feasibility depends on water availability from sources on or near tribal lands. Such availability is subject to the desires of the rights holders to negotiate for use of such water.

3.8 CONCLUSIONS OF CSP TECHNOLOGY COMPARISON

3.8.1 Replacement for Mohave Generating Station Generation

Concentrating solar power (CSP) technology, by itself, cannot totally replace the electrical generation of the Mohave Generating Station. This conclusion is based on several factors:

- **Size Limitations.** There is limited CSP technology that is available in commercial (utility) sizes**.** Parabolic trough technology is currently the most proven solar thermal electric technology, with the largest commercial-scale plant of 80 MW. The largest power towers built to date were the 10-MWe Solar One and Solar Two demonstration plants. There are no large-scale (greater than 5 MW) commercial dish/engine (Stirling) or concentrating photovoltaic power plants operating today.
- **Generation Profile Limitations.** Thermal storage or a hybrid configuration would be necessary to match the existing Mohave Generating Plant's load profile. For parabolic-trough and power-tower CSP technologies, the capital cost for each hour of 885-MW storage ranges from $28,000,000 to $60,000,000. In addition to the cost of storage, the solar field capital cost increases since the solar field has to be larger to provide the heat input to the storage system. For 15 to 16 hours of storage, the solar field is approximately 4 times larger than without storage. Since dish/engine (Stirling) units are self-contained modules without a circulating medium to transfer heat to a storage system, thermal storage is not considered realistic. The same is true for concentrating photovoltaics; although battery energy storage could be considered, it would be prohibitively expensive and massive.
- **Lack of Commercial Examples.** Currently, there are no commercial or prototype hybrid power tower, dish/engine (Stirling), or concentrating photovoltaics systems.
- **High Capital Cost.** The capital costs for the CSP technologies are notably higher than for a conventional coal-fired plant or a combined-cycle plant.
- **Large Land Requirements.** An 885-MW CSP plant, without thermal storage, would occupy an area 2 to 3 times greater than the existing 1,580 MW Mohave Generating Plant. With thermal storage, the area requirements approach 8 to 12 times greater.

3.8.2 Complement to Mohave Generating Station Generation

Although CSP technology cannot totally replace the electrical generation of the Mohave Generating Station, it is a potential alternative to replacing or complementing part of the station's electrical generation, both as dispatchable power systems and as distributed power systems. Dispatchable power systems are capable of providing dispatchable intermediate-load generation in the wholesale bulk-power market, such as the Mohave Generating Station. Distributed power systems provide distributed generation, grid support, remote, and village power markets. The majority of the Navajo/Hopi reservations area is shown to have a very good insolation value of 7 to 8 kWh/m^2/day. Two 345-kV and one 230-kV transmission lines are within the 7 to 8 kWh/m^2/day insolation area. Furthermore, much of the far northeast of Arizona is barren, with wide empty valleys interspersed with low, scrub-covered mesas.

Of the four CSP technologies, the parabolic trough and dish/Stirling engine are considered the best selections for complementing electrical generation of the Mohave Generating Station. This conclusion is based on the following rationales:

- **Technology Risk.** Parabolic-trough technology is currently the most proven solar thermal electric technology. A 50- to 100-MW parabolic-trough plant is readily available for near-term deployment. Parabolic-trough plants would operate as dispatchable power systems, as is currently being done at the SEGS Plants.
- **Solar Energy Conversion Efficiency.** Of all solar technologies, dish/engine systems have demonstrated the highest solar-to-electric conversion efficiency (29.4%), and therefore have the potential to become one of the least expensive sources of renewable energy. The modularity of dish/engine systems allows them to be deployed individually for remote applications, or grouped together for small-grid or end-of-line utility applications. The ability to prove the technology on a small scale can be used to eliminate much of the financial risk associated with the technology risk of this technology. With the technology proven at a small scale, the technology's modularity may allow large combinations of the generating units to provide power quantities similar to those provided by existing large utility plants, at least during periods of optimum insolation.

3.9 CSP TECHNOLOGY PLANT CONFIGURATIONS

In order to estimate reasonable unit sizes for the CSP technologies described above, recent Renewable Portfolio Standards (RPS) requirements in the area were evaluated. Arizona currently has an RPS (called an Environmental Portfolio Standard, or EPS, in Arizona) that requires the state's investor-owned utilities (IOUs) and cooperatives to generate or procure renewable energy supplies totaling 1.1% of total retail sales by 2006. To date, the standard has been more or less on a voluntary basis without specific legal and financial penalties for non-compliance. However, given considerably higher standards in neighboring states and Arizonans interest in supporting higher levels of renewables, the Arizona Corporation Commission (ACC) has been exploring expanding the EPS for over a year. In July 2005, the ACC voted to increase the EPS to 5% by 2015 and 15% by 2025. Rules to implement the order are being considered, including various compliance mechanisms and penalties. The final order was expected later in 2005.

The amount of energy corresponding to the production of Mohave Generating Station that must come from renewable sources was estimated. The unit sizes for each technology that could provide this energy were estimated, based on estimated capacity factors for each technology.

Per RPS, in the years 2007–2012, regulated utilities in Arizona are required to generate 1.1% of their electricity with renewable energy of which 60% is solar-electric power. California retail sellers of electricity are required to increase their procurement of eligible renewable energy resources such that 20% of their retail sales (on a megawatt-hour basis) are procured from eligible renewable energy resources by 2017.

An 885-MW plant at 72% capacity factor (equivalent to Mohave Generating Plant capacity factor) produces approximately 5,600,000 MWh of electricity per year. If all the generation is procured by California, 1,120,000 MWh will theoretically have to come from renewable energy resources by the year 2017. The 1,120,000 MWh represents 180 MW of power at 72% capacity factor.

3.9.1 Parabolic-Trough Configuration

The parabolic-trough capacity factor capability, without thermal storage, is approximately 30%. In order to produce 1,120,000 MWh, a unit size of 425 MW is required.

However, in order to reduce the plant size, provide better load profile match, and eliminate the need for a conventional steam-Rankine power plant for backup, thermal storage of six hours can be considered in the parabolic-trough plant configuration. This is consistent with the design of the parabolic-trough plants in Spain, with both plants having six hours of storage using the Nexant/Sandia indirect two-tank thermal storage technology. With six hours of thermal storage, the capacity factor capability is approximately 43%, which for 1,120,000 MWh corresponds to 300 MW of installed power.

Three plants of 100 MW each are used for the configuration based on the size of current parabolic-trough technology of the 80-MW SEGS VIII and IX plants. Use of current technology-size plants minimizes technology risks associated with efficiency and technology improvements and large scale-up factors and allows suppliers to rely more on initial production volume to reduce costs.

3.9.1.1 Costs

Three 100-MW parabolic-trough plants would provide 300 MW. The estimated capital cost is based on actual costs for the SEGS VIII and IX solar plants with scale-up cost reduction. There are recognized scale-up cost reductions for increasing the plant size:

$$C_B = C_A \left(\frac{A_{MW}}{B_{MW}} \right)^{f_s}$$

where:

C_B = Cost of Plant B

C_A = Cost of Plant A

B_{MW} = MW size of Plant B

A_{MW} = MW size of Plant A

f_s = Scale-up factor

Based on the cost data provided by the SEGS Plant, an average scale-up factor of 0.7 was attained: SEGS I to SEGS II, 0.6 scale-up factor; SEGS II to SEGS III, 0.8 scale-up factor; and SEGS V to SEGS VII, 0.7 scale-up factor. The actual cost for each of the 80-MW SEGS VIII and IX plant was $2875/kW. Neither plant has thermal storage.

For each 100-MW plant, without thermal storage, the scale-up equation is

$\$2{,}460/\text{kW} = \$2{,}875/\text{kW} \times (80\ \text{MW}/100\ \text{MW})^{0.7}$

Increases in the plant cost for various factors are estimated as follows:

- **Physical Storage Cost.** Using thermal storage cost of $50 per kWh, based on the Nexant/Sandia indirect two-tank thermal storage technology design of the parabolic-trough plants in Spain. With six hours storage at $50/kWh, the additional storage costs $300/kW.
- **Increased Solar Field Size.** Thermal storage requires that the solar field size be increased to obtain solar energy for storage. The solar field is defined by the collector area in square meters, which can be estimated by the following simplified equation:

$$C = \left(\frac{kW_d \times f_c \times h}{\eta \times I} \right)$$

where:

C = Collector area square meters (m^2)

kW_d = Electric generation design capacity, kilowatts = 100,000 kW

f_c = Capacity factor = 30% without storage; 43% with 6 hours storage

h = Hours per year (8,760)

η = Net annual efficiency, Solar to Electric = 14%

I = Annual insolation = 8 kWh/m^2/ day x 365 days) = 2,920 kWh/m^2

Without thermal storage the solar field size is

(100,000 kW x 30% x 8,760) / (14% x 2,920 kWh/m^2) = 643,000 square meters

With 6 hours thermal storage the solar field size is

(100,000 kW x 43% x 8760) / (14% x 2920 kWh/m^2) = 921,000 square meters

The breakdown cost in \$/m^2 for the solar field is shown below.

Table 3-6 — Cost Breakdown for Solar Field

Receivers	43 \$/m^2
Mirrors	40
Concentrator Structure	47
Concentrator Erection	14
Drive	13
Interconnection Piping	10
Electronics & control	14
Header piping	7
Foundations/Other Civil	18
Other (Spares, HTF)	14
Total	220 \$/m^2

Thus, the increase in capital cost due to the larger solar field is

[\$220/m^2 x (921,000 m2 - 643,000 m^2)] / 100,000 kW = \$600 /kW

- **Air-Cooled Condenser System.** To reduce the water requirement, an air-cooled system was considered in lieu of an evaporative cooling tower. An air-cooled system will increase the base cost by approximately 8%.

The total estimated capital cost for three 100-MW parabolic-trough plants with 6 hours indirect two-tank thermal storage is as follows:

Table 3-7 — Total Estimated Cost for Three 100-MW Parabolic-Trough Plants

Base Cost	$2,460/kW
Thermal Storage	$ 300/kW
Increased Solar Field Size	$ 600/kW
Air-Cooled Condenser System	$ 200/kW
Total	$3,560/kW

Costs breakdowns are shown below.

Table 3-8 — Cost Breakdowns for Parabolic-Trough System

Capital Cost Estimate

Category Description	% of Total	Category Breakdown: Material	Category Breakdown: Labor
Siteworks & Infrastructure	2.0%		
General siteworks & infrastructure Roads, warehouse, fence Watersupply infrastructure			100%
Solar Field	67.0%	83%	17%
HCE Mirror Metal support structure Drive Interconnection Piping Electronics & control Header piping Pylon Foundations Other Civil Works HTF Fluid Spares			
Heat Transfer Fluid (HTF) System	2.7%	86%	14%
HTF vessels & HXs Pumps Field Erection			
Thermal Energy Storage	12.8%	78%	22%
Heat Exchangers & Mech Tanks & Vessels Nitrate Salt Piping, Instr, Electrical Civil & Structural			
Power Block	9.8%	66%	34%
Steam turbine & generator Electric auxiliaries			
Balance of Plant (BOP)	5.7%	43%	57%
General BOP & cooling Water treatment Fuel handling & treatment Flue gas treatment Electrical Instrumentation & control Other civil works & erection			
Total Direct Cost	**100%**	**77%**	**23%**

The fixed O&M costs are projected to be $33/kW-yr, with variable O&M costs of $30/MWh. The O&M costs for the parabolic-trough plant are based on actual data from the existing SEGS plants.

Costs do not include sales or property taxes or land lease costs.

3.9.1.2 Construction

The estimated construction period for a 100-MW parabolic trough CSP plant is 15 months with a manpower requirement of 1,000 personnel. The labor skills required to build the plant are non-supervisory (75%), supervisory (17%), administrative (5%), and engineering (3%). The construction period is 15 months, and the construction rate is S-shaped, with 23% completed in the first 6 months, 57% completed in 9 months, and 90% completed in 12 months.

The preceding information is based on actual SEGS data and information from the University of New Mexico Bureau of Business and Economic Research study, which evaluated the economic and fiscal impact of building CSP plants in New Mexico (*The Economic Impact of Concentrating Solar Power in New Mexico*, December 2004.) The construction estimates are consistent with the two 50-MW AndaSol project in Spain, which projects a 15-month construction period with a peak labor demand of up to 1,000 workers.

3.9.1.3 Land Requirements

Each 100-MW parabolic-trough solar plant with 6 hours of thermal storage will require approximately 870 acres (1.4 square miles) of area.

3.9.1.4 Water Usage

Use of an air-cooled system in lieu of an evaporative cooling tower reduces the water requirements to the Rankine-cycle makeup and mirror washing. The Rankine-cycle makeup averages 16 gallons per MWh, and mirror washing averages 2 gallons per MWh. For each 100-MW parabolic-trough solar plant, the average annual water requirement is as shown in the following table.

Table 3-9 — Water Usage for Each 100-MW Plant with Air-Cooled Condensers

	Average Amount
Rankine-Cycle Makeup, gal/yr	6,000,000
Mirror Washing, gal/yr	800,000
Total, gal/yr	6,800,000
Total, acre-ft/yr	20.9

3.9.1.5 Staffing

The expected staffing for each plant is presented below in Table 3-10. The expected staffing if the three plants were combined in one site with a common control room is also shown in Table 3-10.

Table 3-10 — Expected Staffing for Parabolic Trough Plant

	Stand-Alone 100-MW Plant	Three 100-MW Plants on Common Site
Administrative	6	6
Technical Services	4	4
Operations	16	24
Maintenance	36	54
Total	62	88

3.9.2 Dish/Stirling Engine

The current dish/Stirling engine technology of 25-kW size modules was used for the configuration. The modularity of dish/engine systems allows them to be deployed individually for remote applications, or grouped together for small-grid or end-of-line utility applications. The dish/engine is an excellent application for remote regions and areas with scarce water resources. The dish/engine capacity factor capability, without thermal storage, is approximately 30%, which for 1,120,000 MWh (same generation as considered for the parabolic-trough technology) corresponds to 425 MW of power. Since dish/engine units are self-contained modules without a circulating medium to transfer heat to a storage system, thermal storage is not considered practical.

In early August 2005, SCE publicly announced the completion of negotiations on a 20-year power purchase agreement with Stirling Energy Systems for between 500 and 850 MW of capacity (producing 1,182 to

2,010 GWh/yr) from the first commercial deployment of a new solar thermal generating technology. According to SES, the commercial, grid-connected dish/engine (Stirling) plant is to begin construction in 2008. The plant will be located in the Mojave Desert and consist of 20,000 dish/engines. SES also signed an agreement for between 300 and 900 MW with San Diego Gas and Electric in September 2005.

For 425 MW of power, a total of 17,000 dish/engines would be required.

3.9.2.1 Costs

The capital cost for dish/engines is approximately \$3,000/kW based on SES information for first 50-MW deployment. The \$3,000/kW is consistent with current cost of \$5,000/kW with reduced unit costs to \$3,000/kW as a result of increased product volume of 2,000 dish/engines for 50 MW of power.

The estimated capital cost of \$3,000 is expected to be less for an application of a 425-MW dish/engine plant based on reduced unit costs as a result of increased product volume. The experience curve describes how unit costs decline with cumulative production, with a specific characteristic that cost declines by a constant percentage with each doubling of the total number of units produced (Lena Neij, "Use of Experience Curves to Analyze the Prospects for Diffusion and Adoption of Renewable Energy Technology," *Energy Policy*, Vol. 23, No. 13, 1997).

The experience curve formula is as follows:

$$C(t) = C_0 Q(t)^b$$

where:

C(t) = Cost per unit as a function of output
C_0 = Cost of the first unit produced
Q(t) = Cumulative production over time
B = Experience index

For each doubling of production, the cost reduction is

$$\frac{C_{CUM_1} - C_{CUM_2}}{C_{CUM_1}} = \frac{C_0 Q_1{}^b - C_0 Q_2{}^b}{C_0 Q_1{}^b} = 1 - \frac{C_0 (2Q_1)^b}{C_0 Q_1{}^b} = 1 - 2^b$$

The value (2^b) is called the progress ratio, denoted ϕ. The progress ratio is used to express the progress of cost reductions for different technologies.

The formula is simplified for use as follows:

$$\phi = \left(\frac{C_2}{C_1} \right)^{\frac{1}{n}}$$

$$n = \frac{1}{\ln 2} \ln \frac{Q_2}{Q_1}$$

where:

C_1 = Cost of initial unit produced

Q_1 = Production quantity for the initial unit cost

C_2 = Desired cost of unit produced

Q_2 = Cumulative production quantity for desired unit cost

ϕ = Progress Ratio

n = Number of doublings of cumulative production

The progress ratio, ϕ, is used to express the progress of cost reductions for different technologies. The lower the value of ϕ, the higher the cost reduction realized. The cost reductions refer to the total costs (labor, capital, administration, research, etc.). The use of experience curves is not an established method, but a correlation that has been observed for several different technologies. A progress ratio of 0.82 for development of wind energy (1980 to 1995) has been identified by the International Energy Agency. The studies on learning curves suggest that a progress ratio of the order of 0.8 to 0.82 have been observed for installed photovoltaics. The Enermodal Study (Enermodal Engineering Limited, Cost Reduction Study for Solar Thermal Power Plant) shows a ϕ range between 0.85 and 0.92 for the installed capital cost of a trough power plant. Arguably, for the highly automated manufactured components, such as the support structure and mirrors, a ϕ of 0.80, as used in the Neij literature, may be more representative based on manufacturing experience. The projected cost estimate is based on progress ratio of 0.85.

The estimated capital cost for a 425-MW plant consisting of 17,000 dish/engines as a result of increased product volume is $1,500/kW. The fixed O&M costs are projected to be $3/kW-yr; the variable O&M costs are projected to be $11/MWh ($0.011/kWh). Costs do not include sales or property taxes or land lease costs.

Both Stirling Energy Systems and Southern California Edison were contacted regarding cost information related to their recently announced power purchase agreement. Both entities indicated that such information was confidential and could not be released for use.

3.9.2.2 Area Requirement

A dish/Stirling engine plant requires approximately one acre per eight 25-kW dish engines. For 17,000 dish/engines, approximately 2,125 acres (3.3 square miles) of area would be required.

3.9.2.3 Water Usage

The only water use required is for mirror washing. Approximately 14 gallons per dish per month is necessary for mirror washing, which converts to 2,856,000 gallons per year (8.8 acre-ft per year) for 17,000 dish/engines.

3.9.2.4 Staffing

The expected staffing for a 425-MW dish/engine plant is presented below in Table 3-11.

Table 3-11 — Expected Staffing for Dish/Stirling Engine Plant

	425-MW Dish/Stirling Engine Plant
Administrative	4
Technical Services	2
Operations	12
Maintenance	100
Total	118

3.10 TRANSMISSION REQUIREMENTS

Direct transmission access costs include the costs of the connection at the plant site, the plant transmission line, and any substation required at the interconnection with the trunk transmission line. For the solar plants, costs are summarized in the following table:

Table 3-12 — Transmission Requirements for Solar Plants

	Dish/Stirling		Trough	
Net Output, MW	425	425	300	300
Connection Voltage, kV	500	230	500	230
Interconnection Cost, $ millions	106.83	73.1	94.6	66.2

Direct transmission access costs shown here do not include the costs of upgrades to the transmission system that may be required to alleviate congestion or single contingency concerns that result from load flow analyses. Those costs are estimated in Section 12.

3.11 SUMMARY

Concentrating solar power technology is not a logical alternative to totally replace the electrical generation of the Mohave Generating Station based on the following considerations:

- There is limited CSP technology that is available in commercial (utility) sizes.
- Thermal storage or a hybrid configuration would be necessary to match the existing Mohave Generating Plant load profile.

The current capital costs for the CSP technologies are notably higher than for a conventional coal-fired plant or a combined-cycle plant.

An 885-MW CSP plant, without thermal storage, would occupy 2 to 3 times the area of the existing 1,580-MW Mohave Generating Plant. With thermal storage, the area requirements approach 8 to 12 times greater.

However, CSP technology is a potential element of a portfolio that could replace or complement the electrical generation of the Mohave Generating Station, both as dispatchable power systems and as distributed power systems. Of the four CSP technologies, the parabolic-trough and dish/Stirling engine are considered the best selections for complementing electrical generation of the Mohave Generating Station.

The parabolic-trough technology was selected because it is the most proven solar technology for the generation of electricity. A 50- to 100-MW parabolic-trough plant is readily available for near-term deployment. Parabolic-trough plants would operate as dispatchable power systems, as is currently being done at the SEGS plants.

The dish/Stirling engine system was selected because such systems have demonstrated the highest solar-to-electric conversion efficiency (29.4%). They have the potential, therefore, to become one of the least expensive sources of renewable energy. The modularity of dish/engine systems allows them to be deployed individually for remote applications, or grouped together for grid or end-of-line utility applications. Furthermore, scale-up from a few dish/engines to utility-scale installations is, at least conceptually, very straightforward.

The two technologies are compared in Table 3-13.

Table 3-13 — Comparison of Parabolic Trough and Dish/Stirling Engine

	Parabolic Trough	Dish/Stirling Engine
Plant Size	300,000 kW	425,000 kW
Number of Units	3	17,000
Unit Size	100,000 kW	25 kW
Thermal Storage	Yes – 6 hours	No
Annual Capacity Factor	43%	30%
Annual Generation	1,120,000 MWh	1,120,000 MWh
Capital Cost	$3,560/kW	$1,400/kW
O&M Cost	$33/kW-yr fixed $30/MWh variable	$3/kW-yr fixed $11/MWh variable
Area Requirement	870 acres per unit	2,125 acres
Water Requirement	6,800,000 gal/yr/unit	2,856,000 gal/yr
Total Staffing	62 per unit (stand alone units) 88 total (combined units)	118

The parabolic-trough technology presents the lower risk of the two CSP technologies based on the nine commercial-scale SEGS solar power plants, which continue to operate daily. While the Stirling engine itself is a well-established technology, the dish/engine CSP technology is currently at a high $/kW capital cost level and there are no large-scale commercial dish/engine power plants operating today in the size contemplated. There is the risk that any or all of the projected cost reductions for the dish/engine CSP technology as a result of increased product volume will not be realized. Since the dish/engines are modular, scale-up cost reductions for increasing the plant size will not be realized.

Parabolic-trough technology, dish/engine technology, or a combination of the two can, in conjunction with other generation technologies, replace or complement the electrical generation of the Mohave Generating Station.

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4. WIND TECHNOLOGY

4.1 WIND ENERGY TECHNICAL FEASIBILITY AND MAXIMUM CAPACITY

Four wind energy sites were evaluated for this study. All four are located in the state of Arizona on or near lands owned by the Navajo and Hopi tribal nations. That portion of Arizona's wind resource equivalent to Class 4 wind or better is estimated to be 2,600 MW by Northern Arizona University. Estimates of technical resources for the state are as high as 20,000 MW; however, economic resources of Class 3 wind or better, suitable for utility scale development, are likely in the 3,000 to 5,000 MW range. Please refer to the 50-meter and 70-meter Arizona wind resource maps developed by AWS Truewinds included as Figures 1 and 2 in Appendix H.

The initial capacity under development on the four sites on near Navajo and Hopi lands with Class 3 or better wind is estimated to be 685 MW, with moderate to higher levels of expansion possible. Three of the sites evaluated are Class 3+ or better. There are also additional sites on or near Navajo and Hopi lands not evaluated in this study that could probably be commercially developed.

All four sites evaluated are technically feasible, and several of these sites are exemplary wind sites with Class 4 to 7 wind resources. With regard to timing of electric generation power sales from these sites, only about 60 MW could possibly be constructed in 2006, and another 75 to 175 MW in 2007. The remainder would likely be phased in through 100-150 MW tranches in 2008, 2009, and 2010.

The four wind energy sites evaluated are Gray Mountain, Aubrey Cliffs, Clear Creek, and Sunshine Wind Park.

The Gray Mountain site is located on the Navajo reservation near Cameron, Arizona, and is about 10 miles away from the Moenkopi Substation. The site has a potential of 150 MW by 2008 and at least 450 MW by 2010, and is currently under development by the Navajo Tribal Utility Authority (NTUA). Please refer to Figure 4-1 and Figure 4-2 below.

Figure 4-1 — Gray Mountain Project Site Map

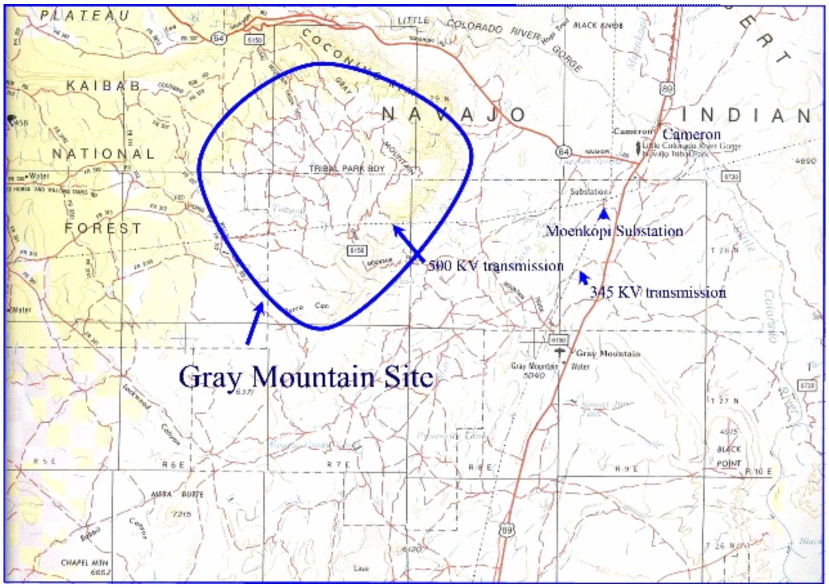
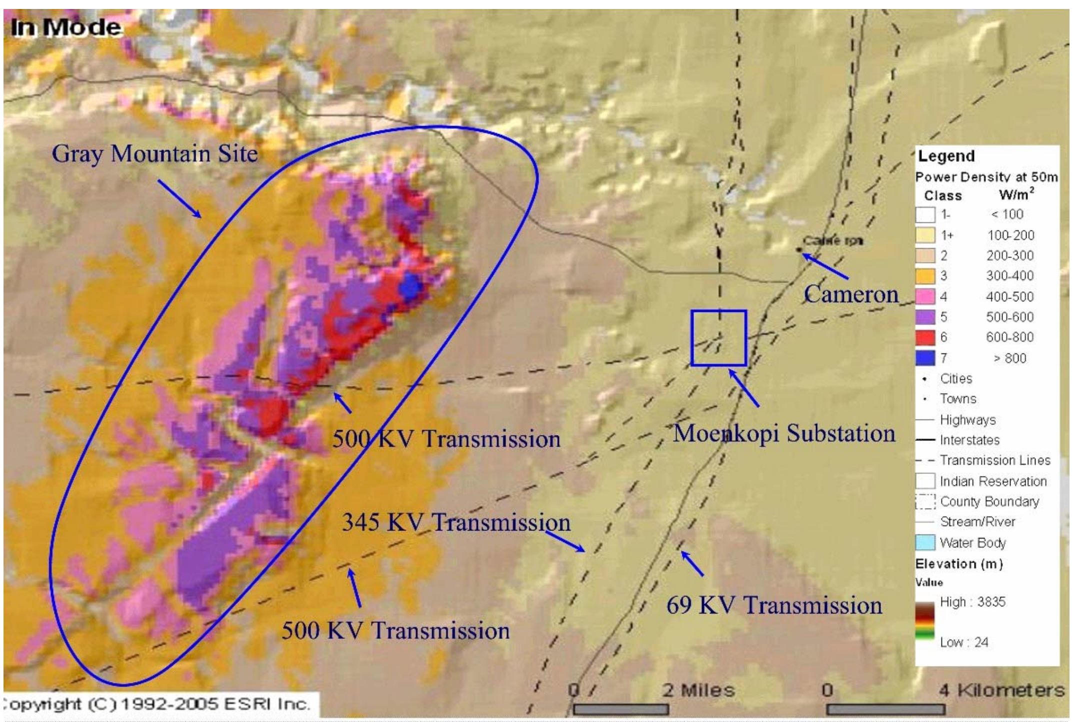


Figure 4-2 — Gray Mountain Site Wind Resource Map



The Aubrey Cliffs site is located on Navajo fee and State Trust lands just northwest of Seligman, Arizona. The site has a potential 100 MW by 2007–2008 with upside development potential, and is currently under development by Foresight Wind Energy, NTUA, and Department of Natural Resources (DNR) of the Navajo Nation. Site information is provided in Figure 4-3 and Figure 4-4 below.

Figure 4-3 — Aubrey Cliffs Project Location Map

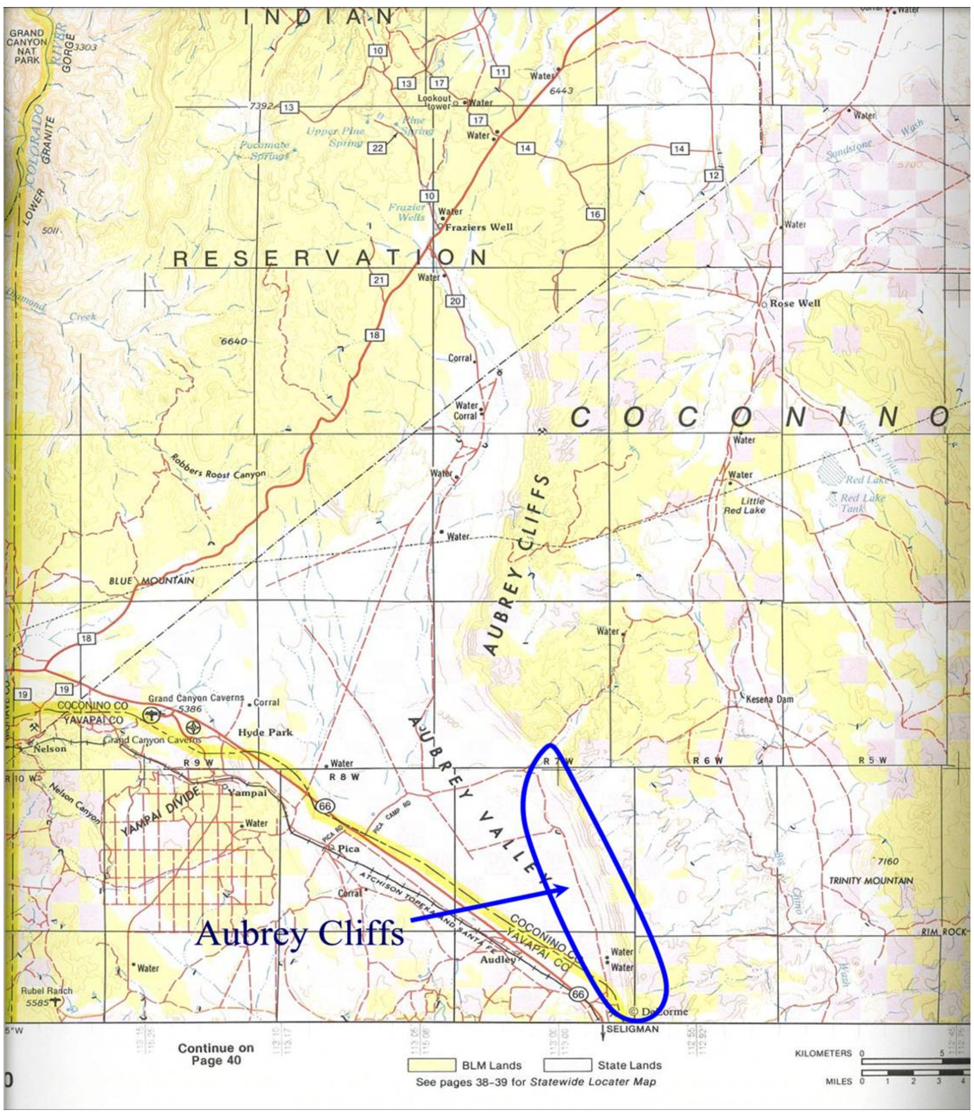
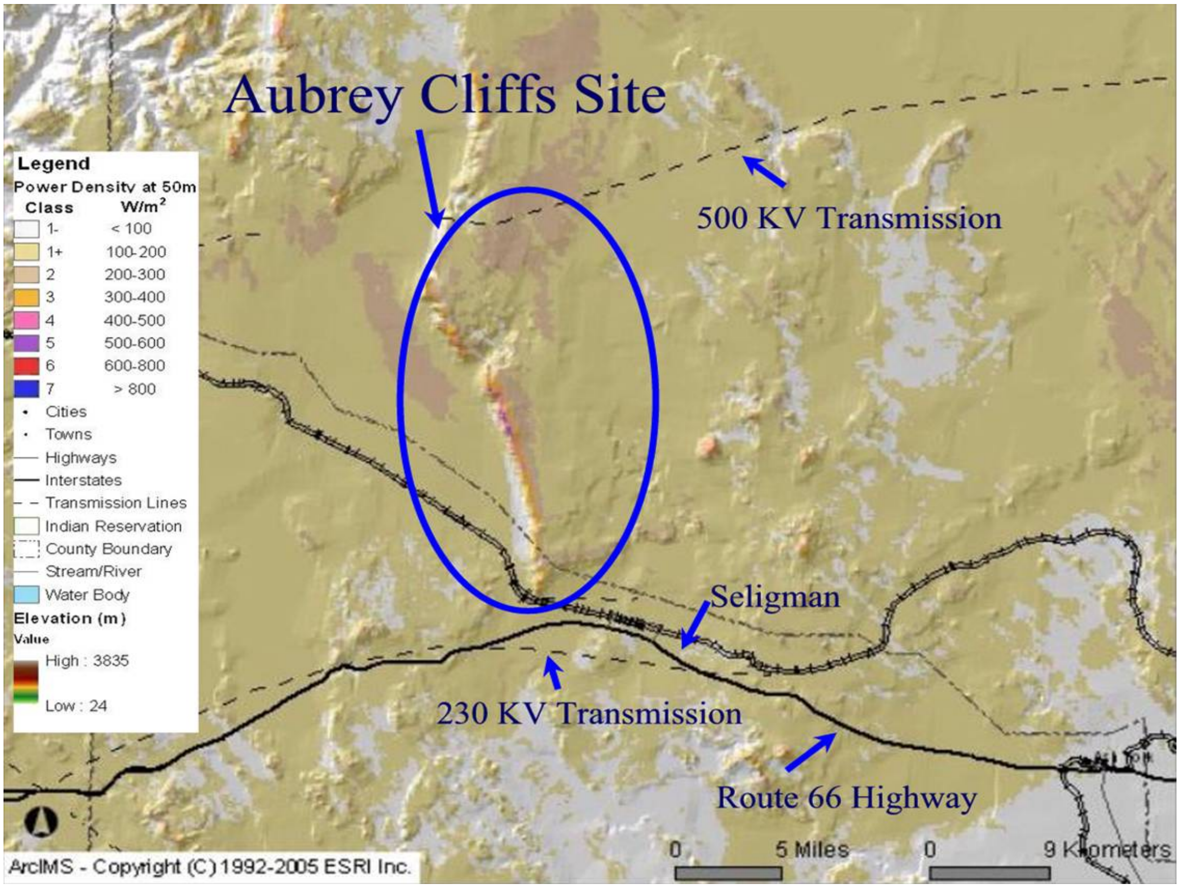


Figure 4-4 — Aubrey Cliffs Site Wind Resource Map



The Clear Creek site is located on Hopi fee and State Trust lands southwest of Winslow and has a potential to provide 75 MW in 2007. The site is currently under development by Foresight Wind Energy and the Hopi Nation. Foresight Wind Energy, LLC (Foresight), a major wind developer focused regionally in the southwestern United States, is a professional and competent wind energy development company. The principals have over 30 years of energy industry experience and have served in lead roles in development and operation of over 250 MW of wind energy projects in the western United States.

The Sunshine Wind Park is located on Hopi fee and private ranch lands owned by two other landowners. The site is 35 miles east of Flagstaff on I-40 near the Meteor Crater and west of Winslow, and has the potential to provide 60 MW by 2006. The site is currently under development by Foresight Wind Energy and the Hopi Nation. Figure 4-5 shows a general map of the area of the Clear Creek and Sunshine areas. Figure 4-6 and Figure 4-7 depict the wind resources available for the sites.

Figure 4-5 — Clear Creek and Sunshine Wind Park Project Location Map

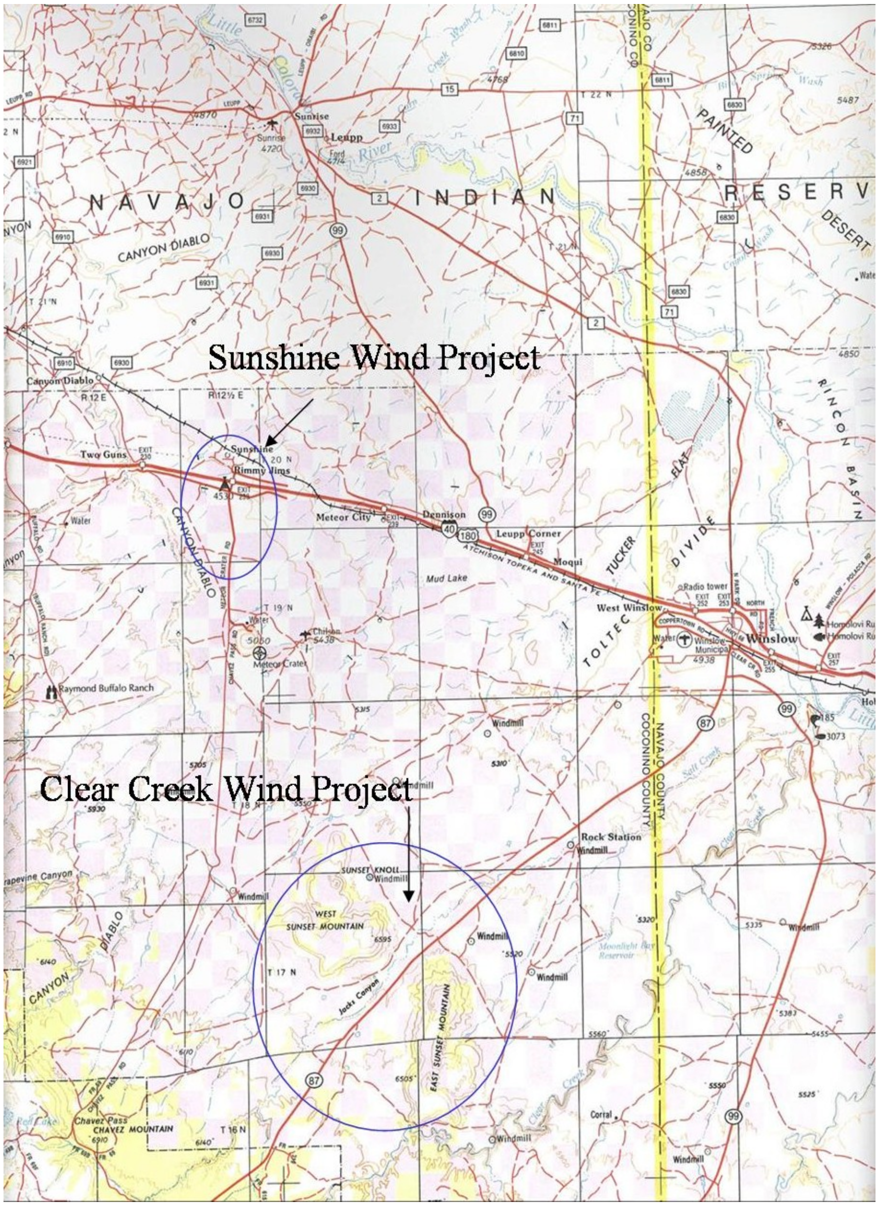


Figure 4-6 — Clear Creek and Sunshine Wind Resource Overview Map

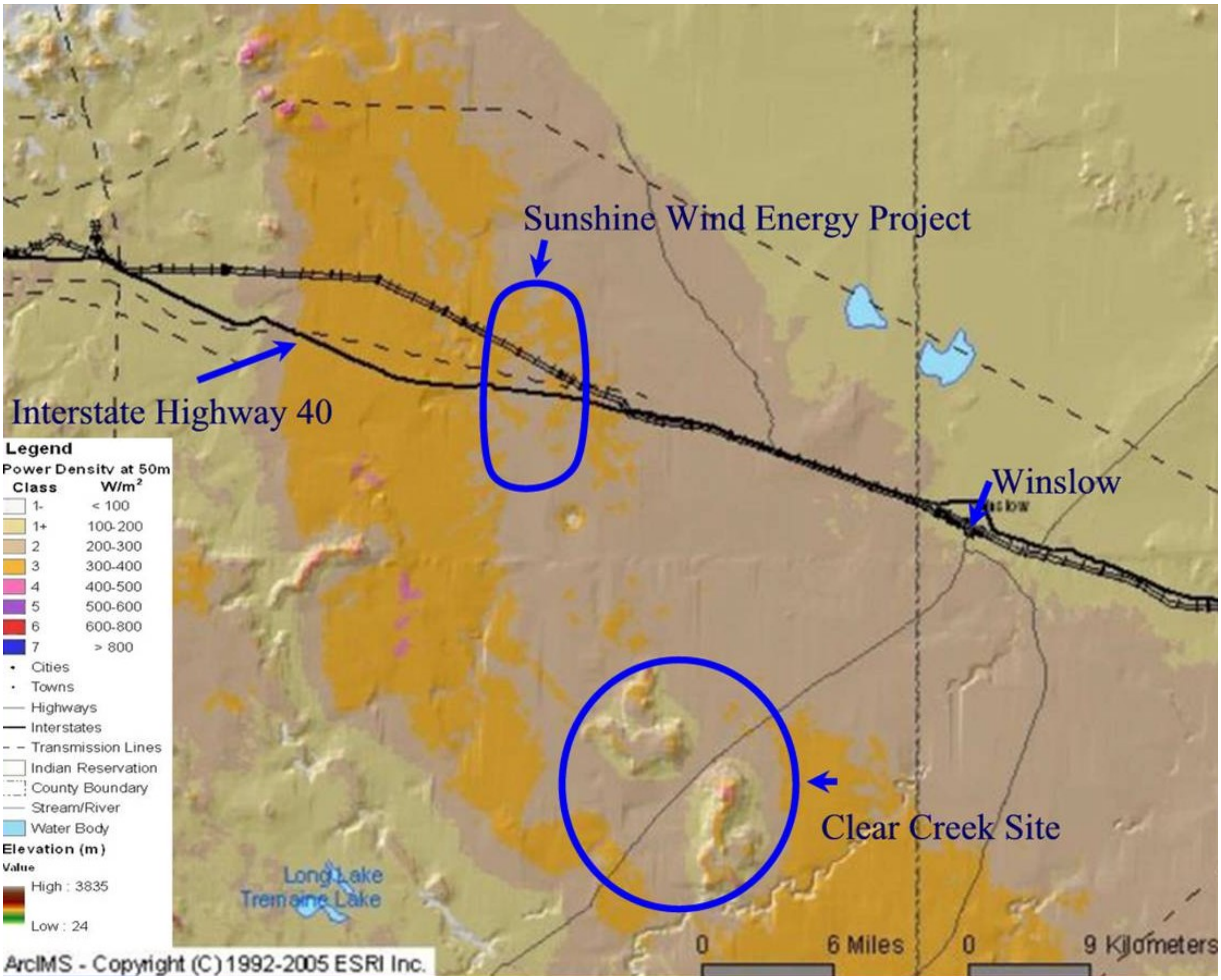
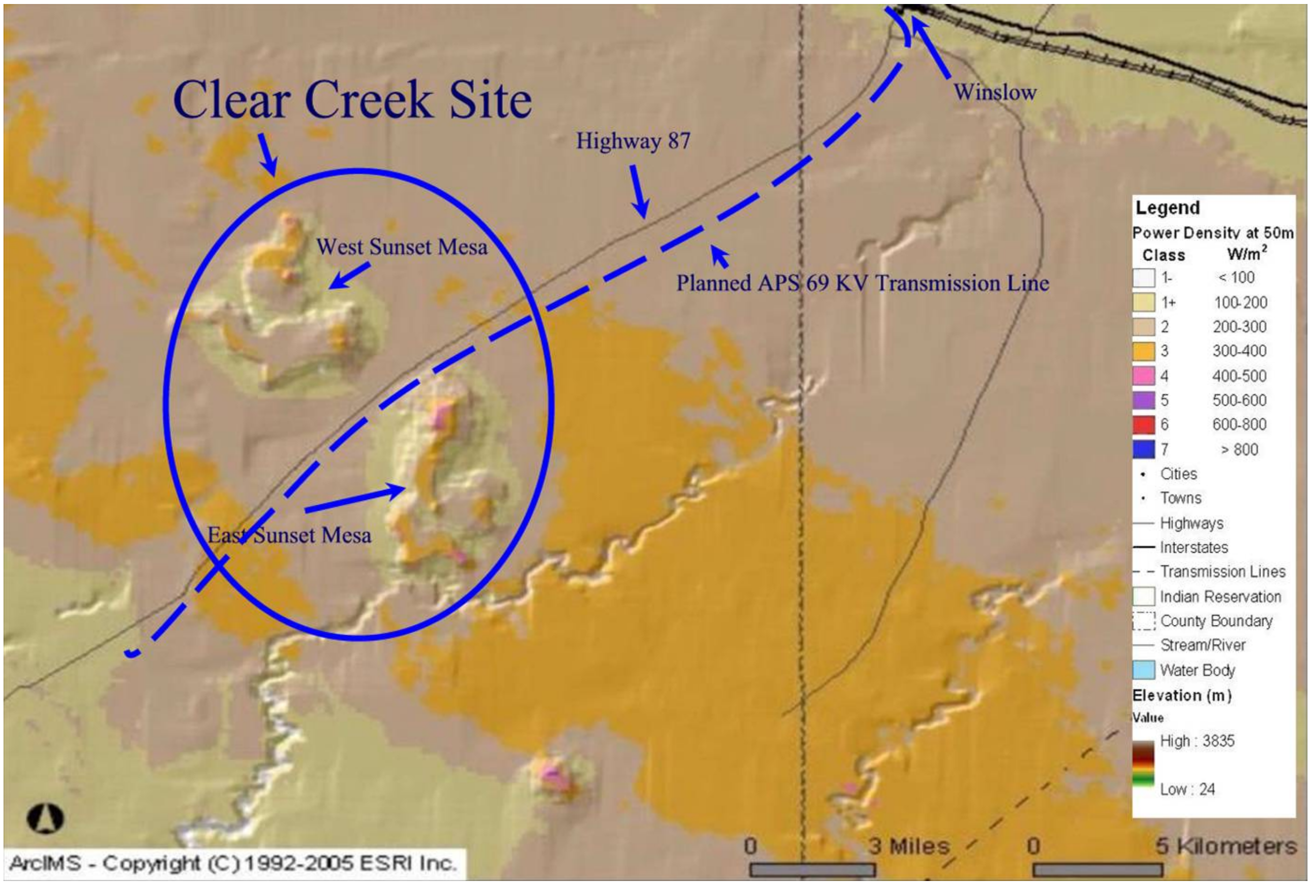


Figure 4-7 — Clear Creek Wind Resource Map



The characteristics of the projects identified are presented in the table below.

Table 4-1 — Wind Project Characteristics

Site	Developer	Wind Class at 80 m	MW	Timing
Gray Mountain	NTUA	4 to 7	450	2008–2010
Aubrey Cliffs	Foresight	3+ to 5	100	2007–2008
Clear Creek	Foresight	3+ to 4	75	2007
Sunshine	Foresight	3	60	2006

All four of these wind energy project sites are located within the State of Arizona. Arizona currently has a Renewable Portfolio Standard (RPS) (called an Environmental Portfolio Standard, or EPS, in Arizona) that requires the state's investor-owned utilities (IOUs) and cooperatives to generate or procure renewable energy supplies totaling 1.1% of total retail sales by 2006. To date, the standard has been more or less on a voluntary basis without specific legal and financial penalties for non-compliance. However, given considerably higher standards in neighboring states and Arizonans interest in supporting higher levels of renewables, the Arizona Corporation Commission (ACC) has been exploring expanding the EPS for over a year. In July 2005, the ACC voted to increase the EPS to 5% by 2015 and 15% by 2025. Rules to implement the order are being considered, including various compliance mechanisms and penalties. The final order was expected later in 2005. Final approval of this standard, even with a rather slow ramp up in percentage requirement in the early years, is expected to support considerable expansion in wind energy development activity in Arizona similar to that seen in states such as Texas, California, Minnesota, Wisconsin, New York, Colorado, and others that have adopted an RPS or legal order mandating utilities in those states to purchase renewable energy supplies. Twenty states in the U.S. have now adopted RPS standards.

4.1.1 Design Basis Technical Assumptions

Design basis technical assumptions for wind generation are summarized in the table below:

Table 4-2 — Design Basis Assumptions

Site	Net Capacity Factor (%)	Wind Class at 80 m	Wind Turbine
Gray Mountain	40	4 to 7	V-82 1.65 MW
Aubrey Cliffs	34	3+ to 5	V-82 1.65 MW
Clear Creek	32	3+ to 4	V-82 1.65 MW
Sunshine	25	3	V-82 1.65 MW

4.1.2 Feasible Capacity Ranges

4.1.2.1 Gray Mountain

The DOE has estimated that Gray Mountain has total wind resource potential of up to 800 MW; however, this estimate may not take into account physical limitations, transmission capacity, economic resources versus technical resources, or other constraints at the site. An estimate to build out to 450 MW over a three-year phased development program of 150 MW per phase seems feasible at this time. The site may have upside potential to this estimate; however, additional study, and some actual permitting, construction, and verification of wind resource data via wind test towers, would be needed to determine the upside potential beyond 450 MW.

4.1.2.2 Aubrey Cliffs

Aubrey Cliffs is initially being developed to a size of 100 MW, but could potentially be built out to 200 MW, depending on the degree to which the wind resource drops off further from the mesa edge and the transmission capacity available on the targeted 230-kV transmission system where interconnection will occur south of Chino Point and Route 66 near Seligman.

4.1.2.3 Clear Creek

Clear Creek is initially being developed to a size of 75 MW. There does not appear to be sufficient planned transmission capacity at this site over the near and intermediate term to exceed 75 MW, but over the long run, it might eventually support 150 MW, depending on transmission capacity. The transmission system at this site is only a 69-kV system, which may prove to be more of a limiting factor than the land area available or the wind resource at this site.

4.1.2.4 Sunshine Wind Park

The Sunshine Wind Park is being developed to a size of 60 MW to fully utilize the available transmission capacity on the 69-kV APS line into which the project would interconnect. Accordingly, the project cannot be expanded easily beyond this size. The planned location of turbines at the site already makes good use of the sandstone outcrops and hill features in order to get the wind resource to a Class 3 level at the 80-meter elevation; however, even though the project has 8,000 acres of land, some of the land at the lower elevations off the ridges, hills, and outcrops may be a Class 2 resource and not economic given today's capital costs for wind turbines.

4.1.3 Fuel Requirements

There are no fuel requirements since the generation equipment is powered by the wind; however, there will need to be electric station service provided to each project from the local electric retail franchise provider in whose territory the projects are located. The projects will need a small amount of electricity to power utilities when the wind is not blowing and to keep automation systems and utilities on.

4.1.4 Water Requirements

Other than drinking water for facility employees or water associated with a sewage system at a field office, there are no ongoing requirements for water associated with a wind energy facility, and the only water usage for the projects will be on a one-time basis for construction of foundations or dust control as required.

4.1.5 Land Requirements

4.1.5.1 Gray Mountain

The Gray Mountain site has between 23,000 and 34,000 acres (35.9 to 53.1 sq. mi.) on which to site wind turbines. Assuming an average of eight turbines per section of land, the number of turbines that could be sited (assuming 1.65 MW turbines) would be 287 turbines, with the potential to site as many as 425 wind turbines. Building 450 MW at this site would equate to 272 turbines using 1.65 MW turbines. If larger turbines are used, somewhat fewer turbines can provide the same number of megawatts.

All of the land at the Gray Mountain site is on the Navajo Reservation and in the jurisdiction of the Cameron Chapter. The elevation at this site is about 6,400 feet above sea level and overlooks the Moenkopi Substation about 10 miles away.

4.1.5.2 Aubrey Cliffs

The Aubrey Cliffs site is an elevated ridgeline or cliff running about 10 miles in length and overlooking Aubrey Valley. This site is very similar in its appearance to many sites developed around McCamey, Texas, along high mesas and ridgelines. The elevation at this site is about 6,300 feet above sea level. If the site is limited to one or two rows of turbines sited along the length of the ridge, this site would consist of about 5,200 acres (8.1 sq. mi.). Assuming a spacing of 750 feet between turbines, about 56 turbines and 92 MW can be sited per row along the ridgeline. It is important to note that the land ownership at this site is a checkerboard of State Trust land and Navajo fee land. Therefore, both the Arizona State Land Department and the Navajo Nation would need to participate to allow this project to proceed as envisioned.

4.1.5.3 Clear Creek

At the Clear Creek site, Foresight Wind Energy is evaluating two mesas. Both sites will have wind studies conducted with wind test towers; however, Foresight plans to proceed with development on only one of the mesas at this time. The two mesas are known as East and West Sunset mountains, located approximately 18 miles southwest of Winslow, Arizona, on both sides of Highway 87. East Sunset appears to have about 4,320 acres (6.8 sq. mi.) across its top, and West Sunset appears to have about 5,760 (9.0 sq. mi.) acres across its top. The elevation of these mesas ranges between 6,100 and 6,500 feet above sea level. Foresight is planning a project of about 75 MW on one of these mesas using 40 to 50 turbines in the 1.5- to 1.65-MW size range. This site would entail leases from both the Arizona State Land Department and the Hopi Tribe as it is a "checker-boarded" site. The Hopi lands at this site are fee simple land holdings.

4.1.5.4 Sunshine Wind Park

Foresight Wind Energy has already leased 8,000 acres (12.5 sq. mi.) north and south of the I-40 interstate highway for the Sunshine Wind Park. The topography is flat plains with some outcropping sandstone hills. The elevation at this site is about 5,400 feet above sea level. The project is laid out in such a way that the turbines will follow ridgelines and hilltops to take advantage of any extra elevation which will be needed to access Class 3 wind at this site. Foresight is planning to use 35 to 40 turbines in the 1.5- to 1.65-MW size range that are suited for low-wind-speed application at this site. The site is leased from three landowners including Hopi fee lands.

4.1.6 General Design Concept

4.1.6.1 Gray Mountain

The layout at Gray Mountain would likely be in rows and columns north to south and east to west but with some interruption and adjustment of the pattern for ravines and low areas and to take advantage of terrain features offering elevation and added wind shear. There is a large amount of land to work with on top of the mountain in a mesa or flat plateau ranging between 23,000 and 34,000 acres. In areas where there is a Class 7 wind resource, the design may need to incorporate vertical axis wind technology in lieu of traditional three-bladed wind turbines. Horizontal axis wind turbines would be used throughout the areas of the mountain with Class 4–6 wind, but may not have a normal 20- to 30-year useful life or survive the wind shear of the Class 7 area of the mountain.

This site would need to have about 15 miles of access road improvements, and a 10-mile transmission system feeder of 34.5-kV line (for each 150-MW project phase) run into Moenkopi Substation. For construction, a cement batch plant would need to be constructed on top of the mountain, since there are no nearby facilities from which cement can be hauled in a timely manner onto the site.

4.1.6.2 Aubrey Cliffs

The layout at this site will be in one or possibly two rows of wind turbines running along the rim or ridgeline of the cliff running generally from north-northwest to south-southeast. The turbines would be sited on the far west side of the feature, sitting back from the cliffs several hundred feet to reduce turbulence and facing Kingman, Arizona. The turbines would likely be spaced about 750 to 900 feet apart along this ridgeline.

This site would need to have 10 to 12 miles of access road improvements, and a 5-mile power collection system feeder of 34.5-kV line run south under or over Route 66 to the 230-kV system south of Chino Point. Cement for foundations can probably be hauled in from Seligman, Kingman, or another nearby city using Route 66.

4.1.6.3 Clear Creek

The layout at this site will likely resemble that of Aubrey Cliffs with one or two rows of turbines sited 750 to 900 feet apart along the ridgeline of the mesas overlooking Highway 87 and Jacks Canyon. Due to limited transmission capacity, even after the planned APS 69-kV extension in the near to intermediate term, Foresight plans to develop only one of the mesas. There will need to be 8 to 10 miles of access road upgrades at this site.

Interconnection will be via a new 4-mile power collection system feeder to the APS 69-kV planned transmission system extension due to be built in 2006. Cement for foundation work can be transported from Winslow or possibly Flagstaff via Highway 87.

4.1.6.4 Sunshine Wind Park

The project and project layout has already secured a conditional use permit (CUP) granted by Coconino County. The layout generally runs from west-northwest to east-southeast along sandstone hill outcrop features, and there appear to be up to four rows of turbines on four separate outcrops. Each row will have from 7 to 12 wind turbines per row. Most of the turbines will be located south of I-40. There is an existing 69-kV transmission line and an existing 69-kV substation on the site for making an interconnection. Foresight has already substantially completed its required capacity and facilities studies with APS at this site for interconnection. Cement for foundation work can be transported from Flagstaff or Winslow on I-40.

4.1.7 Off-Site Facility Requirements

4.1.7.1 Gray Mountain

At Gray Mountain, one 10-mile 34.5-kV transmission line per 150-MW phase will need to be constructed from the project area on top of the mountain to the Moenkopi Substation in order to interconnect with the 500-kV system there. It is likely that telephone lines, fiber optic data communication lines, and electric station service will all need to be run into the project area on top of the mountain as well. A field office with central computer servers, O&M facilities, and office space will also need to be constructed either on the site or at the bottom of the mountain. Approximately 15 miles of access road upgrades with some blasting on sharp corners will need to be made to transport the blades, the generation sets, and the tower sections into the construction site.

4.1.7.2 Aubrey Cliffs

At Aubrey Cliffs, a 5-mile 34.5-kV transmission line from the project area on top of the ridge will need to be constructed underneath Route 66 and south of Route 66 and Chino Point to interconnect with the 230-kV system. A new 230-kV substation would likely be built at the point of interconnection with the 230-kV transmission line south of Route 66. It is likely that telephone lines, fiber optic data communication lines, and electric station service will all need to be run into the project area on top of the mountain as well. A field office with central computer servers, O&M facilities, and office space will also need to be constructed either on the site or at the bottom of the ridge. Approximately 10 to 12 miles of access road upgrades will need to be made to transport the blades, the generation sets, and the tower sections into the construction site.

4.1.7.3 Clear Creek

At Clear Creek, a 4-mile 34.5-kV transmission line will need to be constructed from the project area on top of the ridge towards Highway 87 to interconnect with the 69-kV system there. A small substation would likely be built at the point of interconnection. It is likely that telephone lines, fiber optic data communication lines, and electric station service will all need to be run into the project area on top of the mesa as well. A field office with central computer servers, O&M facilities, and office space will also need to be constructed either on the site or at the bottom of the mesa. Approximately 10 to 12 miles of access road upgrades will need to be made in order to transport the blades, the generation sets, and the tower sections into the construction site.

4.1.7.4 Sunshine Wind Park

At the Sunshine Wind Park, telephone lines, and electric station service will need to be run into the project area.

4.1.8 Site Screening

The sites chosen for evaluation were selected based on four factors:

- Location on or near Navajo or Hopi lands
- Cultural acceptance and sensitivity
- Wind resource potential of Class 3+ or better

- Transmission access

Although there are some excellent wind resource sites in northeastern Arizona on the Navajo lands in the Chuska Mountains, the cultural sensitivity and elevation of those sites made them lower on the priority list. From a technical perspective, the higher elevation in the Chuska Mountains also implies a lower air density, and thus a more degraded power curve output. Blue Canyon and Black Mesa were also initially selected for site visit and evaluation, but were not evaluated due to lack of tribal interest as well as time and prioritization. After some follow up discussion, it is believed these sites may have potential, but are probably not as promising as Gray Mountain or Aubrey Cliffs.

4.2 ENVIRONMENTAL EMISSIONS ISSUES

There are no emissions created in the generation of wind energy.

4.3 CAPITAL AND O&M COST ESTIMATES

Capital and O&M costs for the four projects identified are summarized in the following table.

Table 4-3 — Capital and O&M Cost Estimates

Project Size and Capital Costs	Gray Mountain 3 Phases	Gray Mountain Phase 1	Aubrey Cliffs	Clear Creek	Sunshine
Net MW	450	150	100	75	60
Project Costs $2006	755,017,000	258,031,000	169,196,000	126,570,000	99,671,000
Project Costs per kW, $/kW	1,678	1,740	1,692	1,688	1,661
Fixed O&M, $/kW-yr	23.73	23.73	24.24	24.94	27.08
Variable O&M, $/MWh	0.195	0.195	0.223	0.244	0.279

Please note that variable O&M expenses include consumable materials. Fixed O&M expenses include field operation labor, long-term service agreement expenses, insurance, lenders agency fees, letters of credit (LOC) fees or costs. Property taxes, sales taxes, and land lease or royalty payments are not included in the costs.

4.3.1 Gray Mountain

The "all in" capital costs in un-inflated 2006 dollars for Gray Mountain, excluding all direct transmission access and system upgrade costs, are estimated to be as follows:

Table 4-4 — Gray Mountain Capital Costs

Phases	$	$/Net kW
Phase 1 - 150 MW	258,031,000	1,720
Phase 2 - 150 MW	248,493,000	1,657
Phase 3 - 150 MW	248,493,000	1,657
Total Cost for 450 MW	755,017,000	1,678

The cost of Gray Mountain is higher than the other projects due to three main factors:

- **Access Roads.** 15 miles of access roads are required. Work on the access road will include some blasting on sharp turns in the existing road. This will increase its construction costs relative to the other projects.
- **Depot Facilities.** There are no nearby cities with depot facilities from which cement can timely be hauled to the top of the mountain; therefore, a batch plant will likely need to be constructed atop the mountain to make cement on location for the turbine foundations.
- **Interconnection.** The interconnection into the Moenkopi Substation 10 miles away is quite costly.

The capital costs for Phase I of Gray Mountain assume turbine costs of $1,113/kW in 2006 dollars, for delivery in 2008 and beyond, a substation/transmission-related cost of $26.32 million, and access road upgrade costs of $7.5 million. Because Phase I carries the burden of access roads and substation interconnection costs, even with inflation, Phase 2 costs would be slightly less, and Phase 3 costs only slightly more than Phase 1. All-in capital costs include costs of project financing, a 5% project contingency. Costs do not include sales and local taxes. O&M costs do not include sales and local taxes, property taxes, or land lease fees.

Therefore, even though the wind resource at Gray Mountain is better than the other projects, the expense of Phase 1 of Gray Mountain will likely offset some of its wind resource advantages. Subsequent phases of Gray Mountain should attain some economies of scale and potentially better power price competitiveness relative to Phase I.

4.3.2 Aubrey Cliffs

The capital costs for Aubrey Cliffs assume turbine costs of $1,113/kW in 2005 dollars, for delivery in 2007, and access road upgrade costs of $5 million. All-in capital costs include costs of project financing, a 5% project contingency.

4.3.3 Clear Creek

The capital costs for Clear Creek assume turbine costs of $1,113/kW in 2006 dollars, for delivery in 2007, a substation/transmission-related cost of $6.89 million, and access road upgrade costs of $5 million. All-in capital costs include costs of project financing, a 5% project contingency.

4.3.4 Sunshine Wind Park

The capital costs for the Sunshine Wind Energy Project assume turbine costs of $1,113 /kW in 2006 dollars, for delivery in 2006, and access road upgrade costs of $500,000. All-in capital costs include costs of project financing, a 5% project contingency.

4.4 TRANSMISSION ACCESS REQUIREMENTS

Direct transmission access requirements for the wind sites are described as follows:

- **Gray Mountain.** At Gray Mountain, a 34.5-kV power collection system for each 150-MW project phase will be run 10 miles into the Moenkopi Substation near Cameron to interconnect with the 500-kV transmission system.
- **Aubrey Cliffs.** At Aubrey Cliffs, a 34.5-kV power collection system will be run 5 miles south of Chino Point underneath Route 66, to interconnect with the 230-kV transmission system near Seligman. A substation will need to be constructed at the location of the 230-kV tie.
- **Clear Creek.** At Clear Creek, a 34.5-kV power collection system will be run 4 miles to interconnect with the planned APS 69-kV system upgrade to be constructed in 2006. A substation will need to be constructed at the location of the 69-kV tie.
- **Sunshine Wind Park.** The existing Sunshine APS substation will be substantially upgraded and expanded at Sunshine, and the project will interconnect at 69 kV onsite at this substation.

Cost estimates associated with direct transmission access for each wind site are as follows:

Table 4-5 — Direct Transmission Access Cost Estimates for Wind Sites

	Gray Mountain 3 Phases	Gray Mountain Phase 1	Aubrey Cliffs	Clear Creek	Sunshine
Net Output, MW	450	150	100	75	60
Direct Transmission Access Cost, $ millions	37.5	12.8	12.6	6.89	5.80
Estimated Cost per kW, $/kW	83.3	85.2	126.2	91.9	96.7

4.5 NET OUTPUT ASSUMPTIONS

In order to properly characterize the net output of the plant given the observed available wind resources at the various sites, the following assumptions regarding net output were made:

Table 4-6 — Net Output Assumptions

	Gray Mountain (each phase)	Aubrey Cliffs	Clear Creek	Sunshine
Gross Wind Generation, kWh/yr	584,878,952	341,179,388	229,364,295	164,568,882
Net Wind Generation, kWh/yr (12% array loss)	522,213,349	304,624,454	204,789,549	146,936,501
Net Wind Generation/turbine, kWh/yr	5,119,739	4,479,771	4,095,791	3,583,817
Annual Capacity Factor, %	40	34	32	25

These assumptions result in the net capacities shown for each project.

4.6 ROYALTIES, TAXES, AND OTHER ITEMS

Certain other costs and credits should be taken into account in the performance of integrated resource planning studies that are not included in the capital and O&M costs shown above. These include property taxes, sales and use taxes, income tax, production tax credits, and land lease payments. The parameters used in estimates of these quantities are discussed below and in Section 9 of this report.

4.6.1 Property Tax

For the three project sites within Coconino County, it was assumed that Foresight will obtain similar property tax treatment as for the Sunshine Wind Project. For the Gray Mountain Project on the Navajo Reservation, the normal property tax, which takes the form of the Possessory Interest Tax (PIT), is normally 3%. This would be a fairly high rate of property tax for a wind project and investment of the scale being considered at Gray Mountain versus the customary or industry standards in other states of the U.S.

4.6.2 Sales and Use Tax

Most states allow an industrial machinery sales tax exemption for wind energy projects covering all of the wind turbines, substation, and other facilities and equipment, and the services and labor used to install the equipment. Normally, exemptions cover 85% to 90% of the total capital costs of a project. Since Arizona has not had experience with wind energy projects and since Foresight is still investigating a tax opinion and securing this exemption for Sunshine Wind Project. Arizona State and county sales tax in Coconino County runs 6.525% and is referred to as the Transaction Privilege Tax (TPT).

For the Gray Mountain Project, the tax that is analogous to sales and use tax under Navajo Law is the Business Activity Tax (BAT). This tax is 5%.

Sales and use taxes are not included in the capital and O&M cost estimates shown in this section.

4.6.3 State of Arizona Corporate Income Tax

The State of Arizona has a 6.968% income tax on corporate profits. This tax is applied to federally taxable income to approximate its effect on the three projects which are within the state's jurisdiction. This tax is not included in any cost estimates included in this report.

4.6.4 Federal Production Tax Credit

The U.S. federal production tax credit is a very important assumption that must be considered in the economics of these projects. This credit, under Section 45 of the federal tax code, is set to expire on December 31, 2007. However, it may be extended beyond that date. The credit amounts to an "after tax" benefit of 1.9 cents/kWh for each kilowatt-hour produced for the initial 10-year period of each project. In general, this tax credit is worth up to 1/3 of the net present value of each project, and the viability of any of these projects would need to be re-evaluated if the credit is not available in 2008 and beyond. Any integrated resource plan process that is considering wind resources must take this production tax credit and its possible extension into account.

4.6.5 Lease Payments

Estimates of certain lease payments that would be paid to the Navajo and Hopi nations are shown below. The lease payments are representative of other wind projects in the United States.

Table 4-7 — Lease Payment Summary

Project	Gray Mountain (3 Phases)	Aubrey Cliffs	Clear Creek	Sunshine	Totals
Plant Output, MW	450	100	75	60	
Annual Lease Payments, $	1,530,000	272,000	185,000	135,300	2,122,300

4.7 PERMITTING ISSUES

4.7.1 Gray Mountain

The Navajo Nation internal siting and zoning process will probably require one to two years and has not yet been started for this large-scale project. This process, in general, is as follows:

- Review and consensus by the local Cameron Chapter of the Navajo Nation, resulting in a Chapter Resolution
- Referral to the Tribal Land Administration Resources Office for review and approval
- Review by the Office of the President of the Navajo Nation
- Review by the Legislative Branch –Resources Committee of the Navajo Nation
- Possible review by the Department of the Interior of the U.S.

Since Gray Mountain is on the Navajo Reservation, Coconino County does not have jurisdiction for this project, except perhaps for transportation coordination. It is likely that in the process of forming a resolution approving the project, the Cameron Chapter will want to follow a site permit process similar to that of Coconino County in issuing a Conditional Use Permit. In addition, a building permit is likely to be required from the appropriate local Cameron Chapter Office.

Gray Mountain has already had an initial National Environmental Policy Act (NEPA) study made by NTUA. There do not at this time appear to be any obvious flight path issues with military operational areas (MOAs) or with the Federal Aviation Administration (FAA); however, additional due diligence will be required. Each turbine and each wind measurement tower taller than 200 feet will require an individual FAA permit.

Likely a storm water pollution prevention plan (SWPPP) permit for the construction period will need to be filed with the Department of Natural Resources (DNR) for the Navajo Nation, and some permits from the DNR of the Navajo Nation concerning fish and wildlife, archeological, and historical and cultural clearance will also be required. Additional biological and avian survey studies need to be done at this site. This project seems to have the initial support of the Cameron Chapter of the Navajo, and an initial archeological, historical, and cultural clearance has already been obtained by NTUA in order to install a meteorological wind testing tower.

Since the project would interconnect into and sell its power into the Federal Energy Regulatory Commission (FERC) -regulated high-voltage transmission system at Moenkopi Substation, the project would likely need an Exempt Wholesale Generator (EWG) certificate from FERC. It is not known whether a Certificate of

Convenience and Necessity (CCN) hearing for transmission system tie-in would be needed for building any new transmission feeder to Moenkopi Substation, and this would be a due diligence action item. A CCN determination is usually a state level public utility commission function, especially if there is a need for condemnation or, in some cases, a need to allow for public notice and comment.

The project will likely want to secure an EWG declaration from FERC. In addition, there could be wholesale exemptions needed under Arizona law for the Transaction Privilege Tax.

Additional due diligence would be needed to determine whether there are any waters of the U.S., State of Arizona, or the Navajo Nation affected by the project either at or adjacent to the site or downstream of the site. No obvious waters of the U.S., of the State of Arizona, or of the Navajo were observed on the mountain, or in the path of the transmission line right-of-way to Moenkopi Substation, during the site visit. If a more in-depth environmental due diligence determines that there are affected waters, then there may need to be some Federal, state, or Navajo permits obtained in this regard.

The Kaibab National Forest is located approximately 3 to 6 miles due west of the project site atop Gray Mountain. Some additional due diligence may be needed to determine whether any special permitting or notices will need to be filed with federal authorities or the National Park Service regarding the project.

4.7.2 Aubrey Cliffs

Aubrey Cliffs would be permitted in Coconino County jurisdiction very similar to the site permitting already carried out by Foresight Wind Energy for the Sunshine Wind Park, which has already received a Coconino County Conditional Use Permit. A building permit will be required for construction from Coconino County. Foresight has already done some initial due diligence, and at this time, there does not appear to be any obvious flight path issues with MOAs or FAA problems; however, some additional due diligence is required. Each turbine and each wind measurement tower taller than 200 feet will require an individual FAA permit.

The Navajo Nation internal project approval process will probably take one to two years and has not yet been started. This approval process is believed to be more for approval in lieu of actual permits at this site, as it is off the Navajo Reservation and is fee land owned by the Navajo within Coconino County. It is likely that as a part of the internal Navajo Nation approval process, the DNR for the Navajo Nation will have a significant sign off in the decision making process. The approval and sign off of the NTUA may also be required as the internal Navajo Nation department most involved and knowledgeable about wind energy. While it does not appear that there will be any apparent conflict or compatibility issues, the DNR of the Navajo has been contemplating a residential resort approximately 3 to 5 miles due east of the location of turbines (to be sited along the cliffs on top of the east side of the plateau atop the Aubrey Cliffs feature) and closer to Seligman, Arizona.

Initial screens by the Arizona Game and Fish Department and the U.S. Fish and Wildlife Service (USFWS) have not identified any sensitive species at this site. Additional avian survey work needs to be done and is scheduled to being in the latter half of 2005.

A SWPPP permit will need to be filed with the Department of Environmental Quality for the State of Arizona, and final clearance from the State Game and Fish Department and the USFWS concerning fish and wildlife and, separately, clearances for archeological and historical and cultural will be required. This project seems to have the initial support of the Navajo Nation, and a meteorological wind testing tower has already been installed atop the cliffs to monitor wind data.

Similar to the analysis performed at Sunshine Wind Park, Foresight has had consultants perform initial electronic interference studies to determine whether it can site turbines along the ridgeline in such a manner so as not to interfere with the existing large telecommunications installations at the far south end of Aubrey Cliffs.

Since the project would interconnect into and sell its power into the FERC-regulated 230-kV high-voltage transmission system, the project would likely need an EWG certificate from FERC. It is not known whether a CCN hearing for the transmission system tie-in would be required for building any new transmission feeders to the 230-kV system, and this would be a due diligence action item. The likely location for a substation would be at the point of interconnection with the 230-kV system. Overhead 34.5-kV transmission lines would likely cross Route 66 and run south to an interconnection point with the existing 230-kV transmission system.

The project will likely want to secure an EWG declaration from FERC. In addition, there could be wholesale exemptions needed under Arizona law for the Transaction Privilege Tax.

Additional due diligence will be needed to determine whether there are any waters of the U.S. or State of Arizona affected by the project either at or adjacent to the site or downstream of the site. No obvious waters of the U.S. or waters of the State of Arizona were observed on the site, or in the path of the transmission line easement south of Route 66 during the site visit. If a more in-depth environmental due diligence determines that there are affected waters, then there may need to be some Federal or state permits obtained in this regard.

Foresight is investigating obtaining a State of Arizona Industrial Machinery Sales Tax Exemption for the Aubrey Cliffs Wind Energy Project. Typically, these certifications allow the developer to avoid paying sales tax on a very high percentage of the capital involved in purchasing equipment, services, and labor related to installation of equipment, and most of the personal property and tangibles not classified as real estate that make up a project.

4.7.3 Clear Creek

Clear Creek would be permitted in Coconino County jurisdiction very similar to the site permitting already carried out by Foresight Wind Energy for the Sunshine Wind Park, which has already received a Coconino County Conditional Use Permit. A building permit from Coconino County will be required for construction. Foresight has already done some initial due diligence, and at this time, there does not appear to be any obvious flight path issues with MOAs or FAA problems; however, some additional due diligence is required. Each turbine and each wind measurement tower taller than 200 feet will require an individual FAA permit.

The Hopi Nation will have a significant decision making input and approvals in their internal project approval process, which is being discussed with them by Foresight. This approval process is believed to be more for approval in lieu of actual permits at this site, as it is off the Hopi Reservation and is fee land owned by the Hopi within the Coconino County, State of Arizona, and Federal U.S. jurisdiction.

Phase I biological and avian studies are underway, and Phase II survey work is scheduled to start in the fall of 2005. A SWPPP permit will need to be filed with the Department of Environmental Quality for the State of Arizona, and some permits from the State Department of Game and Fish and USFWS concerning fish and wildlife, archeological, and historical and cultural clearance will also be required. This project seems to have the initial support of the Hopi Nation, and a meteorological wind testing tower has already been installed atop the East Mesa to monitor wind data.

It is believed that no CCN hearing (Certificate of Convenience and Necessity) for transmission system tie-in will be required for building any new transmission feeder to the 69-kV system. The likely location for a substation would be at the point of interconnection with the 69-kV system.

The project will likely want to secure an EWG (Exempt Wholesale Generator) declaration from FERC. In addition, there could be wholesale exemptions needed under Arizona law for the Transaction Privilege Tax. Additional due diligence would be needed to determine whether there are any waters of the U.S. or State of

Arizona affected by the project either at or adjacent to the site or downstream of the site. No obvious waters of the U.S. or waters of the State of Arizona were observed on the site, or in the path of the transmission line easement running from either mesa towards Highway 87 during the site visit. If a more in-depth environmental due diligence determines that there are affected waters, then there may need to be some Federal or state permits obtained in this regard.

Foresight is investigating obtaining a State of Arizona Industrial Machinery Sales Tax Exemption for the Clear Creek Wind Energy Project. Typically these certifications allow the developer to avoid paying sales tax on a very high percentage of the capital involved in purchasing equipment, services, and labor related to installation of equipment and on most of the personal property and tangibles not classified as real estate that make up the Project.

4.7.4 Sunshine Wind Park

Sunshine Wind Park has already been granted its County Conditional Use Permit from Coconino County. A review of the permit application and public outreach materials indicates they are highly professional, quite thorough, and detailed, and that they provide excellent documentation of the due diligence and facts and plans surrounding the project site and its construction and operation. A building permit will be required for construction from Coconino County. Foresight has already done some initial due diligence and at this time, there does not appear to be any obvious flight path issues with MOAs or FAA problems; however, some final micro-siting, surveying, and permitting work is required. Each turbine and each wind measurement tower taller than 200 feet will require an individual FAA permit.

Western EcoSystems Technology, Inc. has completed a Phase I biological assessment of the site and determined there are no endangered species, or critical habitats in the area of the Project. The desert scrub habitat and lack of water and trees limits the concentration of wildlife in the area. The site has received clearance from the Arizona Game and Fish Department and USFWS. Eleven winter migrating bird surveys were conducted in 2004 and 2005 at three sites on or adjacent to the project site. Migratory bird surveys were also conducted in March through May 2005. Fall avian migration studies are currently underway to provide an understanding of the site spanning an entire year. The area is not a migratory fly way, and there do not appear to be any issues or concerns at this time regarding the biological studies conducted to date.

All archeological, cultural, and historical assessments have been completed at this site. There are several telecommunications towers on or adjacent to the site; however, Foresight has already planned for locating the turbines so as to avoid any impact on these telecommunications systems signal paths. Comsearch performed analysis of the worst-case full microwave paths at the project site for Foresight.

The typical SWPPP permit will need to be filed with the Department of Environmental Quality for the State of Arizona. This project seems to have the support of the Hopi Nation, and four meteorological wind testing towers have already been installed at the site to monitor wind data. Two towers are north of I-40 and two towers are south of I-40.

Since the project would interconnect into and sell its power into the FERC-regulated 69-kV high-voltage transmission system, the project would likely need an EWG certificate from FERC. It is believed by Foresight that no CCN hearing for transmission system tie-in is needed since the transmission line and substation are already on the land where the project is located.

The Project will likely want to secure an EWG declaration from FERC. In addition, there could be wholesale exemptions needed under Arizona law for the Transaction Privilege Tax.

No obvious waters of the U.S. or of the State of Arizona were observed on the site during the site visit.

One disaffected landowner adjacent to the project has filed suit against the Coconino County Planning Commission claiming that the County Planning Commission did not have the jurisdiction or legal standing to approve the Sunshine Wind Energy Project. At least at first glance, this lawsuit seems without merit, and baseless in its claim the County did not have jurisdiction or a legal basis for its approval of the Conditional Use Permit. The suit is likely to be either dismissed as baseless or litigated by the County, and should not prevent the Project from proceeding under the Conditional Use Permit it has legally obtained.

Foresight is investigating obtaining a State of Arizona Industrial Machinery Sales Tax Exemption or exemption from the Transaction Privilege Tax for the Sunshine Wind Energy Project. Typically these certifications allow the developer to avoid paying sales tax on a very high percentage of the capital involved in purchasing equipment, services, and labor related to installation of equipment and on most of the personal property and tangibles not classified as real estate that make up the Project.

4.8 CONCEPTUAL PROJECT DEVELOPMENT SCHEDULE

4.8.1 Gray Mountain

Gray Mountain's project development schedule for Phase I of 150 MW is attached in Appendix H. Each of the major project development tasks leading up to construction is shown with start dates, days duration, and finish or completion dates. Given the internal consensus building and the initial approval of the Navajo Cameron Chapter to erect a meteorological tower to measure the wind, the NEPA studies, and archeological clearances already accomplished by NTUA, and assuming a 1- to 2-year internal approval process by the Navajo Nation to develop and approve the construction of the project, it is believed that 150 MW could be constructed starting in the spring of 2008. The likely critical path for this project will not be so much technical or financial as the internal Navajo Nation review and approval process and in working with the Navajo to define an acceptable commercial framework, deal structures that allow for fair and equitable royalties, lease payments, or equity participation or some combination of these financial benefits. Since this type of project will be relatively new to the various departments and branches of the government of the Navajo Nation, some extra time should be anticipated to obtain consensus and approval. The schedule shown is for Phase I only, but it should be feasible to obtain all permits, and to allow flexibility in the contracts to add 150-MW amounts, Phases II and III, in 2009 and 2010. Please note that it is not likely that this project can be constructed in time to capture the Federal Production Tax Credit, which is due to expire December 31, 2007, and that this uncertainty could prove to be a major development risk factor borne by the developer.

4.8.2 Aubrey Cliffs

The project development schedule for Aubrey Cliffs is attached in Appendix H. Each of the major project development tasks leading up to construction is shown with start dates, days duration, and finish or completion dates. Major progress on land leases agreements, environmental due diligence, and Coconino County site permits will need to be made in 2006 for this project to be constructed in 2007. But, assuming progress on these fronts, it seems feasible the project could be constructed starting in the spring of 2007.

Staying on this schedule would have major advantages in ensuring the project will capture the Federal Production Tax Credit for wind due to expire December 31, 2007. This project does have some risk of slipping to 2008 due to the complexity of the checker-boarded land ownership of the State of Arizona and the Navajo Nation at the site and, as shown on its development schedule, is probably slightly less advanced than the Clear Creek Site.

4.8.3 Clear Creek

The Clear Creek project development schedule is attached in Appendix H. Each of the major project development tasks leading up to construction is shown with start dates, days duration, and finish or completion dates. Major progress on land leases agreements, environmental due diligence, and Coconino County site permits will need to be made in 2006 for this project to be constructed in 2007. But, assuming progress on these fronts, it seems feasible the project could be constructed starting in the spring of 2007. Staying on this schedule would have major advantages in ensuring the project will capture the Federal Production Tax Credit for wind due to expire December 31, 2007. The development of this site may proceed a little more quickly than Aubrey Cliffs only because the Hopi Nation has already been involved in the development of the Sunshine Wind Project, and are somewhat familiar with wind energy project development and deal structures. Foresight has also already been discussing the various ways to lease the “checker-boarded” land at the site from either the Hopi or the State of Arizona.

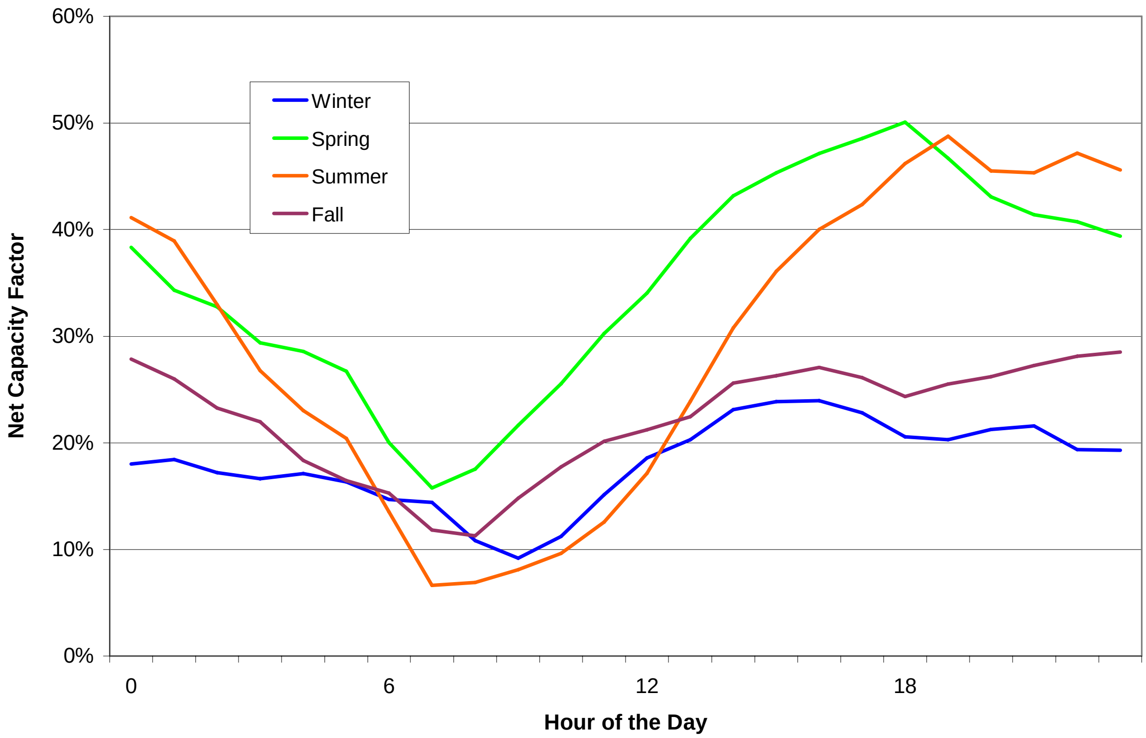
4.8.4 Sunshine Wind Park

The Sunshine Wind Park project development schedule is attached in Appendix H. Each of the major project development tasks leading up to construction is shown with start dates, days duration, and finish or completion dates. The high percentage of complete development tasks and milestones on this project are indicated by the black fill on the schedule bars. Most of this project is in the advanced stages of development with many critical path development milestones complete or nearly complete.

4.9 GENERATION PROFILE AND LOAD DEMAND

For this study, it is assumed that load demand is sufficient to absorb the capacity of these four projects as long as transmission capacity is available. The generation profile for these projects is likely to be more on peak coincident than most wind projects in the U.S. As the figure below indicates, more of the generation will occur in the afternoons, peaking at about 5 to 6 p.m. This situation is likely to make wind generation in Arizona more valuable than wind generation in other parts of the U.S. where, in some instances, the peaks occur well into the evening and night during off-peak periods.

Figure 4-8 — Seasonal-Diurnal Wind Energy Output



4.10 CONSTRUCTION AND OPERATION STAFFING

The major impact on employment for wind energy projects will be during the construction period. On a permanent basis, wind projects typically employ 3 or 4 people per 75 to 100-MW of capacity. The table shown below indicates permanent and construction manpower characteristics for each of the four projects.

Table 4-8 — Manpower Requirements for Wind Projects

Project	MW	Permanent Jobs	Average Construction Jobs	Peak Construction Jobs	Percent Skilled Crafts during Construction
Gray Mountain	450	14	110 (each phase, three phases)	150 (each phase, three phases)	35%
Aubrey Cliffs	100	4	95	130	35%
Clear Creek	100	4	95	130	35%
Sunshine Wind Park	60	3	75	100	30%

Last page of Section 4.

5. NATURAL-GAS COMBINED CYCLE TECHNOLOGY

Natural gas combined-cycle (NGCC) technology was investigated as a potential alternative to replace or complement the electrical generation of the Mohave Generating Station. The Mohave Generating Station is a two-unit 1,580-MW coal-fired power plant located in Laughlin, Nevada, built between 1967 and 1971. The station covers approximately 2,490 acres. This study considered NGCC technology for the Southern California Edison 56% portion (885 MW) of the plant power generation. It is assumed that natural gas fuel can be obtained from natural gas trunk pipelines near the existing Mohave site.

Combined-cycle technology has been used to generate power for a number of years. Combined-cycle technology in the power industry is primarily a combination of the Brayton and Rankine cycles. The combustion turbine operates on the Brayton cycle and the bottoming cycle, which is made up of the heat recovery, steam generator, steam turbine, and related balance-of-plant systems, operates on the Rankine cycle.

The first combined-cycle power plant in the United States using combustion turbines was installed in 1957 for the West Texas Utilities Company. This unit was rated at approximately 38 MW. Over the years, advancements in combustion turbine design have been numerous, leading to increased capacity, performance, and reliability. The advancements in the combustion turbines have lead to increased combined-cycle plant sizes, performance, and reliability.

Combined-cycle plants generally come in discreet sizes. These discreet sizes are a function of the combustion turbine size. Unlike traditional power plants where the plant size is determined by the steam turbine, the combined-cycle power plant size is primarily a function of the combustion turbine. A general rule of thumb for combined-cycle plants that use industrial combustion turbines is that for every 2 MW of combustion turbine power generated, the steam turbine will generate approximately 1 MW of power. Today, combustion turbines have ISO capacity ratings over 250 MW for 60 Hz applications. Therefore, there are combined-cycle plants in 60 Hz applications, utilizing a single combustion turbine, which generate approximately 400 MW of power.

To achieve a power output of approximately 885 MW, the plant configuration for this study will be made up of two nominal 500-MW combined-cycle power blocks. Each 500-MW power block has a 2 x 2 x 1 configuration. The 2 x 2 x 1 designation refers to two combustion turbines, two heat recovery steam generators, and one steam turbine. This configuration and size were selected due to the vast industry experience and to be capable of achieving 885 MW of power.

5.1 NGCC TECHNOLOGY DESCRIPTION

For a combined-cycle power plant, the combination of multiple power cycles is performed to improve the overall efficiency of the total power plant. In general, a simple-cycle combustion turbine (i.e., Brayton cycle) has an efficiency in the range of 19% to 38% on a higher heating value basis. The efficiency range is quite broad due to the firing temperature of the combustion turbine, the pressure ratio, and the blade and component design of the machine. The Rankine-cycle power plant efficiency is typically in the range of 32% to 39% on a higher heating value basis. The Rankine-cycle efficiency is generally a function of the cycle configuration, the steam conditions, the equipment design, and the cooling source. The combination of these two power cycles, representing the combined-cycle power plant, generally provides efficiencies in the range of 48% to 52% on a higher heating value basis.

5.1.1 Combustion Turbine

Typically, combustion turbines used for combined-cycle plants are industrial-frame units (sometimes referred to as heavy-duty units). An industrial-frame combustion turbine is generally designated as such because it is larger, heavier, operates at slower speeds (i.e., typically 3,600 rpm) and is generally considered more rugged. The other classification of combustion turbines is aeroderivative. An aeroderivative combustion turbine is so named because they are modeled after jet engines used in airplanes. These engines are generally smaller, lighter, operate at higher speeds and can require specialized maintenance personnel due to more technical, complex components.

The combustion turbine included in this study is the F-Class, industrial-frame unit. The F-Class unit designation is given to the machine due to the firing temperature. Generally, the F-Class combustion turbine has a firing temperature of approximately 2,350°F to 2,400°F. Most F-Class combustion turbines for 60-Hz applications have an ISO rating in the range of 170 MW to 200 MW depending on the manufacturer. In particular, the F-Class combustion turbine selected for this study is the General Electric PG7241(FA), which is typically called the 7FA. This combustion turbine has an ISO rating of 171,700 kW, a lower heating value heat rate of 9,360 Btu/kWh (36.5%), a pressure ratio of 16, and a speed of 3,600 rpm. Other manufacturers of F-Class combustion turbines, including, but not limited to, Siemens, Alstom, and Mitsubishi Heavy Industries, could also provide machines that would work in this application.

There will be two GE 7FA combustion turbines per nominal 500-MW power block. Therefore, there will be a total of four combustion turbines for the site. The combustion turbines will be designed to fire natural gas as the primary fuel and No. 2 fuel oil as emergency backup. The combustion turbines will be equipped with dry low NO_X burner technology to limit the NO_X emissions from the combustion turbine to 9 ppmvd at 15% O_2 or less when operating on natural gas. Water injection will be used to control the NO_X to 42 ppmvd at 15% O_2 when operating on No. 2 fuel oil.

The combustion turbines will be equipped with an inlet filtration system to protect it from airborne dirt and particles. A pulse-type self-cleaning inlet air filtering system was selected. Evaporative coolers were also selected to lower the combustion turbine inlet air temperature during warm weather operation to enhance the combustion turbine's performance. An inlet silencer is included to reduce the noise emitted from the combustion turbine compressor inlet.

The air enters the compressor section of the combustion turbine through the inlet bellmouth. The air is compressed in the axial compressor through multiple compressor stages. The compressed air leaves the compressor section and is routed to the combustor where fuel is admitted for combustion. The hot combustion gases are directed into the turbine section of the combustion turbine where they are expanded. The turbine section of the combustion turbine drives the combustion turbine compressor and the generator. After expansion in the turbine section, the hot exhaust gases leave the turbine section through the diffuser and are directed to the heat recovery steam generator through the exhaust duct.

A combustion turbine is a constant-volume machine. Therefore, the more mass that goes through the turbine, the greater the output from the turbine. Based on this principle, the performance of the combustion turbine is highly dependent on ambient conditions. As the inlet air temperature is lowered, more inlet air mass will be ingested into the machine and the machine will generate more power output. Similarly, higher atmospheric pressures cause more air to be ingested into the machine, leading to greater output. Therefore, as the site elevation increases, the potential power output of the plant will be less than it would be at sea level.

5.1.2 Heat Recovery Steam Generator

The HRSG is used to generate steam by recovering the wasted energy from the combustion turbine hot exhaust gases. Heat recovery steam generators are typically classified as horizontal or vertical units. Horizontal units have vertical heat exchanger tubes with the exhaust gas flowing horizontally through the unit. These units are widely used in the United States. Vertical units have horizontal heat exchanger tubes with the exhaust gas flowing vertically through the unit across the tubes. The majority of these units are forced circulation units. These units are more widely used in European countries where available space is limited, typically, due to a smaller footprint.

Each combustion turbine exhausts into a dedicated HRSG; therefore, for the two 500-MW combined-cycle power blocks proposed in this study, there will be a total of four HRSGs required. Each HRSG will be three-pressure level, reheat, natural circulation, drum-type units. High-pressure steam will be generated at 1,800 psig and 1,050°F to be used as main steam to the steam turbine. The intermediate-pressure steam will be blended with the cold reheat steam before entering the reheat section of the HRSG. The reheat steam will be generated at 1,050°F and will be routed to the intermediate (reheat) turbine. The low-pressure section of the HRSG will be used for deaeration, and superheated steam from the low-pressure superheater will be sent to the low-pressure steam turbine to generate additional power.

The HRSG will comprise heat exchange sections including superheater(s), evaporator, and economizer(s) for each pressure level of steam generated. In a combined-cycle unit, the condensate is typically heated with the low-pressure economizer section of the HRSG rather than via feedwater heaters that take extraction steam from the steam turbine. This is done to recover as much waste heat from the combustion turbines as possible and to allow as much steam to pass through the steam turbine to generate power and to improve the overall efficiency of the unit. The low-pressure section of the HRSG incorporates an integral deaerator, and the low-pressure drum acts as the deaerator storage tank. Condensate is fed from the low-pressure drum to the boiler feedwater pump(s), where it is pumped to the intermediate- and high-pressure sections of the HRSG.

The design point of the HRSG will be based on the combustion turbine performance at the average ambient conditions. The performance will incorporate 15°F pinch point temperatures and a 20°F evaporator approach temperatures. The HRSG will also be designed for a 2°F temperature drop in the duct between the combustion turbine and the first heat transfer section of the HRSG. A 1% thermal loss is included to account for radiation losses, convection losses, and leakage from the HRSG to the atmosphere. A 5°F temperature drop is included in the steam lines between the HRSGs and the steam turbine. For natural gas operation, the stack temperature is generally kept above 180°F, and for No. 2 fuel oil, the stack temperature is typically maintained above 280°F.

Blowdown systems are included for the HRSG steam drum to remove suspended solids. The blowdown from each HRSG will be routed to a blowdown tank. A continuous blowdown rate of 1% will be used for normal operation.

The HRSGs will be shop-fabricated and assembled to the maximum extent possible permitted by shipping regulations. The HRSGs will be erected on site and set on a concrete slab with foundations designed to withstand the full-of-water loads. The HRSGs will be located outdoors. Each HRSG will have a separate stack with continuous emissions monitoring.

5.1.3 Steam Turbine

There will be one steam turbine for each 500-MW combined-cycle power block. Therefore, there will be two steam turbines required for the site. The steam turbines will be reheat condensing units. Each steam turbine will generate nominally 175 MW of power. High-pressure steam from the HRSG will be sent to the steam turbine as main steam. Cold reheat steam from the steam turbine will be routed to the reheat section of the HRSG. A 10% pressure drop is allocated for steam pressure drop in the cold reheat piping, HRSG reheater, and hot reheat piping. The hot reheat steam is directed to the intermediate or reheat steam turbine. Low-pressure superheated steam from the HRSG is routed to the low-pressure section of the steam turbine.

The steam turbine is a condensing unit where the low-pressure steam exhausts from the steam turbine into either a wet surface condenser or an air-cooled condenser. The unit will include generator and auxiliaries, main steam control and stop valves, reheat stop and pilot valves, turbine control system, casing drains, and so forth. In addition, the unit will include all auxiliary systems associated with the proper operation of the steam turbine including, but not limited to, steam seal, exhaust hood sprays, lube oil, seal oil, and cooling system. The unit will operate at 3,600 rpm and be designed for outdoor installation.

5.1.4 Balance-of-Plant System Descriptions

Brief descriptions of the majority of balance-of-plant systems follow.

5.1.4.1 Mechanical Systems

Mechanical systems include the following:

- **Steam Systems.** The steam systems consist of the main steam, hot and cold reheat steam, intermediate-pressure steam, low-pressure steam, and bypass steam systems. The main steam system includes the main steam piping and components from the heat recovery steam generator superheater outlet to the high-pressure steam turbine control valves. The cold reheat steam system includes the piping and components from the high-pressure turbine exhaust to the HRSG reheat inlet. The intermediate-pressure steam system includes piping and components from the intermediate-pressure superheater outlet to the cold reheat piping connection. The HRSG supplier typically provides this system. The hot reheat steam system includes the piping and components from the final HRSG reheater to the steam turbine reheat stop valve. The low-pressure steam system includes the piping and components from the low-pressure HRSG superheater outlet to the admission point at the low-pressure steam turbine. The steam turbine bypass steam system will be used for startup and for trips, and involves bypassing the steam either to the condenser for the hot reheat and low-pressure bypass systems, or routing the steam from main steam to cold reheat for the high-pressure steam system. The steam piping will generally be routed on a system of pipe racks.

- **Condensate System.** The condensate system will be used to transfer the condensate from the condenser (i.e., either wet surface condenser or air-cooled condenser) hotwell to the low-pressure economizer section of the HRSG. The condensate system will include pumps, piping, and components. The condensate system will also include connections for water sampling and chemical feed.

- **Feedwater System.** The feedwater system will be used to transfer water from the low-pressure drum to the intermediate-pressure and high-pressure economizer sections of the HRSG. The feedwater system will include motor-driven boiler feed pumps, piping, control valves, and components. The feedwater control valves will be used to control the flow of feedwater to the high-pressure and intermediate-pressure systems.

- **Cooling Water System.** The circulating water system will be incorporated in the configuration that includes a wet mechanical draft cooling tower with wet surface condenser. The mechanical draft cooling tower will be designed for the summer ambient conditions. There will be one mechanical draft cooling tower per steam turbine. Therefore, two towers will be installed. The cooling water will be circulated to the wet surface condenser and back to the cooling tower via circulating water pumps. The vertical circulating water pumps will take suction from the cooling tower basin. The circulating water pumps will also supply water to the closed cooling water heat exchanger. The closed cooling water system will be a closed system and circulate cooling water to all of the equipment heat exchangers located throughout the plant.

- **Fuel System.** A new fuel system will be required for the combined-cycle units. The primary fuel will be natural gas with No. 2 fuel oil for emergency backup. The natural gas system will require a new pipeline, fuel gas compressors, fuel gas conditioning and performance heating system, and fuel gas metering system. The No. 2 fuel oil system will require storage and a fuel forwarding system.

- **Inlet Air System.** As discussed in the description of the combustion turbine, an inlet air system will be required for the combined-cycle combustion turbines. A pulse-type inlet air system will be used to filter the ambient air entering the combustion turbine compressor. Filtering the air is required to minimize the effects of erosion, corrosion, plugging, and fouling on the combustion turbine compressor and turbine blades. The pulse-type inlet air system uses cartridges to filter the air. These cartridges are periodically cleaned with a pulse of air from the reverse direction.

  The inlet air system also incorporates evaporative coolers. The evaporative coolers will be installed in the inlet air system to cool the inlet air during warm weather operation. The evaporative coolers use potable quality water to saturate a membrane in the air stream. The inlet air passes through the membrane lowering the air temperature through evaporation of the water. The inlet air system will also include silencing.

- **Flue Gas System.** Each CT/HRSG train will incorporate a flue gas system. Each flue gas system will consist of the ducting from the combustion turbine to the HRSG, the selective catalytic reduction system, the ducting from the HRSG to the stack, the continuous emissions monitoring system (CEMS), and the stack.

  It is anticipated that a selective catalytic control (SCR) system will be required to reduce the nitrogen oxides (NO_X) found in the exhaust gas of the combustion turbine. The combustion turbine is designed for a NO_X emission level of 9 ppmvd at 15% O_2 when firing natural gas. It is anticipated that the NO_X requirements for the Mohave Generating Station will be on the order of 3 to 5 ppmvd at 15% O_2. At this time, it is anticipate that the SCR system will use aqueous ammonia with a catalyst placed in the HRSG. The ammonia is injected in the exhaust gas upstream of the catalyst. The ammonia mixes with the exhaust gas, and the NO_X breaks down into N_2 and O_2 when it comes in contact with the catalyst. Each HRSG will have a dedicated stack with a CEMS located as required to obtain accurate readings.

- **Fire Protection System.** A fire protection system will be required for the combined-cycle power blocks. The system will include detection, alarming, and suppression systems. The fire protection alarming system will be located in the control room. This system will include fire extinguishers, sprinkler system (as required), dry suppression system (as required), piping, pumps, and hydrants to protect the facility.

- **Waste Water System.** A new process waste water system will be required for the combined-cycle facility. The process waste water system will be used to collect and neutralize waste water before discharging to the city. The process waste water system will incorporate piping, neutralization equipment, and components. In addition, combustion turbine water wash drains tanks will be required. These tanks collect water that has drained from the combustion turbines after an off line water wash. This water will be stored in the drains tank until a licensed waste hauler pumps the waste water out of the tank for proper off site disposal.

- **Station and Instrument Air System.** A station and instrument air system will be required for the combined-cycle facility. A separate system will be installed for each 500-MW power block. Each system will include two 100% centrifugal air compressors providing both instrument and station air. The system will also include filters, dryers, receiver, and piping. The system will deliver 125 psig compressed air.

5.1.4.2 Electrical and Control Systems

The electrical systems will provide a source of ac and dc power for the combined-cycle plant auxiliaries. The electrical system will consist of the generation system, medium-voltage system, low-voltage system, uninterruptible power supply (UPS) and dc systems, and motors, new switchyard breakers, generators and generator breakers, auxiliary and main power transformers, and plant electrical auxiliary systems. Electrical systems are described as follows:

- **Generation System.** The generation system will consist of the generators, excitation system, generator buses, generator breakers, and the main power transformers. For this study, each combustion turbine and steam turbine will have a generator (18 kV rated), exciter, generator bus (ISO-phase), generator breaker, and main power transformer (two winding).

- **Medium-Voltage System.** Each 500-MW combined-cycle power block will have a medium-voltage system. The medium-voltage auxiliary system provides feed to motors, other medium-voltage loads and low-voltage unit substations. The medium-voltage system distributes power to the combustion turbine, HRSG, and steam turbine 4,160-V electrical auxiliaries during normal operation, startup, and shutdown. The system will consist of two 100% unit auxiliary transformers (i.e., station service transformers) and associated switchgear.
- **Low-Voltage System.** Each 500-MW combined-cycle power block will have a low-voltage system. The low-voltage system distributes power to the combustion turbine, HRSG, and steam turbine low-voltage electrical auxiliaries during normal operation, startup, and shutdown. The main components are the power center transformers, 480-V power centers, and motor control centers.
- **Uninterruptible Power Supply and DC Systems.** The UPS and dc systems provide highly reliable sources of power for dc protective equipment, instrumentation, control, computers, and electronic circuits that require reliable sources of power. The UPS system provides 120 Vac, single-phase, 60-Hz power to these critical loads. The dc system provides a reliable source of power for the UPS system and critical control and power functions. The dc system will be operated ungrounded except through high-resistance ground detectors and instruments.
- **Motors.** All motors will be designed for across-the-line starting and will not exceed a class B insulation system temperature rise as defined by ANSI C50.41. All motors 25 hp and above will be provided with motor space heaters. Motors will be of the highest efficiency available for the specified application. Motors will be according to NEMA Standard MG-1. All stator windings will be copper.
- **Distributed Control System.** A distributed control system will be used to control the facility. The combustion turbines will come with their own control system. This control system will be tied to the plant controls. However, the primary control system will be by the combustion turbine supplier. The control system will provide coordinated control of steam generation, combustion turbine power generation, and steam turbine power generation. The control system will also provide control of plant systems and data acquisition in the main control room, and interfaces with the combustion turbine generator control system. The operators will be able to start/stop and load the combustion turbines, steam turbine, and all auxiliary equipment from the control room. The combustion turbine controls will be connected to the main control room by a data highway. Local control will also be provided at the combustion turbines and plant auxiliaries.

5.2 PLANT PERFORMANCE

Performance of the major NGCC equipment is provided individually and the overall performance is summarized below. The performance is based on a per 500-MW combined-cycle power block. The overall plant performance (i.e., nominally 1,000 MW) is also provided.

5.2.1 Combustion Turbine Performance

Combustion turbine performance depends on ambient conditions, the combustion characteristics including the type of nitrogen oxide (NO_X) control and the type of fuel being burned, the inlet pressure losses, and the turbine backpressure. The design basis information is as follows:

Table 5-1 — Design Basis Information

Ambient Temperature (dry bulb/wet bulb)		
- Winter	20°F / 20°F	
- Summer	125°F / 79°F	
- Average ambient	67°F / 50°F	
Elevation	714 feet above mean sea level	
Primary Fuel/Secondary Fuel	Natural gas / No. 2 fuel oil	
NO_X Emission Control	Primary Fuel	Secondary Fuel
- Control Type	Dry, low NO_X combustion	Water injection
- Emission Level from Turbines	9 ppmvd at 15% O_2	42 ppmvd at 15% O_2
Inlet Pressure Loss	4 in. H_2O	
Exhaust Pressure Loss	16 in. H_2O	

The GE 7FA combustion turbine is GE's nominal 170-MW F-Class machine. The estimated full-load performance data for the GE 7FA combustion turbine, operating in combined-cycle service with natural gas is as follows:

Table 5-2 — Combustion Turbine Performance Data

Ambient Temperature	20°F	67°F	108°F	125°F
Generator Output, kW	176,950	166,950	149,500	147,350
LHV Heat Input, mmBtu/hr	1,669	1,583	1,459	1,442
HHV Heat Input, mmBtu/hr	1,853	1,757	1,619	1,601
Exhaust Temperature, °F	1,089	1,120	1,141	1,143
Exhaust Flow, klb/hr	3,678	3,482	3,276	3,252

Note: Evaporative coolers are in service for 67°F, 108°F, and 125°F cases.

5.2.2 Heat Recover Steam Generator Performance

The performance of a HRSG is dependent upon the configuration of the surface area within the HRSG, the amount of energy available in the form of hot combustion turbine exhaust gas, the temperature and pressure of the steam being generated, the inlet feedwater conditions, and the HRSG heat losses.

The HRSGs have the following characteristics:

- **Surface Area Impacts.** The greatest impacts on HRSG surface areas are defined by the pinch point temperature difference and the steam drum approach temperature difference. These characteristics were set as follows:
  - 15°F Pinch Point Temperature: Pinch point temperature is defined as the temperature difference between the constant evaporation temperature on the tube side of the HRSG evaporator and the exhaust gas leaving the evaporator section.
  - 20°F Steam Drum Approach Temperature: The steam drum approach temperature is defined as the temperature difference between the subcooled water leaving the economizer outlet and the saturation temperature of the steam drum.
- **Combustion Turbine Backpressure.** The amount of allowable pressure drop through the HRSG impacts the combustion turbine performance and the exhaust temperature entering the HRSG. For this study, a pressure loss of 16 inches water column from the combustion turbine outlet through the HRSG stack was used. This pressure drop also accounts for the pressure loss of the SCR catalyst.
- **Heat Losses.** The amount of heat lost from the HRSG and steam cycle impacts the quantity of steam generated. The HRSG losses were estimated as follows:
  - Radiation and Convection: 1% heat loss from the HRSG due to radiation and convective heat transfer and exhaust gas leakage to the atmosphere.
  - Transition Piece Temperature Loss: 2°F temperature loss through the transition duct work from the combustion turbine exhaust flange through the HRSG inlet.
  - Blowdown: 1% steam drum blowdown for the removal of dissolved solids.
- **Steam Conditions.** The design basis steam conditions are as follows:
  - 1,850 psig/1055°F high-pressure superheater outlet steam
  - 427 psia/1005°F reheater outlet steam
  - 79 psia/462°F low-pressure superheater outlet steam

5.2.3 Steam Turbine Performance

The steam turbine performance depends on the cycle type, the steam conditions entering the steam turbine, and the steam turbine backpressure. For this study, the cycle type that was selected was the reheat cycle. The primary reason for the reheat cycle is to improve the efficiency of the steam turbine. The reheat cycle allows the efficiency to improve through increased steam inlet temperatures. The steam conditions also affect the performance of the steam turbine. The steam turbine performance improves with higher steam pressures and temperatures. However, as the steam conditions are increased, the amount of steam generated is decreased due to the limited energy from the combustion turbine exhaust gases. Therefore, a balance between the improved performance of the steam turbine due to increased steam conditions and the amount of steam generated to make power is necessary. Finally, the steam turbine backpressure affects the amount of power generated by the steam turbine. As the backpressure is increased, the power generated by the steam turbine is decreased.

The design basis steam conditions to the steam turbine are as follows:

- 1,800 psig/1,050°F high-pressure steam (i.e. main steam)
- 410 psia/1,000°F hot reheat steam
- 75 psia/460°F low-pressure admission steam

For this study, two types of cooling were evaluated. The base case was a mechanical draft cooling tower with a wet surface condenser. For this case, the steam backpressures could be maintained relatively low for all ambient conditions. For the average ambient condition, the backpressure was 2.5 inches of mercury absolute (inHgA). The other cooling method was an air-cooled condenser. The air-cooled condenser is a function of the dry bulb temperature. While lower steam turbine backpressures are possible at lower ambient temperatures, high backpressures occur at the high ambient temperatures, which negatively affect the performance. For the average ambient condition, the air-cooled condenser backpressure was 2.5 inHgA.

5.2.4 Plant Performance

The overall plant performance was estimated for the Mohave site. The performance was estimated for the 2 x 2 x 1 500-MW combined-cycle power block operating on natural gas at the site average ambient conditions. To obtain the total site performance estimate (i.e., nominal 1,000-MW facility), the performance estimate for the single 500-MW power block was doubled.

The full-load estimated plant performance while operating on natural gas with a mechanical draft cooling tower is as follows:

Table 5-3 — Plant Performance Data with Cooling Towers

Ambient Temperature	20°F	67°F	108°F	125°F
Gross Generator Output, MW	1,063	1,016	928	917
HHV Heat Input, mmBtu/hr	7,412	7,028	6,476	6,404
Auxiliary Power Estimate, MW	23	22	21	21
Net Generator Output, MW	1,040	994	907	896
Net Plant Heat Rate, Btu/kWh HHV	7,130	7,070	7,140	7,150

The full load estimated plant performance while operating on natural gas with an air-cooled condenser is as follows:

Table 5-4 — Plant Performance Data with Air-Cooled Condensers

Ambient Temperature	20°F	67°F	108°F	125°F
Gross Generator Output, MW	1,063	1,017	902	880
HHV Heat Input, mmBtu/hr	7,412	7,028	6,478	6,404
Auxiliary Power Estimate, MW	23	23	22	21
Net Generator Output, MW	1,040	994	880	859
Net Plant Heat Rate, Btu/kWh HHV	7,130	7,070	7,355	7,460

As part of this study, CO_2 sequestration is being evaluated. Based on information from the Department of Energy's computer program IECM, the performance of the combined-cycle facility is affected by the addition of CO_2 sequestration. From the program, the performance impact is approximately 15% less output and approximately 18% higher heat rate at the average ambient conditions.

5.2.5 Long-Term Performance

During the course of operating a power plant, the power output generally decreases from the new and clean condition due to degradation of the equipment. This degradation causes an increase in the plant heat rate and increases the operating cost for the plant. The primary contributors to the combined-cycle power plant degradation are the combustion turbines and, to a lesser extent, the steam turbine. The combustion turbine and steam turbine degradation can be classified into two categories, recoverable and non-recoverable degradation. The following table summarizes the causes for degradation and identifies which causes are recoverable:

Table 5-5 — Combustion Turbine and Steam Turbine Degradation

Degradation Type	Combustion Turbine	Steam Turbine
Recoverable	Compressor Fouling	Condenser Fouling Reduction in steam supply due to combustion turbine fouling.
Non-recoverable	Blade leakage, erosion, shaft seal leakage, compressor residual fouling	Blade leakage, erosion, shaft seal leakage, blade fouling

The combustion turbine performance will degrade as the compressor fouls from the inlet air and the compressor and turbine blades wear. Most of the compressor fouling impacts can be recovered by frequent on-line and off-line compressor washes. Most of the combustion turbine and steam turbine performance losses due to wear can be recovered with major equipment overhauls. However, these overhauls require outages that, depending on the type of overhaul, could cause a significant amount of down time. Major overhauls are generally recommended every 6 to 8 years depending upon the number of hours of equivalent operation. Predictions for the average amount of degradation have been developed. The performance degradation impact is typically on the order of 3% to 6% reduction in output and 2% to 4% increase in heat rate.

5.2.6 Start-Up Characteristics

The start-up of the combined-cycle plant depends on the condition of the plant before start-up. Generally, start-ups are classified as cold starts, warm starts, and hot starts. The definition of each of these depends on metal temperatures for the steam turbine rotor, HRSG drums, and the combustion turbine rotor with the steam turbine typically being the limiting factor. The estimated times for start-up are as follows:

- Estimated Hot Start-up Time 1 - 2 hours
- Estimated Warm Start-up Time 2 - 3 hours
- Estimated Cold Start-up Time 3 - 5 hours

5.3 COST ESTIMATES

Capital, fixed O&M, and variable O&M cost estimates were developed for the combined-cycle technology. The cost estimates were based on S&L's in-house database of similar projects. Sales and property taxes and land lease costs are not included in the costs presented.

5.3.1 Capital Costs

Current capital cost estimates for the NGCC technology were developed using S&L's in-house database. A single 2 x 2 x 1 500-MW combined-cycle power block cost estimate was developed for each of two different cooling methods. The first case was for a plant with a mechanical draft (MD) cooling tower with a wet surface condenser. The second case was for a plant with an air-cooled condenser. The capital cost estimates are based on current dollars, are based on zero liquid discharge, are based on labor rates commensurate with the Laughlin, Nevada area, and do not include costs associated with demolition of existing structures and equipment on the Mohave site. The capital cost estimates are as follows:

Table 5-6 — Capital Cost Estimates

Configuration	Estimated Capital Cost	Capital Cost per Installed kW*
Single 2x2x1 500-MW Combined-Cycle Power Block with MD Cooling Tower	$300,000,000	604
Two 2x2x1 500-MW Combined-Cycle Power Blocks with MD Cooling Tower	$540,000,000	544
Single 2x2x1 500-MW Combined-Cycle Power Block with Air-Cooled Condenser	$306,000,000	616
Two 2x2x1 500-MW Combined-Cycle Power Blocks with Air-Cooled Condenser	$551,000,000	555

* Based on net power at average ambient conditions

In addition to the costs that were developed for the two cooling methods, a cost estimate was developed for CO_2 sequestration. This estimate is based on the DOE IECM program data. The estimated capital cost for CO_2 sequestration is approximately $350/kW to $400/kW higher than the capital cost estimates provided above. Therefore, for a nominal 1,000-MW combined-cycle plant with mechanical draft cooling towers, the estimated capital cost with CO_2 sequestration is approximately $894/kW to $944/kW. Similarly, for a nominal 1,000-MW combined-cycle plant with air-cooled condensers, the estimated capital cost with CO_2 sequestration is approximately $905/kW to $955/kW.

5.3.2 Operating and Maintenance Costs

The fixed and variable O&M costs were estimated for the natural gas combined-cycle technology.

The fixed O&M costs are those spent regardless of how much the plant operates. The fixed O&M costs include costs for direct and indirect labor for operations and maintenance staff that are permanently employed at the plant site, as well as home office support costs allocable to the plant. In addition, the fixed costs include O&M contract services and materials and power purchased for in-house plant needs during plant outages.

The variable O&M costs are those costs that change with the amount of power generated. The variable O&M costs include chemicals and consumables, catalyst replacement and major maintenance of the combustion turbines, steam turbines, HRSG, and balance-of-plant. The estimate was derived on the basis of an 80% capacity factor and approximately 50 starts per year. On the basis of this duty cycle, the combustion turbines will require a combustion inspection every year, a hot gas path inspection every three years, and a major inspection every six years.

The fixed and variable O&M costs for the natural gas combined-cycle power plant for each of the two cooling methods studied in this report are presented in the following table.

Table 5-7 — Estimated O&M Costs

Current $	MD Cooling Tower with Wet Surface Condenser	Air-Cooled Condenser
Fixed, $/kW-yr	$5.47	$5.47
Variable, $/MWh	$1.97	$1.77

CO_2 sequestration O&M costs were also estimated for this study. The fixed and variable O&M costs were estimated based on the DOE IECM program. The estimated fixed and variable O&M costs for the combined-cycle plant with mechanical draft cooling towers and with CO_2 sequestration are $6.45/kW-yr and $2.32/MWh respectively. The estimated fixed and variable O&M costs for the combined-cycle plant with air-cooled condensers and with CO_2 sequestration are $6.45/kW-yr and $2.08/MWh respectively.

5.4 LAND AREA REQUIREMENTS

Approximate plant land area requirements for the natural gas combined-cycle facility are presented in the following table. The table represents the estimated land requirements for two 500-MW combined-cycle power blocks. In addition, the table provides the approximate area required based on the method of cooling (i.e., mechanical draft cooling towers with wet surface condensers versus air-cooled condensers).

Table 5-8 — Approximate Land Area Required for 1,000-MW NGCC Facility

	MD Cooling Tower with Wet Surface Condenser	Air-Cooled Condenser
Acres without CO_2 Sequestration	30	42
Acres with CO_2 Sequestration	34	46

5.5 WATER USAGE

Approximate water usage for the natural gas combined-cycle facility is provided in the following table.

Table 5-9 — Approximate Water Usage for 1,000-MW NGCC Facility

	MD Cooling Tower with Wet Surface Condenser		Air-Cooled Condenser	
	gpm	acre-ft/yr	gpm	acre-ft/yr
Cooling Tower Makeup Peak / Average	3,500 / 2,300	5,650 / 3,710	0 / 0	0 / 0
Cycle Makeup Peak / Average	66 / 44	110 / 70	66 / 44	110 / 70
Miscellaneous Peak / Average	76 / 76	120 / 120	76 / 76	120 / 120
Total Water Makeup Peak / Average	3,642 / 2,420	5,870 / 3,900	142 / 120	230 / 190

Water availability depends on securing the rights to use the water that is currently being used at the Mohave site. Currently water rights are, in large part, tied to use of coal from the Black Mesa mine. This may impede development of an NGCC plant at the existing site.

5.6 PERMITTING ISSUES

The construction of a NGCC plant at the existing Mohave site near Laughlin, Nevada, will entail a number of permits and approvals before the start of construction. Some permits should be obtained once construction begins, and others should be obtained during commissioning of the plant. The importance of establishing a strict permitting schedule cannot be overstated, as certain procedures (e.g., ambient air quality monitoring and modeling) will require up to two years of lead time. With an adequate knowledge of the applicable regulations and the information required in the various permit applications, SCE can implement an effective permit strategy. A listing of possible permitting issues is provided below:

- **Air Quality Construction Permits.** A New Source Review (NSR) / Prevention of Significant Deterioration (PSD) air quality construction permit is the primary approval necessary for the construction of a power plant. The U.S. EPA has delegated authority for the implementation and enforcement of the NSR/PSD regulations to the Nevada Department of Conservation and Natural Resources – Division of Environmental Protection (NV-DEP).

  Under NSR, new major stationary sources with the potential to emit "significant" amounts of air pollution are required to obtain approval before commencing construction. Table 5-10 gives the major stationary source thresholds for NGCC plants. A 500-MW NGCC plant at the Mohave site would be designated as a major stationary source.

Table 5-10 — Definition of Major Stationary Source

Unit Configuration	Is Unit Configuration Included in One of the 28 Source Categories?	Unit is Classified as a Major Stationary Source if it has the Potential to Emit Greater Than….
Natural Gas Fired Combined Cycle Plant with HRSG and Heat Input >250 mmBtu/hr	Yes	100 tpy
Natural Gas Fired Combined Cycle Plant with HRSG and Heat Input <250 mmBtu/hr	No	250 tpy
Natural Gas Fired Simple Cycle Combustion Turbine – any size	No	250 tpy

Construction of a new major stationary source will be subject to NSR review if potential emissions from the new source are "significant." Significant emissions thresholds are defined in terms of annual emissions rates (tpy). Table 5-11 lists the pollutants for which significant emission rates have been established.

Table 5-11 — PSD Significant Emission Rates

Pollutant	Significant Emissions Rate (tpy)
CO	100
NO_X	40
SO_2	40
PM_{10}	15
VOC	40
H_2SO_4 mist	7

Source: 40 CFR 52.21 (b) (23).

Major new stationary sources in Nevada are required to submit an Air Use Permit application to the NV-DEP before starting construction. The Air Use Permit application is used to identify all applicable federal and state regulations. The permit application requires a comprehensive description of the proposed project, including the following:

— Process description
— Regulatory discussion describing all federal, state, and local air pollution control regulations and a discussion of how the proposed process unit complies with each regulation
— Best Available Control Technology analysis
— Emissions summary and calculations
— Stack/vent parameters
— Site description and process equipment location drawings

— Additional supporting information for specific processes and equipment

The Mohave site is located in Clark County, Nevada. Portions of Clark County (the greater Las Vegas metropolitan area) are currently designated as non-attainment for carbon monoxide (CO), 8-hour ozone (O_3), and particulate matter less than 10 microns (PM_{10}). Although the Mohave site is not located in the non-attainment area, the close proximity would require that the owners of the proposed plant evaluate its impact on the non-attainment area.

It can take up to two years to obtain a Final Air Quality Construction permit: six to nine months to conduct modeling and prepare the permit application material; one year for the state to review the material and issue a draft permit; and three months for public comment and revisions before issuing the final permit.

- **Ambient Air Monitoring.** The NV-DEP maintains a system of ambient air quality monitors throughout the state. Continuous data are collected for O_3, SO_2, NO_X, CO, PM_{10}, $PM_{2.5}$, and meteorological data. An automated data acquisition system is used to retrieve the data from all monitoring locations onto a central data management system. There are a large number of ambient monitors in Clark County, primarily because of the Las Vegas non-attainment area and the operation of large stationary sources such as the existing Mohave station. The NV-DEP conducts routine maintenance and calibration of these monitors for quality assurance.

  Data from the ambient air quality monitors are used to determine compliance with the NAAQS, shown in Table 5-12. The data are used to chart long-term trends in air quality and establish goals. Furthermore, the ambient air quality data is a necessary input for air quality modeling that is used for determining the impact of a proposed power plant.

Table 5-12 — National Ambient Air Quality Standards

Pollutant	Primary Standard 1	Primary Standard 2
PM_{10}	50 µg/m3 (annual mean)	150 µg/m3 (24-hour - 99th percentile)
$PM_{2.5}$	15 µg/m3 (annual mean)	65 µg/m3 (24-hour – 98th percentile)
SO_2	0.03 ppm (annual mean)	0.14 ppm (2nd highest 24-hour)
O_3	0.12 ppm (2nd highest 1-hour)	0.08 ppm (4th highest 8-hour)
CO	9 ppm (8-hour average)	35 ppm (1-hour average)
NO_X	100 µg/m3 (annual mean)	—
Pb	1.5 µg/m3 (quarterly average)	—

- **Air Quality Modeling.** Air quality modeling is used to estimate impacts to ambient air to determine whether the proposed power plant will result in pollutant concentration levels that exceed the applicable ambient air standards. Models allow one to forecast future air quality levels from sources that have not been constructed. Federal law requires that the NV-DEP have legally enforceable procedures in place to prevent construction or modification of any source where the emissions from the projected activity would interfere with the attainment and maintenance of the NAAQS.

  The primary U.S. EPA modeling guidelines are discussed in *40 CFR Part 51, Appendix W – Guideline on Air Quality Models*. There are two levels of sophistication for air quality models. The first level consists of relatively simple estimation techniques that generally use preset, worst-case meteorological conditions to provide conservative estimates of the air quality impact of a specific source. These are called screening techniques or screening models. The purpose of such techniques is to eliminate the need of more detailed modeling for those sources that clearly will not cause or contribute to ambient concentrations in excess of either the NAAQS or the allowable PSD concentration increments. If a screening technique indicates that the concentration contributed by the source exceeds the PSD increment or the increment remaining to just meet the NAAQS, then the second level of more sophisticated models should be applied.

  The second level consists of those analytical techniques that provide more detailed treatment of physical and chemical atmospheric processes, require more detailed and precise input data, and provide more specialized concentration estimates. As a result, they provide a more refined and, at least theoretically, a more accurate estimate of source impact and the effectiveness of control strategies. These are referred to as refined models.

  The U.S. EPA lists a number of recommended and alternative air quality modeling software. Regardless of the sophistication of the software, the utility of the model largely depends on the availability of good meteorological and ambient air quality data. An applicant for an air quality construction permit in Nevada will need to adequately satisfy the NV-DEP that the air quality in the Las Vegas metropolitan non-attainment area will not be negatively impacted by the project.

- **BACT/LAER Analysis.** Southern California Edison will need to demonstrate that their planned NGCC plant will be employ the Best Available Control Technology (BACT) for NO_X, CO, and PM_{10}. BACT is defined as an emissions limitation based on the maximum degree of reduction which, on a case-by-case basis, is determined to be achievable taking into account energy, environmental, and economic impacts and other costs. A typical new NGCC plant will require a SCR system with low-NO_X burners (LNB), in order to achieve a NO_X emission rate of 3.5 to 4.5 ppmvd (at 15% O_2). In addition, an oxidation catalyst (OC) may be required to reduce emission of CO, because of the close proximity of the site to the CO non-attainment area in Las Vegas. Recent BACT determinations have required CO emission limits in the 9.0 to 25.0 ppmvd range; an oxidation catalyst would further reduce these emissions by approximately 70% to 90%. Pipeline quality natural gas is generally considered BACT for PM_{10}, SO_2 and H_2SO_4 emissions, without further controls.

- **Class I Area Impact Review.** The Clean Air Act Amendments of 1977 gave Federal Land Managers (FLM) an affirmative responsibility to protect the natural and cultural resources of Class I areas from the adverse impacts of air pollution. Class I areas include certain national parks and wilderness areas. FLM responsibilities include the review of air quality permit applications from proposed new major sources near Class I areas. If the FLM determines that emissions from a proposed source will contribute to adverse impacts on the air quality or visibility of a Class I area, then he may recommend to the NV-DEP that the permit be denied, unless the impacts can be mitigated.

All new emission sources that have the potential to impact visibility in a Class I area will be subject to pre-construction review by the FLM. Visibility impacts are predicted using computer modeling (e.g., CalPUFF), and are generally a function of emissions of SO_2, SO_3, NO_X, PM_{10}, and ammonia. Sources located near a Class I area will be subject to more rigorous review, and if visibility impacts are predicted by the model, the permitting agency may impose more stringent emission requirements.

The Mohave site is located near numerous Class I areas in California, Utah, and Arizona. Table 5-13 lists the distances between these Class I areas and Laughlin, Nevada.

Table 5-13 — Distances from Laughlin, Nevada, to Class I Areas

Class I area	Distance (miles)
Domeland Wilderness Area (CA)	202
San Gabriel Wilderness Area (CA)	179
Cucamonga Wilderness Area (CA)	184
San Gorgonio Wilderness Area (CA)	139
San Jacinta Wilderness Area (CA)	144
Joshua Tree Wilderness Area (CA)	119
Grand Canyon National Park (AZ)	152
Sycamore Canyon Wilderness Area (AZ)	145
Pine Mountain Wilderness Area (AZ)	174
Mazatzal Wilderness Area (AZ)	195
Zion National Park (UT)	162

- **Local Air Quality Permits.** The Clark County Department of Air Quality and Environmental Management (DAQEM) issues permits for all boilers and steam generators in the county. This permit would be applicable to the HRSG that is a component of a NGCC plant. The permit application requests basic information, such as the manufacturer name, serial number, boiler rating (in hp), minimum and maximum rating per burner (in ft^3/hr or gal/hr), stack height and diameter, exhaust velocity and temperature, and capacity factor.

  The Clark County DAQEM also issues permits for cooling towers. This permit application requests basic information, such as manufacturer name, serial number, circulation rate (in gal/min), maximum TDS (in ppm or mg/L) before purging, drift eliminators and drift loss percentage, and maximum hours of operation per day and per year.

- **Wastewater Discharge Permits.** The existing coal fired power plant (2 x 790 MW) sends its cooling tower blowdown and other plant discharges to a series of lined evaporation ponds. Domestic wastewater from the plant is also treated and sent to evaporation ponds. No plant effluent is discharged to any surface or ground waters of the United States. A new NGCC plant at the Mohave site would likely use a zero liquid discharge (ZLD) system. It is not known whether the existing evaporation ponds could accommodate the additional load or a new evaporation pond will be needed.

  Although a traditional NPDES permit would not be required, the ZLD system would still require permitting approval from the NV-DEP. The existing permit for Mohave Station (permit #NEV30007) requires leak detection systems for the ponds at the site. Such methods include geophysical survey equipment, visual sump inspections, visual liner inspections, and monitoring wells. There are no flow limitations in the permit, except for the package sewage treatment plant design capacity of 36,000 gallons per day.

  There are currently areas of groundwater contamination (high mineral content) on the site from leaking ponds that occurred in the early years of the plant. The existing permit requires an on-going remediation program to bring the groundwater quality to an electrical conductivity below 1,000 microsiemens. The site groundwater is expected to be completely remediated by July 2007.

  A new NGCC plant at Mohave would use the existing ZLD system at the site, or it would require the construction of new ponds to accommodate plant effluent. In either case, the permit with the NV-DEP would need to be revised. This revision would require a public comment period and a public hearing before final issuance of the permit. The total time required for this permit revision could range from 6 months to 1 year.

  During construction, the site would require a General Number 2 NPDES permit (storm water discharges from construction activities) from the Nevada DEP. These permits are issued instantaneously, with only a notification to the state that construction has started. As part of this permit, the construction contractor would need to create a Storm Water Pollution Prevention Plan (SWPPP), which details the measures for preventing debris from entering local streams. The SWPPP typically performs the following functions:

  — Identifies all potential sources of pollution which may reasonably be expected to affect the quality of storm water discharges from the construction site

  — Describes practice to reduce and sequester pollutants in the storm water discharges

  — Assures compliance with the terms and conditions of the General Number 2 NPDES permit

- **U.S. Army Corps of Engineers Permits.** It is unlikely that there are any jurisdictional wetlands in this arid region of the United States requiring a permit from the U.S. Army Corps of Engineers. However, if a new natural gas pipeline connection to the site crossed any “waters of the United States,” including dry creek beds, then a Nationwide Permit #12 (Utility Line Activities) would be required. This general permit allows installation of a pipeline underneath the river or creek, but requires that the water body be returned to its original condition.

- **Solid Waste Disposal Permits.** A NGCC plant would not create any solid waste during operation, outside of household trash and shop wastes. These would be disposed of off-site using a licensed commercial hauler. During construction, hazardous and non-hazardous wastes would likewise be disposed of off-site using a licensed commercial hauler. The plant should make a concerted effort to reuse or recycle construction debris and excavated material. There would be no need for an onsite landfill for an NGCC plant.

- **Public Utility Commission of Nevada (PUCN).** Any new power generation facility in the Nevada will require a Certificate of Public Convenience and Necessity (CPCN) from the PUCN. To obtain a CPCN, an applicant must demonstrate that there is a public need for a new facility and that the proposed utility is willing to serve and able to fulfill the public need.

- **Zoning / Land Use Permits.** The Mohave site is currently zoned for power plant use. It is assumed that a new NGCC power plant could be located entirely within the existing site. While there is no need to obtain a zoning change, the project developers will still need to submit a "Major Project Application: Specific Plan or Land Use & Development Guide" with the Clark County Department of Development Services. This guide costs $1,000 plus $4 per acre (for all acres over 300 acres). The applicant needs only to submit a description of the project and the location of the property (parcel numbers).

  It is possible that some of the landscaping, parking, and fencing requirements have changed since the original plant was built. The Clark County Department of Development Services maintains an Industrial Development Checklist with all of the applicable conditions.

- **Building Permits.** The Clark County Department of Development Services issues all building and civil design permits. These permits are typically obtained throughout construction, and the applications are submitted in phases. The first permits are for grubbing, grading, and other necessary earthwork. Next are the foundation permits for all buildings, warehouses, equipment skids, cooling towers, and so forth. Structural permits come next, as the building fabrications begin. These are followed by plumbing, mechanical (e.g., HVAC), electrical, and fire protection permits for all occupied buildings. The offices, control room, restrooms, and showers will need to be handicap accessible. There will likely be inspections of the construction site by building inspectors and fire officials.

  Obtaining building permits for a major project, such as a power plant, will require continuous interaction with Clark County staff. It is recommended that the project team meet with the appropriate Development Services personnel to establish a submittal schedule and determine how drawings and calculations will be submitted. In some instances, a local permit expediter may need to be hired in order to accelerate the permitting process.

- **Other Permits.** A number of secondary permits will be required for construction of an NGCC power plant at the Mohave site. The delivery of plant equipment in overweight or oversized trucks will require a special use permit from the Nevada Department of Transportation for state roads and the Clark County Department of Transportation for county roads. The construction of a tall stack will require an Obstruction Hazard Determination from the Federal Aviation Administration.

  An NGCC power plant could potentially use fuel oil for startup operations, fire pumps, and emergency generators. Any large petroleum storage tank at the site (>1,100 gallons above ground, any size below ground) will require a permit from the Clark County Fire Marshall. In addition, the site would need to update its Spill Prevention Control and Countermeasure (SPCC) plan to account for the new tanks. The SPCC plan (spelled out in 40 CFR Part 112) details how potential spills of petroleum products are to be contained.

The installation of ammonia storage tanks (either anhydrous or aqueous) for an SCR would not require any permits. However, information on ammonia and other hazardous chemicals will need to be shared with the local Emergency Planning Commission (EPC). Since Mohave Station already participates with the EPC, the list of on-site chemicals would only need to be updated.

5.7 SCHEDULE

A level one schedule was developed for the 1,000-MW natural gas combined-cycle power plant. The total duration from initiation of permit development through commercial operation for the two 2 x 2 x 1 500-MW combined-cycle power blocks is estimated to be 36 months. A breakdown of the major activities is as follows:

- Permitting – 12 months
- Engineering – 26 months
- Procurement – 28 months
- Construction – 18 months
- Start-up and Commissioning – 10 months
- Performance Testing – 2 months

Last page of Section 5.

6. DEMAND-SIDE MANAGEMENT/ENERGY EFFICIENCY TECHNOLOGY

6.1 ENERGY EFFICIENCY RESOURCE AVAILABILITY

6.1.1 Overview and Description of Concept

Southern California Edison's "Final Study Plan" for Mohave Alternatives and Complements includes evaluation of demand-side management (DSM) resource alternatives located outside the state of California. As noted in SCE's filing:[1]

> Based upon D.04-12-016 and stakeholders' comments, the Study will encompass all of the following [(1) through (4), generation alternatives] …
>
> (5) Study of energy efficiency that might be achieved in western U.S. states outside of California with SCE financing, by means of power purchase arrangements under which the resultant available power would be purchased by SCE.

This evaluation was conducted by performing the following:

- Evaluating energy efficiency resource potential in states outside of California
- Examining the institutional and regulatory issues associated with the concept of procuring a DSM resource outside of SCE's territory
- Discussing with a potential utility partner the commercial and regulatory aspects of implementing a DSM resource coupled with a power purchase agreement
- Describing the factors that would influence the price of any commercial arrangement for "DSM transfer" and developing a simple quantitative model to illustrate the way in which DSM resource procurement might work

Ultimately, the pricing arrangements for procurement of DSM resources coupled with a power purchase contract would be subject to negotiation between SCE and any potential utility partners or to the outcome of a competitive solicitation process.

This concept is based on the assumption that there are considerable low-cost efficiency resources in states neighboring California, and that SCE may be willing or directed to procure such resources (through DSM implementation coupled with a power purchase contract) depending on the overall costs in comparison to other alternatives. In doing so, SCE could create, for example, a 10-year power purchase agreement (PPA) with a

[1] Southern California Edison Company Final Study Plan for the Study of Potential Mohave Alternative/Complementary Resources, Docket R.04-04-003, submitted pursuant to CPUC Decision 04-12-016, Ordering Paragraph 3. March 21, 2005. Page 6.

neighboring utility at a price below its avoided costs, yet still high enough to entice the neighboring utility to implement the DSM. The DSM resource would be that available beyond what is already being pursued by the neighboring utility or state.

It is important to note that this mechanism for purchasing energy efficiency resources from another state or another utility is an innovative approach and has not (to our knowledge) been implemented anywhere in the U.S.[2], at least not on the scale considered as part of this study. As such, it required some investigation as to the institutional and contractual arrangements necessary to make it feasible and practical.

6.1.2 Methodology

The scope of work at the outset of the study was as follows:

- Assess the states and utilities in the region that would be appropriate sellers of energy efficiency resources. This includes Arizona, New Mexico, Nevada, Utah, and Colorado.
- Develop an estimate of the technical and economic potential for energy efficiency resources from the candidate states. This estimate would rely heavily upon existing studies, such as *The New Mother Lode: the Potential for More Efficient Electricity Use in the Southwest*, recently prepared by the Southwest Energy Efficiency Project.
- Define more clearly the conceptual mechanism for purchasing energy efficiency resources from other states and other utilities.
    - What types of energy efficiency measures would be eligible?
    - Who would be responsible for ensuring that the energy efficiency measures are installed and the efficiency savings are achieved?
    - What type of efficiency programs (e.g., rebates, shared savings, audits, other) would be used to achieve the savings? Does this issue need to be addressed, or can it be left up to the seller of the efficiency savings?
    - How would the "resultant available power" be determined and would it have to be linked to specific energy efficiency savings?
    - What time periods would the power be provided on (peak, off-peak, seasonal, daily), and would the power necessarily have to be linked to specific energy efficiency savings during those periods?
    - Would the energy efficiency savings have to be monitored and verified, and if so, how?
- Develop an estimate of the amount of economic potential for energy efficiency in the neighboring states that could be sold to SCE through power purchase arrangements. This would include consideration of the extent to which energy efficiency in the neighboring states is being

[2] A "Conservation Transfer Agreement" of a smaller scale was implemented in 1990 between Bonneville Power Administration (BPA) and the Snohomish, Mason and Lewis Public Utility Districts (PUDs) in Washington State, which allowed for saved energy to be delivered to Puget Sound Energy from BPA due to the measures installed in the PUDs.

developed for internal purposes. It would also include consideration of energy efficiency policy developments that would affect the potential for exports, such as the Nevada policy to allow energy efficiency to be used for complying with that state's renewable portfolio standard.

- Assess the economics of the mechanism for purchasing energy efficiency resources from other states and other utilities. What price should SCE be willing to pay to purchase energy efficiency resources? What price should neighboring utilities be willing to accept to sell such energy efficiency resources?
- Identify the contractual arrangements necessary for purchasing energy efficiency resources from other states and other utilities. What duration would the contracts be for? What sort of terms and conditions would be necessary to protect both parties to the contract?
- Assess the institutional challenges for purchasing energy efficiency resources from other states and other utilities. What incentives would other states and utilities have to sell such power? Would energy efficiency programs implemented for this purpose conflict with energy efficiency programs already being implemented by neighboring states and utilities? How would the costs and revenues from the energy efficiency sales be treated in the neighboring utility's rates? Would lost revenues create a problem for the neighboring utility?
- Use the results of the analyses described above to develop a recommendation for the extent to which this sort of energy efficiency purchase can represent an alternative (or partial alternative) to Mohave. To the extent possible, the recommendation will include an estimate of the costs of such a purchase and the amount of efficiency that could potentially be obtained from such a purchase.

6.2 POTENTIAL ENERGY EFFICIENCY RESOURCE AVAILABLE IN THE REGION

6.2.1 Southwest States as the Primary Source of Efficiency Resources

In evaluating out-of-state energy efficiency resources that might be purchased to offset SCE's share of the Mohave generating plant, the study focused on energy efficiency resources available in the southwestern states. While it may also be possible to purchase energy efficiency resources from states in the Northwest (Oregon, Washington, Idaho, and Montana), these states have not been included in this analysis. This analytical choice was made primarily because energy efficiency programs, often very aggressive, in the Pacific Northwest have been underway for some years, resulting in significant electricity savings over the past two decades[3]. These accumulated savings, plus the fact that building energy codes (for example) have generally been more robust in the Northwest than in the Southwest, coupled with the rapid growth of population in several southwestern states, lead us to believe that the remaining unaddressed energy efficiency opportunities in the Northwest are likely to

[3] The results of over two decades of energy efficiency programs in the Northwest are summarized in several documents, available from http://www.nwcouncil.org/energy/rtf/consreport/2004/Default.asp, that comprise the Northwest Power Planning Council's Utility Conservation Achievements Reports: 2004 Survey. This survey, for example, estimates that "[s]ince 1978, regional electricity conservation programs have saved about 2,925 [average] megawatts, more than enough electricity for two cities the size of Seattle".

be not as significant or, probably, as cost-effective to tap as those in other states within easy transmission reach of southern California.

This is not to say that all of the available energy efficiency resources in the northwest have been exhausted; the Energy Trust of Oregon, for example, is launching a re-assessment of remaining energy efficiency opportunities in Oregon, and the Energy Trust and many other northwest jurisdictions have very active energy efficiency programs at present. It is understood, however, that the magnitude of the opportunities available in the Southwest is much greater than those in the Northwest, and that efficiency resources in the Southwest will be available at lower cost. Another factor, for Oregon, is that the efficiency opportunities in the service territories of the state's two large investor-owned utilities are addressed by the Energy Trust, which is an independent, non-utility entity that does not buy or sell power. This means that the utility-to-utility efficiency resource/power transfer arrangement described here would not apply as such in most of Oregon, since power purchases from a third party would be needed to complete the trading arrangement.

Among the southwestern states that could potentially sell energy efficiency resources into southern California, this analysis focuses on Arizona, New Mexico, and Nevada. Colorado, Utah, and Wyoming were excluded, because (a) it may be more difficult to transmit power into southern California from these states, (b) there may be somewhat less energy efficiency potential in these states, and (c) the exclusion simplifies the analysis. To the extent that there are opportunities to sell energy efficiency resources from these states (particularly Colorado with its larger customer base), the study's estimates of energy efficiency potential will be conservative.

6.2.2 SWEEP Study of Energy Efficiency Potential in the Region

The study's analysis began with a review of a recent study by the Southwest Energy Efficiency Project (SWEEP) of the economic potential for energy efficiency in the Southwest (SWEEP 2002). The SWEEP study provides a detailed and comprehensive assessment of the efficiency potential in six southwestern states (Arizona, Nevada, New Mexico, Colorado, Utah, and Wyoming), and provides a useful starting point for the analysis. This section discusses the assumptions and conclusions of the SWEEP study, and the following section describes how those assumptions were used to estimate the amount of efficiency resources that might be readily available for SCE.

The SWEEP study consists of four major analyses, which were conducted for each state in the Southwest. First, it analyzed energy efficiency potentials by establishing baseline consumption and identifying energy savings potential relative to this baseline. The second analysis estimated the costs and benefits of the high efficiency measures, as well as the environmental impacts. The third analysis estimated macro-economic impacts from the high efficiency scenario, such as job impacts and income effects. Finally, the study identified policies necessary to achieve identified saving potentials.

The SWEEP study began by developing a base-case scenario electricity demand forecast by residential, commercial and industrial sectors, and by state, through the year 2020. It then developed a high-efficiency scenario by sector and state through 2020. This scenario assumed widespread adoption of cost-effective, commercially available energy efficiency measures during 2003–2020.

Some of the key assumptions in the analysis include the following:

- Any measures whose costs are below the retail electricity price are deemed cost-effective.
- For measures such as high-efficiency appliances or air conditioners, the “cost” of the measure is assumed to be the incremental cost for greater energy efficiency at the time of equipment replacement or purchase for a new building.
- Installed costs of measures are increased by 10% to account for the costs of policy and program implementation.

The study also made assumptions regarding the implementation rates necessary to realize the maximum potential efficiency savings. For existing buildings, the study assumed that 4.4% of the potential efficiency measures could be implemented per year and would reach 80% by 2020. For new buildings, the study assumed that 50% of the potential efficiency measures are installed as of 2003, and the percentage of implementation would increase steadily over time until it reached 100% implementation in 2010.

The SWEEP study notes that the high-efficiency scenario is conservative in two ways. First “miscellaneous” end-use appliances for residential buildings were not included in this analysis. This category accounts for approximately 35% of electricity use in housing and includes such appliances as active-mode consumption of TVs, VCRs, computers, and other electronic devices, evaporative coolers, and water pumps. Second, the analysis did not include new energy efficiency measures beyond the measures identified as cost-effective today.

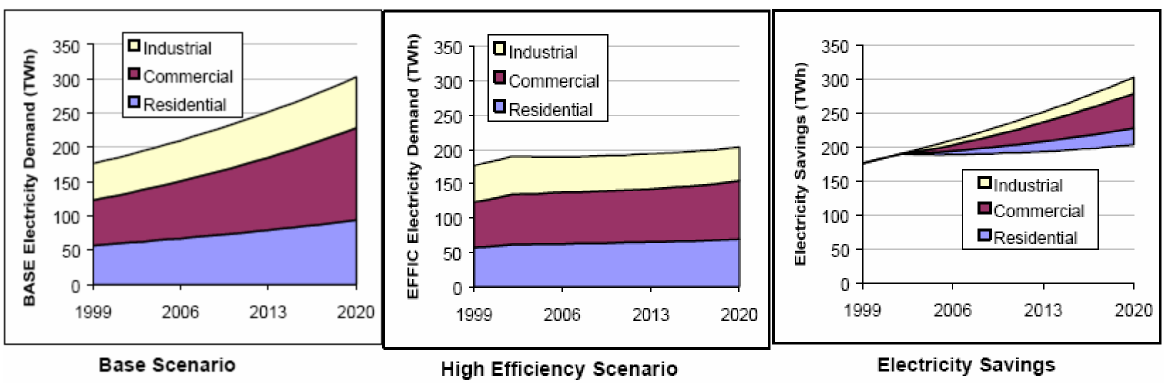
The results of the SWEEP analysis are summarized in Table 6-1 and Figure 6-1 below. The table indicates that the states in the region could reduce total electricity consumption by roughly 17% to 19% by 2010, and that by as much as 31% to 35% by 2020. The figure presents the potential efficiency savings by sector, and indicates that the total amount of efficiency savings is enough to reduce future load growth to nearly zero.

Table 6-1 — SWEEP Estimates of Energy Efficiency Potential – All Sectors

Year 2010		Region	AZ	CO	NV	NM	UT	WY
Baseline Consumption	GWh	232,658	79,755	54,516	34,797	21,229	28,702	13,657
Savings Potential	GWh	41,437	14,690	9,074	6,130	4,070	4,825	2,648
Savings Potential	%	17.8	18.4	16.6	17.6	19.2	16.8	19.4

Year 2020		Region	AZ	CO	NV	NM	UT	WY
Baseline Consumption	GWh	302,380	107,791	71,680	45,522	24,871	36,885	15,634
Savings Potential	GWh	99,038	36,585	22,352	14,155	8,897	11,500	5,552
Savings Potential	%	32.8	33.9	31.2	31.1	35.8	31.2	35.5

Figure 6-1 — SWEEP Estimates of Energy Efficiency Potential – By Sector



The SWEEP study estimated the net economic benefits of energy efficiency by comparing the incremental cost of the energy efficiency measures with the benefits of the reduced costs (i.e., avoided costs) for electricity supply. The avoided costs include the costs of power plant construction, fuel, O&M, transmission, distribution, and purchased power. In addition, consumers and businesses receive benefits from reduced natural gas prices influenced by reduced demand for natural gas for power plants. The SWEEP study did not include the economic benefits of reducing air emissions from power plants.[4]

Table 6-2 and Figure 6-2 present a summary of the economic benefits of the SWEEP energy efficiency potential. They indicate that by 2020 the energy efficiency could reduce electricity costs in the region by as much as $28 billion. The

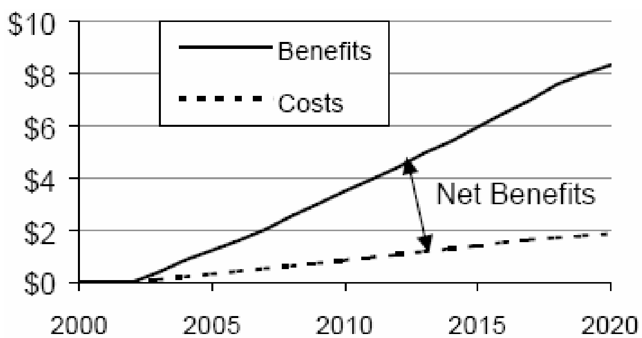
[4] Note that in its 2006-2008 energy efficiency portfolio, Southern California Edison regarded emissions reduction as economic benefits to energy efficiency measures (SCE 2005).

benefit cost ratio is 4.2, which suggests that for every dollar spent on energy efficiency, total electricity costs will be reduced by roughly four dollars.

Table 6-2 — Costs and Benefits of the High Efficiency Scenario by 2020 (billion cumulative present value dollars, in year 2000 dollars)

Sector	Energy Efficiency Costs	Overall Benefits	Net Benefits	Benefit-Cost Ratio
Commercial	3.0	17.7	14.7	5.8
Residential	3.2	9.3	6.1	2.9
Industrial	2.6	10.1	7.5	3.9
Total	**8.8**	**37.1**	**28.2**	**4.2**

Figure 6-2 — Costs and Benefits of the High Efficiency Scenario by 2020 (billion present value dollars, in year 2000 dollars)



Finally, the SWEEP study called for implementing seven different policies and programs with which states in the southwest can capture the energy efficiency potentials identified in the analysis. Those policies and programs include the following:

- System benefit charge or other mechanisms for funding utility (or state-based) energy efficiency programs,
- Utility rate reform,
- Building energy codes,
- Appliance efficiency standards,
- Tax incentives for innovative energy-efficient technologies,
- Public sector investment in energy efficiency,
- Market transformation effect.

The study identified ranges of percentages representing the potential savings which these policies or programs can contribute to energy savings. These are presented in Table 6-3. The ranges of the percentage in savings are mainly based on experiences from past energy efficiency policies and programs in various states. The upper ranges represent the aggressive implementation of policies and programs.

Table 6-3 — Potential Electricity Savings from Different Policy Options

Policy or program	Electricity savings potential in 2020 (%)
SBC-based Energy Efficiency Programs	10 – 15
Utility Rate Reform	3 – 6
Building Codes	4 – 8
Appliance Standards	4
Tax Incentives	1 – 2
Public Sector Investment	1 – 2
Market Transformation Effect	5 – 10
Total	**28 – 47**

6.2.3 Readily Available Energy Efficiency Potential in Arizona, Nevada, and New Mexico

The SWEEP study provides a useful indication of the *total* potential for cost-effective energy efficiency in the region. However, the electric utilities in Arizona, Nevada, and New Mexico would not be able to implement this level of energy efficiency savings for the purpose of selling power to SCE for several reasons. First, among all the policies listed in Table 6-3 above, electric utilities would only be able to implement the first set of policies: SBC-Based Energy Efficiency Programs.[5] Second, the SWEEP study assumed very aggressive implementation activities, and electric utilities might not have the interest or the capacity to pursue energy efficiency resources at this very aggressive level. Third, the utilities in these three states are already undertaking energy efficiency activities for their own customers, and thus have fewer efficiency resources available for selling to other utilities.

The SWEEP energy efficiency estimates, therefore, were adjusted to account for these three factors, and to develop an estimate of the "readily available utility efficiency," i.e., the amount of efficiency that a utility could implement — using standard industry energy efficiency programs — for the purpose of selling power to SCE. This analysis is presented in Table 6-4 below. Note that the energy savings in Table 6-4 (in GWh) are based on

[5] There is also precedent for electric utilities implementing substantial market transformation programs, often at very low cost per unit savings. This potential is not included in this report. Electric utilities might be able to undertake activities to implement the other policies listed in Table 6-3. However, they are less able to have a direct influence on these policies, and thus they have been left out of our analysis.

cumulative efficiency activities from all the previous years. For example, the savings in 2010 are a result of the efficiency investments from 2006 through the end of 2010.

For each state, the top row in Table 6-4 presents the estimates from the SWEEP study of the total electricity efficiency savings potential in each state. The next row presents a rough estimate of the portion of that total potential that can be obtained through utility-run energy efficiency programs. This estimate is derived by simply taking one-third of the total efficiency potential, based on Table 6-3 above, which indicates that the SBC policies will result in anywhere from 32% to 36% of the total efficiency savings.

Table 6-4 — Readily Available Utility Efficiency Potential in Arizona, Nevada, and New Mexico (GWh)

Arizona	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
SWEEP Total Efficiency Potential	7,253	9,104	10,961	12,822	14,690	16,792	18,900	21,014	23,134	25,260
SWEEP Utility Efficiency Potential	2,393	3,004	3,617	4,231	4,848	5,541	6,237	6,935	7,634	8,336
Easily Acheivable Utility Efficiency	1,197	1,502	1,808	2,116	2,424	2,771	3,119	3,467	3,817	4,168
Current Utility Efficiency Practices	221	328	436	543	651	759	866	974	1,081	1,189
Readily Available Utility Efficiency	976	1,174	1,373	1,572	1,773	2,012	2,252	2,494	2,736	2,979
Nevada	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
SWEEP Total Efficiency Potential	3,251	3,967	4,686	5,407	6,131	6,910	7,692	8,477	9,264	10,054
SWEEP Utility Efficiency Potential	1,073	1,309	1,546	1,784	2,023	2,280	2,538	2,797	3,057	3,318
Easily Acheivable Utility Efficiency	536	655	773	892	1,012	1,140	1,269	1,399	1,529	1,659
Current Utility Efficiency Practices	449	682	691	933	945	1,216	1,250	1,541	1,582	1,803
Readily Available Utility Efficiency	88	-27	82	-41	67	-75	19	-142	-53	-144
New Mexico	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**
SWEEP Total Efficiency Potential	2,173	2,650	3,125	3,598	4,069	4,561	5,052	5,541	6,028	6,513
SWEEP Utility Efficiency Potential	717	875	1,031	1,187	1,343	1,505	1,667	1,829	1,989	2,149
Easily Acheivable Utility Efficiency	359	437	516	594	671	753	834	914	995	1,075
Current Utility Efficiency Practices	27	33	40	47	53	60	67	73	80	87
Readily Available Utility Efficiency	332	404	476	547	618	693	767	841	915	988
Total: AZ+NV+NM (GWh)	1,396	1,551	1,931	2,078	2,457	2,629	3,039	3,192	3,597	3,823
Total: AZ+NM (GWh)	1,308	1,578	1,848	2,119	2,391	2,705	3,019	3,335	3,650	3,967
Total: AZ+NM (MW)	223	269	315	361	407	461	514	568	622	676

The third row for each state presents the “easily achievable” utility efficiency potential. This represents the portion of the total utility potential that could be achieved with moderate, as opposed to aggressive, investment and activity levels. It accounts for the fact that utilities might not have the interest or capacity to obtain all the cost-effective energy efficiency savings that are achievable, and that some efficiency measures are more difficult to implement in practice than to assess in theory. This analysis assumes that the easily achievable utility efficiency potential will be one-half of the SWEEP estimate of the total utility efficiency potential. In other words, the savings in the third row are equal to one-half of the savings in the second row.

The fourth row for each state presents an estimate of the amount of energy efficiency savings that is likely to be developed as a result of utility and regulatory policies in place today.

In Arizona, Arizona Public Service Company (APS) recently prepared a DSM Program Portfolio Plan that is expected to result in an average of $16 million per year of investment for 2005–2007 (APS 2005). The cumulative efficiency savings from APS by 2010 is estimated to reach roughly 651 GWh.[6]

In Nevada, a law was recently passed that allows electric utilities in the state to use energy efficiency savings to comply with the Portfolio Energy Standard (PES). The standard requires a certain portion of the companies' portfolio to consist of either energy efficiency, renewable resources, or both. Efficiency can be used to meet up to 25% of the PES, and of the efficiency that is used, one half of it must be from the residential sector. The efficiency portion of the PES is multiplied by the companies' recent load forecast to estimate the amount of energy efficiency that is expected to be developed by the electric companies as a result of this new policy.[7]

In New Mexico, there is much less energy efficiency activity than in the other two states assessed here. Utilities in New Mexico have a budget of roughly $2 million per year to implement energy efficiency programs. (SWEEP 2005) In the absence of a forecast of the amount of efficiency savings expected from these investments, we have developed a rough estimate for this study. It is assumed that the utilities in New Mexico will be able to achieve energy efficiency savings for an average cost of roughly $20/MWh, where the MWh are equal to the savings over the entire life of the efficiency measures.[8] It is also assumed that the efficiency measure installed have an operating life of 15 years on average. Under these assumptions, it is estimated that the $2 million dollars per year invested in New Mexico will result in roughly 7 GWh of energy efficiency savings per year.[9]

The fifth row for each state in Table 6-4 presents the estimate of the readily available utility efficiency savings. It is derived by subtracting the savings of the existing utility efficiency policies from the readily achievable

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6 This estimate includes actual efficiency saving from 2003 and 2004, because the potential savings estimates in the SWEEP study are based on load and efficiency data as of 2002.

7 The PES law does not *require* utilities to implement this level of energy efficiency. Instead, it *allows* them to implement this amount of efficiency as an alternative to developing renewable resources. Given the current economic advantage of energy efficiency over renewable generation, it is safe to assume that the electric companies in Nevada will be pursuing as much of this energy efficiency option as possible.

8 See the following section for a discussion of the cost of saved energy for typical utility energy efficiency programs. While it may cost more to achieve the efficiency savings in New Mexico, we use this assumption to be conservative, i.e., to avoid overstating the readily available efficiency potential.

9 The estimates in Table 6.4 include actual efficiency saving from 2003 and 2004, because the potential savings estimates in the SWEEP study are based on load and efficiency data as of 2002.

utility efficiency. This estimate provides a rough indication of the amount of efficiency that could be developed by electric utilities and sold to SCE.

Note that Arizona has, by far, the largest potential for readily available utility efficiency savings. This is because Arizona has the largest amount of electricity consumption, and thus the largest amount of efficiency potential.

Also, note that the readily available efficiency potential in Nevada is relatively low, and in some years negative, under these assumptions. This is because the Portfolio Energy Standard will be encouraging the two electric utilities there to develop a large amount of energy efficiency savings, leaving very little, or no, efficiency left to be sold to SCE. This finding is consistent with the general understanding among utility efficiency stakeholders in Nevada; that it will be challenging for the utilities to meet the efficiency portion of the PES.[10] For this reason, Nevada has been removed entirely from the estimate of the potential for efficiency resources that could be sold to SCE.[11]

The next-to-the-last row in Table 6-4 presents the estimate of the amount of energy efficiency savings (in GWh) in Arizona and New Mexico that could readily be made available for sale to SCE. The final row presents the amount of capacity (in MW) that this level of savings might represent. This level of capacity is estimated using the results of the SWEEP study, which found that in the entire Southwest region 99,038 GWh of energy would result in 16.9 GW of capacity. This same relationship of capacity to energy is used to estimate the capacity savings in Table 6-4.[12]

In summary, by 2010, there are at least 2,394 GWh of energy and 408 MW of capacity available from Arizona and New Mexico. To put this in perspective, SCE's share of the Mohave generation is roughly 5,700 GWh per year, and its share of the Mohave capacity is 885 MW. Thus, by 2010, energy efficiency from Arizona and New Mexico could replace over 40% of the energy and over 45% of the capacity from the Mohave plant. This is a very conservative estimate of the potential to replace Mohave with efficiency resources, as a result of the

[10] Synapse Energy Economics is representing the Nevada Bureau of Consumer Protection in the Nevada Demand-Side Management Collaborative, and this statement is based on recent informal comments of several parties within the Collaborative, particularly representatives for Nevada Power Company and Sierra Pacific Power Company.

[11] Note that the Nevada utilities are likely to have more energy efficiency opportunities from the commercial and industrial sectors than from the residential sector. Thus, the 50% residential requirement is likely to mean that some commercial and industrial energy efficiency will be available above and beyond the PES. However, we have chosen not to include this potential in our estimates.

[12] The capacity savings may well be considerably higher than this if sufficient emphasis is placed on efficiency measures that save energy during peak periods.

adjustments made above. A highly motivated utility could obtain more than the easily achievable efficiency savings identified here.

Furthermore, although Nevada, Colorado, Utah, Wyoming, and the Northwest states were excluded from the analysis, efficiency might also be purchasable from those states. This report focused on Arizona and New Mexico, however, because these states are likely to have the most efficiency potential that is easiest to sell to SCE. If SCE were interested in purchasing more efficiency than identified above in Table 6-4, then it should look to these other states in the region.

6.2.4 Approximate Cost of Energy Efficiency in the Region

In order to demonstrate the economics of SCE purchasing energy efficiency from another utility, a rough estimate of the likely cost of developing energy efficiency resources in the region was developed. A more detailed analysis would be beyond the scope of this analysis. Nonetheless, it is possible to use estimates of the cost of saved energy in several other states to provide examples of what efficiency might cost.

Table 6-5 below presents a summary of the cost of saved energy for six states that implement relatively large energy efficiency programs. The cost of saved energy (in $/MWh) is calculated by dividing the initial costs of implementing an energy efficiency measure in any one year (including administration costs), by the cumulative energy savings over the total lifetime of the efficiency measure. Thus, the cost of saved energy can be compared directly with the cost of generation from a power plant, or the cost of purchasing power through a contract or the spot market. Table 6-5 indicates that the cost of saved energy for these states has ranged from $23/MWh to $44/MWh in the past.

Table 6-5 — Cost of Saved Energy from Selected States

State	Cost of Saved Energy ($/MWh)
California	30
Connecticut	23
Massachusetts	40
New Jersey	30
New York	44
Vermont	30

Source: ACEEE 2004, page 30, Table 5.

Table 6-6 below presents additional information on the cost of saved energy for states and utilities relevant to the Southwest region. In its recent DSM Program Portfolio Plan, APS estimated that its energy efficiency activities in 2005–2007 will cost $18/MWh on average. Nevada Power (NVP) recently submitted an Annual DSM Report detailing the historical efficiency activities of NVP and Sierra Pacific Power (SPP) in 2004, which indicates that the cost of saved energy was roughly $13/MWh.[13] SCE's own energy efficiency plan assumed that it will spend roughly $37/MWh to achieve the energy efficiency savings. Finally, the SWEEP study assumed that the energy efficiency savings identified in the study will cost roughly $20/MWh.[14]

Table 6-6 — Cost of Saved Energy in the Southwest Region

State	Cost of Saved Energy ($/MWh)	Source
Arizona Public Service Co.	18	APS 2005, page 4
Nevada Power and Sierra Pacific Power	13	NVP 2005, Exhibit B, Table 1
Southern California Edison	37	SCE 2005
SWEEP Study	20	SWEEP 2003

In practice, the cost of saved energy can vary widely depending upon the particular efficiency measure, the sector being served, the utility, the delivery costs, and other factors. For example, lighting programs tend to cost less than those addressing other measures, commercial and industrial customers are typically less costly to serve than residential customers, and utilities that tend to address measures comprehensively (as opposed to cream-skimming) tend to spend more money to achieve efficiency savings.

Costs in Table 6-5 and Table 6-6 are provided merely to illustrate the typical range of the cost of saved energy from a variety of efficiency programs. Based on this range, it is assumed that the amount of readily available efficiency savings presented in Table 6-4 can be achieved for a cost of $40/MWh or less. A high estimate was chosen in order to be conservative. APS is one of the best sources of efficiency purchases for SCE, and they estimate that efficiency costs them only $18/MWh. On the other hand, it may cost more for APS to go above and beyond the efficiency opportunities that they are already planning to pursue.

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13 The companies spent $10.6 million to save 78,300 MWh per year. We assume that the average measure life is 10 years, in order to estimate the cost of saved energy for lifetime energy savings. This average measure life is relatively short because most of the NVP and SPP savings are from commercial programs which we assume to include mostly lighting measures.

14 This cost is for the efficiency associated with all types of policies, not just the utility-run energy efficiency programs. Other policies (e.g., appliance standards and building codes) tend to have relatively low costs to implement, and thus might be responsible for lowering this average cost figure.

Also, this cost of saved energy is assumed to include the cost incurred by the electric company implementing the efficiency programs, as well as any costs incurred by the customer participating in the programs. In other words, it is based on the Total Resource Cost test, which requires accounting for both utility and customer costs. In very rough terms, approximately \$30/MWh would be incurred by the utility, and the remaining \$10/MWh would be incurred by the customer. The costs incurred by the utility would include all the program administration costs, marketing and delivery costs, monitoring and verification costs, and the utility portion of the cost of the measure itself.

6.2.5 References for this Subsection

- American Council for an Energy Efficient Economy (ACEEE) 2004. *Five Years In: An Examination of the First Half-Decade of Public Benefits Energy Efficiency Policies*, Martin Kushler, Dan York and Pattie White, April.
- Arizona Public Service Company (APS) 2005. *APS Demand-Side Management Program Portfolio Plan: 2005-2007*, July 1.
- Nevada Power Company (NVP) 2005. *Integrated Resource Plan 2003, Ninth Amendment to the Action Plan*, Submitted to the Nevada Public Utilities Commission, August 15.
- Southern California Edison, 2005, *Testimony Of Southern California Edison Company In Support Of Its Application for Approval of Its 2006-08 Energy Efficiency Programs and Public Goods Charge and Procurement Funding Requests*, before the California Public Utilities Commission, June 1, 2005.
- Southwest Energy Efficiency Project (SWEEP) 2005. *Utility Energy Efficiency Policies and Programs in the Southwest*, Howard Geller, Presentation to the Energy Efficiency Task Force Meeting, Santa Fe, New Mexico, March.
- SWEEP 2004. *Utility Energy Efficiency Policies and Programs in the Southwest*, Howard Geller, September 17.
- SWEEP 2002. *The New Mother Lode: the Potential for More Efficiency Electricity Use in the Southwest*, a report in the Hewlett Foundation Energy Series, November.

6.3 PURCHASE POWER ARRANGEMENTS WITH NEIGHBORING UTILITIES

To investigate the feasibility and practicality of the DSM resource / power purchase alternative/complement, discussions were held with PNM Resources of New Mexico. Initial attempts to discuss the issue with Arizona Corporation Commission staff and Arizona Public Service personnel have yet to result in substantive discussions. The aim of these conversations was to obtain feedback on the willingness of parties to participate in the DSM resource procurement, and to determine the key issues facing potential utility partners considering a

DSM/power purchase arrangement with SCE.[15] In particular, Synapse sought to obtain information on the regulatory and institutional concerns or barriers that may exist, and to determine the commercial factors that would influence the pricing arrangements that would accompany the DSM implementation/power purchase alternative. Another goal was to determine the likely range of prices or at least the driving factors in price determination before completion of the final report.

The discussions with PNM sought to answer the following questions:

- Is this a concept that PNM would consider seriously?
- What types of questions would need to be clarified in order to actually make this happen?
- What might pricing arrangements look like between PNM and SCE?
- Is there a pricing concept PNM could convey to us that would allow us to create some practical examples?
- Would SCE be the right company for PNM to make such an arrangement with, or would PNM be better off forging such a relationship with a different company?
- What particular New Mexico regulatory issues should we be aware of?
- Would PNM be willing to try this sort of DSM/power purchase contract agreement even though the concept is not well proven?
- How would environmental credits associated with a DSM resource, if any, be treated?

The conversations did not result in confirmation of any particular commercially acceptable pricing arrangements or price bounds. However, PNM did maintain an expression of interest in the concept. The conversations did reveal that a major concern existed concerning the manner in which the New Mexico Public Service Commission might view any arrangements that did not allow for freed-up generation capacity to remain available to New Mexico jurisdictional ratepayers. Based on this perspective, the DSM resource illustrative example provided in this chapter presumes significant retention of "freed-up" peaking capacity for the host utility in the neighboring state.

6.3.1 Approach to Analyzing the DSM Resource

The approach used to analyze the DSM resource first determined the range of DSM implementation costs and then considered the interaction between the DSM resource and the power purchase contract that must be coupled

[15] Synapse thanks the PNM personnel for the time taken to speak with us on the issues. PNM was aware that all discussions were focused on establishing a "proof of concept," or disproving such a concept, and that no commercial implications are to be taken from any of the information provided in the example

with the resource in order to physically flow the resulting "freed up" energy to SCE territory. A simple spreadsheet model was developed to test the assumptions used. The model allowed for an analysis of the way in which DSM peak shaving benefits would provide value to any potential partnering utilities. It was determined that the simplest and most effective demonstration of the DSM technology option concept would be to construct a power purchase arrangement that flowed "flat" or baseload power to SCE equivalent to the total annual energy saved by the DSM measures installed in the partnering utility's service territory, while simultaneously allowing for all incremental peak load reduction benefits to accrue to the partnering utility. This was determined after first investigating alternative models that "flowed" the DSM savings profile directly to SCE.

Table 6-7 below lists stakeholder objectives and sample approaches to reach those objectives when considering the DSM technology option.

SCE customers will be made better off, or at least will not be harmed, if the DSM technology option is no more expensive than the next available alternative, accounting for the value of the power over peak and off-peak periods. In the example used to illustrate the DSM technology option, the DSM contract price was set equal to $70/MWh, for a 24 x 7 flat "baseload" product flowed into SCE territory from the Palo Verde hub; this is somewhat less than existing estimates for SCE avoided costs[16], and less than the costs for some of the other supply alternatives. Thus, SCE customers remain at least neutral to the DSM option if a partnering utility is willing to receive $70/MWh for a 24 x 7 product. As the example shows, the peak reduction benefits together with the revenues received from a contract price of $70/MWh appear to be adequate to provide enough incentive to a partnering utility to consider the transaction.

The partnering utility's customers who directly participate in the DSM program offerings will be made better off through bill savings resulting from DSM measure installation. Those partnering utility customers who choose not to participate in any installation program will not see any rate impact, as long as the way in which benefits flow to the partnering utility allows them to offset the lost revenues from the DSM installations. The partnering utility's management and shareholders will consider the DSM technology option as long as the lost revenues arising from the DSM installations are at least offset by the wholesale sale (i.e., the 24 x 7 product flowed to SCE) revenues (net of DSM costs) and the net production cost savings associated with peak load reduction.

in this section.

The example illustrated in the following section purposefully considered a conservative allocation of the DSM benefits by keeping the partnering utility customers "held harmless," i.e., there was no rate impact assumed on the partnering utility side. As indicated in Table 6-7 and in the example to follow, the partnering utility's "participating" customers receive considerable benefit through direct bill reduction resulting from the DSM measures.

Table 6-7 — DSM Technology Option – Analysis of Stakeholder Interests

Stakeholder	Stakeholder Objectives	Sample Approaches to Meeting Stakeholder Objectives
SCE Customer	No rate increase relative to other technology options.	Purchase power/DSM costs to SCE must be less than or equal to— –Other technology options; –SCE avoided costs; or –Mohave costs after retrofit.
SCE Shareholder	Fair earnings compensation.	To be determined by CPUC.
Partnering Utility – All Customers and Shareholders	Reduced cost of electric service; improved reliability; improved fuel diversity; reduced environmental impacts; improved economic development; minimize future capacity and energy costs.	Implementation of cost-effective DSM in general results in these system-wide benefits.
Partnering Utility Customer Direct Participant in DSM Program	Reduced bills from installed DSM measures.	Customers elect to participate in program; customer contribution less than total savings.
Partnering Utility Customer So-Called "Non-Participant"	No change in near-term rates.	Flow sufficient benefits to partnering utility so that all its customers benefit.
Partnering Utility Shareholder	Compensated for lost revenue; fair earnings compensation.	Partnering utility retains near-term peak-load reduction benefits (reduced total costs to generate, reduced losses, no change in rates).

Note: Tribal stakeholder benefits of the DSM resource are not directly addressed in the DSM illustrative example. Some direct DSM measure benefit could occur depending on DSM program structure, if DSM measures are made available for installation on the reservations or are delivered near the reservations by enterprises based on the reservations or employing tribal members. Tribal indirect impacts are addressed in Chapter 9 of the report.

[16]Based on an examination of material included in "Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs," October 25, 2004, by Energy and Environmental Economics, Inc.; a review of the "Comparative Cost of California Central Station Electricity Generation Technologies," August 2003 by the staff of the California Energy Commission; and considering increased natural gas price trends.

6.3.2 Demand-Side Management as a Peaking Resource

In general, DSM resources have the potential to reduce peak load requirements in the service territories in which they are implemented, in addition to providing energy savings during shoulder and off-peak periods. For areas outside the Desert Southwest, there is considerable data available describing "DSM load shapes" and providing, among other details, annual load factors and coincident factors for DSM technologies.[17] However, the SWEEP study examined for the Desert Southwest region contained only an aggregate representation of the way in which DSM implementation will result in peak benefits. The actual DSM resource being evaluated is thus not defined with specificity. In particular, there is no list of the exact measures to be installed or of the technologies or behavioral changes to be promoted. Thus, there is no concrete set of DSM load shapes to evaluate for the DSM technology option. But that does not imply that the benefits of peak load reduction seen with DSM cannot be accounted for in the analysis undertaken for the DSM resource; the SWEEP study's aggregate "DSM load shape" can be used to approximate the peak load reduction benefit accruing to the "partnering" utility implementing the DSM measures. The example below accounts for the peak-load reducing benefits of DSM by recognizing the higher value of energy saved during peaking periods.

6.3.3 Example of DSM Implementation / Purchase Power Agreement

The following simplified example illustrates how the economics behind the DSM implementation / power purchase agreement might work. Conceptually, the DSM alternative represents procurement of a resource that is less expensive, or at least no more expensive, than other supply options facing SCE. Simultaneously, the DSM technology option allows a partnering utility (for example, PNM or another southwest region utility) to sell additional energy at wholesale; that is, energy that is only freed up and available for sale because of the DSM procurement. Thus, the arrangement could become a "win-win" approach because of the existence of (1) low DSM resource costs; (2) higher SCE avoided costs, or higher SCE costs based on a comparison to other options; and (3) value to the partnering utility in the form of peak period benefits, if the power purchase contract is not "shaped" to reflect the actual DSM savings "load" profile. The example uses a flat 24 x 7 power purchase product coupled with DSM implementation and retention of DSM peaking benefits by the partnering utility. It illustrates one way to ensure that all stakeholders are at least neutral and some are made better off by the adoption of the DSM option. The example does not directly illustrate certain temporal aspects of the DSM

[17] For example, the Northwest Power and Conservation Council posts publicly available savings and shape data on a wide array of DSM measures. These can be found at http://www.nwcouncil.org/energy/rtf/supportingdata/.

resource, such as front-loaded costs and savings seen over the life of the DSM measures; it uses levelized total resource costs (TRC) to represent the costs associated with a given megawatt-hour of energy savings.

The study scope for the DSM alternative does not include a detailed examination of the rate impacts affecting the neighboring utility ratepayers. In the example below, zero rate impact is assumed, when in reality there could be beneficial rate impacts if the savings associated with the use of the less expensive resource are shared not only between SCE and the partnering utility, but between SCE, the partnering utility, and the partnering utility's regulated ratepayers.[18]

The example uses the information gleaned from the SWEEP study to posit a DSM total resource cost of $40/MWh, and a utility cost of $30/MWh, assuming a customer contribution of $10/MWh. The total annual contract quantity of 300 GWh/yr is based on an assumption that the DSM resource could ramp up to such a level of implementation over the course of five years. This quantity is a somewhat arbitrary amount chosen to illustrate the workings of the contract; it is considerably below the energy efficiency potential identified in the earlier section of this report; and it can be scaled up linearly at least to the "readily available utility efficiency" identified in Table 6-4.

This assumption of 300 GWh/yr is not meant to be limiting in any way; it merely allows for a snapshot analysis of savings during a single year that are equivalent to the total energy flowing to SCE in the power purchase component of the transaction. If the DSM resource were employed up to the "readily available utility efficiency" seen in Table 6-4, it could conservatively replace approximately 42% of the annual energy and 45% of the capacity of SCE's share of the Mohave plant. The 300 GWh/year leads to a peak savings of 51 MW, based on the peak savings to annual energy savings ratio found in the SWEEP study.

The example shows the assumed, negotiated contract particulars for the power purchase / DSM resource procurement. The postulated contract price of $70 per MWh would depend on resource cost assumptions: the DSM implementation cost itself, SCE's avoided costs, and the partnering utility's cost structures with and without the presence of the DSM savings. The value chosen for the example is based on a minimum level of revenues required by the partnering utility to compensate for production costs and lost retail revenues while simultaneously reflecting an estimate of the benefits the partnering utility gains from peak load reductions and associated reduction in generation production cost to serve its retail load.

[18] The timing of forthcoming rate cases, and the existence of policies related to "decoupling" of utility profits from utility sales will also affect rate impacts. We address institutional "decoupling" issues in a subsequent section.

The example illustrates the tradeoffs between losing retail sales due to DSM installation and gaining wholesale sales through the power purchase component of the contract. In this instance, a retail price of $73/MWh has been used to demonstrate the effect of lost retail revenues. The current rate structure in the PNM service territory includes a retail rate of approximately $73/MWh or 7.3 cents/kWh. At a contract price of $70/MWh, the partnering utility would see a revenue increase (to partially offset the retail revenue loss) of $21 million per year.

The example includes an estimate of the peak load reduction benefit seen by the partnering utility. The peak benefit arises from three interacting effects: (1) the wholesale power purchase flows physical power equal to 34 MW for all hours of the year, while the DSM savings include 51 MW on average during peak times; (2) the partnering utility's overall system load profile is flattened (its annual load factor increases) due to the peak shaving effect of the DSM measures; and (3) the line loss benefits accrue directly to the partnering utility, which does not have to generate to compensate for the distribution system losses. Additional transmission level loss savings are likely (given the location of the "freed up" power closer to SCE's load center, at Palo Verde), but have not been quantified; nor have any additional beneficial effects associated with potential reduced distribution investment. For the 300-GWh transfer, the partnering utility offsets the lost retail revenue of $21.9 million per year with $21 million per year from SCE, and with $3.1 million per year in net DSM peak reduction benefit, arising from production cost savings, for a net gain of $2.3 million per year.

Lastly, the effect of the DSM measures on the partnering utility participating customer is shown below. In this example, the vast majority of the benefits accrue to these customers, for a total of $18.9 million net savings per year for the 300-GWh/yr quantities. The allocation of the vast majority of benefits to participating customers of the partnering utility reflects an approach that minimizes the regulatory risk of interregional DSM transfers by ensuring that partnering utility ratepayers are held harmless when "freed up" power is used to meet out-of-state loads. This does not imply that such a benefits allocation is the only way to effect a DSM transfer; alternative allocation strategies are possible (e.g., increase the customer contribution) that retain the viability of the DSM option while possibly lowering the costs to SCE.

Table 6-8 — Illustrative Example of DSM Implementation / Purchased Power Arrangement

Contract Particulars and Assumptions			Comments/Definitions
Total Cost (TRC) of DSM (Cost of Saved Energy)	40	$/MWh	Levelized TRC - High end of range of observed costs
Customer Contribution	10	$/MWh	Estimate
Net Utility Cost of DSM	30	$/MWh	
DSM Resource Qty / Purchased Power Qty	300	GWh/year	Contract Quantity
DSM Resource Qty - Peak Savings	51	MW	Based on aggregate peak impact factor from SWEEP
Negotiated or RFP-based Contract Price	70	$/MWh	Negotiated Contract Price or Result of RFP
Average MW Flow to SCE	34	MW	Average MW Flat Flow at 300 GWh per Year
Power Purchase Shape	24 x 7	Hrs/Week	Flat, Constant Power Flow All Year
Estimate of SCE Avoided Cost to Compute SCE Benefits	70	$/MWh	Estimate - to assume neutral impact on SCE
Average Annual SCE Impact (Customers and Shareholders)			
Resource Savings			
Avoided Costs	70	$/MWh	
Total Contract Price	70	$/MWh	
Price Difference, Avoided Costs - Contract Price	0	$/MWh	
Annual Quantity of Savings	300	GWh/year	
Net Savings	-	$/Year	Equal to Price Difference x Resource amount
Estimate of Average Annual PNM Shareholder Impact			
Revenue Loss Impact Before Peak Reduction Benefit			
Payment from SCE	70	$/MWh	Contract Price
Quantity Wholesale Sale to SCE	300	GWh/year	Contract Quantity
Total Revenue Increase from Purchased Power Contract	21,000,000	$/Year	Contract price x quantity flowed / saved
Retail Rate	73	$/MWh	Approximate based on current rates
Quantity Lost Retail Sales	300	GWh/year	
Lost Retail Revenues from Effect of DSM	21,900,000	$/Year	Contract quantity x retail price
Revenue Loss Impact Before DSM Peak Reduction Benefit	(900,000)	$/Year	Revenue increase from PP minus lost retail revenues
Estimate of DSM Peak Reduction Benefit			
On Peak Costs of Generation	80	$/MWh	Estimate based on PV Market
Off Peak Costs of Generation	35	$/MWh	Estimate
Share of DSM Savings Occuring During Peak Periods	67.0%		Estimate
Share of System Load On-Peak without DSM	70.0%		Estimate
Share of System Load On-Peak with DSM	69.3%		Estmate based on DSM Savings % On-Peak Periods
Share of Power Purchase Contract Flow On-Peak	57.0%		Based on 6X16 on-peak definition, 52 weeks/year
System Size	30	10^6 MWh/Yr	Base to allow DSM GWH at 1% of retail load
T&D Loss Savings as % of Retail Load	5.0%		Estimate
Total Production Cost Savings Including Loss Effect	12,154,778	$/Year	Based on On and Off Peak Costs - See Model
Total Utility DSM Costs	9,000,000	$/Year	Utility Costs x Resource Quantity
Net DSM Peak Reduction Benefit	3,154,778	$/Year	Delta Production Costs incl. T&D Loss Effect
Net Impact Including Peak Reduction Benefit	2,254,778	$/Year	Net Peak Benefit Less Revenue Loss Impact
Estimate of Average Annual PNM Participant Impact			
DSM Savings	300	GWh/year	
Retail Rate	73	$/MWh	
Gross Savings to Participating Customers	21,900,000	$/Year	Quantity x Retail Rate
Customer Contribution	3,000,000	$/Year	Per Unit Customer Contribution x Quantity
Net Savings to Participating Customers	18,900,000	$/Year	

6.3.4 Barriers to Implementation

The barriers to implementation of the DSM technology option include the following:

- Actual or perceived economics of the transaction from the perspective of the partnering utility
- Uncertainties with regulatory reception in the neighboring states
- Increasing local efforts to undertake DSM opportunities
- Lack of experience with interregional DSM resource transfers

The primary barrier to implementation is likely the perceived economics of the transaction from the partnering utility's perspective. To make up retail lost revenues, the partner must be persuaded that the magnitude of peak savings effects is adequate to offset the portion of retail lost revenues not recouped through wholesale sales, while ensuring an adequate financial incentive for shareholders. The economics of the DSM option as illustrated in the example above are sensitive to peak and off-peak power costs and the ratio of those costs; to the negotiated price for the transfer; to the load shape of the DSM measures; to the estimated distribution loss savings; and to the level of customer contribution. All of these driving factors must be given careful attention by the potential partnering utility in determining whether the incentive is large enough to consider the DSM transfer.

Regulatory barriers to implementation include the revenue risks partnering utilities face from home state utility commissions. The DSM technology option involves reduced retail sales and increased wholesale sales, with different revenue streams associated with each. Also, the retention of benefits associated with peak load reduction could flow through to ratepayers as a means of keeping the "freed up" capacity, or a portion of it, in the home state. This could reduce the effective shareholder incentive available to partnering utilities. The DSM transfer would also compete with existing neighboring state utility DSM efforts; at this time, the potential DSM savings far outstrips the efforts currently underway in Arizona, New Mexico, or Nevada, but local efforts could increase the cost of DSM measures incremental to those being captured by the home state itself.

6.4 INSTITUTIONAL AND REGULATORY SUPPORT FOR DSM PROCUREMENT

The example provided in the previous section uses retail lost revenues in estimating the benefits to the partnering utility for the DSM resource procurement / power purchase agreement. It is possible that under different forms of regulation in New Mexico (or other states that might be involved in potential DSM resource procurements), the existence of a rate-making structure that "decouples" a utility's profits from its regulated retail sales may help to reduce the lost margin often associated with lost revenues, and subsequently lower the contract price for the DSM resource (by lowering the risk of revenue recovery for the partnering utility). In this example, the retail lost revenues are mostly recouped through wholesale gained revenues. However, there may be circumstances in which the existence of a “decoupling” framework could help to put downward pressure on the price otherwise required to enter into a “DSM transfer” such as is contemplated herein. The remainder of this section describes the relationship between decoupling and the prospects for DSM procurement in other states.

6.4.1 Relationship between Regulatory “Decoupling” and Prospects for External Purchase of Efficiency Resources

The incentive for utilities to participate in agreements to implement energy efficiency programs in the states neighboring California in general, and to implement energy efficiency programs to enable power transfers to southern California in particular, is, not surprisingly, directly related to the effect those programs are likely to have on corporate profits. Under traditional utility ratemaking, if sales are higher than forecasted in a utility’s rate case, the utility accrues higher profits. Correspondingly, when sales fail to meet forecasts levels—including as a result of energy efficiency programs—utility profits decline. Of the various methods open to utility regulators for reducing or eliminating this disincentive to pursue energy efficiency programs, the “decoupling” of utility profits from the level of sales is a concept that has been implemented or is under discussion in many states. A very brief review of the concept of decoupling is provided below. The status and apparent direction of decoupling-related initiatives in Arizona, Colorado, Nevada, New Mexico, Utah, and Oregon are then summarized. These are the states where it is most likely to be technically feasible to transfer energy efficiency resources to SCE. The reason for this is that these states have available to them both considerable and untapped efficiency resources and appropriate electricity transmission infrastructure allowing sales of power to southern California.

The status of decoupling discussions in the states that are candidates for “energy efficiency resource trading” of the type described here is germane because of its effect on incentives for the utility in whose service territory the efficiency resources are located. Although most jurisdictions allow recovery of funds spent on DSM programs, and many offer some form of shareholder incentives for efficiency programs mounted by the utilities, it is far less likely that a utility commission would approve utility incentives toward participation in energy efficiency programs not paid for by the utility itself. The utility with an energy efficiency resource to “sell” is likely, therefore, to suffer loss of sales and loss of margins if its service territory hosts successful DSM programs underwritten by other parties. Indeed, this is one of the concerns expressed in conversations with PNM. If utility profits and sales are decoupled, however, the utility's financial disincentive to participate in an energy efficiency resource trading arrangement will be substantially reduced. Thus, the status of decoupling and similar disincentive-removal policy discussions in the states around California bears watching. This is not to say that decoupling is necessarily *essential* to a successful energy efficiency resource trading arrangement; a combination of financially attractive terms for power exported to southern California, assistance with mounting more aggressive DSM programs in its own territory (in part, perhaps, to address regulatory and public pressure to do so), and perhaps environmental considerations (reduced greenhouse gas emissions, for example) may make such trading sufficiently attractive to garner utility participation even in the absence of decoupling. The decoupling of utility profits from sales, however, is likely to lower the barriers to utility participation in a trading arrangement.

6.4.2 Decoupling: Concept and Proposed Mechanisms

A recent review of decoupling of utility profits from sales includes the following summary description:[19]

> Traditional electric and gas utility ratemaking mechanisms unintentionally include very strong financial disincentives for utilities to support or implement EE [Energy efficiency] and DG [Distributed Generation]. More so than any other issue, this fundamental 'throughput disincentive'….discourages utilities from promoting EE/DG that lowers customer costs. The net effect of the disincentive is that utilities' management interests are misaligned with a public interest in least-cost electric and gas energy service. This misalignment is somewhat arbitrary; but it can be directly remedied through 'decoupling' utility profits from sales or instituting similarly effective regulatory approaches.
>
> Decoupling involves regular adjustment (downward or upward) of utility rates to account for actual sales volume, rather than waiting until the next rate case to evaluate revenue requirements and adjust rates. This type of balancing mechanism is known as an Electric Revenue Adjustment Mechanism ('ERAM'). Some utilities have used an alternative approach, adopting a Lost Revenue Adjustment Mechanism (or LRAM). An LRAM can help reduce the throughput disincentive, but it fails to address the underlying problem.

The same review goes on to note:

> A large majority of electric utility costs are fixed, to pay for capital-intensive equipment such as wires, poles, transformers and generators. Utilities recover most of these fixed costs through volumetric-based rates, which change every 3-5 years with each so-called major 'rate case', the traditional and dominant form of utility ratemaking. But between rate cases, utilities have an implicit incentive to maximize their retail sales of electricity (relative to forecast levels, which set 'base' rates); i.e., to maximize the "throughput" of electricity across their wires, in order to ensure recovery of fixed costs and maximize allowable earnings (recovery of variable costs is

[19] The information is taken from a review conducted by Synapse Energy Economics on behalf of the U.S. Environmental Protection Agency. The U.S. EPA has not yet issued its final report and it may contain changes to the language initially provided by Synapse.

assured through regular – e.g., quarterly - adjustments such as for fuel, and thus doesn't impose analogous disincentives.)

With traditional ratemaking, there is no mechanism to prevent 'over-recovery' of these fixed costs, which occurs if sales are higher than projected; and no way to prevent 'under-recovery', which can happen if forecast sales are too optimistic (such as when weather or regional economic conditions deviate from forecast or 'normal'). This dynamic creates an automatic disincentive for utilities to promote energy efficiency or distributed generation, because those actions – even if clearly established and agreed-upon as less expensive means to meet customer needs - will reduce the amount of money the utility can recover towards payment for fixed costs.

In concept, decoupling severs the relationship between utility revenues and the volumes of sales per customers. In one form of decoupling, regulators set an allowable return per customer, and rates are periodically adjusted so reflect changes in revenue per customer as sales increase or decrease[20]. In this method, differences between revenues allowed by regulators and actual revenues received in each year following a rate case are tracked, and any differences are taken into account in adjusting customer rates (either up or down) in the following year. With this mechanism in place, utilities' economic disincentives to pursue energy efficiency are reduced, since any increase or decrease in sales per customer will be compensated for fairly promptly by rate adjustments. Decoupling does place a limit on "upside" net revenues by a utility, but also limits the "downside" effect of reduced sales related to either energy efficiency or a weather-related decrease in consumption.[21]

6.4.3 Consideration of Decoupling Policies in Southwest States and in Oregon

The following brief survey summarizes the status, and in some cases some of the history, of formal and informal discussions regarding implementing the decoupling of utility profits and sales in six western states. As such, these summaries provide one indicator of which states are more likely, at least from an incentives/disincentives regulatory perspective, to be the first hosts of efficiency resource trading arrangements (for example, New Mexico and Utah), and which may be less likely to host such arrangements in the short term.

6.4.3.1 Arizona

The concept of decoupling of utility profits from sales has received limited attention in Arizona. One of the two major gas utilities operating in the state, Southwest Gas, did propose to the Arizona Corporation Commission a decoupling mechanism, but that proposal was rejected by the Commission. A 2005 Commission Staff report on DSM policy did touch upon the issue of lost net revenue recovery by utilities, noting arguments for and against

[20] See, for example, Wayne Shirley, *Barriers to Energy Efficiency*. Presentation prepared for the Regulatory Assistance Project, June, 2005.

the concept as expressed by parties to a 2003/2004 workshop process to discuss DSM policy in Arizona. There is no discussion of decoupling in the Commission Staff's document. The staff ultimately took no position on lost net revenue recovery, noting that the Commission would decide the issue on a case-by-case basis.[22] Looking forward, a Commission Staff member indicated that decoupling was "not recommended" by the staff, and that while it is expected that the issue will be brought up again in the context of the next gas utility rate case, the idea has yet to be considered for electric utilities in Arizona, and there are no current plans to do so.

6.4.3.2 Colorado

A considerable effort by energy efficiency advocates was mounted in the 1990s to establish decoupling of utility sales and net revenues as Public Service Commission policy in Colorado. These efforts, however, proved unsuccessful. This year, Colorado House Bill 05-1133, "Concerning measures to promote energy efficiency," initially included text instructing the Commission to "[a]dopt a procedure for decoupling a gas distribution utility's sales and revenues," though the version of the bill ultimately forwarded to the governor for signature was not as explicit, instructing the Commission only to "identify barriers that financially penalize gas distribution utilities if they implement cost-effective energy efficiency programs for their customers."[23] In early June, however, Governor Owens vetoed the bill out of concerns that residential customers would be burdened unfairly with costs for gas energy efficiency programs (the bills exempted commercial and industrial customers from the application of cost-adjustment mechanisms that would allow gas utilities to recover energy efficiency program costs).[24] Some energy efficiency advocates familiar with the Colorado situation rate the prospects of adopting decoupling mechanisms under the current Commission as very unlikely.

6.4.3.3 Nevada

The State of Nevada, guided by what is now the Public Utilities Commission of Nevada, was an early leader in the movement to implement integrated resource planning (IRP), adopting what was then called "least-cost utility

[21] The application of decoupling to smooth weather-related consumption variations is particularly of interest for gas utilities.

[22] The Commission Staff's First Draft of Proposed DSM Rules in DSM Rulemaking Docket No. RE-00000C-05-0230, dated April 15, 2005, is available in two volumes: Draft Demand-Side Management Rules (http://www.cc.state.az.us/utility/electric/DSM-Exhibit1.pdf), and Staff Report on DSM Policy for the Generic Proceeding Concerning Electric Restructuring Issues, Et Al (Docket Nos. E-00000A-02-0051, E-01345A-01-0822, E-00000A-01-0630, E-01933A-02-0069), (http://www.cc.state.az.us/utility/electric/DSM-Exhibit2.pdf).

[23] See HOUSE BILL 05-1133, available as http://www.swenergy.org/legislative/2005/colorado/HB%201133%20Bill%20Language%20to%20Governor.pdf

[24] See Governor's Office press release dated June 3, 2005 at http://www.colorado.gov/governor/press/june05/hb1133.html.

planning" in 1983.[25] The IRP process led the two large private electric utilities in the state to pursue moderately successful DSM programs through the mid-1990s. At that time, a move toward a restructured and competitive utility environment in Nevada caused the utilities to substantially drop their DSM programs.

In 2001, however, the move toward restructuring was reversed, and the utilities began offering DSM programs again. At present, utilities receive an adder equal to a 5% return on equity to encourage demand-side management, but rewards for DSM are linked to expenditures, not performance, and there remains little incentive to mount DSM programs that do not build rate base. Decoupling of utility revenues from sales was recently proposed by a gas utility in a recent rate case, but the request was denied by the Commission.[26] One of the Commissioners, speaking in a national forum on energy efficiency and renewable energy, indicated that it was not clear to him "whether we have statutory authority to specifically implement either lost revenue or decoupling," though he indicated that the passage of Senate Bill 188 (the central provisions of which were ultimately included in Assembly Bill 03, which was signed into law in June of 2005[27]) might cause the Commission to "to take another look at the whole incentive structure for DSM and EE programs and make sure that programs are coherent as a whole"[28].

6.4.3.4 New Mexico

Considerable recent activity in the energy efficiency and renewable energy policy areas has helped to put active consideration of decoupling of utility net revenues and sales on a fast track in New Mexico. Governor Richardson's "Clean Energy Executive Order and Task Forces," established under Executive Order 2004-019, includes a Task Force on Utility Energy Efficiency. This includes among other duties consideration of "[r]ate issues like decoupling and treatment of utility program costs"[29]. In addition, and probably of more immediate relevance to policy implementation, the New Mexico Public Regulation Commission (NMPRC) has an active proceeding on energy efficiency rulemaking that will in the coming months, probably within 2005 or 2006, draft a set of general rules for decoupling of net revenues and sales for both electric and gas utilities. The rules will be

[25] Robert Balzar, Howard Geller, and Jon Wellinghoff (2004?), The Rebirth of Utility DSM Programs in Nevada. Available as http://www.swenergy.org/programs/nevada/127.pdf.

[26] From http://www.swenergy.org/pubs/Nevada_Energy_Efficiency_Strategy.pdf, in "Order in Docket No. 04-3011. Public Utilities Commission of Nevada. Aug. 26, 2004," "PUCN denied Southwest Gas's request to decouple gas sales and revenues in a recent rate case decision."

[27] See description in 2005 Nevada Legislative Effort by the Southwest Energy Efficiency Project (SWEEP), at http://www.swenergy.org/legislative/nevada/.

[28] Notes on DSM Incentives in Nevada, dated 5/19/05, and provided as background to a presentation by Nevada PUC Commissioner Carl Linvill to the State Technical Forum on EE/RE, organized by the Keystone Center for the USEPA.

[29] Jon T. Brock, New Mexico Eyes Clean Energy and Efficiency. From http://www.electricenergyonline.com/IndustryNews.asp?m=1&id=32109, dated February, 2005.

drafted by a group including representatives of the Commission staff, utilities, non-governmental organizations, and consumer groups. The general rules ultimately agreed to by this group will then be used to develop utility-specific decoupling mechanisms in the context of the next rate cases for the gas and electric utilities operating in the state.

6.4.3.5 Oregon

A number of different mechanisms for alleviating utility disincentives to pursue DSM were tried during the 1990s for electric utilities, including lost revenue adjustments, shared savings, and decoupling. Oregon's investor-owned utilities no longer run DSM programs themselves, but rather collect a 3% "public purpose charge," which is spent on DSM programs through the independent non-profit Energy Trust of Oregon, which began operation in 2002. As a result, decoupling and related mechanisms are no longer in use for electric utilities in Oregon. In 2001, a decoupling mechanism covering 90% of the difference between actual and expected weather-normalized revenue per customer was adopted by the Public Utilities Commission for Northwest Natural Gas. The mechanism for Northwest Natural Gas, and for the electric-utility mechanisms formerly in use, was designed largely through a consensus process, with only "general guidance" from the Commission[30].

6.4.3.6 Utah

The concept of decoupling utility profits from sales was discussed in Utah at least as early as 1991–1992, when it was raised by a party to PacifiCorp's integrated resource plan review.[31] At the time, the Utah Public Service Commission directed that an existing or new task force study decoupling and associated issues related to incentives and disincentives for the acquisition of demand-side resources, and to report back to the Commission. This process ultimately did not result in the adoption of a decoupling rule. The issue surfaced again in the mid-1990s, when a decoupling rule was proposed by a party in the context of an electric utility proceeding, but the proposal was ultimately abandoned. In the last year or so (2004–2005), tentative and informal discussions have begun with Questar Gas, the major gas utility in Utah, regarding the possibility of decoupling profits from sales, with an eye toward removing utility disincentives toward DSM as well as addressing some other problems, such as declining sales per customer, faced by the utility. It is, as yet, unclear whether this process will lead to a

[30] Notes on Oregon - Decoupling Natural Gas Sales, dated 5/19/05, and provided as background to a presentation by Oregon PUC Head of Utility Division Lee Sparling to the State Technical Forum on EE/RE, organized by the Keystone Center for the USEPA.

[31] Public Service Commission of Utah, Docket No. 90-2035-01, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order on Standards and Guidelines. Issued June 18, 1992.

proposal for addressing disincentives, or whether such a proposal, if offered, will include decoupling. Mindful that whatever ruling is accepted with regard to the gas utility will likely result in consideration of similar measures for the electric utilities in Utah, the state agency, utility, and other representatives involved in the discussion intend to proceed very carefully and deliberately in looking at decoupling and other options. In any case, the presence of these discussions would seem to be a clear indication of interest in the decoupling idea in Utah.

6.5 TRANSMISSION REQUIREMENTS

Because of the existence of supply resources owned by neighboring utilities (for example, by both PNM and APS) at the Palo Verde hub point at the California border, specific transmission assessments for the DSM alternative have not been conducted,. Unlike the alternative and complementary supply resources in the Study Area, the DSM resource will not require transshipment across Arizona/Nevada because its source point is already at the California border.

6.6 CONCLUSIONS

The following conclusions can be drawn from the analysis of the DSM resource alternative/complement:

- A sufficient amount of cost-effective DSM resource potential exists in the states neighboring California for this resource to be considered as a potentially viable technology option for SCE. In particular, relatively untapped, cost-effective DSM potential exists in Arizona, New Mexico, and Nevada.
- The overall economics of the transaction appear attractive based on a set of reasonable and, in some ways, conservative assumptions made in the analysis of the resource. It is important to consider all of the benefits arising from the DSM alternative, given the existence of retail lost revenues and their effect on pricing requirements. For example, distribution system loss avoidance is a considerable benefit and should not be underestimated. The allocation of the benefits between utility customers and utility shareholders will affect the economics and could prove decisive to the viability of the DSM technology option.
- The proximity of the Palo Verde hub to the SCE territory, and the relative liquidity of wholesale power supply at the hub, makes it easier for utility companies located in the Southwest states to consider a commercial arrangement with SCE. In these instances, there is no need to secure transmission to deliver the DSM resource from the actual service territory of the partnering utility.
- The uncertain regulatory environment in partnering utility states and the relative inexperience with interregional DSM transfers increase the risk associated with the DSM alternative when compared to more standard DSM implementation considerations.

Last page of Section 6.

7. OTHER RENEWABLE ENERGY TECHNOLOGY

Other renewable power technologies were investigated as a potential alternative to replace or complement the electrical generation of the Mohave Generating Station. This study considers geothermal and biomass technology for SCE's 56% portion (885 MW) of the plant power generation. Two types of renewable technologies were investigated: geothermal and biomass.

The total renewable generation for geothermal and biomass as compared to other renewable sources in the four state area (Arizona, Colorado, New Mexico, and Utah) area is shown in Table 7-1.

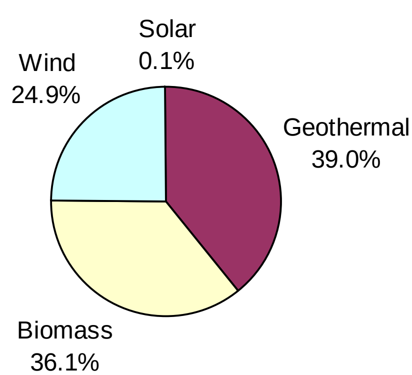
Table 7-1 — Total Renewable Net Generation: Four-State Area

Total Renewable Net Generation in 2002 (thousand Kilowatthours)

	Hydro	Geothermal	Biomass	Solar	Wind	Total
Arizona	7,427,180	0	141,060	459	0	7,568,699
Colorado	1,209,007	0	29,834		139,006	1,377,847
New Mexico	264,591	0	19,408	0	0	283,999
Utah	457,732	217,651	11,197	0	0	686,580
Total	9,358,510	217,651	201,499	459	139,006	9,917,125

Source: DOE/EIA Renewable Energy Trends with Preliminary Data for 2003

Figure 7-1 — Renewable Percentage (without Hydro): Four-State Area

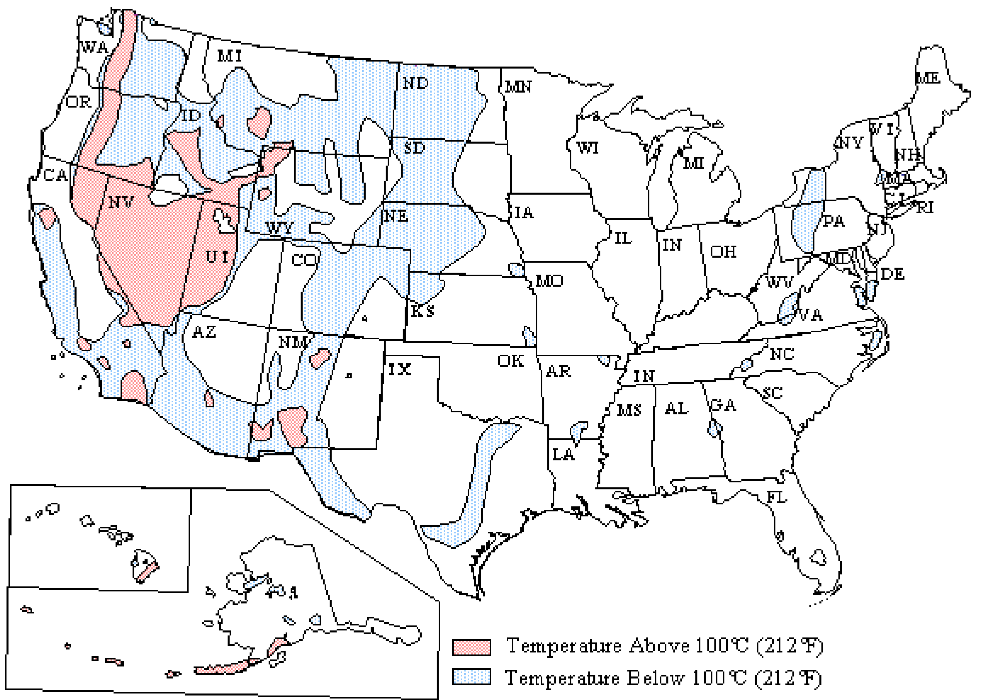


DOE/EIA Renewble Energy not including hydro trends with prelimimary data for 2003

7.1 GEOTHERMAL

Geothermal power plant technology consists of three types: flashed, dry steam, and binary. The map showing areas suitable for geothermal power plants is shown in Figure 7-2.

Figure 7-2 — Geothermal Resources



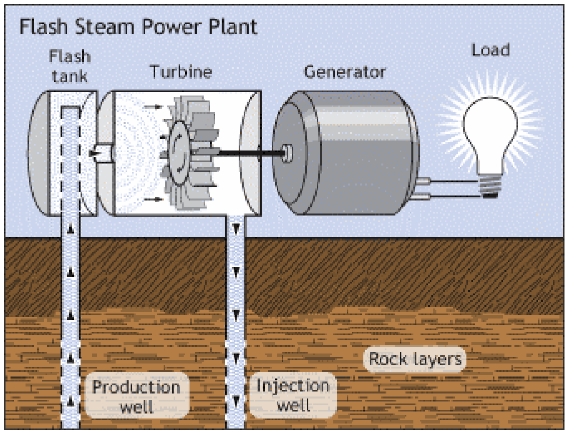
Source: ESRI, 1995

7.1.1 Technology

7.1.1.1 Flashed Steam Plants

Most geothermal power plants operating today are "flashed steam" power plants. Hot water at temperatures greater than 360°F (182°C) are pumped under high pressure to generation equipment at the surface. The hot water is passed through one or two separators where, released from the pressure of the deep reservoir, part of it flashes (explosively boils) to steam as shown in Figure 7-3. The force of the steam is used to spin the turbine generator. To conserve the water and maintain reservoir pressure, the geothermal water and condensed steam is generally redirected down an injection well back into the periphery of the reservoir, to be reheated and recycled.

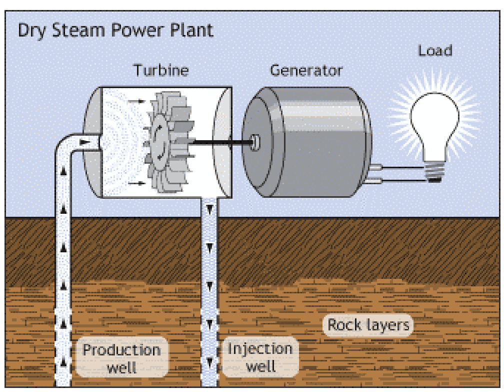
Figure 7-3 — Flashed Steam Plant



7.1.1.2 Dry Steam Plants

A few geothermal reservoirs produce mostly steam and very little water. Here, the steam shoots directly through a rock-catcher and into the turbine as shown in Figure 7-4. The Geysers dry steam reservoir in northern California has been producing electricity since 1960. It is the largest known dry steam field in the world and, after 40 years, still produces enough electricity to supply a city the size of San Francisco.

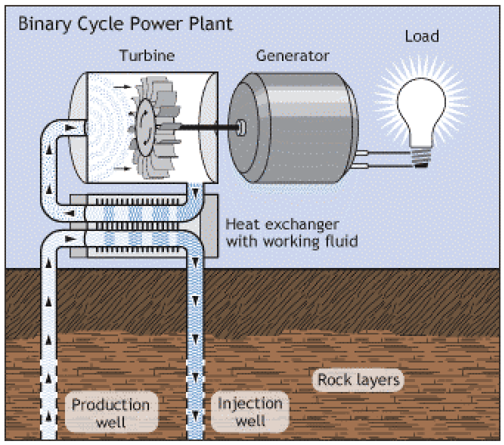
Figure 7-4 — Dry Steam Plant



7.1.1.3 Binary Power Plants

In a binary power plant, the geothermal water is passed through one side of a heat exchanger, where its heat is transferred to a second (binary) liquid, called a working fluid, in an adjacent separate pipe loop as shown in Figure 7-5. The working fluid boils to vapor which, like steam, powers the turbine generator. It is then condensed back to a liquid and used over and over again. The geothermal water passes only through the heat exchanger and is immediately recycled back into the reservoir. The advantage of the binary cycle is that it can operate with water from 225°F (107°C) to 360°F (182°C).

Figure 7-5 — Binary Power Plant



Although binary power plants are generally more expensive to build than steam-driven plants, they have several advantages:

- The working fluid (usually isobutane or isopentane) boils and flashes to a vapor at a lower temperature than does water, so electricity can be generated from reservoirs with lower temperatures. This increases the number of geothermal reservoirs in the world with electricity-generating potential.
- The binary system uses the reservoir water more efficiently. Since the hot water travels through an entirely closed system, it results in less heat loss and almost no water loss.
- Binary power plants have virtually no emissions.

7.1.2 Current Technology Status – Geothermal

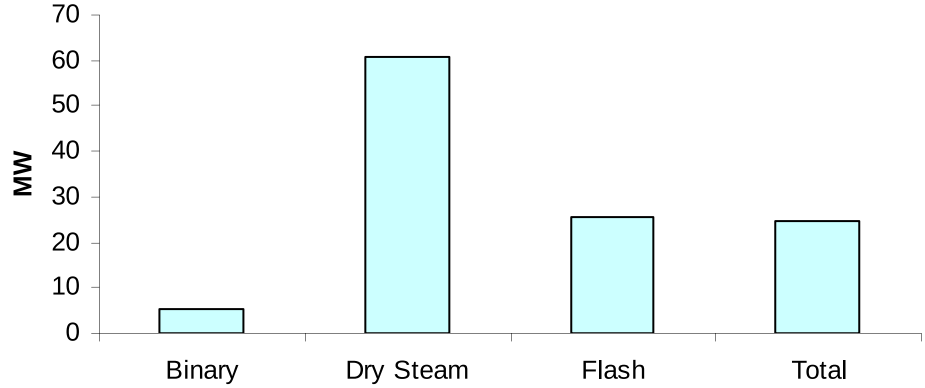
In 2003, geothermal contributed 16% of the non-hydro renewable electricity produced in the United States. The technology is mature and proven to be a reliable source of electricity. There are 113 geothermal power plants in operation in the southwest region area (California, Nevada, and Utah) with a total net capacity of 1,613 MW (see Table 7-2).

Table 7-2 — Geothermal Plants in Southwest Region

		Location				
Type	Data	Califorinia	Nevada	Utah	Grand Total	Percent
Binary	Sum of Nameplate Capacity (MW)	184	89	2	276	
	Sum of # of Units	20	30	3	53	
	Sum of Annual Avg Gross Capacity (MW)	131	63	7	201	
	Sum of Annual Avg Net Capacity (MW)	173	46	4	222	14%
Dry Steam	Sum of Nameplate Capacity (MW)	1635		9	1644	
	Sum of # of Units	26		1	27	
	Sum of Annual Avg Gross Capacity (MW)	932		7	939	
	Sum of Annual Avg Net Capacity (MW)	878		4	882	55%
Flash	Sum of Nameplate Capacity (MW)	669	151	26	846	
	Sum of # of Units	24	8	1	33	
	Sum of Annual Avg Gross Capacity (MW)	590	148	26	764	
	Sum of Annual Avg Net Capacity (MW)	357	129	23	509	32%
Total Sum of Nameplate Capacity (MW)		2488	240	37	2765	
Total Sum of # of Units		70	38	5	113	
Total Sum of Annual Avg Gross Capacity (MW)		1653	211	39	1903	
Total Sum of Annual Avg Net Capacity (MW)		1408	174	31	1613	100%
Average Capacity (MW)						
	Binary				5	
	Dry Steam				61	
	Flash				26	
	Total				24	
Average Net Capacity Factor(%)						
	Binary				80.5%	
	Dry Steam				53.7%	
	Flash				60.1%	
	Total				58.3%	

The average size plant for the three types is 24 MW, with dry steam being the largest and binary the smallest, as shown in Figure 7-6. Dry steam is the largest plant and the geological reservoirs are mainly found in California, with some in Utah.

Figure 7-6 — Geothermal Power Plants – Average Capacity



7.1.3 Potential Geothermal Technology for the Mohave Study

Available information on geothermal resources published by the Idaho National Engineering and Environmental Laboratory (INEEL) for the Department of Energy (DOE) was reviewed. INEEL produced resource maps of 13 western states. An overview of the results of the study for the four-state area along with the results by state are shown in Appendix I.

The available geological information indicate that thermal wells and springs within tribal lands range from 20°C (68°F) to 50°C (122°F) with the exception of two wells greater than 50°C (122°F). The water from thermal wells needs to be greater than 225°F (107°C) for generation of electricity. Hot water from geothermal wells in the low to moderate temperature range (30°C [86°F] to 150°C [302°F]) have applications for building heating, greenhouses, fish farming, and a wide variety of other uses.

The location of wells greater than 50°C within or near tribal lands in New Mexico is as follows:

- Northwest edge of Cibola National Forest near Fort Wingate (near tribal lands)
- Six miles west of Bisti Wilderness Area (within tribal lands)

The well near Bisti could potentially support a binary geothermal power plant. Without a detailed feasibility study of the wells potential, it is assumed that the size plant would be between 2.5 and 5 MW.

7.1.4 Capital Cost

The cost for small geothermal power plants depends on the power plant, drilling cost, and resource quality. Capital cost for the power plant is similar to small conventional power plants. The cost exploration, drilling, and resource quality depends on the well.

Resource quality is evaluated as follows:

- **High Quality.** Resource has a high temperature (> 250°C), with good field-wide permeability, and is likely to be a dry steam or two-phase reservoir, with low gas content and benign chemistry.
- **Medium Quality.** Resource has a temperature between 150°C and 250°C.
- **Low Quality.** Reservoir has a temperature below 150°C or a resource that, although it has a higher temperature, has poor permeability, high gas content, and difficult chemistry.

Without a detailed feasibility study and because the surrounding wells have lower temperatures, it must be assumed that the well is low to medium quality and will be in the range of 1.25 to 2.5 MW gross capacity. Capital cost for small geothermal power plants range from $1,800 to $3,400 per kilowatt based on studies done by NREL and the World Bank. The studies are shown in Table 7-3 to Table 7-5.

The well at Bisti would be similar to plants in the NREL study and, as such, would have a gross capacity of as much as 2.5 MW with a estimated capital cost of $3,400 per kilowatt.

Table 7-3 — Geothermal Direct Capital Costs

		High Quality Resource	**Medium Quality Resource**	**Low Quality Resource**
		$/kW	$/kW	$/kW
Small Plants (< 5 MW)	Exploration	400 – 800	400 – 1000	400 – 1000
	Steam Field	100 – 200	300 – 600	500 – 900
	Power Plant	1100 – 1300	1100 – 1400	1100 – 1800
	Total	**1600 – 2300**	**1800 – 3000**	**2000 – 3700**
Medium Plants (5-30 MW)	Exploration	250 – 400	250 - 600	
	Steam Field	200 – 500	400 – 700	
	Power Plant	850 – 1200	950 – 1200	
	Total	**1300 – 2100**	**1600 – 2500**	**Not Suitable**

		High Quality Resource	Medium Quality Resource	Low Quality Resource
		$/kW	$/kW	$/kW
Large Plants (>30 MW)	Exploration	100 – 200	100 – 400	
	Steam Field	300 – 450	400 – 700	
	Power Plant	750 – 1100	850 – 1100	
	Total	**1150 – 1750**	**1350 – 2200**	**Not Suitable**

Exploration costs are assumed to be made up of geoscientific surface exploration (US$600,000) and one (small plant development) to five exploration wells, each well costing about US$1.5 million.

Table 7-4 — Geothermal Binary Power Plant Capital Cost ($2000)

Plant	Resource		Gross Capacity	Net Capacity	Auxiliary Power	Capital Cost		Remarks
	°C	L/min	kW	kW	kW	$	$/kW	
Empire, Nevada	118	4,500	1,200	1,000	200	2,585,000	2,155	Existing 1,800-ft well/air-cooled condenser
Exergy/AmericCulture, New Mexico	116-118	3,800	1,420	1,000	420	3,370,000	2,373	Existing 400-ft well/exit heat for fish hatchery
Milgro-Newcastle, Nevada	127		945	750	195	2,550,000	2,698	Exit heat to green house/well cost $400,000 (included)
Ormat/LDG, New Mexico	150-160	2,900	1,300	900	400	2,870,000	2,207	Existing 1,300 ft well/ air-cooled condenser
Vulcan, New Mexico	112	7,600	1,260	1,000	260	2,200,000	1,746	Existing well

Source: NREL/CP-550-30275

Table 7-5 — Geothermal Binary Power Plant Capital Cost ($2000) – Summary

	Plant Cost ($/kW)	Field Cost ($/kW)	Well Cost ($/kW)	Total Cost ($/kW)
Empire, Nevada	2,089	256	0	2,585
Exergy/Americulture, New Mexico	2,600	185	30	3,370
Milgro-Newcastle, Nevada	2,495	165	333	3,400

Source: NREL/CP-550-30275

7.1.5 Operating and Maintenance Costs

The O&M cost will be about 1.4 ¢/kWh based on a plant load factor of 80% based on two small geothermal plants in New Mexico (see Table 7-6).

Table 7-6 — Geothermal Binary Power Plant O&M Cost ($2000)

Plant	Annual O&M Cost		Cost of Energy
	($/kW)	(¢/kWh)	(¢/kWh)
Empire, Nevada	$80	1.37	8.8
Exergy/AmeriCulture, New Mexico	$70	1.42	6.4
Milgro-Newcastle, Nevada	$30	0.54	6.2

Source: NREL/CP-550-30275.
Assumptions: Cost of Energy (COE) includes all costs (capital and O&M).
Plant Load Factor is 80%.

7.1.6 Cost of Energy

The cost of energy (COE) is between 6.2 and 10.5 ¢/kWh based on information from World Bank (Table 7-7). This is comparable with the 2000 study by NREL of the top eight locations (Gawlink and Kutscher) with a range of 7 to 9 ¢/kWh.

Table 7-7 — Geothermal Cost of Energy

	High Quality Resource ($/MWh)	Medium Quality Resource ($/MWh)	Low Quality Resource ($/MWh)
Small Plants (< 5 MW)	50 – 70	55 – 85	60 – 105
Medium Plants (5-30 MW)	40 – 60	45 – 70	Normally not suitable
Large Plants (> 30 MW)	25 – 50	40 – 60	Normally not suitable

Discount rate of 10% and capacity factor of 90% are assumed.
Source: World Bank

7.1.7 Water Usage

Binary geothermal technology requires approximately the same water resource as a conventional power plant. A closed-loop binary-cycle geothermal plant requires 1,300 to 1,500 gallons per minute (gpm) to generate 1 MW with a 300°F fluid temperature and air temperature of 60°F and 45 to 75 gpm of cooling tower make-up. The proposed 2.5 MW binary geothermal power plant at Bisti would require 8.8 to 10.3 acre-feet of water per day

(3,210 to 3,759 acre feet per year) at a plant load factor of 80% as shown in Table 7-8. Dry cooling will reduce the water usage to 8.5 to 9.8 acre-feet per day (3,103 to 3,580 acre-feet per year) but will result in capital costs about 3% to 6% higher and an 8% to 9% loss in plant performance.

Table 7-8 — Water Usage

	gpm per MW		gal per day		acre-ft per day		acre-ft per year	
	Min	Max	Min	Max	Min	Max	Min	Max
Closed Loop Cycle								
300°F fluid	450	600	958,776	1,278,367	2.94	3.92	1,074	1,432
210°F fluid	1,300	1,500	2,769,796	3,195,918	8.50	9.81	3,103	3,580
Cooling Tower Make-up	45	75	95,878	159,796	0.29	0.49	107	179
Total Flow Requirements								
300°F fluid			1,054,653	1,438,163	3.24	4.41	1,181	1,611
210°F fluid			2,865,673	3,355,714	8.79	10.30	3,210	3,759

Assumptions: Air Temperature = 60°F
Plant Capacity = 2.5 MW
Net Capacity = 1.85 MW
Plant Load Factor = 80%
1 acre foot = 325,851 gal

7.1.8 Conclusion

The geological information shows that all the known thermal wells and springs on the tribal lands are low to moderate temperature with the exception of one well in New Mexico near Bisti. The temperature for the low to moderate wells is not high enough to generate electricity. The well near Bisti could potentially support a binary power plant of at most 2.5 MW.

7.2 BIOMASS

Biomass power plants (biopower) use agricultural residues, residues from forestry and wood processing, and energy crops (fast growing trees) as fuel to power direct combustion and gasification. Biomass consists of plant material such as the following

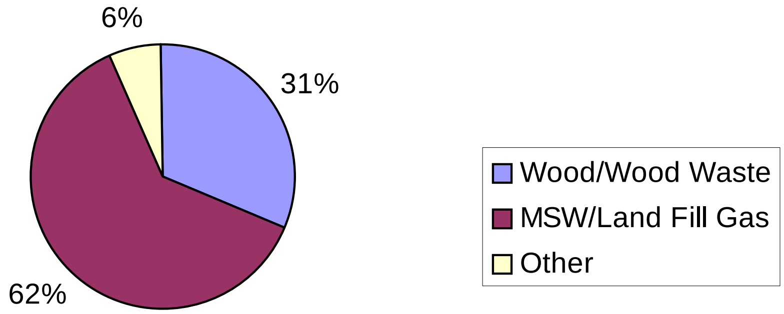
- Fast growing trees and grasses, like hybrid poplars or switchgrass
- Agricultural residues, like corn stover, rice straw, wheat straw or used vegetable oils

- Wood waste, such as sawdust and tree prunings, paper trash, and yard clippings.

Next to hydropower, more electricity is produced from biomass than any other renewable energy resource in the United States.

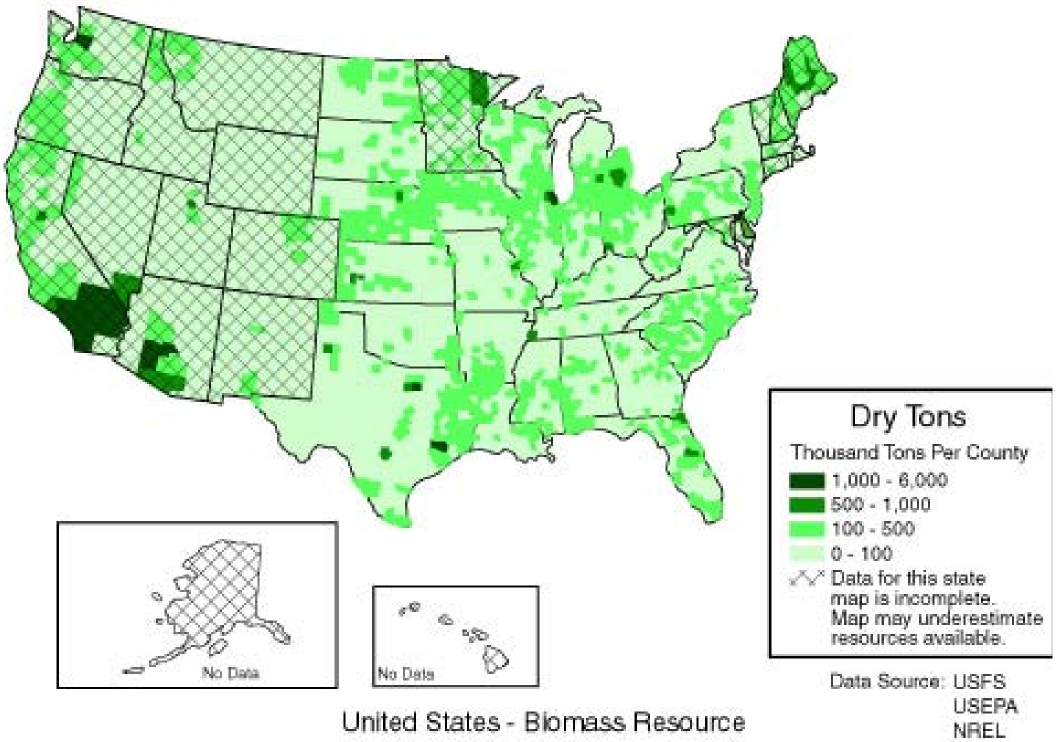
- U.S. generation of electricity from biomass is ~ 7,800 MW
- 60 million tons per year, most of which is clean wood and agricultural waste
- Approximately 80% is generated in the industrial sector, primarily in pulp and paper industry

Figure 7-7 — Biomass for Electric Generation[a]



(a) Electric utilities and Independent Power Producers
Source: DOE/EIA Renewable Energy Trends 2003 with Preliminary Data for 2003

Figure 7-8 — Biomass Resources in the United States



7.2.1 Technology

7.2.1.1 Direct Combustion

Most biopower facilities operating today are direct combustion power plants. The biomass product is burned in the boiler, which converts water to steam and drives a turbine generator. The process is the same as conventional coal-fired power plants. Virtually all biomass electric power plants use conventional boilers and steam turbines.

7.2.1.2 Gasification

The gasification process converts a solid biomass to a gas that can be burned in a combustion turbine, co-fired with coal or used in a fuel cell. This technology is still in the demonstration stage of development.

7.2.1.3 Co-Firing

Biomass can be co-fired with coal, displacing up to 15% of the coal feedstock.

7.2.2 Current Technology Status – Biomass

Biopower is a proven technology and a reliable source of production of electricity. There is about 10 GW of installed capacity: 7 GW from the forest and agricultural industry, 2.5 GW of municipal solid waste and 0.5 GW of other capacity (such as landfill gas). The net generation from biomass in the four-state area was 201,499 kWh, which is 2% of the total renewable generation as shown in Table 7-9.

Table 7-9 — Biomass Net Generation in the Four-State Area in 2002

	Wood/ Wood Waste (MWh)	Biomass MSW/ Landfill Gas (MWh)	Other Biomass (MWh)	Total (MWh)	Percent of Total Renewable
Arizona	0	49,604	91,456	141,060	1.9%
Colorado	0	0	29,834	29,834	2.2%
New Mexico	0	0	19,408	19,408	6.8%
Utah	0	11,197	0	11,197	1.6%
Total	0	60,801	140,698	201,499	2.0%

Source: DOE/EIA Renewable Energy Trends with Preliminary Data for 2003
MSW – Municipal Solid Waste
Other – Agriculture byproducts/crops, sludge waste, tires, and othe biomass solids, liquids, and gases

The largest traditional biomass capacity is from using wood or wood by-product. There are more than 500 such facilities in operation throughout the country. A group of 16 biomass power plants using wood products, industry leaders in North America, shows that the average net capacity is 43 MW, the largest plant is 79.5 MW, and the average net capacity factor is 68% as shown in Table 7-10.

Table 7-10 — Biomass Industry Leaders

Plant	Location	Online	Capacity	Capacity Factor
	State	Year	Mwe	%
Bay Front	Wisconsin	1979	30	62%
Kettle Falls	Washington	1983	46	82%
McNeil	Vermont	1984	50	35%
Shasta	Califorinia	1987	50	96%
Stratton	Maine	1989	45	90%
Tracy	Califorinia	1990	18.5	80%
Tacoma (co-fire)	Washington		12	27%
Colmac	Califorinia	1992	49	90%
Grayling	Michigan	1992	36.2	63%
Williams Lake	British Columbia	1993	60	106%
Multitrade	Viriginia	1994	79.5	19%
Ridge	Florida	1994	40	57%
Greenidge (co-fire)	New York	1994	10.8	80%
Camas (cogen)	Washington	1995	38	65%
Snohomish (cogen)	Washington	1996	43	60%
Okeelanta (cogen)	Florida	1997	74	70%
Total			682	
Average			43	68%

Source: NREL/SR-570-26946, Lessons Learned from Existing Biomass Power Plants.

All of this biomass capacity is from direct-combustion boiler/steam technology.

There is a large fuel supply throughout the United States, but there is a lack of infrastructure to obtain and transport the fuels. Princeton University research shows that of the total biomass available, only half can be economically used as fuel, with one-third from agricultural waste and two thirds from forestry product residue. For biomass to be economical as a fuel for generating electricity, the source needs to be close (less than 100 miles) to the point of use.

7.2.3 Potential Biomass Technology for the Mohave Study

Available information on biomass resources published by NREL and the State of Arizona was reviewed. The results of the study for the four-state area are shown in Appendix J.

7.2.3.1 Arizona

Arizona does not produce a large volume of agricultural crops of forest residue. Currently there is about 5 MW of electricity produced from landfill gas and animal waste. Generation potential estimated by the *Renewable Energy Atlas of the West* is 1 million MWh/yr.

7.2.3.2 New Mexico

New Mexico is arid and as such has less potential for agricultural and forest residue for production of fuels for biomass energy. Generation potential estimated by the *Renewable Energy Atlas of the West* is 1 million MWh/yr.

7.2.3.3 Utah

Utah is arid and as such has less potential for agricultural and forest residue for production of fuels for biomass energy. Generation potential estimated by the *Renewable Energy Atlas of the West* is 1 million MWh/yr.

7.2.3.4 Colorado

Colorado has significant agricultural crops, which could be used for biomass. The Colorado Office of Energy Management and Conservation is working on a demonstration project using methane produced by hog farms. Generation potential estimated by the *Renewable Energy Atlas of the West* is 4 million MWh/yr.

7.2.4 Capital Cost

The capital investment for biomass fueled direct fire combustion power plant is about $2,000 per kW installed as shown in Table 7-11. Oak Ridge National Laboratory estimates the same capital cost.

Table 7-11 — Wood Biomass Costs

Capacity	Fuel Use	Capital Cost			O&M Cost	
MW	green tpy	million $	$/kW$_{installed}$	$/kWh	million $	$/kWh
10	100,000	20	2,000	0.2854	2	0.0285
75	800,000	150	2,000	0.2854	15	0.0285

Source: USDA Techline Wood Biomass for Energy

Assumptions: Plant Load Factor 80%
Auxiliary Power Usage 4%
Plant Efficiency - 18 to 24%

7.2.5 Operating and Maintenance Costs: Biomass

O&M costs are presented in the table below:

Table 7-12 — Operating and Maintenance Costs

Plant Type	$/MWh
Typical coal-fired power plant	23
Cofiring biomass	21
Direct fire biomass power plant	52 to 67
Electricity from Landgas	29 to 36

Source: From Oregon Department of Energy

7.2.6 Water Usage: Biomass

Biopower technology requires approximately the same water resource as a conventional power plant. Using the average plant size of 20 MW, the approximate water usage would be as follows.

Table 7-13 — Approximate Plant Water Usage

	Gallons per year	Acre-ft per year
Rankine-cycle make-up	2,100,000 (demineralized)	6.44
Cooling Tower make-up	32,000,000	98.2

Dry cooling would eliminate the cooling tower make-up water usage but would result in capital costs approximately 3% to 6% higher and would result in an 8% to 9% loss in output.

7.2.7 Conclusion

Production of electricity in the quantities significant enough to be considered as part of a replacement of or complement to the existing Mohave plant from other renewable resources would require a feedstock of municipal solid waste and/or forestry residue.

Power generation from municipal solid waste requires a large source (population) and the ability to sort and provide combustible solid waste as a fuel source. The expansive area and lack of large population concentrations in tribal lands make this a complex option. However, municipal solid waste is not considered biomass. Biomass plants in the U.S. only use uncontaminated feedstock, which contains no toxic chemicals. Potentially hazardous materials (such as creosote-wood and batteries) would have to be removed from municipal solid waste at additional cost to be considered true biomass.

Tribal lands have large forests and the potential to support a forestry industry, but this is not a likely option in the near future. In the late 1950s, the Bureau of Indian Affairs and the Navajo Tribal Council created the Navajo Forest Products Industries (NFPI). From 1962 to 1992, NFPI cut and processed an average of 40 million boardfeet of lumber each year, creating thousands of jobs and tribal revenue. Unfortunately, this program was carried out with little concern for how these activities affected Navajo subsistence and the spiritual use of the forests. In the early 1990s an intra-tribal conflict arose over the use of the forests. This conflict resulted in closure of the sawmill in 1995.

Power generation from methane produced from animal waste is currently only in the demonstration stage and, as such, would not be considered as a proven reliable source of energy.

The use of fast-growing crops to provide fuel for biomass is in an early stage of development within the United States. Additional research is required to modify direct-firing equipment to burn the agricultural crops efficiently and meet environmental standards. Oak Ridge National Laboratory (ORNL) and INEEL scientists are working to gather experimental and operational data to validate the supply chain for fast-growing crops to overcome the technical barrier of lack of sustainable supply of biomass. Factors involving cost, environmental impact, social impact and economic impact are being researched.

Therefore, the potential for developing feedstock for a biomass power plant within tribal lands within the next few years of a size large enough to play a significant role in replacing or complementing lost generation from the Mohave Project is extremely low.

Last page of Section 7.

8. CO_2 SEQUESTRATION

8.1 OVERVIEW OF GEOLOGIC SEQUESTRATION OF CARBON

Carbon sequestration is the "capture and secure storage of carbon that would otherwise be emitted or remain in the atmosphere."[1] In this study, we reviewed geological methods of carbon sequestration, that is, the capture, transport and storage of carbon dioxide, produced by power plants and other point sources, in underground formations. Carbon dioxide may also be sequestered by pumping it to the deep ocean floor or by improving upon natural processes that sequester carbon dioxide, e.g., forestation projects. While these methods for carbon sequestration may be technologically and economically feasible, they are beyond the scope of this report. However, we do explore five types of geologic sequestration: enhanced oil recovery, enhanced gas recovery, sequestration in unminable coal seams, sequestration in deep saline aquifers, and sequestration in natural CO_2 domes.

8.1.1 Enhanced Oil Recovery Using Carbon Dioxide

Enhanced oil recovery (EOR) using carbon dioxide (CO_2-EOR) involves the injection of carbon dioxide in order to improve pressure in the reservoir and, thereby, the flow of oil.[2] There are approximately 74 CO_2-EOR projects worldwide.[3] Most of these are in the United States, in the Permian Basin of West Texas and southeastern New Mexico.

While domestic production of oil is approximately 6 million barrels per day, less than 700,000 barrels per day are currently produced using enhanced oil recovery. Approximately half of these barrels were produced via CO_2-EOR, primarily using CO_2 pumped from natural CO_2 domes in the Southwest. Tertiary EOR techniques,[4] such as CO_2-EOR, could increase the percentage of original oil in place (OOIP) that is ultimately recovered from 10% under primary recovery to 30 to 60%.[5]

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[1] Herzog, Howard and Dan Golomb, 2004. "Carbon Capture and Storage from Fossil Fuel Use," in C.J. Cleveland (ed.), *Encyclopedia of Energy*, Elsevier Science Inc., New York, pp 277-287, 2004. Available at http://sequestration.mit.edu/pdf/enclyclopedia_of_energy_article.pdf.

[2] Schlumberger Oilfield Glossary, 2005. Available at http://www.glossary.oilfield.slb.com/Display.cfm?Term=enhanced%20oil%20recovery.

[3] Baker, Richard, 2004. "What is Important in the Reservoir for CO_2 EOR/EGR and Sequestration?" For *APEGGA Annual Conference on GHG Opportunities: Small and Large Technologies*, April 22-24, 2004. Available at http://www.apegga.org/Members/ProfDev/Presentations/Baker.ppt.

[4] Primary oil recovery is the recovery of oil without aid of a drive fluid such as water or gas. Secondary oil recovery involves the injection of gas or water to produce oil. Tertiary oil recovery techniques stimulate flow of oil that was not extracted during the primary or secondary phases of recovery using other gases (such as carbon dioxide), steam or chemicals.

[5] U.S. DOE, "Enhanced Oil Recovery/CO_2 Injection, 2005. Available at http://www.fe.doe.gov/programs/oilgas/eor/.

While the technology for enhanced oil recovery using CO_2 is commercial, most CO_2-EOR projects are not intended to sequester carbon dioxide and as such perform a "blowing down" of the reservoir during decommissioning. Blow down, which releases some of the pressure in the reservoir by releasing some of the CO_2 injected over the life of the project, is intended to maximize oil recovery and recover CO_2 gas that is recycled for use in another CO_2-EOR project. As such, CO_2-EOR projects, as they are implemented currently, do not provide permanent sequestration of CO_2.

Current CO_2-EOR technology is divided into miscible and immiscible technologies. Two liquids are said to be "miscible" if they can be mixed together. Under miscible CO_2-EOR, the CO_2 is injected at high pressure and at such a temperature that it forms a supercritical fluid. Miscible CO_2-EOR is the most widely used CO_2-EOR technology and is more appropriate for recovery of light oil. Immiscible CO_2-EOR, while less common, can be used to recover heavy oils.[6]

The Weyburn CO_2-EOR project in Saskatchewan, Canada is one of a few CO_2-EOR projects using an anthropogenic source of carbon dioxide and is the only one specifically designed to monitor the reservoir's ability to store carbon dioxide. As such, no blow down phase is planned for Weyburn. Unless they were also designed for carbon sequestration, it is unlikely that future CO_2-EOR projects would similarly *not* have a blow down phase.

Weyburn purchases CO_2 from a coal gasification plant in Beulah, North Dakota. The project has been in operation since September 2000. As of February 2004, 98 billion cubic feet of CO_2 had been injected into Weyburn and approximately 5,500 metric tons (tonnes) of CO_2 per day was purchased. The gas injected into Weyburn is 95% pure carbon dioxide. Resulting incremental production is estimated to be 7,000 to 9,000 bbl/day over normal unit production of 22,400 bbl/day.[7]

While 5 years is, geologically-speaking, a very short time to determine the risk of CO_2 migration, the risk assessment modeling performed to date predicts that there may be limited migration of CO_2 from the reservoir to

[6] For more on how miscible and immiscible CO_2-EOR technologies work see Section 3 of "Basin Oriented Strategies for CO_2Enhanced Oil Recovery: Onshore California Oil Basins." Prepared by Advanced Resources International, Inc. for the U.S. Department of Energy, March 2005. Available at http://www.fe.doe.gov/programs/oilgas/publications/eor_co2/California_CO2-EOR_Report_web.pdf.

[7] Petroleum Technology Research Centre, "History/Background." Available at http://www.ptrc.ca/access/DesktopDefault.aspx?tabindex=0&tabid=111.

surrounding geologic formations, but no leaks to the surface.[8] The modeling was performed to predict storage performance over the 5,000 years following the end of the EOR project.

8.1.2 Carbon Sequestration with Enhanced Gas Recovery

Carbon dioxide could also be used in enhanced gas recovery (CSEGR) projects. While still a theoretical undertaking, it is thought that CO_2 injected at a well some distance from the gas-producing well will cause increased production of natural gas. CSEGR is untested because of the cost of CO_2 and because there is a concern that the CO_2 will rapidly mix with the natural gas, degrading the resource. Nonetheless, CSEGR is a natural option for carbon sequestration, since the formations in which natural gas is held are proven to have sequestered a gas for many years. Indeed, both depleted oil and gas reservoirs could store carbon dioxide regardless of whether such storage revives hydrocarbon production.

8.1.3 Enhanced Coal Bed Methane Recovery

Similarly, carbon dioxide could be stored in unminable coal seams. It is common knowledge that methane can be found in coal seams. The production of coal bed methane, while still less common than traditional sources of methane, is a growing source of natural gas. Enhanced coal bed methane recovery using carbon dioxide (ECBM) is being explored through existing R&D projects such as COAL-SEQ, which are experimenting with the injection of CO_2 into these seams for long-term storage and enhanced recovery of methane.[9] A unique aspect of the COAL-SEQ project is that injection of CO_2 is accompanied by N_2, a primary component of power plant flue gases. If both gases can successfully displace methane, it may no longer be necessary to separate the CO_2 from the flue gas, lowering the overall cost of sequestration.

8.1.4 Sequestration in Deep Saline Aquifers

Carbon dioxide may also be sequestered in deep saline aquifers. Saline aquifers are porous sandstone or sand formations sealed by low permeability rock formations. The geology of individual saline aquifers is likely to be less well understood, since they are not employed in the production of commodities such as gas and oil. However, saline aquifers have been used as storage for natural gas to accommodate seasonal changes in demand, and the technology does exist to evaluate saline aquifers for this purpose.

[8] Petroleum Technology Research Centre, "Results." Available at http://www.ptrc.ca/access/DesktopDefault.aspx?tabindex=0&tabid=115.

[9] More information on COAL-SEQ is available at http://www.coal-seq.com/Proceedings2004/ProjectFactSheet.pdf.

The world's first commercial-scale carbon sequestration project in a saline aquifer has been operating successfully since 1996.[10] Statoil, the Norwegian owner of the Sleipner natural gas field, decided to invest in the project because of the high cost of carbon dioxide emissions; Norway had imposed a tax of about $40/tonne in the 1990s. The natural gas coming from the field contains more CO_2 than is allowed under commercial and pipeline specifications and as such must be removed before transport, so Statoil was faced with the prospect of paying the tax for the release of these CO_2 emissions. The CO_2 is captured from the natural gas and injected into the Utsira formation, a vast aquifer of sand and salt water.[11]

8.1.5 Sequestration in Natural CO_2 Domes

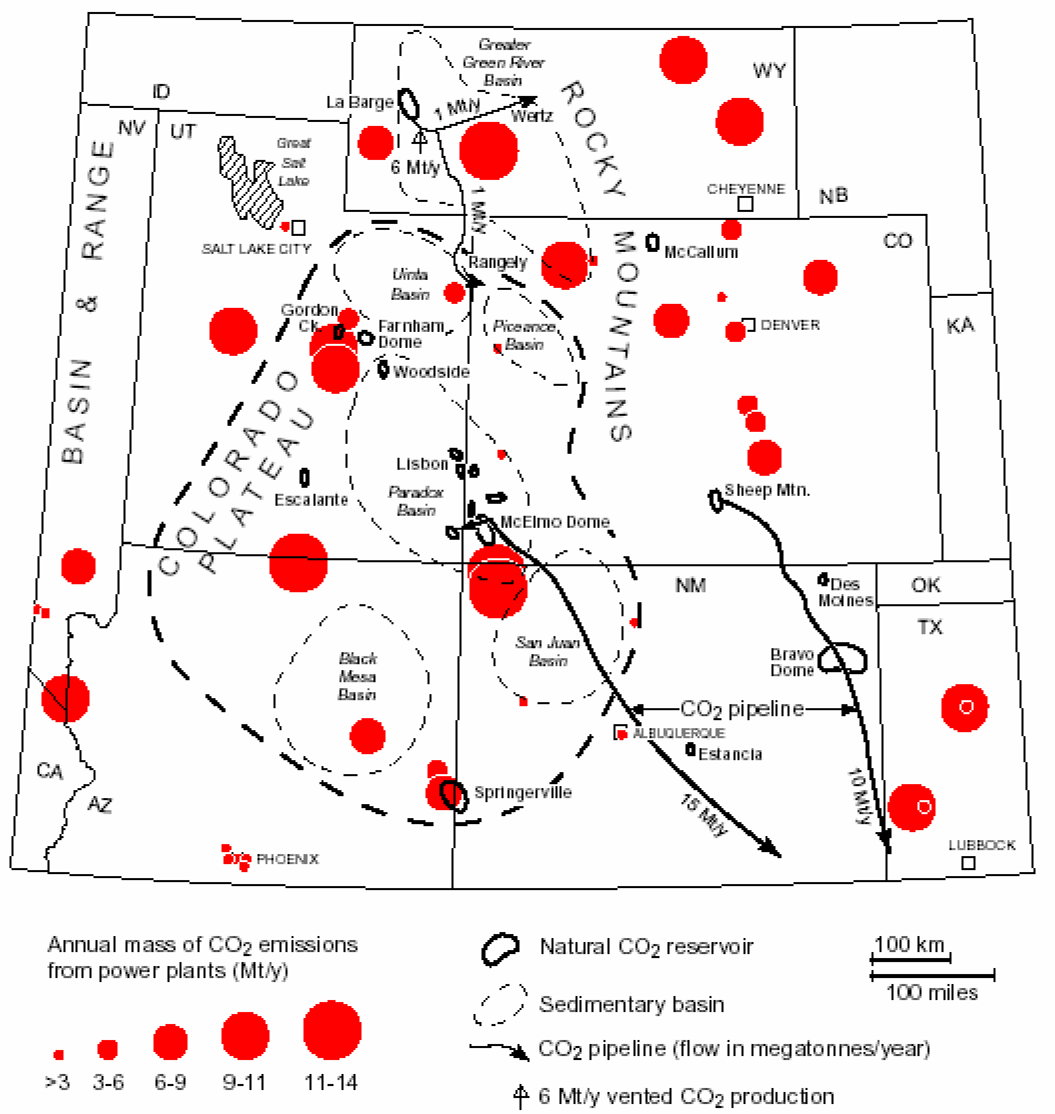
Natural CO_2 domes or reservoirs are an obvious analog for carbon sequestration. These domes have proven their ability to store CO_2 gas over long periods of time. Previously, these reservoirs were the lowest cost source for CO_2 for industrial uses such as enhanced oil recovery and dry ice. Now they are being examined as possible candidates for CO_2 storage themselves.[12] A study led by the Utah Geological Survey (UGS) and funded by the DOE, suggests that CO_2 from coal-fired power plants could replace the CO_2 already extracted from the natural domes. Figure 8-1 shows the relative concentration of CO_2 emissions from coal-fired power plants along with the CO_2 domes that have been in production.

[10] Torp, Tore A. and Ken R. Brown, 2004. "CO_2 Underground Storage Costs as Experienced at Sleipner and Weyburn." *Proceedings of the 7th International Conference on Greenhouse Gas Control Technologies*, September 5-9, 2004. Available at http://uregina.ca/ghgt7/PDF/papers/peer/436.pdf.

[11] Torp, Tore A. and Ken R. Brown. 2004.

[12] Allis, R., et al. "Natural CO_2 Reservoirs on the Colorado Plateau and Southern Rocky Mountains: Candidates for CO_2 Sequestration," 2001, *Proceedings of the First National Conference on Carbon Sequestration*, Washington DC, May 2001, pp. 19. Available at http://geology.utah.gov/emp/co2sequest/pdf/reservoirs.pdf.

Figure 8-1 — Natural CO_2 Domes, Carbon Emissions from Power Plants, and CO_2 Pipelines



Source: Allis, R., et al.,2001.

If a 1,000 MW coal-fired power plant emits 9 million tonnes per year of CO_2, then, UGS estimates, "the volume of CO_2 at standard temperature and pressure after 20 years is 3.6 Tcf." This is similar to the quantity of CO_2 withdrawn from the McElmo dome for the period 1982–2001. While it appears technically feasible, it is not clear under what circumstances the owners of these domes, e.g., Kinder Morgan, would be willing to accept CO_2 rather than sell it.

8.1.6 Industrial Uses for CO_2

Finally, there are many uses for carbon dioxide in industry, for example, in the production of dry ice, as a refrigerant, for carbonation of beverages, as a compressed gas or in fire extinguishers. However, none of these uses requires significant amounts of CO_2 and, ultimately, do not provide long-term sequestration of CO_2.

8.2 FEASIBILITY OF GEOLOGICAL CARBON SEQUESTRATION

While the sequestration of carbon can be motivated by the economic benefits of enhanced hydrocarbon production (oil and gas), the primary motivator for the advancement of the technology is the expectation that anthropogenic carbon dioxide emissions will have to be controlled in order to mitigate global climate change. International scientific consensus holds that the world is warming, the climate system is changing, and that most of the warming observed over the past 50 years is due to human activities (primarily fossil fuel combustion).[13] Increasingly, there is interest in climate mitigation activities such as carbon sequestration.

While carbon sequestration will not be the sole solution to climate change, the worldwide capacity for storing carbon is predicted to be substantial. Worldwide capacity for geological sequestration of carbon is outlined in Table 8-1.

Table 8-1 — Worldwide Capacity for Geologic Carbon Sequestration

Sequestration Option	Capacity[a,b]	
	CO_2 (gigatonnes)	Carbon (gigatonnes)
Depleted oil and gas reservoirs	360 – 3,600	100 – 1,000
Deep saline formations	360 – 36,000	100 – 10,000
Coal seams	36 – 360	10 – 100

Source: Adapted from Herzog, Howard and Dan Golomb, 2004. "Carbon Capture and Storage from Fossil Fuel Use." *Encyclopedia of Energy*, 2004. Available at http://sequestration.mit.edu/pdf/enclyclopedia_of_energy_article.pdf.

a Worldwide anthropogenic carbon emissions are approximately 7 gigatonnes C per year

b Orders of magnitude estimates

Domestic capacity in the United States is shown in Table 8-2.

[13] Y. Ding, J.T. Houghton, et al. editors, 2001. Climate Change 2001: The Scientific Basis (Contribution of Working Group I to the Third Assessment Report of the IPCC). Intergovernmental Panel on Climate Change. 2001. Available at: http://www.grida.no/climate/ipcc_tar/wg1/index.htm

Table 8-2 — Domestic Storage Capacity for Carbon Dioxide

Sequestration Option	Capacity[a]	
	CO_2 (million tonnes)	Carbon (million tonnes)
Depleting Oil Reservoirs	50,000	15,000
Depleting Gas Reservoirs	100,000	30,000
Unmineable Coal Beds	50,000	15,000
Saline Aquifers	Large	Large

Source: Beecy, David, 2003. "Recent Developments in Carbon Management at DOE." From *Proceedings of COAL-SEQ II*, Washington D.C. 2003. Available at http://www.coal-seq.com/Proceedings2003/Beecy.pdf.

a. U.S. anthropogenic carbon emissions are approximately 1,600 million tonnes C per year.

Saline aquifers have a very large potential carbon dioxide storage capacity; however, these formations tend to be less well characterized because they are not generally employed for industrial or commercial uses.

The geologic feasibility of carbon sequestration through EOR at the Bakersfield oil fields, for emissions from a plant at the existing Mohave site, and through sequestration in natural formations for a plant located near the Black Mesa mine, respectively are treated in Appendix C.

8.3 POLICY AND LIABILITY BARRIERS TO CARBON SEQUESTRATION

Both technological and policy barriers confront the widespread application of carbon sequestration. First, the cost of capture technologies, compression and transport to the sequestration site is significant.[14] Specifically, the removal of carbon dioxide from flue gas streams or before combustion during the gasification process exacts an "energy penalty" that creates a cost in addition to the capital and operating costs associated with the capture and transport infrastructure. In some cases, i.e. for enhanced oil and gas recovery, that cost can be made up, in whole or in part, by selling the carbon dioxide. In general, however, widespread deployment of carbon sequestration will need to be motivated by a governmental policy. Greenhouse gas regulation that allows for offsets from carbon sequestration is the most logical policy. Projections of the prices of such offsets are provided in Appendix D.

[14] This discussion assumes that the source of carbon dioxide will be from an industrial facility such as an IGCC coal plant or a coal gasification facility. This discussion makes no judgment as to whether an electrical generating station is more economic than an on-site coal gasification plant at the Black Mesa mine, but simply recognizes that both options have the technical potential to capture and sequester their carbon dioxide emissions.

Second, carbon sequestration faces liability issues. Figueiredo, et al.,[15] terms these liabilities: operational liability, climate liability and *in situ* liability. Operational liability applies to the potential risks associated with the transport of carbon dioxide to the sequestration site. These are the risks of a well or pipeline failure and are quite familiar to the gas and oil industry. Because carbon dioxide is non-toxic and non-flammable, leaks from a CO_2 pipeline present less public and environmental health issues than leaks from a natural gas or oil pipeline. The risk posed by CO_2 leaks is that the gas will not be able to diffuse to a concentration that is breathable, causing asphyxiation. Such a situation could occur in depressions or bowls since CO_2 is heavier than air.

Climate liability will be an issue if regulations are in place to control greenhouse gases, and as such, a penalty is associated with the release of carbon dioxide. If geologic sequestration is an eligible method to reduce carbon dioxide emissions, there would be a certain level of risk and associated liability arising from leaks, whether during transport or because the injection well does not properly function.

Furthermore, *in situ* liability is associated with the actual storage of carbon dioxide. As mentioned above, at high enough concentrations, carbon dioxide can cause asphyxiation. While the probability that such a situation would occur is small, it is a risk that must be considered when designing carbon sequestration sites. Another example of *in situ* risk is the possibility that leakage of carbon dioxide could lead to “soil acidification or suppression of respiration in the root zone.”[16] The risk that carbon dioxide would contaminate drinking water is very slight. Formations used for carbon sequestration are at depths far below those of most drinking water aquifers and, in the case of hydrocarbon reservoirs, would probably have already contaminated the water source if there were a connection between the reservoir and the aquifer.

Since few, if any, states have an existing and clear regulatory framework to govern carbon sequestration, there is some concern that this uncertainty will limit carbon sequestration projects. There is, however, the possibility that an insurance solution will be available to tackle this issue.[17] Requests for more information were not answered, but it appears that Swiss Re, the world’s largest reinsurance company, has expressed interest in developing an insurance product specifically for carbon sequestration projects. Though the details are not available, such a product could potentially resolve many, if not all, of these liability issues.

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[15] de Figueiredo, M.A., D.M. Reiner and H.J. Herzog, 2005. “Framing the Long-Term In Situ Liability Issue for Geologic Carbon Storage in the United States.” Accepted by *Mitigation and Adaptation Strategies for Global Change*, 2005. Available at http://sequestration.mit.edu/pdf/Liability_Issue.pdf.

[16] de Figueiredo, M.A., D.M. Reiner and H.J. Herzog, 2005.

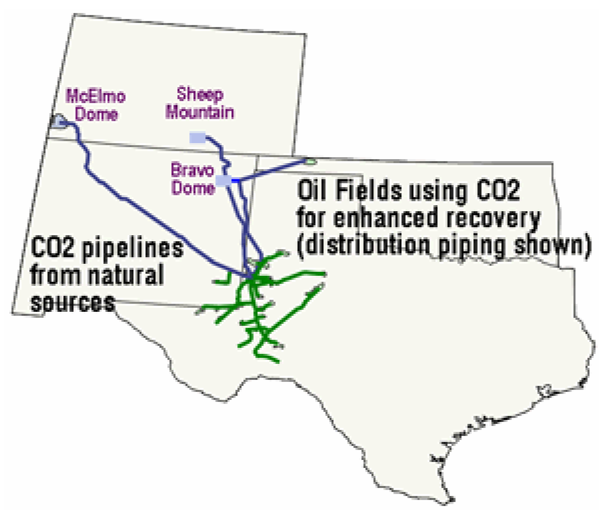
[17] Presentation by Ian Duncan, Ph.D of the Texas Bureau of Economic Geology at the 2005 Gasification Technologies Conference in San Francisco, California on October 11, 2005.

8.4 ECONOMICS OF CARBON SEQUESTRATION

8.4.1 Market for CO_2 Gas in Enhanced Oil Recovery

There is already an existing market for CO_2 gas (as opposed to the Kyoto-inspired emissions allowances). The CO_2 market is largely concentrated in West Texas. A series of pipelines from natural CO_2 domes in Colorado and New Mexico carries CO_2 to West Texas for use in enhanced oil recovery. Figure 8-2 below shows this infrastructure.

Figure 8-2 — Existing CO_2 Pipelines and Sources



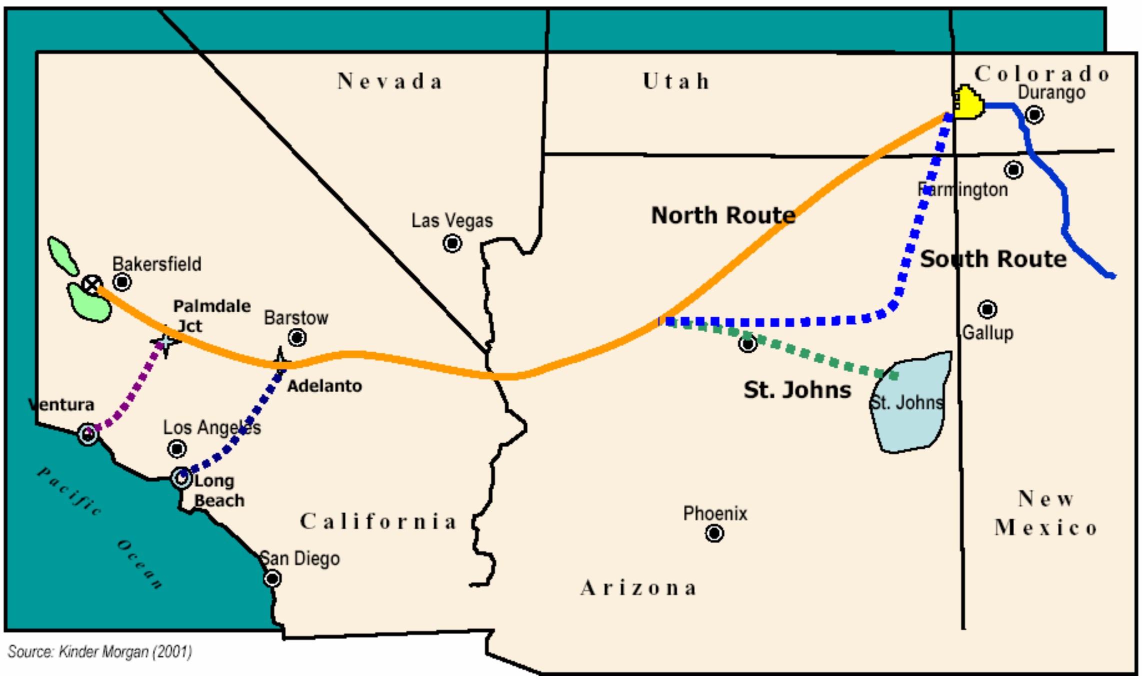
Source: WESTCARB, http://www.westcarb.org/transport.htm

As recently as 2002,[18] Kinder Morgan CO_2 Company and Ridgeway Petroleum were discussing the possibility of developing a 600-mile pipeline to California to serve demand for CO_2 in the state (a possible route for the pipeline is shown in Figure 8-3). Kinder Morgan is the owner of the McElmo CO_2 dome, shown just west of Durango, Colorado, in Figure 8-3, and Ridgeway Petroleum owns the St. Johns formation in Arizona. No information on more recent developments on the pipeline is available. The owners confront a number of large obstacles in building the pipeline. The first is the length and mountainous terrain over which the pipeline must travel. The second is the relative uncertainty regarding the market for CO_2 in California. Limited information is available on the price of CO_2 gas that could be expected in California. The most recent CO_2-EOR project in

[18] Billingsley, Eric, 2002. "CO_2 Project Brewing in Western New Mexico." *New Mexico Business Weekly*, 27 December 2002.

California at the Lost Hills reservoir trucked CO_2 gas over 120 miles at a cost of about $3.50/Mcf[19] or over $61/ton, but other, local sources could potentially provide CO_2 at a cheaper price. Calls to Ridgeway and Kinder Morgan requesting an update on the status of the pipeline were not returned and there is some indication that it will not be built because refineries in the Los Angeles area can provide CO_2 at a lower cost.[20]

Figure 8-3 — Proposed CO_2 Pipeline to Bakersfield, California



The ability of the Mohave Generating Station to access the pipeline, should it be built, in order to sell its own CO_2 (assuming it installs a capture system) will be determined not just by the cost to access the pipeline, but also by the willingness of Kinder Morgan and Ridgeway to allow other parties to use the pipeline. That degree of willingness is currently an unknown.

The potential market for CO_2 gas in California is thought to be significant because of the potential for CO_2 -EOR in California's onshore oil fields. The major onshore basins and oil fields are shown in Figure 8-4, along with a conceptual pipeline route to bring CO_2 from the hydrogen plants at the oil refinery complex at the Wilmington Oil field.

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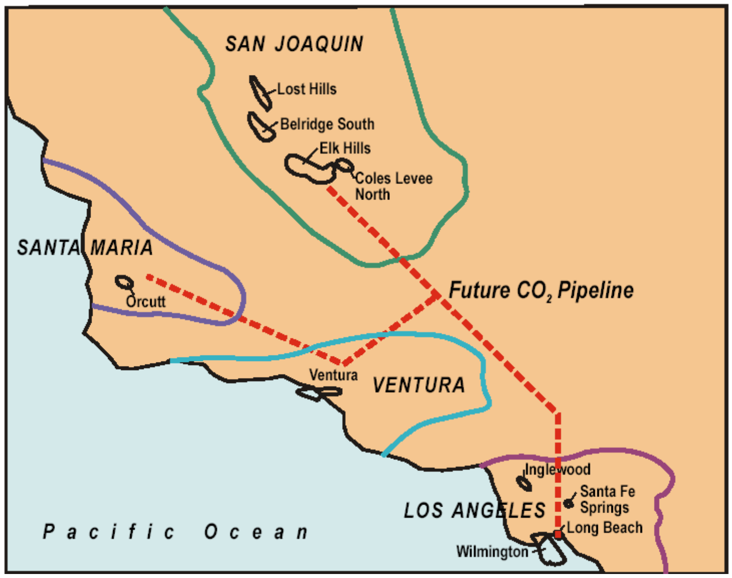
[19] Ruether, John, et al., 2002. "Gasification-based Power Generation with CO_2 Production for Enhanced Oil Recovery." For the *2002 Pittsburgh Coal Conference.* Available at http://www.netl.doe.gov/coal/gasification/pubs/pdf/35.pdf.

[20] Personal Communication with Julio Friedmann, Lawrence Livermore National Laboratory. October 12, 2005.

Figure 8-4 — California On-Shore Basins and Reservoirs



Source: Taken from Advanced Resources International, 2005. "Basin Oriented Strategies for CO2 Enhanced Oil Recovery: Onshore California Oil Basins." Prepared by Advanced Resources International, Inc. (ARI) for the U.S. Department of Energy, March 2005. Available at http://www.fe.doe.gov/programs/oilgas/publications/eor_co2/California_CO2-EOR_Report_web.pdf.

In the past, some CO_2 injection at California oil fields has occurred, primarily during the 1980s, but current CO_2 -EOR activities in California are virtually non-existent, largely because of a lack of CO_2 supply.[21]

California is the fourth largest oil-producing state in the nation, behind Louisiana, Texas, and Alaska, respectively.[22] Advanced Resources International recently published a study evaluating the potential to recover California's "stranded oil" through CO_2-EOR. California's onshore oil reservoirs originally held 83 billion barrels (Original Oil in Place or OOIP). To date, 26 billion barrels have been recovered or proved.[23] This leaves 57 billion barrels of oil stranded (Remaining Oil in Place or ROIP). Table 8-3 shows the ROIP amenable to CO_2-EOR.

[21] Advanced Resources International, 2005.

[22] Advanced Resources International, 2005.

[23] Advanced Resources International, 2005.

Table 8-3 — Stranded Oil Amenable to CO_2 -EOR in California

Basin	Number of Reservoirs	OOIP (Billion Bbls)	Cumulative Recovery/ Reserves (Billion Bbls)	ROIP (Billion Bbls)
San Joaquin	29	11.9	3.8	8.1
Los Angeles	36	14.1	4.2	9.9
Coastal	23	5.9	1.8	4.1
Total	88	31.9	9.8	22.1

Source: Advanced Resources International, 2005.

The economically recoverable oil resource using miscible CO_2-EOR, Table 8-4, is much lower. It is limited to 50 million barrels in just the San Joaquin Basin; the basin that incorporates the Bakersfield area. These estimates were developed assuming an oil price of $25 per barrel, a CO_2 cost of 5% of the oil price and a rate of return (ROR) hurdle rate of 25% (before tax).

Table 8-4 — Economically Recoverable Resources Using Miscible CO_2-EOR

Basin	Number of Reservoirs	OOIP (Million Bbls)	Technically Recoverable (Million Bbls)	Economically Recoverable (Million Bbls)
San Joaquin	24	8,900	860	50
Los Angeles	15	7,830	470	—
Coastal	20	4,690	450	—
Total	59	21,420	1,780	50

Clearly, the price of oil, as it refers to the price of West Texas Intermediate (WTI), a light, sweet crude, is much higher than the price of oil used in the Advanced Resources International (ARI) study. As of September 21, 2005, WTI crude oil futures were trading at over $60 per barrel on NYMEX through 2011. WTI oil can be expected to trade at a slight premium to other, less-desirable light oils and to heavy crudes found in California reservoirs, though these crudes are still trading at prices much higher than $25/barrel. Though it is not feasible to re-do ARI's analysis for this study, as a general trend, higher oil prices would be expected to make more CO_2-EOR projects economically feasible.

Under alternative scenarios outlined below in Table 8-5, additional oil resources would become economically recoverable, including oil in the Los Angeles and Coastal Basins.

Table 8-5 — Additional Recoverable Resources under Various Scenarios

Basin	Scenario 2: "State of the Art"[a] (Million Bbls)	Scenario 3: "Risk Mitigation"[b] (Million Bbls)	Scenario 4: "Ample Supplies of CO_2"[c] (million Bbls)
San Joaquin	1,060	1,380	1,780
Los Angeles	700	1,290	1,370
Coastal	70	830	830
Total	1,830	3,500	3,980

a. Scenario assumes oil price of $25 per barrel, a CO_2 cost of 5% of the oil price, and an ROR hurdle rate of 15% (before tax).

b. Scenario assumes oil price of $35 per barrel, a CO_2 cost of 5% of the oil price, and an ROR hurdle rate of 15% (before tax).

c. Scenario assumes oil price of $35 per barrel, a CO_2 cost of 2% of the oil price, and an ROR hurdle rate of 15% (before tax).

The "State of the Art" scenario assumes use of miscible CO_2-EOR technology at deep, light oil reservoirs, immiscible CO_2-EOR at deep, heavy oil reservoirs and much higher volumes of CO_2 injection over what is traditionally injected. A total of 1,830 million barrels are recoverable in this scenario.

The "Risk Mitigation" scenario assumes an increase "in the EOR investment tax credit, reduced State production taxes and Federal and State royalty relief (for projects on Federal and State lands)" providing an equivalent increase in the price of oil of $10 per barrel. A total of 3,500 million barrels are recoverable under this scenario. Any other change that led to a similar price increase could be expected to have the same effect.

The "Ample Supplies of CO_2" scenario assumes a generous supply of EOR-ready CO_2 at a lower cost. A total of 3,980 million barrels are recoverable under this scenario.

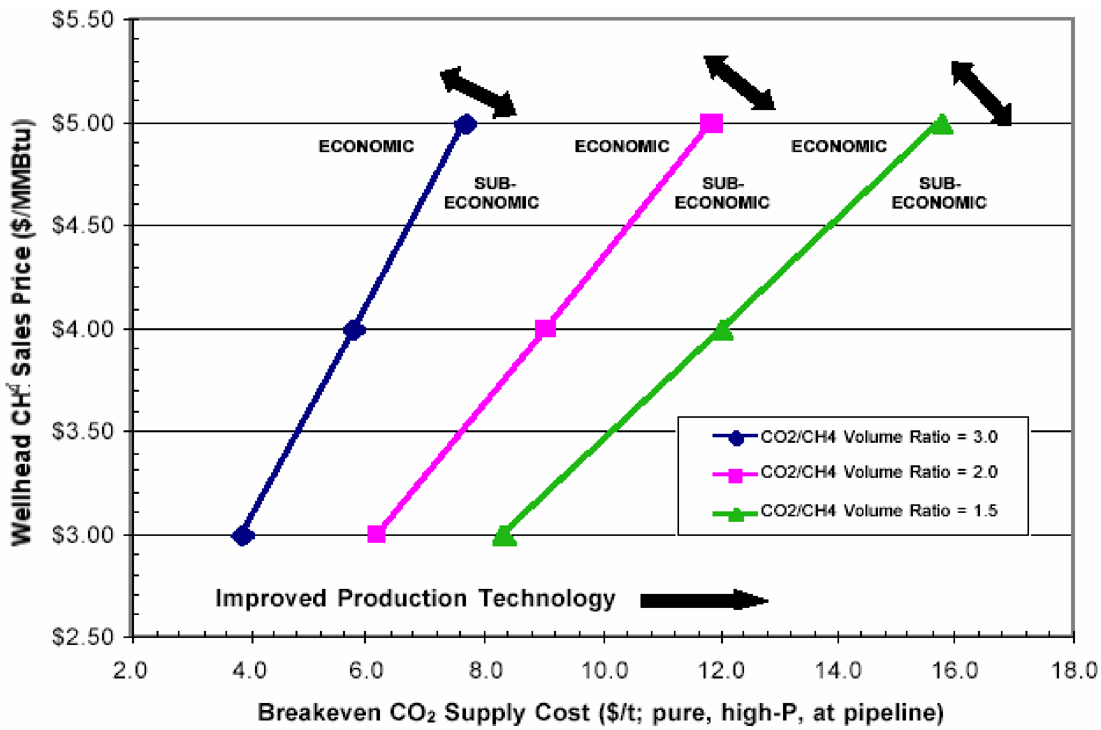
The volumes of CO_2 needed to recover these barrels are significant. ARI projects that the market for CO_2 in California could reach 18 Tcf, plus 40+ Tcf of recycled CO_2. Over 1 billion tons of CO_2 could potentially be stored.[24] As a matter of practicality, however, CO_2-EOR will only occur if the CO_2 supply to the point of use is economical. At this point, is it is not possible to conclude that the provision of CO_2 from power plants outside of California, such as Mohave, would be economical. As noted above, it is quite possible that CO_2 would be more economically provided from hydrogen plants at the Wilmington Oil field.

[24] Advanced Resources International, 2005.

8.4.2 Market for CO_2 Gas in Enhanced Gas Recovery

Despite its theoretical status, there has been some effort to evaluate the economics of carbon sequestration for enhanced gas recovery (CSEGR).[25] The analysis by Oldenburg, et al., found that CSEGR could be economical at a CO_2 cost of $10/ton, a cost comparable to that of natural CO_2, but below the costs of capture from power plants.[26] This analysis was performed without consideration for the effect that a climate change policy would have on this decision-making, which one would expect to positively affect the decision to pursue CSEGR using anthropogenic carbon dioxide.

Figure 8-5 — Economic Analysis of CSEGR at California Depleting Gas Field



Source: Ernest Orlando Lawrence Berkeley National Laboratory, 2004.

The analysis performed was specific to the Rio Vista gas field in California, but the same dynamics could be expected at other gas fields; that is, that the results were highly dependent on the cost of CO_2, the cost of natural gas, and the ratio of CO_2 injected to natural gas produced. Logically, higher gas prices mean that operators can

[25] Oldenburg, C.M., S.H. Stevens and S.M. Benson, 2003. "Economic Feasibility of Carbon Sequestration with Enhanced Gas Recovery (CSEGR)." Berkeley Lab Report LBNL-49762, 2003. Available at http://www-esd.lbl.gov/GEOSEQ/pdf/oldenburg_etal138.pdf.

tolerate higher CO_2 costs, as Figure 8-5 demonstrates. As with oil prices, higher natural gas prices would tend to make more CSEGR projects economically feasible. As of September 21, 2005, Henry Hub NYMEX natural gas futures were trading at or above $7/mmBtu through the end of 2010 (note that the wellhead price in Figure 8-5 is shown, not the Henry Hub price).

8.5 CAPITAL COSTS ASSOCIATED WITH GENERATION ALTERNATIVES

Capital costs were developed for the 282.5-mile pipeline from the existing Mohave site to the Bakersfield area. The results of these analyses are shown in the following tables:

Table 8-6 — CO_2 Pipeline and Compression Costs for Mohave Site

		IGCC CO_2 Removal without Shift Conversion	IGCC 90% CO_2 Removal	NGCC 90% CO_2 Removal*
Corresponding Plant Net Output	MW	522.9	473.6	423
CO2 Removal Rate	ton/hr	155	490	185
Pipeline Nominal Diameter	inches	14	18	14
Pipeline and Compression Cost	$ millions (2006)	370.8	542.2	370.8
	$/kW	709.1	1,144.8	876.6

* Pipeline costs are assumed equal for the IGCC CO2 Removal without Shift Conversion and the NGCC 90% CO2 Removal since pipeline diameters are equal and the increased flow would be handled by a slight increase in compressor size. Total compressor cost is less than 3% of the pipeline cost.

A suitable deep saline aquifer site for an IGCC plant at the Black Mesa mine site is identified in Appendix C at a distance of approximately 45 miles south of the mine site. The capital costs estimated for the Mohave site were adapted to estimate the cost for a pipeline of this length. The results of this estimate are as follows:

[26] Ernest Orlando Lawrence Berkeley National Laboratory, 2004. "GEO-SEQ Best Practices Manual, Geologic Carbon Dioxide Sequestration: Site Evaluation to Implementation." September 30, 2004. Available at http://www.netl.doe.gov/coal/Carbon%20Sequestration/pubs/GEO-SEQ_BestPract_Rev1-1.pdf

Table 8-7 — CO_2 Pipeline and Compression Costs for Black Mesa Site

		IGCC CO_2 Removal without Shift Conversion	IGCC 90% CO_2 Removal
Corresponding Plant Net Output	MW	537.1	483.9
CO2 Removal Rate	ton/hr	155	490
Pipeline Nominal Diameter	inches	14	18
Pipeline and Compression Cost	$ millions (2006)	49.2	86.4
	$/kW	91.6	178.5

A natural gas-fired combined-cycle (NGCC) plant was not contemplated at the Black Mesa site.

It can be seen that pipeline costs are very high, indicating that, economically, their use can likely be justified only if they can generate a rate of return from the product shipped. However, the proximity of the sequestration location to the Black Mesa mine reduces pipeline costs significantly.

8.6 PERMITTING ISSUES

The installation of a new CO_2 pipelines from the Mohave site to Bakersfield, California or from the Black Mesa site to a sequestration site will entail a number of permits and approvals before the start of construction.

- **Environmental Impact Statement.** Since the pipelines will cover at least two adjacent states and may need to traverse federal lands, and Environmental Impact Statement (EIS) will most likely be necessary. The National Environmental Policy Act (NEPA) requires an EIS for all such projects that have a federal scope. An EIS is a full disclosure document that details the process through which a project was developed, includes consideration of a range of reasonable alternatives, analyzes the potential impacts resulting from the alternatives, and demonstrates compliance with other applicable environmental laws and executive orders. The EIS process in completed in the following ordered steps: Notice of Intent (NOI), draft EIS, final EIS, and record of decision (ROD). A properly prepared EIS will include the following sections:
  - **Purpose and Need.** The Purpose and Need Section of an EIS is one of the most important. The purpose and need discussion drives the development of the range of alternatives. This section will need to demonstrate that utilizing CO_2 gas for oil field recovery and CO_2 sequestration are the best uses of the gas. The environmental benefit of sequestration over emission of the greenhouse gas must be shown.
  - **Alternatives.** The Alternatives Section describes the process that was used to develop, evaluate, and eliminate potential alternatives based on the purpose and need of the project. The discussion should include how alternatives were selected for detailed study, the reasons why some alternatives were eliminated from consideration, and describe how the alternatives meet the need for the project and avoid or minimize environmental harm. For

developing alternative routes for a CO_2 pipeline, the requirements of 23 CFR 771.111(f) state that projects must connect logical termini, have independent utility, and not restrict the consideration of future transmission alternatives. The “no-build” alternative is always included as a benchmark against which the impacts of the other alternatives can be compared.

— **Affected Environment.** This section provides information on the existing resources and the condition of the environment. It should focus on the import issues in order to provide an understanding of the project area relative to the impacts of the alternatives. The affected environment should discuss the existing social, economic, and environmental settings surrounding the project. It should also identify environmentally sensitive features in the project corridor.

— **Environmental Consequences.** This section describes the impacts of the project alternatives on the environment and documents the methodologies used in evaluating these impacts. Information in this section is used to compare project alternatives and their impacts. This section should describe in detail both the impacts of the proposed action and the potential measures that could be taken to mitigate these impacts. Mitigation must be considered for all impacts, regardless of their significance. Environmental impacts should be discussed in terms of their context and intensity.

— **Comments and Coordination**. The EIS must summarize the scoping process and list any comments received during public meetings. Between the draft and the final EIS, the preparer must consider and respond to all substantive comments received. The final EIS must include copies of the comments and responses.

- **Public Utility Commission of Nevada.** Any new linear pipeline in the state of Nevada will require a Certificate of Public Convenience and Necessity (CPCN) from the Public Utility Commission of Nevada. To obtain a CPCN, an applicant must demonstrate that there is a public need for the CO_2 pipeline and that the proposed utility is willing to serve and able to fulfill the public need. An EIS, described above, may be a necessary component of the CPCN process.

- **California Public Utility Commission.** Any new linear pipeline in the state of California will require a CPCN from the California Public Utility Commission. To obtain a CPCN, an applicant must demonstrate that there is a public need for the CO_2 pipeline and that the proposed utility is willing to serve and able to fulfill the public need.

- **Arizona Corporation Commission.** The Arizona Corporation Commission (ACC) typically regulates the siting of transmission lines, pipelines, and other linear utilities. They issue Public Convenience and Necessity (CPCN) determinations for investor-owned and cooperative utilities. However, the ACC does not have authority over power plant siting in tribal lands. A CO_2 pipeline from the Black Mesa Mine to Cortez, Colorado, would not fall under the jurisdiction of the ACC. Since Navajo County borders New Mexico, the pipeline would not traverse any parts of Arizona outside of tribal lands.

- **New Mexico Public Regulation Commission.** Any new CO_2 pipeline in the state of New Mexico will require a Certificate of Public Convenience and Necessity (CPCN) from the New Mexico Public Regulation Commission. There is no indication that tribal land in New Mexico is exempt from jurisdiction by the Public Regulation Commission. To obtain a CPCN, an applicant must demonstrate that there is a public need for the CO_2 pipeline and that the proposed utility is willing to serve and able to fulfill the public need.

- **Colorado Public Utility Commission.** Any new CO_2 pipeline in the state of Colorado will require a CPCN from the Colorado Public Utility Commission. To obtain a CPCN, an applicant must demonstrate that there is a public need for the CO_2 pipeline and that the proposed utility is willing to serve and able to fulfill the public need.

- **Underground Injection Well Permit.** Injection of CO_2 into the oil fields in Bakersfield, California would require permitting under the U.S. EPA's Underground Injection Control (UIC) program. The UIC program classified injection wells into five classes. This project would be considered a Class II well, which is defined by injection of fluids associated with oil and natural gas recovery. In California, Class II well permits are issued by the California Department of Conservation – Division of Oil and Gas Recovery. Their office is in Bakersfield, and they have permitted numerous Class II wells in the area. This permit would require public notification in a local newspaper, but would only require a public hearing if there were significant interest in the project.

  Injection of CO_2 into a sequestration location at a saline aquifer would also require permitting under the U.S. EPA's UIC program. Injection wells typically require a state permit. This permit typically requires public notification in a local newspaper, but typically only requires a public hearing if there were significant interest in the project.

- **U.S. Army Corps of Engineers Permit.** It is possible that there are some jurisdictional wetlands in the path of the CO_2 pipeline; if any would require filling, then the developer must seek an U.S. Army Corps of Engineers permit. If the CO_2 pipeline will cross any "waters of the United States," including dry creek beds, then a Nationwide Permit #12 (Utility Line Activities) would be required. This general permit allows installation of a pipeline underneath the river or creek, but requires that the water body be returned to its original condition. A permit would be issued for each crossing, provided that they meet the criteria for Nationwide Permit #12. One permit officer from the U.S. Army Corps of Engineers would be assigned to the entire project. Typical permit review times could take up to one year.

- **Zoning / Land Use Permits.** Each county along the right-of-way will need to grant approval for the CO_2 pipeline.

- **Building Permits.** At various points along the CO_2 pipeline, compression stations will need to be installed. At each station, a building permit from the local municipality or county will need to be obtained. Since these structures will not be regularly occupied, the design requirements are not as strict.

- **Other Issues.** It is recommended that the project developers seek concurrence from the State Historical Preservation Officers (SHPO) in both Nevada and California or in Arizona, New Mexico, and Colorado, as necessary, to determine that no known historical or archeological features are in the path of the CO_2 pipeline. There is no permit that would need to be obtained, nor does the SHPO have authority to stop a project. Still, obtaining concurrence would be sound planning. Similarly, the Nevada Natural Heritage Program (part of the Department of Conservation and Natural Resources) and the California Department of Fish and Game should be consulted to determine whether there are any known threatened or endangered species along the path of the CO_2 pipeline.

8.7 CONCLUSION

There is limited experience worldwide with carbon dioxide injection projects dedicated to long-term carbon storage. A number of policy, economic, and technical barriers confront geologic sequestration to varying degrees. As research and development projects progress and policies such as carbon dioxide regulations are put into place, we may see more activity in carbon sequestration.

The available evidence appears to demonstrate that there is a potentially significant market for CO_2 gas. However, the ability to tap into that market is constrained by lack of supply and uncertainties about the technical feasibility of enhanced gas recovery. Any carbon dioxide producing power plant at the Mohave site would need to perform further economic analyses to justify the transport of its CO_2 to a gas or oil field in California.

It is also important to keep in mind that while enhanced hydrocarbon recovery can potentially be an economically feasible endeavor without subsidy or assistance, it is not a net-zero method to sequester anthropogenic carbon dioxide. The oil and gas produced will also result in the release of CO_2 when burned. It is worth noting however, if CO_2 captured from an IGCC plant were used in EOR *instead* of natural CO_2 that would otherwise have been newly extracted from a dome and the resulting oil production was no more than would otherwise have occurred, then there would be a net positive climate change benefit to using CO_2 from the IGCC plant. However, in a regulatory or legislative setting, this argument might be problematic. Furthermore, without greenhouse gas (GHG) regulation, it is not clear what incentive there would be to substitute more expensive anthropogenic CO_2 for cheaper natural CO_2, particularly when pipelines from CO_2 domes to oil fields already exist.

Last page of Section 8.

9. TRIBAL ISSUES

9.1 SCOPE OF STUDY

The scope of work at the outset of the study included investigating the following areas:

- Employment impacts for certain technology options;
- Estimates of royalties, taxes and other costs assumed to be paid to the tribes in the course of implementing certain technology options;
- Costs of land, water, and Black Mesa Mine coal;
- Requirements and likelihood of permitting for generation plants, new or renewed coal mining operations, and right of way (ROW) permitting for power lines, roads and pipelines;
- Acceptability of development on Hopi and Navajo lands for certain technology options;

Employment impacts and estimates of tax liabilities for the various technology options were developed and are presented in this report. Due to their complexity and confidential nature, it was agreed by the stakeholders that issues of royalties, as well as land, water, and coal costs, permitting, and acceptability, were not to be developed further. Therefore, these issues are discussed only briefly.

Economic benefits would flow to the tribes—as governmental entities—from the initial investment in and operation and maintenance of any of the technology options. Those economic benefits would take the form of tax revenues on investments in the construction and operation of the option; royalties, fees, and similar payments; and taxes paid by employees of the businesses operating those technology options, along with any similar taxes and payments from secondary economic activity flowing from the technology option. Tribes would likely see additional expenses in some areas from government services provided and reduced expenses in other areas. Royalties, land rents, and similar revenue would be due to the tribes for many of the options studied in this report and would form an important part of the quantitative benefits to the tribes. However, since critical data were not available due to the confidentiality restrictions mentioned above, no quantitative estimates of those benefits were possible. Tax revenues to the tribes from investment, operation and maintenance outlays, and direct employment were estimated, but tax revenues from expenditures by employees and secondary business activity were not estimated as part of this study. However, the amount of employment in those secondary business activities on the reservations and adjacent counties was estimated and is included in the totals shown in Section 9.4. A critical factor in estimating employment impacts for these technology options would be the effect of tribal employment preference requirements. As only limited information on the effects of those requirements was available, employment impacts had to be based on certain assumptions about preferences.

Section 9.2 begins with a review of land tenure and of approval issues. Section 9.3 presents estimates of the taxes that would be payable to the Navajo Nation by technology options on tribal land.[1] Finally, Section 9.4 presents estimates of the direct and indirect employment benefits expected from a selection of technology options under study.

9.2 TRIBAL ISSUES IN CONTEXT

Any discussion of the above issues or the processes by which they are addressed, even a cursory one, depends critically on a clear understanding of the varieties of land tenure that occur in and around tribal lands. Therefore, this section begins with a review of those categories and then reviews a few of their implications relevant to energy development projects. That discussion necessarily includes various complexities and identifies certain potential barriers to development. They are potential barriers in the sense that if they arise, they would need to be overcome. Overcoming such barriers can be time-consuming and complex in some cases. In other cases, especially when all relevant parties are in accord, addressing approvals and permitting may be less complex and more streamlined.

As detailed in Chapter 10 of this report, there are numerous financial benefits that can be available to the owners of energy projects on tribal land and to the tribes involved. In addition to the tax benefits and other financial incentives outlined in Chapter 10, there are certain other advantages and simplifications that may flow from siting energy projects on tribal land. For example, tribes may now negotiate energy development leases with third parties without obtaining U.S. government approval.[2] Also, certain federal laws provide preferential standing for purchases from certain businesses located on Indian reservations.[3] Another preference exists for purchases from businesses owned by Native Americans.[4]

[1] No taxes have been enacted by the Hopi Tribe at this time.

[2] EPACT 2005, Section 2604. This could be valuable in relation to the technology options of non-tribal ownership of IGCC at Black Mesa, wind development at Gray Mountain and, possibly, other sites, and both solar energy sites under consideration.

[3] HUBZone Act of 1997, Public Law 105-135 expanded by P.L. 106-554.

[4] Small Business Act, Public Laws 85-536 and 95-507, Sec. 8(a).

Of course, there can be substantial benefits to tribes that host energy projects. Among those that flow directly to the tribes are tax revenue, royalties, and land lease revenue. Benefits that flow to tribal members and their families include direct employment and training opportunities that stem from the project, indirect employment in businesses that support the project (contractors for maintenance and other services, vendors of supplies and other goods, and so on), and further employment supported by re-spending of personal or business income from direct and indirect employment. In addition, there can be social benefits to communities that benefit from these economic impacts. Depending on the nature of the project, there may also be other effects on the community, the environment, and the local economy, but the balancing of all these consequences is an important part of determining which energy projects best suit the tribes.

This study does not intend to convey the impression that energy projects cannot or should not be developed on tribal lands; many such developments have occurred and, no doubt, more will occur. Indeed, numerous advantages, financial and otherwise, may ease the way for such developments, depending on project and site qualifications. However, it is important to begin with a clear understanding of the potential issues that might confront potential owners, developers, tribes and other stakeholders.

9.2.1 Land Tenure Issues and Their Relation to Approval and Permitting

A technology option's physical location affects its permitting, approvals, taxation, land ownership or leasing, and other factors. For example, type of land ownership and the nature of the approvals for business activity that a type of land ownership mandates are important and can be a "gating" item for proposed enterprises. Although, as is explained below, some of the above subtasks are not being pursued to completion, an informational summary of the types of locations and certain permitting issues that might be relevant to the study or to subsequent consideration by the stakeholders is provided below.

An *Indian reservation* is a geographic territory over which a particular form of governmental jurisdiction has been created by action of federal law. Within a given reservation, there may be one or many of the following forms of land ownership:

- **Land can be held in trust by the U.S. for a tribe.** The consent process for business activities on such land involves approvals from both the tribe and the federal government. Because federal approval is required, certain federal laws—such as the National Environmental Policy Act (NEPA), which may require the federal government to draft an environmental impact statement regarding a new proposed activity—may make the process of getting projects approved on land held in trust by the U.S. for a tribe a cumbersome task.

- **Land can be held by the U.S. in trust for individual tribal members.** Typically, over time, such lands have been passed down from one original owner to many heirs—often through several generations. The consequence is that a large number of individual owners may hold a fractional undivided interest in the land's title. These lands are referred to as "fractionated" allotments. Activities on such lands generally require the consent both of the federal government and of at least 50% of the allotment owners.[5] While such approvals are certainly possible, the multiple ownership scenario of this type of land and the approval process represents a large degree of complication for potential business activities.
- **Land can be owned by the tribe.** This scenario is less complicated, as federal approval of business activities on such pieces of land are eliminated. However, the tribal government must still approve use.
- **Land can be owned by the U.S. in trust for joint use by more than one tribe.** Approval of business activities on joint lands requires approvals from multiple tribal governments as well as by the U.S. government. This may represent some significant issues for potential businesses.
- **Land can be owned by a non-tribal business entity.** In this scenario, the U.S. government does not need to approve use of the land.
- **Land can be owned by non-tribal individuals.** In this situation, again, federal approval of use of land is not required.

Lands that fall under these latter two ownership scenarios sometimes are known as "checkerboard lands." Such lands often were originally owned by the tribes or tribal members, but then were sold to private, non-trial owners. An example of checkerboard land follows:

> The 1830 Treaty of Rabbit Creek [sic] called for the removal of the Choctaw from their ancestral homeland in the Carolinas, Mississippi, and Tennessee to Oklahoma Territory.[6] Subsequently, 104,320 acres in Mississippi were awarded to the 5,000 Choctaw who remained on the traditional lands. Fraudulent land sales fueled the checkerboarding of the reservation. Today, 8,400 members live on 29,000 checkerboard acres in seven communities. Using the profits generated by tribal business, the tribe is purchasing reservation land to consolidate and fill in the checkerboard areas within each of the communities. The goal is to simplify jurisdictional and development issues for the tribe and for the state of Mississippi.[7]

In addition to the above reservation ownership scenarios, the U.S. can hold land for tribes or tribal members outside of a reservation. Such land has the same approval-of-use issues as those lands held by the U.S. within a

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[5] See 25 Part 162 (Leasing and Permitting) C.F.R. section 162.605(b)

[6] The treaty more usually called "The Treaty of Dancing Rabbit Creek." The complete title given in the treaty, itself, is "A treaty of perpetual, friendship, cession and limits, entered into by John H. Eaton and John Coffee, for and in behalf of the Government of the United States, and the Mingoes, Chiefs, Captains and Warriors of the Choctaw Nation, begun and held at Dancing Rabbit Creek, on the fifteenth of September, in the year eighteen hundred and thirty." Charles J. Kappler, *Indian Affairs: Laws and Treaties*, Washington: U.S. Govt. Printing Office, 1904, vol. II, p. 310 ff.

[7] The Urban Institute, Inc., 2004.

reservation boundary. Finally, land can be owned by the tribe outside of the reservation. This type of land is known as “tribal fee land.” The tribe owns such land, because it purchased it outright. For such parcels of land, the tribe likely does not exercise governmental authority; but as the land’s owner, the tribe can control activities on such lands.

Table 9-1 summarizes the various technology options, their proposed locations, and ownership issues.

Table 9-1 — Technology and Land Use Approval Issues

Technology	Proposed Location	Land Owner Type	Requires Tribal Approval?	Requires Federal Approval?
IGCC	Laughlin, NV	Private	No	No
IGCC	Black Mesa, AZ	No specific site has been identified, but the general area surrounding the Black Mesa mine is land held in trust by the U.S. for the Navajo Nation with the subsurface (mineral) estate held in trust by the U.S. jointly for the Navajo Nation and the Hopi Tribe	Yes	Yes
NGCC	Laughlin, NV	Private	No	No
Solar	Northeast of Black Mesa Coal Mine, AZ	No specific site has been identified, but the general area is land held in trust by the U.S. for the Navajo Nation	Yes	Yes
Solar	East of Tuba City, AZ	No specific site has been identified, but the general area is land held in trust by the U.S. for the Hopi Tribe	Yes	Yes
Wind	Gray Mountain	Land held in trust by the U.S. for the Navajo Nation	Yes	Yes
Wind	Clear Creek (southwest of Winslow, AZ)	On Hopi fee and Arizona State lands	Yes	Not as to trust issues
Wind	Aubrey Cliff (northwest of Seligman, AZ)	Navajo fee and Arizona State lands	Yes	Not as to trust issues
Wind	Sunshine (located 35 miles east of Flagstaff on I-40 near the Meteor Crater and west of Winslow)	Hopi fee and private ranch lands owned by two other landowners,	Yes	Not as to trust issues
Biomass	Unspecified	N/A	N/A	N/A
Geothermal	Unspecified	N/A	N/A	N/A

In summary, numerous issues connected with approvals for land use can arise for potential business operations, and various approval processes may apply, depending on the circumstances. To the extent that more land is required for the business activities and this increased land requirement involves additional tracts under new and different ownership statuses, the potential for approval difficulties increases significantly.[8] Specifically, additional owners may be affected, additional approval processes may be triggered, or both. As a result, those generating technologies mentioned in this study that require use on land held by the U.S. or on land held by multiple owners may present business challenges.[9] On the other hand, when all relevant parties are in accord, addressing approvals and permitting may be less complex and more streamlined.

Furthermore, as explained in Chapter 10 of this report, there are numerous financial benefits that can be available to the owners of energy projects on tribal land and to the tribes involved, and certain other advantages and simplifications may exist, such as purchase preferences. The substantial benefits to tribes and the communities that host energy projects may justify approval. Balancing all these consequences is an important part of determining which energy projects are best suited to the tribes.

9.2.2 Acceptance and Permitting, Royalties, and Other Payments to Tribes

Examples of aspects of a project proposal that would affect acceptance and permitting for projects include royalties and other payments, compensation provisions for individuals and communities that are affected, and effects on land, air and water, on employment, and on other uses of land.

Most of the specific technology options under consideration for siting on or near tribal land, including an IGCC facility at Black Mesa, wind, and solar, would face exceedingly complex water rights issues and aquifer studies currently under way, highly confidential royalty negotiations also under way, and numerous other issues not in the public domain. To a large extent, even the historical values and issues relating to some of these types of matters lie outside the public domain. However, it should be kept in mind that life extension or renewal of the existing Mohave Generating Station would also raise such issues.

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[8] It is important to note that members of tribes can own land outside of a reservation. These owners are not required to obtain tribal or federal approval for business activities on their lands. Such lands would be subject to generally applicable state and federal laws, but not to any laws unique to Indians or Indian tribes.

[9] This does not mean that a larger size of the leasehold, *per se*, makes approval more difficult. Rather, if increased land requirements lead to a need for lands that are under different and additional types of ownership or trusteeship, this could trigger additional types of approval requirements and could add to the complexity of approval. In addition, even a project located on land under a single type of ownership or trusteeship may require acquisition or use of land under additional types of ownership or trusteeship for ancillary uses, such as access roads or transmission lines.

9.3 TAXES

9.3.1 Overview of Applicable Taxes

Tribes have the authority to levy taxes on business activity conducted on tribal land in a manner analogous to the authority of states. Among the most significant benefits for development of the various technology options is their potential as tax revenue sources. The technology options under consideration would be subject to such taxes if their operations were conducted on tribal land.

The Navajo Nation (NN) has enacted three taxes that would be applicable to businesses conducted on its tribal land:

- **Possessory Interest Tax**, which applies to the property rights under a lease, including the rights to use or possess tribal lands, to lease premises, rights-of-way, and rights to underlying natural resources; 24 N.N.C. § 204 (A) and (C). Under the Navajo Nation Code (N.N.C.), projects on leased tribal land that generate electricity or transmit electricity at voltages above 14.5-kV would be classified as "Class two possessory interest." This would appear to apply to the IGCC technology option at Black Mesa Mine, the Solar 1 and Solar 2 sites, and some or all of the wind sites identified elsewhere in this study; 24 N.N.C. § 204 (J). It is possible that other renewable options would also fall under that classification if proposed locations have been identified. The valuation of such an interest would be determined by the fair market value, the present value of projected net income over the life of the lease, or such other method as is adopted by the Office of the Navajo Tax Commission; 24 N.N.C. § 205. The taxable value of such an interest would be 100% of the valuation; 24 N.N.C. § 216.[10] The rate of tax currently in effect (according to the Code) is 3%, subject to change within the range of 1% to 10%; 24 N.N.C. § 206.

- **Business Activity Tax**, which applies the gross receipts ("source-gains") from personal property produced, processed or extracted within the Navajo Nation ("Navajo goods") or from services performed within the Navajo Nation of any person engaged in trade, commerce, manufacture, power production, or other productive activity wholly or in part within the Navajo Nation ("branch"); 24 N.N.C. § 404 (A)-(D).[11] Gross receipts are generally based on fair market value; 24 N.N.C. § 404 (F). The rate of tax is set by regulation within the range of 4% to 8%, but is reduced by 40% for construction activity; 24 N.N.C. § 406.

- **Sales Tax**, which applies to the gross receipts of person from the sale of real or personal property, services, or other productive activity; 24 N.N.C. § 607 (H). The tax rate is set by

[10] It is possible that some possessory interests, such as those relating to DSM options would be classified as commercial uses. Also, certain renewable technology options might include in their implementation commercial, industrial, manufacturing, assembly or fabrication uses. Such purposes would be classified as "Class three possessory interests" and would be taxable at 10% of their valuation. 24 N.N.C. §§ 204 (J) and 217.

[11] Various deductions from these gross receipts are allowed including, in particular, compensation paid to members of the Navajo Nation, certain payments to the Navajo Nation, and purchases of Navajo goods and services and cost of raw materials imported into the Navajo Nation to be used in manufacturing Navajo Nation goods. 24 N.N.C. §§ 405 (B) and 408 (H). Amounts on which Navajo Sales Tax has been paid are exempt. 24 N.N.C. § 480 (A). Navajo Nation government, subdivisions and wholly owned enterprises are exempt. 24 N.N.C. § 408 (B). Special provisions apply to credits that coordinate with other taxes, especially for "new business" (post-1998). 24 N.N.C. §§ 404 (I) and 409 (B) (1).

regulation within the range of 2% to 6%; 24 N.N.C. § 605. Effective during and after calendar 2006, sales by the Navajo Nation government, political subdivisions and enterprises are subject to 100% of the Sales Tax; 24 N.N.C. § 608 (B) (5). Certain exemptions relevant to this study exist, including for sales for resale and sale of certain securities; 24 N.N.C. § 609 (C).

The Oil and Gas Severance Tax (24 N.N.C. §§ 301-345) and the other taxes set out in Title 24 of the N.N.C. do not appear to apply to the technology options under consideration in this study.

The Hopi Tribe does not, at present, have a tax code; and, under the Hopi Tribe's Constitution, a referendum vote of the Tribe's members would be necessary to change that situation.

In the next subsection, this basic information regarding tribal taxes that would apply to the technologies that may be considered for tribal land (IGCC at Black Mesa, Solar 1 and 2, and the four wind sites) is used, along with the investment and O&M estimates, to estimate the tax payments that would be due under identified provisions of the Navajo Nation Code.

9.3.2 Estimation of Navajo Nation Possessory Interest Tax

Table 9-2 presents estimates of the Possessory Interest Tax (PIT) payments that would be required for selected technology options and locations. The notes following the table explain the derivation of input values and assumptions made during the calculation of these estimates. In general, where assumptions were required, the option resulting in the larger tax due was used.

Table 9-2 — Navajo Nation Possessory Interest Tax Estimate

All dollar amounts are in 2006 dollars

Option	Land Requirement (acres) (Note 7)	Fair Market Value (FMV) (Note 6)	Capital Cost for Generating Options OR Annual Budget for EE Options	Annual Net Income (Note 8)	Present Value (PV) of Projected Net Income (Note 8)
IGCC at Black Mesa	300	$90,000	$1,082,992,688	$77,975,474	$967,600,863
Parabolic Trough	2,610	$783,000	$1,066,333,920	$76,776,042	$952,717,070
Solar Stirling Engine	2,125	$637,500	$730,095,000	$52,566,840	$652,304,082
Wind (150 MW at Gray Mountain)	10,000	$3,000,000	$711,205,595	$51,206,803	$635,427,325

Option	Land Requirement (acres) (Note 7)	Fair Market Value (FMV) (Note 6)	Capital Cost for Generating Options OR Annual Budget for EE Options	Annual Net Income (Note 8)	Present Value (PV) of Projected Net Income (Note 8)
EE on Reservation	2	$160,000	$30,520,000	$15,260	$62,569
EE from Reservation	10	$800,000	$30,520,000	$152,600	$625,690

Computation of Tax	PIT Class	Initial Tax Rate per N.N.C.	Applicable Percentage	PIT Based on FMV ($/year)	PIT Based on PV of Projected Net Income ($/year) (Note 9)	Notes
IGCC at Black Mesa	2	3%	100%	$2,700.00	$29,028,026	1, 5
Parabolic Trough	2	3%	100%	$23,490.00	$28,581,512	5
Solar Stirling Engine	2	3%	100%	$19,125.00	$19,569,122	5
Wind (150 MW at Gray Mountain)	2	3%	100%	$90,000.00	$19,062,820	5
EE on Reservation	3	3%	10%	$480.00	$188	2, 4
EE from Reservation	3	3%	10%	$2,400.00	$1,877	3, 4
EE on Reservation	None			$0.00	$0	2, 4
EE from Reservation	None			$0.00	$0	3, 4

Other Inputs		
Value of undeveloped rural land (Note 11)	$300	per acre
Value of undeveloped commercial real estate (Note 11)	$80,000	per acre
Real discount rate	7%	per year
Economic Life of generating options	30	years
Program Life of EE options	5	years
ROE for generating options	16%	per year
Equity percentage for generating option	45%	
Profit percentage for EE options	5%	per year
Percent of EE delivered on Reservation	1%	
Percent of EE delivered on or from Reservation	10%	

Notes:

1. For IGCC at Black Mesa, the study assumes that Navajo Nation (NN) PIT applies. The study does not need to reach the question of whether the proceeds (or other NN tax proceeds) are subject to sharing under Secakaku v. Navajo Nation, 964 F. Supp. 1359 (D. Ariz. 1997), because sharing of the tax proceeds does not necessarily affect the amount of those proceeds.

2. For the Demand Side Management (DSM)/Energy Efficiency (EE) on the NN Reservation option, for illustrative purposes, the study assumes that a small percentage of the total program is delivered on the NN by a non-tribal enterprise based on the Reservation. This is not meant to imply any position regarding the best or most likely way of organizing such an enterprise. The assumed percentage of savings delivered on Reservation is shown under "Other Inputs."

3. For the EE from Reservation option, for illustrative purposes, the study assumes that a percentage of the total program is delivered both on and off of the NN Reservation by a non-tribal enterprise based on the Reservation. This is not meant to imply any position regarding the best or most likely way of organizing such an enterprise. The percentage is shown under "Other Inputs."

4. This analysis considers two extreme alternatives for EE options with regard to PIT. First, the study assumes that EE options would operate out of pre-existing rented commercial space and that they would not require any new leases of tribal land. This means that no new lease would be required for lands, nor the severance of any products from tribal lands. Therefore, the study also assumes that EE options would not be subject to PIT. Alternatively, the study considers the possibility that a new lease of tribal land would be required to house the operations of the EE option, and that such an operation would be classified as a commercial operation and as a Class 3 possessory interest. 24 N.N.C. section 204(K). NOTE: Due to the exemption for PIT amounts less than $100,000 per year, any amount less than that would not be due.

5. PIT Class 2 possessory interest applies to generation at voltages above 14.5 kV. 24 N.N.C. § 204(J). The wind options are specifically expected to produce power at 34.5 kV. Projects of the size of the IGCC and solar options usually interconnect at 34.5 kV or higher.

6. FMV (Fair Market Value) is estimated based on a value per acre of undeveloped rural land in the southwest, except for the EE options. For the EE options, FMV is based on a value per acre for undeveloped commercial real estate. Both values are shown under "Other Inputs."

7. Land requirements do not include ROW for any necessary transmission lines. Land for IGCC assumes a requirement for ash storage; (Prelim. Draft page 2-15). Land for parabolic trough option is estimated based on 300 MW plant size and 6 acres/MW; (Prelim. Draft Table 3-3). Land for Stirling engine option is estimated based on 425 MW plant size and 4 acres/MW; (Prelim. Draft Table 3-3). Land for EE is based on estimated requirement for office, shop, garage, warehouse space for two different program sizes.

8. Projected Net Income for generating options is assumed to be a fixed percentage of the overnight capital cost of each option. That percentage is the product of the ROE and the equity percentage shown under "Other Inputs." Projected Net Income for EE options is assumed to be a fixed percentage of the annual expenditure on efficiency program. NPV (Net Present Value) of Projected Net Income is calculated using the real discount rate (excluding inflation) and assumed operating lives shown under "Other Inputs."

9. PIT is subject to various exemptions and valuation is subject to various exclusions. In particular, PIT amounts less than $100,000 per year are exempted. Also, in the PV of Projected Net Income method of valuation, certain expenses are deducted. However, since the analysis begin with net income, such exclusions do not appear to be relevant.

10. This analysis assumes that one 50-MW block of EE is acquired spread out over 5 years of implementation. To the extent that more than one block is acquired, PIT revenue could occur. However, even if eight blocks (400 MW) were acquired, the PIT based on PV of projected net income would still be only $15,017 per year for the 10% "on or near reservation" scenario, which is below the $100,000 per year exemption amount.

11. The land values used in the study are the midpoints of estimates provided by Simmons Realty of Winslow Arizona.

Simmons price ranges:

—Undeveloped rural land: $100 to $500 per acre

—Commercially zoned land in a small town: $10,000 to $150,000 per acre

9.3.3 Estimation of Navajo Nation Business Activity Tax

Table 9-3 presents estimates of the Navajo Nation Business Activity Tax (BAT) payments required for selected technology options and locations. The notes following the table explain the derivation of input values and assumptions made during the calculation of these estimates.

Table 9-3 — Navajo Nation Business Activity Tax Estimate

All dollar amounts are in 2006 dollars

Option	Ongoing Salaries Paid to NN members (Note 1)	Annual Water Use (acre-ft) (Note 5)	Land Requirement (acres) (Note 5)	Purchase of NN Goods and Services (Note 2)	Payment to NN other than Taxes under 24 N.N.C. (Note 2)	Standard Deduction (Note 3)	Deductions (Note 4)
IGCC at Black Mesa	$11,536,000	1,919	300	$1,893,562	$88,633,360	$18,935,616	$102,062,922
Parabolic Trough	$4,928,000	58	2,610	$452,016	$840,815	$4,520,160	$6,220,831
Solar Stirling Engine	$6,608,000	8	2,125	$446,760	$645,594	$4,467,600	$7,700,354
Wind (150 MW at Gray Mountain)	$1,291,500	0	11,333	$210,240	$1,365,000	$2,102,400	$2,866,740
EE on Reservation	$85,456	0	2	$3,052	$600	$125,000	$125,000
EE from Reservation	$854,560	0	10	$30,520	$3,000	$305,200	$888,080

	Generation output (MWh per year) (Note 5)	Gross Receipts (2006$ per year) (Note 6)	Deductions (2006$ per year) (Note 4)	Taxable Gross Receipts (Gross Receipts - Deductions)	Annual BAT Payable on Ongoing Operations	Notes
IGCC at Black Mesa	4,733,904	$189,356,160	$102,062,922	$87,293,238	$4,364,662	
Parabolic Trough	1,130,040	$45,201,600	$6,220,831	$38,980,769	$1,949,038	
Solar Stirling Engine	1,116,900	$44,676,000	$7,700,354	$36,975,646	$1,848,782	
Wind (150 MW at Gray Mountain)	525,600	$21,024,000	$2,866,740	$18,157,260	$907,863	
EE on Reservation	N/A	$305,200	$125,000	$180,200	$9,010	7
EE from Reservation	N/A	$3,052,000	$888,080	$2,163,920	$108,196	7

Other Inputs		
Percent of salaries paid to NN members--generation options	80%	
Percent of salaries paid to NN members--EE options	80%	
Illustrative value for coal	$40	per ton
Illustrative value for water	$1,000	acre-ft
Annual coal use for IGCC	2,165,609	tons

Other Inputs		
Percent of gross receipts for other NN goods and services	1%	
BAT Tax Rate	5%	
Illustrative price for power sold by generation options	$40.00	per MWh
Value of undeveloped rural land (Note 8)	$300	per acre
Value of undeveloped commercial real estate (Note 8)	$80,000	per acre

Notes:

1. The analysis assumes that 80% of salaries are paid to Navajo Nation members. For EE options, labor is based on estimates of breakdown for total budget of $30,520,000 per year. In addition, the analysis assumed $70,000 per year as the salary and compensation per employee. Wind ongoing labor costs were assumed per tables provided in this study.
2. Navajo goods and services and other payments are assumed to include coal (where applicable), water, and contract services. For coal and water, for illustration, the analysis assumes the purchase value shown in "Other Inputs." If this purchase value is paid to the Navajo Nation, there would be a resulting deduction for purposes of BAT, as shown in these tables. For other goods and services, the study assumes a percentage of the remaining gross receipts as shown under "Other Inputs." For this analysis, the study assumes that land is leased at the value shown in "Other Inputs" and that lease payments are made to the Navajo Nation, resulting in a deduction for purposes of BAT. Payments for land, water, and coal are shown under "Payment to NN other than Taxes." *If any of the above payments are shared with or made to another entity such as, for example, the Hopi Tribe, the deductions available under the BAT Code would be reduced accordingly.*
3. The standard deduction is 10% of gross receipts or $125,000, whichever is greater.
4. Greater of (Salaries + Purchase of NN Goods and Services + Payments to NN other than Taxes) OR Standard Deduction.
5. Generation output for each option = (Capacity * Capacity Factor * 8,760). Data for IGCC is from Chapter 2. Data for Parabolic Trough and Dish/Stirling are from Chapter 3. Gray Mountain land lease value is in Chapter 4.
6. Gross receipts for generation options is annual output times illustrative price shown under "Other Inputs." Gross receipts for EE options are annual budget of $30,520,000 times 1% for "On Reservation" and 10% for "From Reservation."
7. For EE from Reservation, the analysis assumes that 10% of the total program is delivered off of the NN Reservation by a non-tribal enterprise based on the reservation. This is not meant to imply any position regarding the best or most likely way of organizing such an enterprise.
8. Land values are derived from midpoint estimates provided by Simmons Realty of Winslow Arizona.

   Simmons price ranges:

   —Undeveloped rural land: $100 to $500 per acre

   —Commercially zoned land in a small town: $10,000 to $150,000 per acre

9.3.4 Estimation of Navajo Sales Tax

Table 9-4 presents estimates of the Navajo Sales Tax (NST) payments that would be due for selected technology options and locations. The notes following the table explain the derivation of input values and assumptions made during the calculation of these estimates. Materials and equipment used in construction of generating options are assumed to be purchased off the reservation.

Table 9-4 — Navajo Nation Sales Tax Estimate

All dollar amounts are in 2006 dollars

Option	Construction Services (Note 1)	Annual O&M Contract Services (Note 1)
IGCC at Black Mesa	$23,975,000	$3,160,000
Parabolic Trough	$72,650,939	$616,000
Solar Stirling Engine	$210,073,000	$826,000
Wind (150 MW at Gray Mountain)	$52,690,207	$1,598,049
EE on Reservation	N/A	$30,520
EE from Reservation	N/A	$305,200

	One-time NST on Construction Services	Annual NST on Contract Services
IGCC at Black Mesa	$719,250	$94,800
Parabolic Trough	$2,179,528	$18,480
Solar Stirling Engine	$6,302,190	$24,780
Wind (150 MW at Gray Mountain) (Note 2)	$1,580,706	$47,941
EE on Reservation	$0	$916
EE from Reservation	$0	$9,156

Other Inputs	
NST tax rate	3%

Notes

1. For IGCC, the annual value of contract services is from Chapter 2. For IGCC, the construction value is the estimated labor requirement times $70,000 per person-year. For parabolic trough, the construction services value is as shown in Chapter 3. Annual value is assumed to be 10% of permanent O&M labor (88 positions at $70,000). For dish/Stirling engine, the construction value is as given in Chapter 3. Annual value is assumed to be 10% of permanent O&M labor (118 positions at $70,000). For wind, the annual and construction values are as given in Chapter 4. The salary and compensation per employee was assumed to be $70,000 per year. EE annual value estimated at 10% of on Reservation budget. See Table 9-3 sheet for budgets.

2. *One-time sales tax amount for wind does not include sales tax on the wind turbines themselves.* This is estimated to be $7,166,250 (see Chapter 4)

9.3.5 Summary of Navajo Nation Tax Estimates

Table 9-5 summarizes the results of the above estimation process. For the Navajo Sales Tax, there is a separate estimate of the amount due as a result of initial investment activity and an estimate (in 2006 dollars) of the ongoing annual taxes due. The PIT, BAT, and NST (Annual) estimates reflect the first year values of items that would be expected to be ongoing taxable items. It is important to keep in mind that these tax revenues exclude any royalties for coal or water and any land lease payments. Also, if any of the above payments are shared with or made to another entity, such as, for example, the Hopi Tribe, the deductions available under the BAT Code would be reduced accordingly, and the one-time sales tax amount for wind does not include sales tax on the wind turbines themselves, estimated by S&L to be $7,166,250.

Table 9-5 — Summary of Navajo Nation Taxes

Option	PIT	BAT	NST (Annual)	Total (Annual)	NST (One-Time)
IGCC at Black Mesa	$29,028,026	$4,364,662	$94,800	$33,487,488	$719,250
Parabolic Trough	$28,581,512	$1,949,038	$18,480	$30,549,031	$2,179,528
Solar Stirling Engine	$19,569,122	$1,848,782	$24,780	$21,442,685	$6,302,190
Wind (150 MW at Gray Mountain)	$19,062,820	$946,080	$47,941	$20,056,841	$1,580,706
EE on Reservation	$188	$9,010	$916	$10,113	$0
EE from Reservation	$1,877	$108,196	$9,156	$119,229	$0

It should be noted that certain Navajo Nation taxes may apply to projects that are outside the Reservation, but on Navajo fee land. The Nation explicitly claims jurisdiction over such lands; 7 N.N.C. § 254(A). The Nation has in fact applied its Business Activity Tax to non-Indian activities on those lands; see, for example, *Texaco v. Zah*, 5 F.3d 1374 (10th Cir. 1993). It seems likely that leases of such land would also be subject to the Nation's Possessory Interest Tax, inasmuch as the tax applies to ". . . the property rights under a lease approved, consented to, or granted by the Navajo Nation," which consent would certainly be required for any leases on lands it owns; 24 N.N.C. § 204(A). Finally, since the Navajo Nation's Sales Tax applies to ". . . all areas within the territorial jurisdiction of the Navajo Nation government . . ." that tax may also apply on off-reservation land owned by the nation in fee; 24 N.N.C. § 607(J).

9.4 EMPLOYMENT IMPACTS

9.4.1 Overview of Technology Options Modeled

Eight alternative energy options that could be developed on or near the Navajo or Hopi reservations were characterized for the purpose of estimating the potential economic impacts associated with each. All the scenarios were based on the schedules and costs set out elsewhere in this report. Three additional information sources were used to develop the detailed expenditure patterns. The Stirling Engine/Dish scenario was based on a combination of expenditure and employment data from Sargent & Lundy and SES, while the detailed breakdown of capital expenditures for wind generation was taken from a study of the inputs to wind generation manufacturing and construction.[12] The breakdown of DSM outlays was based Synapse's experience. Only the effect of the actual outlays for capital goods, labor, and O&M expenses were modeled. Taxes and royalties were not modeled.

The eight simulation scenarios, plus one variation on the first scenario, were defined as follows:

1. **Integrated Gasification Combined Cycle (IGCC)**. Assumptions associated with this development include no carbon dioxide removal, dry cooling, a plant located in the Black Mesa area on Navajo reservation land with approximately 540 MW capacity, no specific ownership designation, approximate plant construction period of 4 years, and total initial plant investment of $1,082,993,000. This scenario did not address the economic impacts of purchase or transportation of coal fuel for the plant.

   Simulation variant 1A includes all of the above plant specifications, but includes the effect of purchasing 100% of the coal used to fuel the plant from mines on Navajo and Hopi reservation land. Only the direct purchase of the coal, estimated by Sargent & Lundy to total 2,165,609 tons per year[13], was represented in the modeling; no royalty fees or Navajo or Hopi taxes or fees in connection with the coal mining were modeled in this variant.

2. **Solar Parabolic Trough**. Assumptions associated with this development include no storage systems, air-cooled condenser, three plants with approximately 300 MW total capacity located on Navajo reservation land in Navajo County, no specific ownership designation, approximate plant construction period of 2 years, and total initial plant investment of $1,066,334,000.

[12] See "Wind Turbine Development: Location of Manufacturing Activity," Technical Report, September 2004, Renewable Energy Policy Project, available on the Internet at http://www.repp.org/articles/static/1/binaries/WindLocator.pdf

13 The direct model input was converted to an employment change in NAICS 21211 (Coal Mining) of 104 jobs per year following completion of the plant construction. This estimate was based on output per employee data of 20,828 tons, derived from U.S. Department of Energy coal production data for Navajo and Hopi tribal lands (13.538 million tons) and reported employment at the associated mines for the year 2000 (650 persons).

3. **Stirling Engine/Dish**. Assumptions associated with this development include approximately 17,000 dish/engine units, located on Navajo reservation land in Navajo County, approximately 425 MW total capacity, no specific ownership designation, approximate plant construction period of 3 years, with phased operation beginning in year 1, and total initial plant investment of $730,095,000.

4. **Wind Turbines, Gray Mountain**. Assumptions associated with this development include a location in Coconino County on Navajo tribal land, approximately 450 MW total capacity, no specific ownership designation, approximate plant construction period of 2 years, and total initial plant investment of $711,206,000.

5. **Wind Turbines, Aubrey Cliffs**. Assumptions associated with this development include a location in Coconino County on Navajo tribal lease land, approximately 100 MW total capacity, no specific ownership designation, approximate plant construction period of 1 year, and total initial plant investment of $155,170,000.

6. **Wind Turbines, Clear Creek**. Assumptions associated with this development include a location in Coconino County on Navajo tribal lease land, approximately 75 MW total capacity, no specific ownership designation, approximate plant construction period of 1 year, and total initial plant investment, $116,005,000.

7. **Wind Turbines, Sunshine.** Assumptions associated with this development include a location in Coconino County on Hopi fee land, approximately 60 MW total capacity, no specific ownership designation, approximate plant construction period of 1 year, and total initial plant investment of $91,359,000.

8. **Energy Efficiency Program.** Assumptions associated with this development include development and funding of a program serving the premises of utility customers in New Mexico and Arizona, who would subsidize the purchase and installation of energy-saving appliances, lighting, air conditioning, new building design and other fixtures and equipment that would result in annual reductions of 10 MW in electric demand each year for a five-year period, reaching a total savings of 50 MW by the end of the five-year program. Program investment would total $30,520,000 per year for each of five years. Further project description and other assumptions associated with this option are detailed below.

More detailed technical descriptions of each of these options appear elsewhere in this report. All source data associated with the above options and their costs were provided by Sargent & Lundy, Synapse Energy Economics, and Stirling Energy Systems.

9.4.2 Economic Modeling of Energy Efficiency

The Energy Efficiency option modeled in this report contemplates the creation of a five-year, $30.5 million per year, program to subsidize the purchase and installation of energy-saving appliances, lighting, air conditioning, new building design, and other fixtures and equipment for residential, commercial, and industrial utility customers in Arizona and New Mexico.

Table 9-6 presents the stream of annual expenditures necessary to support an efficiency program of the type analyzed in this study. It is based on a program that is estimated to save 10 MW per year for five years, for a total of 50 MW.

Chapter 6 of this study estimates that there is at least 400 MW of efficiency savings that are readily available in Arizona and New Mexico by 2010. The smaller amount is assumed here to represent the economic impacts of a single energy efficiency purchase by SCE from a utility or utilities in Arizona or New Mexico. If additional purchases, or purchases of greater size, are made by SCE, then the economic impacts would scale up approximately linearly from those identified here.

Table 9-6 — Expenditures in Support of Energy Efficiency

Efficiency Savings and Expenditures:					
	2006	2007	2008	2009	2010
Annual energy savings (GWh):					
Incremental	59	59	59	59	59
Cumulative	59	117	176	235	293
Annual capacity savings (MW):					
Incremental	10	10	10	10	10
Cumulative	10	20	30	40	50
Annual efficiency cost (1000$)	30,520	30,520	30,520	30,520	30,520

Associated with each 10-MW increment of capacity savings is an estimated 59 GWh/yr of energy savings, based on a load factor of 67% from the SWEEP study. After five years of efficiency programs, these programs would result in 293 GWh of savings in each year.

The efficiency savings are assumed to cost $40/MWh. This cost includes roughly $30/MWh from the electric company and $10/MWh from the participating customer. The estimate of $40/MWh is based on the full lifetime savings from efficiency measures. At this cost of saved energy, there will need to be roughly $30 million dollars per year invested in energy efficiency in order to save 10 MW and 59 MWh per year.

These annual expenditures are allocated to three customer sectors (residential, commercial, and industrial) for three different types of efficiency programs (new construction, appliances, and retrofit). Table 9-7 presents the portion of the total expenditures that are assumed to be invested in each of the sectors and in each of the program types.

The allocation of expenditures by program type (in percentage terms) is based on typical utility efficiency programs that are both mature and comprehensive. That is, the programs seek to address all cost-effective efficiency markets, and makes programs available to all customer types.

Table 9-7 — Investment by Sector

Annual Expenditures by Program Type (1000$):				Allocation of expenditures by program type:			
	New Construction	Appliances	Retrofit	NC	Appliances	Retrofit	Total
Residential	3,052	4,578	3,052	10%	15%	10%	35%
Commercial	6,104	3,052	4,578	20%	10%	15%	45%
Industrial	1,526	1,526	3,052	5%	5%	10%	20%
Total	10,682	9,156	10,682	35%	30%	35%	100%

Finally, the annual expenditures by program type are allocated to different types of goods and services, for the purposes of modeling their impact on the economy. Table 9-8 presents the assumptions of the percentages of annual expenditures that will flow to the different types of goods and services, and Table 9-9 presents the annual expenditures that result from these assumptions.

Table 9-8 — Percentages of Allocation of Expenditures to Types of Goods and Services

Percentage allocation of expenditures:			
	NC	Appliances	Retrofit
Residential:			
Labor	40%	10%	30%
Lighting	10%	50%	30%
Refrigeration	5%	20%	20%
HVAC	45%	20%	20%
Commercial:	---	---	---
Labor	40%	10%	30%
Lighting	15%	50%	40%
Refrigeration	5%	20%	15%
HVAC	40%	20%	15%
Industrial:	---	---	---
Labor	40%	10%	30%
Lighting	15%	40%	20%
Refrigeration	5%	10%	15%
HVAC	40%	10%	15%
Miscellaneous / n	0%	30%	20%

Table 9-9 — Annual Expenditures by Types of Goods and Services ($000s)

Annual Expenditures by Type of Goods and Services:	New Construction	Appliances	Retrofit
Residential:			
Labor	1,221	458	916
Lighting	305	2,289	916
Refrigeration	153	916	610
HVAC	1,373	916	610
Commercial:	---	---	---
Labor	2,442	305	1,373
Lighting	916	1,526	1,831
Refrigeration	305	610	687
HVAC	2,442	610	687
Industrial:	---	---	---
Labor	610	153	916
Lighting	229	610	610
Refrigeration	76	153	458
HVAC	610	153	458
Miscellaneous	0	458	610
Totals	10,682	9,156	10,682
All Sector Totals:			
Labor	4,273	916	3,205
Lighting	1,450	4,425	3,357
Refrigeration	534	1,679	1,755
HVAC	4,425	1,679	1,755
Miscellaneous	0	458	610

As noted earlier, the assumptions in Table 9-8 are based on typical utility programs that are both mature and comprehensive. Thus, the programs are assumed to address a variety of cost-effective end-uses and measures, specifically ones that prevent cream-skimming and, therefore, promote efficiency across lighting, refrigeration, HVAC, and miscellaneous industrial end-uses such as motors.

Nonetheless, it is assumed that lighting measures will be a large portion of the efficiency investments, because these measures are very cost effective and readily available. HVAC measures will also be a large portion of the efficiency investments, particularly in the new construction sector, because of the high degree of air conditioning in the region and the relatively rapid growth in homes and businesses in the region.

It is also assumed that these programs will be managed by an electric utility, but that it will be agreed in advance that the utility will hire a tribal-based energy service company to perform a certain portion of the energy auditing and efficiency installation and retrofitting activities. Specifically, it is assumed that about 10% of the audit and measure installation services delivered by the program will be on customer premises within normal contractor travel distances from the Navajo reservation and, therefore, will be delivered via a tribal-based energy service company described above. In addition, we assume, for illustrative modeling purposes, that of the approximately 10% of work performed by that tribal-based energy service company, about two-tenths (i.e., 2% of the total program) will actually be performed on one or both reservations.[14]

It is estimated that approximately 10% of the program delivery, with a total wage bill of $750,000, would employ approximately 15 energy efficiency specialists based in Apache County, Arizona, close to the Arizona/New Mexico state line. The modeling does not, however, reflect, any additional labor input required to provide training for those energy efficiency specialists.

The labor categories in Table 9-7 and Table 9-8 include the labor associated with the utility's administration, marketing, and monitoring and evaluation activities, as well as the energy service company's labor.

Even though these energy service company employees will be based on the Navajo reservation, the economic impacts of this are diluted by the fact that much of their time and associated expenditures will occur in the most heavily populated urban areas of Arizona and New Mexico. As a result, only about half of the income generated by these activities is assumed to be retained as a direct local economic input.

It is also assumed that certain aspects of the program, especially the residential lighting and appliance portions, will rely on mail order of efficient goods and fulfillment of rebates for point-of-sale and coupon discounts. Therefore, an order-fulfillment and distribution facility will be associated with this program. For this study, we assumed that this facility will be operated on reservation land (also located in Apache County, Arizona, for economic modeling purposes) employing approximately 16 persons, with a total wage bill of $800,000. We do not mean to imply that this would actually be the best or most likely location on the two reservations for such a facility, only that it is a plausible location that was used for modeling purposes.

9.4.3 Economic Impact Model Methodology and Specification

The economic model used to perform all eight simulations and variants was developed by Regional Dynamics, Inc. (REDYN), based in Phoenix, Arizona. The REDYN model is a dynamic, multi-regional, nonlinear, endogenous, Input-Output (I/O), computable general equilibrium (CGE) economic and demographic model based on the North American Industrial Classification System (NAICS). The model is based on I/O methodology, with detailed make and use tables and social accounting matrix features for all entities, a

[14] These shares were based on county and regional shares of population, total nonagricultural employment and manufacturing and mining employment. Reservation shares were based solely on population shares of each of the six reservation counties in the year 2000. While it is recognized that this approach may overstate the demand for some energy efficiency products, due to the relatively low rural electrification rates and household incomes on the

comprehensive commodity production transformation function, and impedance-based commodity trade flows developed by Oak Ridge National Laboratories.

The REDYN model incorporates advances in New Economic Geography (NEG) to calculate all local and multi-regional trade flow effects due to direct and endogenous changes in demand for supplies, other resources, and final goods and services. The model includes active regions for more than 3,100 U.S. counties, 700 industries, 820 occupations, hundreds of commodities, and a 50-year forecast horizon in a 2-terabyte database.

The model estimates employment, output, wages, occupations, income, gross product, demand, self-supply, trade flows, and demographic impacts associated with user-defined economic events, such as the eight subject scenarios. All model inputs associated with these scenarios were developed with consultation from the REDYN model architect and the Synapse Energy Economics project manager.

The REDYN model constructed for this analysis consists of nine county-defined regions:

- Apache County, Arizona
- Coconino County, Arizona
- Navajo County, Arizona
- Balance-of-State, Arizona
- McKinley County, New Mexico
- San Juan County, New Mexico
- Balance-of-State, New Mexico
- San Juan County, Utah
- Balance-of-State, Utah

Thus, Arizona is divided into four regions (one for each reservation county and one for the rest of the state); New Mexico is divided into three regions (again, one for each reservation county and one for the rest of the state); and Utah into two regions (one for San Juan County and one for the rest of the state).

The model simulations make no assumptions regarding plant ownership and associated profits, royalties, leasing arrangements, or special taxes or fees. It should be noted that tribal ownership of these facilities or payment of

reservation lands, this may be offset by understated demand associated with industrial efficiency work associated with mining and associated operations on royalty, lease, and fee revenues could yield substantial additional income streams and related local economic benefits for the Navajo and Hopi tribes and the surrounding counties.

Due to very limited tribal data available, model extensions to estimate Hopi and Navajo reservation impacts were limited to sharing algorithms applied to REDYN model output, based on benchmark population, employment, and other economic and demographic data. That is, for each type of job created in the reservation counties, a portion was allocated to each of the tribes. For some types of jobs, the allocation was based on the population of each tribe compared to the total county population. For others, the allocation was based on project-specific data that affected tribal employment shares. Tribal population shares were adjusted in each model simulation to reflect tribal hiring preference laws and the mix of skill levels associated with various employment categories for both plant construction and operational periods. Given current tribal experience in the management and operation of energy production facilities, it was assumed that tribal employment shares at similar proposed facilities on or near reservation land would equal 80% of total direct plant employment, slightly above levels at existing facilities now operating near the edge of reservation lands. [15]

9.4.4 Summary of Economic Impacts

All of the economic impacts shown in Table 9-10 below represent total employment impacts, including direct, indirect, and induced jobs[16]. All employment impacts are expressed as incremental changes in employment above baseline economic model projections.

- **Simulation 1: Integrated Gasification Combined Cycle (IGCC).** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are expected to total more than 330 jobs per year. Depending upon preferential hiring practices and job training provisions, at least 200 of these positions would be likely to be filled by Navajo or Hopi tribal members. Employment gains during the

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reservation lands.

[15] The net impact of these modifications varied in the nine simulations due to the number of jobs estimated in each county by the REDYN model, the types of jobs estimated and specific information associated with each potential project. During the construction phase, the net effect of these adjustments served to increase the tribal share of employment in the six counties encompassing the Hopi and Navajo reservations as follows: Simulations 1 and 1A, from 32% to 65%; Simulation 2, from 33% to 37%, Simulation 3, from 33% to 44%, Simulation 4, from 27% to 51%, Simulations 5-7, from 27% to 51%, and Simulation 8, from 56% to 96%. During the operational phase of each project, these shares increased as follows: Simulation 1, from 33% to 60%, Simulation 1A, from 33% to 56%, Simulation 2-3, from 33% to 45%, Simulations 4-6, from 24% to 68%, and Simulation 7, from 24% to 72%.

[16] Employment multipliers in the REDYN model vary by type of employment (or investment category), and county/region. Because model simulation inputs were often dollar-based investment values and not employment counts, especially during the construction phase, simple employment multipliers are not available. For example, in Simulation #3, the addition of 118 direct jobs per year associated with plant operation and maintenance in Navajo County results in 153 jobs in Navajo County, a net multiplier of 1.29, 244 jobs in the six counties encompassing the Hopi and Navajo reservations, a net multiplier of 2.06, and 665 jobs in the three state region, a net multiplier of 5.63.

four-year plant construction period will total approximately 215 new jobs, with about two-thirds of these (approximately 140) expected to be among tribal members on the two reservations.

- **Simulation 1, Variant 1A: Integrated Gasification Combined Cycle (IGCC) with coal inputs from Navajo County.** Construction phase economic impacts for this variant are identical to those in Simulation 1. Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations, however, are expected to total 565 positions, as coal mining jobs in Navajo County to supply fuel for the plant are included. Assuming approximately 80% of the plant operation personnel and 90% of the incremental mining operation jobs are tribal members, about 280 of these positions are estimated to be Navajo nation members, with about 40 positions to be held by Hopi tribal members.

- **Simulation 2: Solar Parabolic Trough.** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 180 positions, with average annual employment during the two-year construction period exceeding 725 jobs. The magnitude of this project, its compressed construction schedule, and significant on-site assembly work is estimated to result in the largest single-year construction impacts of any of the contemplated projects. Tribal employment during the two-year construction phase is estimated to total about 530 annual jobs, with about 495 of these estimated to be filled by Navajo tribal members and about 40 by Hopi tribal members.

- **Simulation 3: Stirling Engine/Dish.** Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to exceed 240 jobs per year, with average annual construction employment during the three-year construction period of about 475 jobs in the same six counties. This project is estimated have significant on-site assembly work and related employment opportunities for tribal members, representing more than 210 jobs per year during the construction period. During operation, this facility is estimated to generate nearly 110 jobs for tribal members in the six counties encompassing the Navajo and Hopi reservations, most of which will be in Navajo County, where the plant would be located.

- **Simulation 4: Wind Turbines, Gray Mountain.** Although construction-related employment associated with this project is estimated to exceed 350 jobs per year during the two-year construction period, total permanent employment impacts following completion of this wind turbine facility in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 21 jobs per year. About two-thirds of these permanent jobs are estimated to accrue to tribal members.

- **Simulation 5: Wind Turbines, Aubrey Cliffs.** Tribal employment growth during the one year construction phase of the Aubrey Cliff wind turbines is estimated to total about 65 jobs, with permanent tribal job growth of about 4 positions. Total permanent employment impacts following completion of the plant in the six counties encompassing the Navajo and Hopi reservations are estimated to total 6 jobs.

- **Simulation 6: Wind Turbines, Clear Creek.** Total construction-related job growth in the six counties encompassing the Navajo and Hopi reservations during the one-year construction of the Clear Creek wind turbines is estimated to total approximately 115 jobs, with about 50 of these likely to be among tribal members. Permanent employment gains associated with this facility is estimated to total about 17 in the entire New Mexico/Arizona/Utah region, with about 6 of these in the six-county reservation area.

- **Simulation 7: Wind Turbines, Sunshine.** Employment impacts associated with the Sunshine wind turbine facility are estimated to be the lowest among the nine scenarios contemplated. With a total investment value of about $91 million, this facility is estimated to result in about 90 new jobs in the six counties encompassing the Navajo and Hopi reservations during the one-year construction phase. Total permanent employment impact in the Arizona/New Mexico/Utah region following completion of the plant is estimated to be about 12 new jobs, with approximately 4 of these in the six-county reservation area. With the facility located on Hopi fee land, it is anticipated that a higher percentage of both construction and operational positions would accrue to Hopi tribal members.

- **Simulation 8: Energy Efficiency Program.** Total employment impacts over the five-year life of the program in the six counties encompassing the Navajo and Hopi reservations are estimated to total about 205 net new annual jobs throughout Arizona and New Mexico, with the most significant job impacts in the balance of Arizona and New Mexico regions. Because the program distribution center and installation crews are assumed for the sake of this simulation to be based in Apache County, on the Arizona/New Mexico border, most of the tribal job growth is estimated to be among Navajo Nation members. About 40 full-time jobs per year during the five-year life of the program are estimated to result from this investment among Navajo tribal members.

Table 9-10 — Employment Impacts

Total Plant Investment

Economic Simulation #	1	1A	2	3[17]	4	5	6	7	8
Total Plant Investment ($ millions)	$1,083	$1,083	$1,066	$730	$711	$155	$116	$91	$153

Construction Phase Total Average Annualized Jobs

Economic Simulation #	1	1A	2	3	4	5	6	7	8
Six Reservation Counties	213	213	727	477	355	156	116	92	41
Navajo Nation	129	129	247	193	170	60	44	35	39
Hopi Tribe	9	9	20	18	12	4	3	2	1
Remainder of Arizona	744	744	3,090	2,778	1,669	733	548	432	426
Remainder of New Mexico	237	237	977	424	222	98	73	57	105
Remainder of Utah	163	163	376	193	270	120	90	71	20

[17] Note: In Simulation 3, some operational impacts begin during the construction period, as operation is phased in.

Economic Simulation #	1	1A	2	3	4	5	6	7	8
Remainder of U.S.	9,573	9,573	19,995	9,591	14,071	6,216	4,647	3,659	1,028
Number of Years to Completion	4	4	2	3	2	1	1	1	5

Construction Phase Total Employment Impact (job-years)

Economic Simulation #	1	1A	2	3	4	5	6	7	8
Six Reservation Counties	852	852	1,454	1,431	710	156	116	92	205
Navajo Nation	515	514	494	579	340	60	44	23	194
Hopi Tribe	36	36	39	53	24	4	3	14	3
Remainder of Arizona	2,976	2,976	6,180	8,334	3,338	733	548	432	2,130
Remainder of New Mexico	948	948	1,954	1,272	444	98	73	57	525
Remainder of Utah	652	652	752	579	540	120	90	71	100
Remainder of U.S.	38,292	38,292	39,990	28,773	28,142	6,216	4,647	3,659	5,140

Operation Phase Total Average Annual Jobs

Economic Simulation #	1	1A	2	3	4	5	6	7	8
Six Reservation Counties	333	565	182	244	21	6	6	4	N/A
Navajo Nation	172	278	72	96	14	4	4	1	N/A
Hopi Tribe	27	41	9	13	1	0	0	2	N/A
Remainder of Arizona	297	581	209	282	22	5	5	4	N/A
Remainder of New Mexico	113	214	82	111	4	1	1	1	N/A
Remainder of Utah	31	59	21	27	2	1	1	0	N/A
Remainder of U.S.	1,909	3,606	1,199	1,619	119	30	30	22	N/A

Last page of Section 9.

10. FINANCIAL ISSUES

This section summarizes those financial incentives that are available to owners and investors of electric generation facilities. The incentives are broken down into two general categories:

- Those directed towards the commercialization of specific generation technologies of interest in the Mohave Alternatives/Complements Study (including IGCC, wind, solar, NGCC, and energy efficiency);
- Those directed towards tribal activities or to economic development activities for which tribes are likely to be eligible. For this study, this category specifically focuses on financial incentives directed towards tribal-owned generation facilities and those directed towards low-income communities.

In both cases, financial incentives generally come from the federal or state governments in the form of tax advantages. This include income tax credits, exemptions and deductions for investments, sales tax exemptions on equipment purchases, variable property tax exemptions on the value added by the generation system, production credits based on the quantity of energy produced, job creation credits, and accelerated or special depreciation allowances. Other non-tax incentives generally come in the form of federal, state, and private foundation grants, loans with advantageous terms, or loan guarantee programs. Various forms of technical assistance are also available in some cases. The overall affect of the combined incentives is to help decrease generation costs, increase revenues, and stimulate the construction of new facilities using, perhaps, new technologies that might otherwise be uneconomic or in regions that, for whatever reason, would benefit from an economic boost. This study explores all federal incentives, plus state incentives in Nevada, New Mexico, and Arizona.

The applicability of each of the incentives depends not only on the nature of the business, but also on the type of owner(s) and the specific legal relationship of the owner(s) to the electric generation project. In other words, different legal entities qualify for different incentives.

All in all, the value of the financial incentives and the movement of monies directed towards development is significant (potentially tens of millions of dollars annually for some types of projects or recipients) and can truly drive not only specific types of generation but also their geographic location.

The following section reviews various financial incentives that are potentially available. The next section details information on business classifications. Thereafter, there is a section that looks at hypothetical packages of financial incentives directed at specific technologies/business entities.

10.1 FINANCIAL INCENTIVES

10.1.1 Methodology

This subsection reviews incentives available to different types of supply and demand-side technologies along with incentives directed towards tribal activities and towards economic development, in general. The list of incentives was developed by reviewing the following sources:

- The Domenici-Barton Energy Policy Act of 2005 (EPACT 2005)
- Various Internal Revenue Service income tax forms
- USDA, DOE, and U.S. Small Business Administration websites
- Federal Grants Wire website
- The Database of State Incentives for Renewable Energy (DSIRE), which is an ongoing project of the Interstate Renewable Energy Council (IREC), funded by the U.S. Department of Energy and managed by the North Carolina Solar Center.
- Community Development Financial Institutions Fund website
- The Administration for Native Americans (ANA) website
- The Minority Business Development Agency website
- Indian Community Development Block Grant website
- Buzgate website: Buzgate is a business-to-business resource portal that provides information, goods, and services tailored to small and medium sized businesses.
- City of Henderson, Nevada website: lists many economic development opportunities.
- EDAWN website: EDAWN (Economic Development Authority of Western Nevada) is a private/public partnership committed to recruiting and expanding quality companies that have a positive economic impact on the quality of life in the western Nevada region.
- Various papers including Nancy Pindus's "Overcoming Challenges to Business and Economic Development in Indian Country, " presented to the Department of Health and Human Services: Office of the Assistant Secretary for Planning and Evaluation, August 2004.
- Various additional documents and websites.

A series of tables has been developed, – one for each technology alternative considered in this study, and one for economic development incentives. The tables are laid out in similar formats, with information regarding the eligible technology, name of the incentive program, the dollar amount of the incentive, terms associated with the program, the program administrator, eligible recipients, and the effective dates that the incentive is in place.

10.1.2 Technology-Specific Financial Incentives

Table 10-1 — IGCC Incentives

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
IGCC	EPACT 2005, Section 1307. Credit for Investment in Clean Coal Facilities	Tax Credits	Up to $800 million for IGCC projects and up to $500 million for other advanced coal-based technologies and up to $350 million for industrial gasification.	(1) 20% credit for industrial gasification projects, (2) 20% credit for integrated gasification combined-cycle (IGCC) electric generation projects, and (3) 15% credit for other advanced coal-based projects that produce electricity. The Federal share of the cost of a coal or related technology project funded by the Secretary cannot exceed 50%.	Secretary of Energy	The project must be located in the United States.	2006-2014
IGCC	EPACT 2005, Section 414, Coal Gasification	Loan Guarantees	The DOE Secretary shall provide guarantees for no more than $2 billion at any time.	Plants must be at least 400 MW in capacity. Power must be sold to the deregulated marketplace (the generation facility cannot receive any subsidy from ratepayers.) The guarantees can only be for 80% of the cost of a project.	Secretary of the Interior	Not specified	Not specified
IGCC	EPACT 2005, Section 1701, Incentives for Innovative Technologies	Loan Guarantees	Not specified	A guarantee shall not exceed an amount equal to 80% of the project cost of the facility. Maximum of 30 year loan; maximum of 90% of the projected useful life of the project to be financed; must have design that accommodates carbon capture	Secretary of Energy	Gasification projects, as well as others	Not specified
IGCC	EPACT 2005, Section 1301, Extension and Modifications of Renewable Electricity Production Credit	Tax Credits	The Tax Act extends the availability of the Section 45 energy credit. Two new qualifying energy resources are added: hydropower and Indian coal. The credit for electricity generated from a hydropower facility is reduced by 50%, however. For Indian coal	Eligible Technologies: Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration, Refined Coal, Indian Coal, Anaerobic Digestion, Small Hydroelectric; A business can take the credit by completing Form 8835, "Renewable Electricity Production Credit,"	Secretary of Energy, U.S. Treasury	Commercial and Industrial sectors	Through January 1, 2008

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			facilities, there is a seven-year credit period. Indian coal production facilities will receive an increase in tax credit during the 7-year period beginning January 1, 2006 in the amount of $1.50/ton through 2009, and $2.00/ton after 2009.	and Form 3800, "General Business Credit."			

Table 10-2 — Natural Gas CC Incentives

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Natural Gas CC	EPACT 2005, Section 1327. Arbitrage rules not to apply to prepayments for natural gas.	Tax exempt bonds	Not specified	Tax exempt bonds for pre-payment towards natural gas contracts.	Secretary of Energy	*still under study and possibly not applicable to SCE or tribes. Applies to any contract to acquire natural gas for resale by a utility owned by a governmental unit	Applies to obligations after 8/8/2005

Table 10-3 — Carbon Sequestration Incentives

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Carbon Sequestration	EPACT 2005, Section 2602, Indian Energy Education Planning and Management Assistance	Grants for energy education, research and development, planning and management needs	$20,000,000 per year	Programs focus is: energy efficiency, studies that support tribal acquisitions of energy related activities; planning, construction, operations, maintenance of electrical and T&D facilities on Indian Lands, carbon sequestration; Priority will be given to tribes with adequate electric service (as determined by the Director.)	Director of the Office of Indian Energy Policy and Programs, Department of Energy	Indian tribes	2003-2016
Carbon Sequestration	EPACT 2005, Section 1701, Incentives for Innovative Technologies	Loan Guarantees	Not specified	A guarantee shall not exceed an amount equal to 80% of the project cost of the facility. Maximum of 30-year loan.	Secretary of Energy	Carbon capture and sequestration practices and technologies, including agricultural and forestry practices that store and sequester carbon	Not specified
Carbon Sequestration	Enhanced Oil Recovery Tax Credit: IRS Form 8830	Tax Credits	15% tax credit for costs associated with a qualified enhanced oil recovery project, including cost of the CO_2 injectant, cost of depreciable, tangible property, and cost of intangible drilling related to the project.	The 15% credit is reduced when the reference price per barrel of oil exceeds the base value of $28 (as adjusted by inflation.) For 2004, there was no reduction of the credit. Not applicable to those paying alternative minimum tax (AMT).	U.S. Treasury	Those filing income taxes with IRS	1990

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Carbon Sequestration	Proposed H.R.1128	Tax Credits	Amends the Internal Revenue Code to allow a business tax credit for amounts of Sets the credit amount at 75 cents (adjusted for inflation) per 1,000 standard cubic feet of the carbon dioxide captured.	Qualified carbon dioxide must be from anthropogenic industrial sources (e.g., an ethanol plant, fertilizer plant, or chemical plant) and used as a tertiary injectant in enhanced oil and natural gas recovery.	U.S. Treasury	Those filing taxes with IRS	Latest Major Action: 3/3/2005 Referred to House committee. Status: Referred to the House Committee on Ways and Means.

Table 10-4 — Energy Efficiency Incentives

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Energy Efficiency	EPACT 2005, Section 2602, Indian Energy Education Planning and Management Assistance	Grants for energy education, research and development, planning and management needs	$20,000,000 per year	Programs focus is: energy efficiency, studies that support tribal acquisitions of energy related activities; planning, construction, operations, maintenance of electrical and T&D facilities on Indian Lands, carbon sequestration; Priority will be given to tribes with adequate electric service (as determined by the Director.)	Director of the Office of Indian Energy Policy and Programs, Department of Energy	Indian tribes	2003-2016
Energy Efficiency	EPACT 2005, Sec. 126. Low Income Community Energy Efficiency Pilot Program	Grants	$20 million annually	Monies issued for--(1) investments that develop alternative, renewable, and distributed energy supplies;(2) energy efficiency projects and energy conservation programs;(3) studies and other activities that improve energy efficiency in low income rural and urban communities;(4) planning and development assistance for increasing the energy efficiency of buildings and facilities; and(5) technical and financial assistance to local government and private entities on developing new renewable and distributed sources of power or combined heat and power generation.	Secretary of Energy	Units of local government, private, non-profit community development organizations, and Indian tribe economic development entities	2006-2008
Energy Efficiency	USDA Renewable Energy Systems and Energy Efficiency Improvements Program , Section 9006 of the 2002 Farm Bill	Guaranteed Loan Funds/ Grants	2005 funding: up to $200 million; Grants: 25% of eligible project costs; Guaranteed loans: 50% of eligible project costs ; maximum grant: Grants: $500,000 per renewable-energy project; maximum guaranteed loans: $10 million (pending)	The guarantees can only be for 80% of the cost of a project; developers will share in the risk.	USDA	Funds are targeted towards agricultural producers and small rural businesses. Biomass (including anaerobic digesters), geothermal, hydrogen, solar, and wind energy, as well as energy efficiency improvements. Eligible participants: · A	2003-2007

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
						private entity including a sole proprietorship, partnership, corporation, cooperative (including a cooperative qualified under section 501(c)(12) of the Internal Revenue Code, and an electric utility, including a Tribal or Governmental Electric Utility that provides service to rural consumers on a cost-of service basis without support from public funds or subsidy from the Government authority establishing the district. These entities must operate independent of direct Government control.	

10.1.3 Renewable Energy Incentives

Table 10-5 — Federal Incentives for Renewables

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Renewable Energy	USDA Renewable Energy Systems and Energy Efficiency Improvements Program, Section 9006 of the 2002 Farm Bill	Guaranteed Loan Funds/ Grants	2005 funding: up to $200 million; Grants: 25% of eligible project costs; Guaranteed loans: 50% of eligible project costs ; maximum grant: Grants: $500,000 per renewable-energy project; maximum guaranteed loans: $10 million (pending)	The guarantees can only be for 80% of the cost of a project; developers will share in the risk. Funds are targeted towards agricultural producers and small rural businesses. Biomass (including anaerobic digesters), geothermal, hydrogen, solar, and wind energy, as well as energy efficiency improvements.	USDA	Eligible participants: · A private entity including a sole proprietorship, partnership, corporation, cooperative (including a cooperative qualified under section 501(c)(12) of the Internal Revenue Code, and an electric utility, including a Tribal or Governmental Electric Utility that provides service to rural consumers on a cost-of service basis without support from public funds or subsidy from the Government authority establishing the district. These entities must operate independent of direct Government control.	2003-2007
Renewable Energy	EPACT 2005: Section 54 holders of clean renewable energy bonds	Tax Credits from Bond Issuances	Bonds designated specifically for "Clean Renewable Energy." The credit rate on the bonds will be determined by the Secretary of the Treasury and will be a rate that permits issuance of CREBS, an interest-free loan –	95% of proceeds from the bond issuance must be used to finance capital expenditures incurred for qualifying facilities. The credit will be includable in gross income (as if it were an interest payment on the bond) and can be claimed against regular income tax	Secretary of Energy and Secretary of Treasury	Qualified issuers include governmental bodies (including Indian tribal governments) and mutual or cooperative electric companies.	January 1, 2006 ton December 31, 2008

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			that is, without original issue discount and at a 0% interest rate. A national limitation of $1 billion of CREBS is available to qualified projects.	liability and alternative minimum tax liability.			
Renewable Energy	EPACT 2005: Section 202, Renewable Energy Production Incentive Program	Production Incentive	Production credits vary by technology. They are based on kilowatt-hours of generated electricity; For any facility, the amount of such payment shall be 1.5 cents per kilowatt hour, adjusted for inflation for each fiscal year beginning after calendar year 1993. No maximum specified regarding total amount of funding availability	Qualifying facilities: solar, wind, biomass, or geothermal energy, landfill gas, livestock methane, ocean	U.S. Treasury and Secretary of Energy	A not-for-profit electric cooperative, a public utility, a State, Commonwealth, territory, or possession of the U.S., or the District of Columbia, or a political subdivision, an Indian tribal government or subdivision, or a Native Corporation	2006-2026
Renewable Energy	EPACT 2005, Section 1301, Extension and Modifications of Renewable Electricity Production Credit	Tax Credits	The Tax Act extends the availability of the Section 45 energy credit for two years (through December 31, 2007) for electricity produced from renewable resources, for all except solar facilities (expires December 31, 2005) and refined coal facilities (expires December 31, 2008). It extends the credit period from five to ten years for qualifying facilities placed in service after August 8, 2005. Two new qualifying energy resources are added: hydropower and Indian coal. The credit for electricity generated from a hydropower facility is reduced by 50%, however. For Indian coal facilities, there is a seven-year credit period. Indian coal production facilities will receive	Eligible Technologies: Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration, Refined Coal, Indian Coal, Anaerobic Digestion, Small Hydroelectric; A business can take the credit by completing Form 8835, “Renewable Electricity Production Credit,” and Form 3800, “General Business Credit.”	Secretary of Energy, U.S. Treasury	Commercial and Industrial sectors	Through January 1, 2008

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			an increase in tax credit during the 7-year period beginning January 1, 2006 in the amount of $1.50/ton through 2009, and $2.00/ton after 2009.				
Renewable Energy	EPACT 2005, Section 1701, Incentives for Innovative Technologies	Loan Guarantees	Not specified	A guarantee shall not exceed an amount equal to 80% of the project cost of the facility. Maximum of 30 year loan.	Secretary of Energy	Projects include renewable energy systems and others	Not specified
Renewable Energy	EPACT 2005, Sec. 126. Low Income Community Energy Efficiency Pilot Program	Grants	$20 million annually	Monies issued for--(1) investments that develop alternative, renewable, and distributed energy supplies;(2) energy efficiency projects and energy conservation programs;(3) studies and other activities that improve energy efficiency in low income rural and urban communities;(4) planning and development assistance for increasing the energy efficiency of buildings and facilities; and(5) technical and financial assistance to local government and private entities on developing new renewable and distributed sources of power or combined heat and power generation.	Secretary of Energy	Units of local government, private, non-profit community development organizations, and Indian tribe economic development entities	2006-2008
Renewable Energy	Energy Policy Act of 2005 (Section 1336 - 1337), Business Solar Investment Tax Credit, Credit For Business Installation Of Qualified Fuel Cells And Stationary Microturbines	Tax Credits	Currently 10% for geothermal electric and solar; from January 1, 2006 until December 31, 2007, the credit is 30% for solar, solar hybrid lighting, and fuel cells, and 10% for microturbines. The geothermal credit remains at 10%. Maximum incentive: $550 per 0.5 kW for fuel cells; $200/kW for microturbines; no maximum specified for other technologies	Microturbines must be less than 2 MW; fuel cells must be at least 0.5 kW; eligible technologies: Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Geothermal Electric, Fuel Cells, Solar Hybrid Lighting, Direct Use Geothermal, Microturbines	Secretary of Energy and Secretary of Treasury	Those businesses filing taxes with IRS	1/1/2006-12/31/2007

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Renewable Energy	26 USC § 168, UNITED STATES CODE SERVICE TITLE 26. INTERNAL REVENUE CODE SUBTITLE A. INCOME TAXES Modified Accelerated Cost-Recovery System. (MACRS)	Depreciation	Businesses can recover investments in solar, wind and geothermal property through depreciation deductions. The MACRS establishes a set of class lives for various types of property, ranging from three to 50 years, over which the property may be depreciated. In the case of investments on Indian Property: recovery period is: 3-year property ....2 years 5-year property ....3 years 7-year property ....4 years 10-year property ....6 years 15-year property ....9 years 20-year property ....12 years Nonresidential real property .... 22 years.	Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Geothermal Electric.;	U.S. Treasury	Those businesses filing taxes with IRS	1986
Renewable Energy	EPACT 2005, Section 210.	Grants	$50,000,000 annually	Grants to improve the commercial value of forecast biomass for electric energy, useful heat, transportation fuels, and other commercial purposes	Secretary of Energy	Any Indian tribe is eligible, as are towns, townships, municipalities, local governments, and counties	2006-2016
Renewable Energy	DOE's Office of Energy Efficiency and Renewable Energy's Tribal Energy Program	Grant	The FY2004 program budget included $6 Million, and 2.5 million in funding for 18 tribes for FY2005.	Financial and technical assistance to tribes for feasibility studies and shares the cost of implementing sustainable renewable energy installations on tribal lands. This program seeks to promote tribal energy self-sufficiency and fosters	Department of Energy, Office of Energy Efficiency and Renewable Energy	Tribal government	Not specified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
				employment and economic development on America's tribal lands			
Renewable Energy	USDA: Value Added Producer Grants	Grants	A total of $14.3 million in grants was allocated for fiscal year 2005' Grant awards for fiscal year 2005 supported energy generated on-farm through the use of agricultural commodities, wind power, water power or solar power. The maximum award per grant was $100,000 for planning grants and $150,000 for working capital grants. Matching funds of at least 50% were required.	"On-farm" Biomass, wind, water power, solar	USDA	Value-Added Producer Grants are available to independent producers, agricultural producer groups, farmer or rancher cooperatives, and majority-controlled producer-based business ventures	Not specified
Renewable Energy	The Farm Security and Rural Investment Act of 2002 (2002 Farm Bill): USDA Conservation Security Program (CSP) Production Incentive	Grant	The 2005 CSP sign-up includes a renewable-energy component. Eligible producers will receive $2.50 per 100 kWh of electricity generated by new wind, solar, geothermal and methane-to-energy systems. Payments of up to $45,000 per year will be made using three tiers of conservation contracts, with a maximum payment period of 10 years.	Wind, solar, geothermal, methane-to-energy systems. The goal is to promote the conservation and improvement of soil, water, air, energy, plant and animal life, and other conservation purposes on Tribal and private working lands. Working lands include cropland, grassland, prairie land, improved pasture, and range land, as well as forested land that is an incidental part of an agriculture operation.	USDA's Natural Resources Conservation Service	Farmers; The program is available in all 50 States, the Caribbean Area and the Pacific Basin area. The program provides equitable access to benefits to all producers, regardless of size of operation, crops produced, or geographic location.	Not specified

Table 10-6 — State Incentives for Renewables

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Nevada							
Renewable Energy	Nevada Administrative Code, NAC 704.8901 through NAC 704.8937, Nevada Renewable Energy Credits	Tax credits for production	Varies; Higher value for solar RECs than other technologies; "Renewable energy credit" means a unit of credit which: 1. Equals 1 kilowatt-hour of electricity generated by a renewable energy system. 2. For a solar facility that reduces the consumption of electricity by the generation of solar energy, equals the amount of consumption of electricity, natural gas or propane that is reduced at the facility by the operation of the solar facility. 3. For a net metering system, equals the amount of metered electricity generated by the system or, if the system does not use a meter to measure the kilowatt-hours of electricity generated by the system, equals the estimate of the electricity generated by the system	Passive Solar Space Heat, Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Solar Pool Heating	Nevada Public Utilities Commission of Nevada	Commercial, Industrial, Residential, Nonprofit, Schools, Local Government, Utility, State Government, Tribal Government, Agricultural, Institutional	Effective through June 30, 2007
Renewable Energy	NEVADA REVISED STATUTES ANNOTATED TITLE 32. REVENUE AND TAXATION CHAPTER 361. PROPERTY TAX Nevada's	Property tax abatement	50% property tax abatement for real and personal property used to generate electricity from renewable energy.	The exemption may be taken over a 10 year period for a facility with a generating capacity of at least 10 kW. Renewable energy includes biomass, solar, and wind. The definition of biomass includes agricultural crops and agricultural wastes and residues; wood and wood wastes and residues; animal wastes; municipal wastes; and aquatic plants.	Nevada Commission on Economic Development and Nevada Department of Taxation	Commercial, Utility, (Renewable Energy Power Producers)	2001 to unspecified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	Renewable Energy Producers Property Tax Abatement						
Renewable Energy	TITLE 32. REVENUE AND TAXATION, Ch. 361. Property tax assessment § 361.079 Renewable Energy Systems Property Tax Exemption	Property Tax Exemption	In Nevada, any value added by a qualified renewable-energy system shall be subtracted from the assessed value of any residential, commercial or industrial building for property tax purposes. 100% exemption.	Qualified equipment includes solar, wind, geothermal, solid waste and hydroelectric systems. This exemption applies for all years following installation.	Nevada Department of Taxation	Commercial, Industrial, Residential	Not specified
Renewable Energy	NEVADA ASSEMBLY BILL No. 3, Renewable Energy/Solar Sales Tax Exemption	Sales Tax Exemption	100% exemption from local sales taxes; 2% state sales tax still applies	Nevada law exempts from local sales and use taxes the sale, storage and consumption of any products or systems designed or adapted to use renewable energy to generate electricity and all of its integral components. Included in the exemption are all sources of energy that occur naturally or are regenerated naturally, including biomass (agricultural crops, wastes and residues, wood, wood wastes, and residues, animal wastes, municipal waste and aquatic plants), fuel cells, geothermal energy, solar energy, hydropower and wind.	Nevada Department of Taxation	Commercial, Residential, General Public/Consumer	Currently set to expire 12/31/05
Arizona							
Renewable Energy	ARIZONA REVISED STATUTES, A.R.S. § 42-5075, TITLE 42. TAXATION, Arizona Solar	Sales Tax Exemption	$5,000 per system for retailers; $5,000 per contract for contractors	Solar/wind retailer or contractor must register with the Arizona Department of Revenue	Arizona Department of Revenue	Commercial contractors	1/1/97-1/11/2011

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	and Wind Equipment Sales Tax Exemption						
New Mexico							
Renewable Energy	HB 995 of 2005: New Mexico Biomass Equipment & Materials Deduction	Sales Tax Exemption	100% of value of biomass equipment and biomass materials used for the processing of biopower, biofuels or bio-based products may be deducted for purposes of calculating Compensating Tax due. New Mexico's Compensating Tax is an excise, or "use" tax, which is typically levied on the purchaser of the product or service for using tangible property in the state.	The tax applies to imports of factory and office equipment, and other items. The rate is 5% of the value of the property or service.	New Mexico Taxation & Revenue Department	Commercial, Industrial taxpayers	4/5/2005 to unspecified
Renewable Energy	House Bill 251 of 2004, New Mexico Clean Energy Grants Program	Grants	Program Budget: $2,000,000 for 2005 RFP; maximum amount: $200,000	Supports the development of renewable energy, energy efficiency, and alternative transportation fuels technologies. Capital projects resulting from the current Request for Proposals will be required to meet performance measures established for the Program, including a 5% reduction in energy consumption in building projects or 15% increase in alternative fuel usage.	New Mexico Energy, Minerals and Natural Resources Department, Energy Conservation and Management Division	Schools, Local Government, State Government, Tribal Government	Unspecified
Renewable Energy	New Mexico Renewable Energy Production Tax Credit	Production Credit, Enacted in 2002, and amended in 2003 by HB 146,	A tax credit against the corporate income tax of one cent per kilowatt-hour for companies that generate electricity from wind, solar, or biomass	The credit is applicable only to the first 400,000 megawatt-hours of electricity in each of 10 consecutive years. To qualify, an energy generator must use a zero-emissions generation technology and have capacity of at least 10 megawatts. Energy generation from all participants combined must not exceed two million megawatt-hours of production annually.	New Mexico Taxation & Revenue Department	Commercial, Industrial taxpayers	2002 to unspecified

10.1.4 Financial Incentives for Tribal Activities and Economic Development – General

These incentives, by definition, include the use of programs, services, and funding to attract new business or to retain and expand existing businesses. This study examined incentives directed specifically towards tribes (who may also qualify for economic development incentives targeted to low-income and rural areas.) These include tax-exempt revenue bonds, federal grant and loan guarantee programs, freedom from liability of federal income tax and more. Those economic incentives that are currently available at the federal level, as well as state initiatives in Nevada, Arizona, New Mexico, and Utah are reviewed below.

Table 10-7 — Currently Available Economic Incentives

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Energy - all resources	EPACT 2005, Section 2602, Indian energy resource development program	Grants to develop or obtain managerial and technical capacity to develop energy on Indian land; grants and low interest loans to promote the integration of energy resources, and to process, use, or develop these energy resources; grants to an tribal environmental organization that represent multiple Indian tribes.	There are authorized "such sums as are necessary"	Activities might include training programs, development of model environmental policies and tribal laws, recommended standards for reviewing implementation of tribal environmental laws and policies	Secretary of the Interior	Indian tribes	2006-2016
Energy Efficiency, conservation, carbon sequestration	EPACT 2005, Section 2602, Indian energy Education Planning and Management Assistance	Grants for energy education, research and development, planning and management needs	$20,000,000 per year	Programs focus is: energy efficiency, studies that support tribal acquisitions of energy related activities; planning, construction, operations, maintenance of electrical and T&D facilities on Indian Lands, carbon sequestration; Priority will be given to tribes with adequate electric service (as determined by the Director.)	Director of the Office of Indian Energy Policy and Programs, Department of Energy	Indian tribes	2003-2016

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Not specified	EPACT 2005, Section 2602, Department of Energy Loan Guarantee Program	Loan Guarantees	The aggregate outstanding amount guaranteed at any time under this section shall not exceed $2 billion	Loans are provided to provide for and expand the provision of electricity on Indian lands. Loan amount cannot be more than 90% of the unpaid principle and interest due on any loan made to an Indian tribe for energy development	Secretary of Energy	Preference will be given to an energy and resource production enterprise, partnership, consortium, corporation, or other business with a majority of interest that is owned and controlled by one or more Indian tribes.	Available under funds are expended
Not specified	EPACT 2005, Section 2603, Indian tribal Energy Resource Regulation	Grants	Not specified	Grants for development of energy resource inventory, feasibility studies, development and enforcement of tribal laws relating to energy, development of technical infrastructure to protect the environment	Secretary of the Interior	Indian tribes	Not specified
Not specified	EPACT 2005, Section 2604. Leases, Business Agreements, and Rights-of-way involving Energy Development or Transmission	Leases and Business Agreements	Unspecified amount; establishes a process by which an Indian tribe, upon demonstrating its technical and financial capacity and receiving approval of their Tribal Energy Resource Agreement, could negotiate and execute energy resource development leases, agreements and rights-of-way with third parties without first obtaining the approval of the Secretary of the Interior.	The tribe may enter leases or business agreements for the purpose of energy resource development on tribal land. Lease agreement cannot exceed 30 years	Secretary of the Interior	Indian tribes	Not specified
Energy Efficiency	EPACT 2005,	Grants	$20 million annually	Monies issued for--(1) investments	Secretary of Energy	units of local	2006-2008

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	SEC. 126. Low Income Community Energy Efficiency Pilot Program			that develop alternative, renewable, and distributed energy supplies;(2) energy efficiency projects and energy conservation programs;(3) studies and other activities that improve energy efficiency in low income rural and urban communities;(4) planning and development assistance for increasing the energy efficiency of buildings and facilities; and(5) technical and financial assistance to local government and private entities on developing new renewable and distributed sources of power or combined heat and power generation.		government, private, non-profit community development organizations, and Indian tribe economic development entities	
Renewable Energy	EPACT 2005: Section 202, Renewable Energy Production Incentive Program	Tax Credits	Production credits vary by technology. They are based on kilowatt-hours of generated electricity; For any facility, the amount of such payment shall be 1.5 cents per kilowatt-hour, adjusted for inflation for each fiscal year beginning after calendar year 1993. No maximum to total amount of funding availability.	Qualifying facilities: solar, wind, biomass, or geothermal energy, landfill gas, livestock methane, ocean	U.S. Treasury and Secretary of Energy	a not-for-profit electric cooperative, a public utility, a State, Commonwealth, territory, or possession of the U.S., or the District of Columbia, or a political subdivision, an Indian tribal government or subdivision, or a Native Corporation	2006-2026
Energy Efficiency/Renewable Energy	USDA Renewable Energy Systems and Energy Efficiency Improvements Program , Section 9006 of the 2002 Farm Bill	Guaranteed Loan Funds/ Grants	2005 funding: up to $200 million; Grants: 25% of eligible project costs; Guaranteed loans: 50% of eligible project costs ; maximum grant: Grants: $500,000 per renewable-energy	The guarantees can only be for 80% of the cost of a project; developers will share in the risk.	USDA	Funds are targeted towards agricultural producers and small rural businesses. Biomass (including anaerobic digesters), geothermal,	2003-2007

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			project; maximum guaranteed loans: $10 million (pending)			hydrogen, solar, and wind energy, as well as energy efficiency improvements. Eligible participants: · A private entity including a sole proprietorship, partnership, corporation, cooperative (including a cooperative qualified under section 501(c) (12) of the Internal Revenue Code, and an electric utility, including a Tribal or Governmental Electric Utility that provides service to rural consumers without support from public funds or subsidy from the Government authority establishing the district. These entities must operate independent of Government control.	
Renewable Energy	DOE's Office of Energy Efficiency and Renewable	Grant	The FY2004 program budget included $6 Million, and 2.5 million	Financial and technical assistance to tribes for feasibility studies and shares the cost of implementing sustainable	Department of Energy, Office of Energy Efficiency	Tribal government	Not specified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	Energy's Tribal Energy Program		in funding for 18 tribes for FY2005.	renewable energy installations on tribal lands. This program seeks to promote tribal energy self-sufficiency and fosters employment and economic development on America's tribal lands.	and Renewable Energy		
Not applicable	Taxpayer Relief Act of 1997: USDA Empowerment Zone and Enterprise Community (EZ / EC) Program	Grants, Tax-exempt bonds, wage credit provision, work opportunity tax credit, Qualified Zone Academy Bonds, Brownfields Deductible Expense, Internal Revenue Code 26 U.S.C. § 179 Expensing:	Grant amount is unspecified; Round III rural zones can each issue up to $60,000,000 in "new bonds" to finance zone facilities in addition to Round I type tax exempt bonds. Round II "new bonds" are not subject to private activity bond volume caps or the special limits on issue size applicable to Round I type issues; 20% tax credit for the first $15,000 in wages paid to a qualified employee (for a tax credit of up to $3,000 per employee).	It addresses a comprehensive range of community problems and issues, including many that have traditionally received little federal assistance, reflecting the fact that rural problems do not come in standardized packages but can vary widely from one place to another; it represents a long-term partnership between the federal government and rural communities—ten years in most cases—so that communities have enough time to implement a series of interconnected and mutually-supporting projects and build the capacity to sustain their development beyond the term of the partnership.	USDA Rural Development	Tribes and others	1997- Dec.31, 2009
Not applicable	USDA / Rural Business Cooperative Service: Federal Agriculture Improvement and Reform Act of 1996	Grant	Unspecified amount.	Grants are targeted towards business and economic development planning, training, etc.			1996- unspecified
Not applicable	USDA / Farm Service Agency, Indian Tribes and Tribal Corporation	Loan Guarantees	$2 million is authorized.	The purpose of this program is to eliminate fractional ownership of lands. Through loans, tribes and tribal corporations can acquire additional	Loan funds cannot be used for any improvement or development	Limited to any Indian tribe recognized by the Secretary of the	Unspecified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	Loans			land. Loan funds may be used to acquire land and interest therein for the benefit and use of the tribe or its members for purposes such as rounding out farming and ranching units or elimination of fractional heir ships. Funds may also be used for incidental costs connected with land purchase such as appraisals, title clearance, legal services, land surveys, and loan closing. Loan funds may be used to refinance non-United States Department of Agriculture preexisting debts that applicant incurred to purchase land subject to certain conditions.	purposes, acquisition or repair of buildings or personal property, payment of operating costs, payment of finder's fees, or similar costs	Interior or tribal corporation established pursuant to the Indian Reorganization Act or community in Alaska incorporated by the Secretary of Interior pursuant to the Indian Reorganization Act which does not have adequate uncommitted funds to acquire lands within the tribe's reservation or in a community in Alaska. The tribe must be unable to obtain sufficient credit elsewhere at reasonable rates and terms and must be able to show reasonable prospects of repaying the loan as determined by an acceptable repayment plan and a satisfactory management plan for the land being acquired.	
Not applicable	HUBZone Act of 1997	Contract preferences	This program provides federal contract preferences to small businesses located in		USDA, HUD, SBA	All Native American lands qualify for preferential treatment.	1997-unspecified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			HUB Zones - historically underutilized business zones. The purpose of the program is to increase employment, capital investment, and economic development in these zones.				
Not applicable	U.S. Treasury Indian Reservation Economic Investment Act of 2001	Tax Credits	Provides tax credits to those investments that promote Indian reservation economic development. Credit is based on the level of unemployment on the reservation.		U.S. Treasury	Unclear	2001-unspecified
Not applicable	U.S. Treasury Indian Employment Tax Credit	Tax Credits	A tax credit is provided to those that employ Native Americans that live on or near a reservation. More specifically, for every Native American employee or employee who is a spouse of a Native American, the employer can claim a credit of 20% of the first $20,000 of wages and medical insurance expense.		U.S. Treasury	Unclear	Unspecified
Not applicable	U.S. Treasury Community Development Financial Institution Fund: Native CDFI, Established under the Reigle	loans, investments, financial services and technical assistance, and training;		The Fund seeks to assist Native Communities to create CDFIs that will primarily serve Native communities as well as to strengthen CDFIs already primarily serving those communities. "Primarily Serves" is defined as 50% or more of the applicant's activities being directed to a Native Community	U.S. Treasury	CDFIs that serve Native communities.	1994 - unspecified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	Community Development and Regulatory Improvement Act of 1994.			(such as a reservation, Alaska Native Village, or Hawaiian Home Land or to Native American, Alaska Native, or Native Hawaiian people). "Native CDFI" is defined as a CDFI that primarily serves a Native Community.			
Not applicable	New Markets Tax Credit	Tax Credits	The project receives a tax credit of 39% of the qualified investment over a 7-year period. The structure of the project is important – can be structured such that the project investor receives credit without controlling the project; in this, taxpayers make equity investments in low-income businesses located in low-income communities. The taxpayer can claim a tax credit equal to 5% of its equity investment of the first three years and 6% over the next four years. (Total 39%)	The taxable investor must create a special purpose entity known as a community development entity (CDE). To do this, the CDE must be classified as either a domestic corporation, a limited liability company, or a partnership with a valid employment identification number. At least 60% of CDE activities must be directed towards serving low-income communities.	U.S. Treasury	The New Markets Tax Credit was devised to encourage third-party investors to invest in low-income communities. Qualifying businesses must therefore be located in a low-income community and have a substantial connection to that low-income community. Reservations qualify and are given some priority.	1994 - unspecified
Not applicable	Small Business Association: Public Law 95-507	Preferential treatment for subcontractors	Requires each public contract to be performed in the United States which exceeds $10,000 in amount to include a clause requiring that small business concerns owned and controlled by socially and economically disadvantaged individuals be given the		SBA	Eligible individuals: (1) Black Americans; (2) Hispanic Americans; (3) Native Americans; (4) other minorities; and (5) other individuals determined by the SBA pursuant to the Small Business Act.	1978-unspecified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
			maximum practicable opportunity to participate in such contracts. Defines such ownership and control as: (1) at least 51% ownership by disadvantaged individuals; and (2) management of such concerns by one or more disadvantaged individuals.				
Not applicable	Department of Commerce: Public Works and Economic	Grants	Investments in facilities such as water and sewer system improvements, industrial access roads, industrial and business parks, port facilities, railroad sidings, distance learning facilities, skill-training facilities, business incubator facilities, redevelopment of brownfields, eco-industrial facilities, and telecommunications infrastructure improvements needed for business retention and expansion.	Eligible projects must fulfill a pressing need of the area and must: 1) improve the opportunities for the successful establishment or expansion of industrial or commercial plants or facilities; 2) assist in the creation of additional long-term employment opportunities; or 3) benefit the unemployed/underemployed residents of the area or members of low-income families.	Department of Commerce	Indian tribes qualify, as well as others	1965 - unspecified
Not applicable	Department of Commerce: Minority Business Development Administration	one-on-one assistance in writing business plans, marketing, management and technical assistance and financial planning	Not specified	Not specified	Department of Commerce: Minority Business Development Agency	Assistance is available to minority business owners (including Native Americans.)	Not specified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
Not applicable	U.S. Department of Housing and Urban Development Indian Community Development Block Grant Program	Grants	Direct grants for use in developing viable Indian and Alaska Native Communities, including decent housing, a suitable living environment, and economic opportunities, primarily for low and moderate income persons.	Wide variety of commercial, industrial, agricultural projects that may be recipient owned and operated or which may be owned and/or operated by a third party.	The program is administered by the six area ONAPs with policy development and oversight provided by the Denver National Program Office of ONAP.	Eligible applicants for assistance include any Indian tribe, band, group, or nation (including Alaska Indians, Aleuts, and Eskimos) or Alaska Native village which has established a relationship to the Federal government as defined in the program regulations. In certain instances, tribal organizations may be eligible to apply.	Not specified
Not applicable	Bureau of Indian Affairs Indian Economic Development	Grants	Unspecified; funds are used to improve Native American economies.	Not specified	Department of the Interior	Tribes	Not specified
Not applicable	U.S. Department of Interior Indian Loans	Direct and guaranteed loans	The Bureau has Credit Reform loan accounts (post 1991) for the Indian Direct Loan Program and Indian Loan Guarantee Program and a Liquidating Fund for loans made before 1992.	Funds are to be used for economic development.	Department of the Interior	Indian tribes and organizations, Indian individuals, and Alaska Natives	Not specified
Not applicable	U.S. Department of Health and Human Services / Administration for	Grants	ANA promotes lasting self-sufficiency and enhances self-government largely		U.S. Department of Health and Human Services	American Indians, Native Americans, Native Alaskans, Native Hawaiians	Not specified

Eligible Technology	Program Name	Incentive Type	Incentive Amount	Terms	Program Administrator	Eligible Recipients	Effective Date
	Native Americans Program: Social and Economic Development Strategies (SEDS)		through grant awards that support social and economic development strategies. These awards are competitive financial assistance grants in support of locally determined and designed projects to address community needs and goals. This approach of promoting self-sufficiency supports native communities in their efforts to reduce dependency on public funds and social services by increasing community and individual productivity through community development. In FY 2003, ANA awarded approximately $20 million for social and economic development projects.			and Pacific Islanders	

In addition to the above, there are a variety of resources that are available to assist local businesses, provide business information, and support specific industry sectors. Many of these are aimed primarily at small business, but may be of interest in connection with tribal enterprises or businesses on or near tribal lands that could supply goods and services to larger projects.

Nevada

- THE NEVADA DEPARTMENT OF EMPLOYMENT, TRAINING AND REHABILITATION (DETR). Provides a number of labor related services to Nevada's job seekers and employers. Services include, but are not limited to, applicant recruitment and screening, career enhancement training program, and provision of labor market information.
- THE COMMUNITY COLLEGE OF SOUTHERN NEVADA, INSTITUTE FOR BUSINESS & INDUSTRY. Offers Corporate and Customized Training to address training and educational needs of Southern Nevada business and industry. This program specializes in developing customized group training to help companies achieve staff development and company performance objectives.
- NEVADA BUSINESS SERVICES. Funded by the U.S. Department of Labor through the Workforce Investment Act to provide employment and training services to eligible residents of four southern Nevada counties. Services that can be offered to employers include new employee assessment, pre-screening and recruitment, on-the-job training and customized training.
- MANAGEMENT ASSISTANCE PROJECT (MAP). Is the industrial extension program of the Nevada System of Higher Education and its partners. Its primary purpose is to work directly with Nevada companies to strengthen their global competitiveness by providing information, decision support and implementation assistance in adopting new, more advanced technologies, techniques and best business practices. MAP focuses on the manufacturing, mining, and construction industries. It provides its knowledge in employee development, specialized worker, supervisory, and managerial training, technology development, business systems improvement, and also provides field engineers to support Nevada industry.
- THE TECHNOLOGY BUSINESS ALLIANCE OF NEVADA (TBAN). Dedicated solely to the development of the high-tech community in Southern Nevada. Through its innovative "Virtual Accelerator" program, TBAN seeks to foster entrepreneurs and attract Venture Capital partners to the region.
- THE NEVADA TECHNOLOGY COUNCIL. Is a membership-supported organization, with a statewide membership base of both private and public sector individuals who are interested in effecting change and affecting policy to enhance technology growth in Nevada. NTC membership includes entrepreneurs, business leaders, technologists, prominent government officials, scientists and involved citizens.
- THE HENDERSON BUSINESS RESOURCE CENTER. Provides business development expertise to new and growing businesses in Southern Nevada. The Business Resource Center

provides opportunities for new and developing companies. Three distinct programs for Applicants, Tenants and Affiliates—support all types of new and existing businesses.

- THE NEVADA SMALL BUSINESS DEVELOPMENT CENTER (SBDC). Provides free and low-cost business management training and counseling for new and expanding businesses throughout Nevada.

- THE NEVADA MICROENTERPRISE INITIATIVE (NMI). A private non-profit community development financial institution founded in 1991 that provides business tools to assist in overcoming barriers that entrepreneurs face in starting or expanding a business. They offer business training, business loans, and networking.

- THE SERVICE CORPS OF RETIRED EXECUTIVES (SCORE) "COUNSELORS TO AMERICA'S SMALL BUSINESS." A source of free and confidential small business advice to help build businesses—from idea to start-up to success. The SCORE Association is a nonprofit association dedicated to entrepreneurial education and the formation, growth and success of small businesses nationwide.

  SCORE's national network of 10,500 retired and working volunteers are experienced entrepreneurs and corporate managers/executives. These volunteers provide free business counseling and advice as a public service to all types of businesses, in all stages of development.

- THE NEVADA PROCUREMENT OUTREACH PROGRAM (POP). Works to increase the flow of contract dollars to Nevada businesses by providing training and technical assistance to find, bid on, and win federal, state and local contracts.

- THE NEVADA COMMISSION ON ECONOMIC DEVELOPMENT (CED). Administers Nevada incentive programs, Nevada's International Trade Program, Procurement Outreach Program (POP), and Nevada Film Office. CED also offers tax information, county statistics, financing options and current information on what's happening in economic development in NV.

- THE COMMUNITY BUSINESS RESOURCE CENTER. Acts as an information provider for business related services for entrepreneurship and enterprise development. CBRC is a recognized leader in community economic development as it works closely with industry, government, and non-profit sector organizations, to assist Nevada small businesses. The services offered by CBRC include direct referral services to resource providers, coordination of work groups addressing economic development issues, and leadership among community development organizations involved in improving the quality of life in Nevada.

- CHURCHILL ECONOMIC DEVELOPMENT AUTHORITY'S (CEDA). This organization's primary goal is to diversify and improve the local economy. This is achieved by trying to expand and grow businesses by providing them with the most current information and assistance possible, including walking them through the various permitting agencies.

- NEW VENTURES CAPITAL DEVELOPMENT COMPANY. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.

- SOUTHERN NEVADA CERTIFIED DEVELOPMENT CORPORATION. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.
- ECONOMIC DEVELOPMENT AUTHORITY OF ESMERALDA/NYE. EDEN is a regional development organization dedicated to building partnerships that foster sustainable economic growth and prosperity in the communities of Esmeralda and Nye Counties.
- EDAWN. The Economic Development Authority of Western Nevada is a private, non-profit corporation that works with primary industry entities to help them relocate, expand, retain or start and grow their businesses.
- NEVADA STATE DEVELOPMENT CORPORATION. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.

Arizona:

- SMALL BUSINESS ADMINISTRATION (SBA) ARIZONA DISTRICT OFFICE. Works to aid, counsel, assist and protect the interests of small business concerns, to preserve free competitive enterprise and to maintain and strengthen the overall economy of our nation.
- PRESTAMOS CDFI, LLC. Provides small loans ranging from under $100 to a maximum of $25,000 to prospective, small business borrowers and backed by the U.S. SBA.
- SELF-EMPLOYMENT LOAN FUND, INC WOMEN’S BUSINESS CENTER. Provides small loans ranging from under $100 to a maximum of $25,000 to prospective, small business borrowers and backed by the U.S. SBA. Also provides training, technical assistance, etc.
- SOUTHWESTERN BUSINESS FINANCING CORPORATION. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.
- ARIZONA DEPARTMENT OF COMMERCE. Offers tax information, county statistics, financing options and current information on what’s happening in economic development in Arizona.
- BUSINESS DEVELOPMENT FINANCE CORPORATION. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.
- FUND A SCIENTIST. A website where individuals or institutions with funding can seek out scientists with innovative projects and provide support.
- PPEP HOUSING DEVELOPMENT CO. Provides small loans ranging from under $100 to a maximum of $25,000 to prospective, small business borrowers and backed by the U.S. SBA.
- SMALL BUSINESS DEVELOPMENT CENTER (SBDC), (with locations at Central Arizona College, Coconino Community College, Mohave Community College, Gila Community

College, Maricopa Community College, Yavapai College, Northland Pioneer College, Cochise College, Eastern Arizona College, pima Community College, Arizona western College). The SBDC works with start-up and existing business owners providing free counseling services on issues such as business planning, registering a business, financing, regulations, licensing, and more.

- SELF-EMPLOYMENT LOAN FUND, INC WOMEN'S BUSINESS CENTER. Provides small loans ranging from under \$100 to a maximum of \$25,000 to prospective, small business borrowers and backed by the U.S. SBA. Also provides training, technical assistance and access to loans for low-income individuals.

- MICROBUSINESS ADVANCEMENT CENTER OF SOUTHERN ARIZONA. Provides training, resources, referrals, support and advocacy to those seeking to create, sustain or grow micorbusinesses in southern Arizona.

- SCORE COUNSELORS TO AMERICA'S SMALL BUSINESS. The Service Corps of Retired Executives (SCORE) "Counselors to America's Small Business" is a source of free and confidential small business advice to help build businesses—from idea to start-up to success. The SCORE Association is a nonprofit association dedicated to entrepreneurial education and the formation, growth and success of small businesses nationwide.

  SCORE's national network of 10,500 retired and working volunteers are experienced entrepreneurs and corporate managers/executives. These volunteers provide free business counseling and advice as a public service to all types of businesses, in all stages of development.

- TUCSON/PIMA COUNTY WOMEN'S BUSINESS CENTER ARIZONA COUNCIL FOR ECONOMIC CONVERSION. Offers three business training tracks including "Growing Business," "Expanding Business," and "Start-up Business." All tracks are supported by a quarterly schedule of short and long-term training.

New Mexico

- SMALL BUSINESS ADMINISTRATION (SBA) NEW MEXICO DISTRICT OFFICE. Works to aid, counsel, assist and protect the interests of small business concerns, to preserve free competitive enterprise and to maintain and strengthen the overall economy of the nation.

- ENCHANTMENT LAND CERTIFIED DEVELOPMENT CORPORATION. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.

- WOMEN'S ECONOMIC SELF-SUFFICIENCY TEAM (WESST). SBA's network of more than 60 Women's Business Centers (WBC) provide a wide range of services to women entrepreneurs at all levels of business development.

- NEW MEXICO ECONOMIC DEVELOPMENT DEPARTMENT. Offers tax information, county statistics, financing options and current information on what's happening in economic development in New Mexico.

- FUND A SCIENTIST. A website where individuals or institutions with funding can seek out scientists with innovative projects and provide support.
- SMALL BUSINESS DEVELOPMENT CENTER (SBDC) (with offices located in NMSU-Alamogordo, Albuquerque, South Valley, New Mexico State University-Carlsbad, Clovis Community College, Northern New Mexico Community College, San Juan College, University Of New Mexico-Gallup, New Mexico State University-Grants, New Mexico Junior College, Las Cruces, Luna Community College, University Of New Mexico-Los Alamos, University Of New Mexico-Valencia, Eastern New Mexico University-Roswell, Santa Fe Community College, Western New Mexico University, Mesalands Community College). The SBDC works with start-up and existing business owners providing free counseling services on issues such as business planning, registering a business, financing, regulations, licensing, and more.
- SCORE COUNSELORS TO AMERICA'S SMALL BUSINESS. The Service Corps of Retired Executives (SCORE) "Counselors to America's Small Business" is a source of free and confidential small business advice to help build businesses—from idea to start-up to success. The SCORE Association is a nonprofit association dedicated to entrepreneurial education and the formation, growth and success of small businesses nationwide.

  SCORE's national network of 10,500 retired and working volunteers are experienced entrepreneurs and corporate managers/executives. These volunteers provide free business counseling and advice as a public service to all types of businesses, in all stages of development.
- BUSINESS INFORMATION CENTER (BIC). provides counseling, access to hardware, software, telecommunications, and more.

Utah

- SMALL BUSINESS DEVELOPMENT CENTER (SBDC) (with offices located in Blanding, Cedar City Office, Ephraim Office, Logan Office, Ogden Office, Orem/Provo Office, Price Office, Salt Lake City Office, St. George Office, State Director's Office, Uintah Basin Office, Utah District Office). The SBDC works with start-up and existing business owners providing free counseling services on issues such as business planning, registering a business, financing, regulations, licensing, and more.
- BUSINESS INFORMATION CENTER (BIC). provides counseling, access to hardware, software, telecommunications, and more.
- WOMEN'S BUSINESS CENTER. Supports the success of women business owners throughout Utah with counseling, training and loan-packaging assistance.
- SMALL BUSINESS ADMINISTRATION (SBA) UTAH DISTRICT OFFICE. Works to aid, counsel, assist and protect the interests of small business concerns, to preserve free competitive enterprise and to maintain and strengthen the overall economy of the nation.
- UTAH MICROENTERPRISE LOAN FUND (UMLF). A private, non-profit, multi-bank community development financial institution (CDFI) providing financing and management support to new and existing small businesses.

- FUND A SCIENTIST. A website where individuals or institutions with funding can seek out scientists with innovative projects and provide support.
- UTAH DEPARTMENT OF COMMUNITY AND ECONOMIC DEVELOPMENT. A state wide government agency which offers tax information, county statistics, financing options and current information on what's happening in economic development in Utah.
- SCORE COUNSELORS TO AMERICA'S SMALL BUSINESS. The Service Corps of Retired Executives (SCORE) "Counselors to America's Small Business" is a source of free and confidential small business advice to help build businesses—from idea to start-up to success. The SCORE Association is a nonprofit association dedicated to entrepreneurial education and the formation, growth and success of small businesses nationwide.

  SCORE's national network of 10,500 retired and working volunteers are experienced entrepreneurs and corporate managers/executives. These volunteers provide free business counseling and advice as a public service to all types of businesses, in all stages of development.
- NORTHERN UTAH CAPITAL, INC. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.
- DESERET CERTIFIED DEVELOPMENT COMPANY. A non-profit corporation partnering with the U.S. SBA and private sector lenders to provide growing businesses with long-term, fixed-rate financing for major fixed assets, such as land and buildings.

10.1.5 Summary

Based on the tables above, it is clear that there are many sources of incentives that can be used to fund the development and construction of the various technologies being reviewed in this study. Many of the incentives were recently devised through the enactment of the Energy Policy Act of 2005. Additional federal incentives are available through the Department of Agriculture, Department of Treasury, Department of Energy, and others. In addition to these federal programs, states offer many energy-related incentives, particularly with regard to renewable generation.

In addition, many incentives are available on the federal, state, and local levels to spur economic development, particularly for low-income communities, including tribes. These incentives can be significant, in terms of spawning new technologies on reservation lands.

In sum, each of the reviewed programs has very specific eligibility requirements. If these requirements are met, large amounts of money are potentially available to fund technology options.

10.2 BUSINESS CLASSIFICATIONS

Businesses that are owned by Indian tribes and by tribal members can operate under a variety of legal structures. The choice of classification affects to a great extent the business's—

- Federal and state tax status,
- Ability to attract investment monies,
- Business strategy and day-to-day operational authority,
- Liabilities, and
- Law and government.

All of the above must be taken into account when a business opportunity is initiated. When a land owner proposes a new generating facility, for example, the owner must consider not only the natural resources (such as land, oil, gas, coal, and wind), but also the business's access to federal programs that are associated with these resources, legal immunities, authority over day-to-day business operations, and more.

Many of the above are defined or constrained by the business's legal structure. Depending on its ownership and specific attributes, a business organization may be defined as—

- A tribal enterprise that is owned and controlled by the tribe and subject to tribal law;
- A non-tribal enterprise that is either (a) subject to the laws of the tribe, and perhaps also to the laws of the state in which the enterprise operates or (b) only subject to the laws of the state in which it operates.

In this section, business classifications for both tribal and non-tribal enterprises are explored. The report then looks at how those classifications affect taxes, ability to issue bonds, gain investment funds, liabilities, and more. Finally, the report discusses which structure may be most appropriate for each of the Mohave Alternatives and Complements Study's technology options.

10.2.1 Non-Tribal Enterprises

Businesses that are formed under state law are generally classified as sole proprietorships, corporations, limited liability companies (LLCs), partnerships, or business trusts. Each of these entities is described in more detail below.

- **Sole Proprietorships.** A sole proprietorship is owned by one individual, who retains responsibility for any business liabilities that are incurred. Any business revenues and expenses are included on the owner's personal tax return. This type of business is unincorporated.

- **Corporation.** A corporation is a legal entity with rights similar to those of a U.S. citizen; the corporation must abide by the laws of the state of incorporation and those of the states or other jurisdictions where it does business. The most salient features of a U.S. business corporation include the following:

  Corporations are owned by stockholders who own shares in the business.

  Although stockholders own the business, they do not control the day-to-day business operations. Instead, they vote to elect a board of directors, who oversees the business and ensures that business decisions reflect shareholders' best interests. The board of directors often consists of top management within the organization, along with some outside persons with relevant industry expertise. The separation of ownership from management gives corporations permanence and allows for perpetual lifetime.

  Corporations are established with no defined termination date; the assets and structure exist beyond the lifetime of any specified individuals. This allows the structure of the business to persist over time, which helps mitigate uncertainties that investors would have if the business was to be dissolved on a certain date.

  In a limited liability type of corporation, stockholders have no individual responsibility for the corporation's debt's and obligations. The most a stockholder can lose is the amount he/she paid for the stock, hence their "limited liability." This feature allows corporations to venture into projects that entail some level of risk.

  Corporations can both borrow and lend money.

  Corporations can deduct health insurance premiums paid on behalf of an owner-employee from the corporations' federal income taxes.

  Corporations can deduct other expenses such as life insurance costs from the corporations' federal income taxes.

  Corporations can readily establish retirement plans for employees.

  The United States federal taxation system recognizes two types of corporations:

  — **C-Corp.** The most common form of corporation, the C-corporation has few ownership restrictions and must pay corporate taxes; all publicly traded corporations have C-corporation status. C-corporations pay income taxes just as an individual does, and C-corporations do not receive a deduction on dividends they pay to stockholders. This leads to the so-called "double-taxation" of corporate profits: a given profit becomes subject to income tax twice, once at the corporate level, as an item of income, and once at the stockholder level, as a dividend.

  — **S-Corp.** Commonly used by small business proprietors, the S-corporation pays no corporate taxes, but instead passes profits and losses directly to its owners (the stockholders) who declare such profits and losses as part of their personal taxable income. In this manner, S-corporations resemble partnerships, although some subtle differences in taxation exist. As a result, S-corporations do not become subject to the "double-taxation" that C-corporations must endure. However, not all corporations qualify for S-corporation treatment. An S-corporation must generally have no more than 75 stockholders, all of them natural persons (not other corporations or entities), and all of them residing in the United States; moreover, the S-corporation can only issue a single class of stock."[1]

- **Partnership.** A partnership represents an agreement between individuals and/or corporations both of which share profits and losses. Unlike Corporate shareholders, all partners retain liability for the debts of each fellow-partner. When a partnership is established, it must specify a termination date, such as the death of one of the partners. Upon occurrence of such an event, the partnership may undergo a reorganization and re-establish itself. However, this presents major business uncertainty for all parties involved. Partnerships offer tax advantages relative to classification as a Corporation.[2]

- **Limited Liability Company (LLC).** A limited liability company has members, rather than partners. The LLC is a relatively new business entity, which was adopted by most states only in the last 10 years. The benefits of an LLC are that it is free from many of the tax and business problems inherent in the corporate and partnership structure. More specifically, "the LLC provides the *protection from liability* of a corporation without the formalities of corporate minutes, bylaws, directors, and shareholders. In contrast to corporate law, which allows shareholders and officers to be individually sued if the corporate formalities are not followed, the LLC law specifically bars a lawsuit against a member for the liabilities of the LLC. That is an important distinction to understand. The principle shareholders and officers of a corporation are routinely named as defendants in lawsuits against the company, forcing them to incur attorney's fees to defend themselves and rendering the corporate shield meaningless from a practical standpoint. A primary goal of the LLC legislation was to change this result by clearly stating that the members and managers of the LLC could not be named in a lawsuit against the company. The new law was drawn specifically to provide a vehicle which would protect the owners from liability associated with the business, what the corporation was intended for but no longer accomplished. The LLC is also convenient to maintain. The owners are permitted to adopt flexible rules regarding the administration and operation of the business. For tax purposes, it is treated like a partnership. That means the LLC itself pays no income tax. All of the income and deductions flow through directly to the members and is reported on their personal tax returns."[3]

- **Business Trust.** This business entity is mostly used for investment projects, such as mutual funds, real estate, etc. Some state jurisdictions allow this classification, including. Utah,

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[1] http://en.wikipedia.org/wiki/Corporation#Taxation_of_non-corporate_entities

[2] Since 1996, United States partnerships and limited liability companies have had the right to elect whether the United States government will treat them as corporations or as "flow-through" entities under the IRS' check-the-box regulations (see form 8832). The income tax assessment process does not treat a flow-through entity as a person for income tax purposes; instead it divides its income and loss (and every other tax attribute) among its partners, who report them proportionately to the IRS. Some limits exist on an entity's ability to elect flow-through treatment: most importantly, a publicly traded company cannot elect flow-through treatment; in practice this means that publicly traded corporations remain subject to a more stringent tax régime than do closely held companies.

[3] The Asset Protection Law Center, 2005. "A complete reference source on offshore trusts, family limited, partnerships, limited liability companies and advanced asset protection strategies," The Asset Protection Law Center , The Law Offices of Robert J. Mintz, found at http://www.rjmintz.com/appch6.html

Nevada, and Arizona. It is unclear whether New Mexico allows the establishment of this type of entity.

Like U.S. natural citizens, Indian tribes are eligible to establish each of the above entities with the exception of S-Corporations, which are primarily reserved for natural citizens. As for taxes, a summary of tax-related features of the various structures is shown below in Table 10-8. In addition, it is important to keep in mind that each of these business structures is subject to the laws of the state of incorporation.

Table 10-8 — U.S. Business Classification Options and Tax Consequences

Business Entity	Tribes eligible to own?	Business is required to pay federal and state income taxes?	Distributions to tribes, as owners, are free of federal income taxes?	Distributions to tribes, as owners, are free of state income taxes?
Sole Proprietorship	Yes	Yes	Yes	Yes
C-Corporation	Yes	Yes	Yes	Yes
S-Corporation	No	Not applicable	Not applicable	Not applicable
LLC	Yes	Yes	Yes	Yes
Partnership	Yes	Yes	Yes	Yes
Business Trust	Usually not applicable	Not applicable	Not applicable	Not applicable

Note: Generally, if the tribal members live on the reservation, distributions paid to them by corporations that operate on reservation land are not subject to state income taxes, but are subject to federal income taxes

Because most stakeholders of this study are likely more familiar with the above state-defined organizational structures and because in many ways they are similar to one another, the remainder of this study compares these, as a group, in general, to those of the individual tribal business structures. From this point forward, sole proprietorships, C-corporations, partnerships, and LLCs will together be referred to as “state corporations.”

10.2.2 Tribal Enterprises

While U.S. tribes and tribal members can establish any of the business structures (except S-corporations) that U.S. citizens can establish, tribes and tribal members also can establish tribal-specific enterprises. Such businesses and organizations may offer their owners some discreet advantages, financially and socially. Tribal business entities are described in greater detail below:

- **Tribal Government Entities.** This category includes tribal governments, subdivisions of tribal government (including tribal government agencies and divisions) and unincorporated enterprises of tribal governments. By definition, businesses operated by tribal governments or subdivisions of tribal governments are wholly owned by the tribe. Tribal governments and subdivisions are exempt from federal and state income taxes, and the tribe maintains control of day-to-day business decisions and operations. Businesses operated as arms of tribal governments are subject to generally applicable federal substantive law, but are not subject to state law unless a specific federal law has made them so, or unless (and to the extent) they operate outside a reservation; and such businesses have been held to possess immunity from nonconsented suits in state, federal, and tribal courts. This immunity may be seen as a risk by non-tribal investors, without an explicit waiver.

Unlike state corporations, tribal governments generally do not separate ownership from business management. For tribal organizations, the owner is the tribe, the same entity that makes major business decisions. This direct tribal control may be seen as a risk in the eyes of non-tribal investors, who might be concerned that business decisions could be tied to political considerations

- **Federally Chartered Tribal Corporation.** These entities are incorporated under Section 17 of the Indian Reorganization Act of 1934. In order to qualify for this classification, the business must by wholly owned by the tribe. Applying for Section 17 status, which must be approved by the Secretary of the Interior, is not always a simplistic process. However, one advantage of this classification is clear exemption from federal taxes.

  Under a federally chartered tribal corporation, the tribe may or may not retain control of the basic business decisions and operations, depending on the terms of the corporation's charter. Such entities are subject to generally applicable federal laws and, presumably, are subject to tribal law, but are not subject to state laws unless they have been made so by federal law or unless (and to the extent) they operate outside a reservation.

- **Tribally Chartered Corporation**. Tribally chartered corporations can be owned, in whole or in part, by a tribal government, by tribal members, or by non-Indians. It is presently unclear whether tribally chartered corporations are exempt from federal income taxes (this issue is currently being reviewed by the Internal Revenue Service). However, it is likely that income derived by shareholders from a tribally chartered corporation that is not owned by a tribal government will remain subject to federal income taxation; but income derived by shareholders who are tribal members living on a reservation from a tribally chartered corporation doing business on a reservation will likely be exempt from state income taxation. Finally, business revenues earned off the reservation will likely be subject to state income taxes for all shareholders.

  Tribally chartered corporations are subject to tribal law, but if they are not owned by the tribe, their business decisions are not controlled by the tribe; and they do not have sovereign immunity from nonconsented suits. These factors may or may not be attractive to non-tribal investors or financing sources.

The table below summarizes the main features of the tribal business classifications.

Table 10-9 — Major Features of Various Tribal Business Classifications Compared to Those of a State Chartered Corporation

	Must by owned wholly owned by the tribe?	Exempt from federal and state income taxes?	Tribe retains control over operations, jobs, employee training, incomes, and tribal way of life?	Immunity from nonconsented lawsuits? *	Preferred by third-party investors?	Preferred with respect to new technology risks?
Tribal Gov't, Subdivision of Tribal Gov't, Unincorporated Enterprises of Tribal Gov't	Yes	Yes	Yes	Yes, absent explicit waiver	No	Presents challenges (see text on Implementation of "unproven" technologies or processes)
Federally Chartered Tribal Corporation under section 17	Yes	Yes	Possibly, depending on terms of charter	Yes, absent explicit waiver	Yes	Yes
Tribally Chartered Corporation	No	Unclear **	No	No	Presents challenges (see text on capital investment requirements)	Yes
State corporations, in general	No	No	No	No	Yes	Yes

Source: Atkinson, Karen, 2005. "Choosing a Business Structure," a presentation presented at Law Seminars International: *Tribal Energy Southwest Conference*, Las Vegas, Nevada, April 7-8, 2005.

* Investors and developers of major projects typically insist on some sort of waiver of tribal immunity. In addition, the federal government is not barred from suing tribes. Without such a waiver, the sovereign immunity of the tribe precludes lawsuits.

** The U.S. Internal Revenue Service is currently reviewing rules regarding this issue.

It is clear from Table 10-9 that different business classifications offer different advantages for tribal owners. Yet, to some extent, this table oversimplifies the task of determining which structure is best for a tribally-owned business; individual businesses have very specific concerns, each of which should be considered before choosing a legal business classification.

A number of issues that tribes should consider before choosing and structuring a specific classification for a business enterprise are discussed below. The major issues include authority, third-party investor preference, revenue type and potential, technology risks, and whether the business would be exempt from federal and state taxes and eligible for special incentives.

10.2.2.1 Tax Implications

Certain types of business classifications are exempt from paying federal and state income taxes. Such savings represent a significant percentage of retained earnings over those business entities that must make such payments. However, while the tax breaks that are identified in Table 10-9 exist for tribal governments, business subdivisions of tribal governments, and federally chartered tribal corporations, the U.S. Treasury Department and Internal Revenue Service are currently examining whether tribally chartered corporations will be free of federal income tax on revenue-generating activities, and how tribal/non-tribal partnerships will be viewed for tax purposes.

In any case, a tribe or a business owned by a tribal government may qualify for the following additional special tax treatments and financing options:

Federal:[4]

- Persons and organizations that contribute to tribally owned enterprises are allowed to deduct their contribution from their income taxes.
- Persons and organizations that contribute to tribally owned enterprises are eligible to reduce their owed estate and gift taxes.
- Treatment as a government under the private foundation excise tax rules.
- Tax-exempt bond financing authority (Indian Tribal Governmental Tax Status Act of 1982 [IRC §7871]).[5]
- Exemption from federal excise tax on gasoline, diesel, kerosene if fuel is used for an essential government function. (Tribal utilities have been accepted as essential governmental purposes.)
- Accelerated deprecation for equipment and infrastructure on tribal lands.
- Conduit financing capabilities.
  - Utilizes a tax-exempt entity, other than a Tribal Authority, to issue tax-exempt bonds (the borrower issues bonds—proceeds are lent to Tribal Authority).
  - The IRS is currently challenging this type of financing.
- Tax-exempt utility can use tax-exempt bonds to pre-pay for natural gas and electricity.
  - In effect since 2003.[6]
  - 90% of the gas or electricity must be used to serve retail customers of the issuer or to sold to another governmental utility for its retail customers.

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[4] Nilles, Kathleen, 2005. "Structuring Energy Projects: Tax Considerations," a presentation presented at Law Seminars International: Tribal Energy Southwest Conference, Las Vegas, Nevada, April 7-8, 2005.

[5] Tribes are treated like states for purposes of the bond act with two restrictions: 1) bonds can only be issues to finance facilities that serve an "essential governmental functions," 2)Tribes cannot issues private activity bonds except for manufacturing facilities operated by the tribal government. Tribal utilities qualify for such bonds.

[6] Golub, Howard, 2005. "Financing Tribal Energy Projects," Nixon, Peabody, LLP, Las Vegas, NV, April 7, 2005.

State:

- Exemption from sales tax and other taxes for purchases made on Indian reservations. (However, tribes can levy their own sales taxes.)
- Exemption of Native Americans from state income taxes, provided that they live on reservation land and that the income in question is earned on the reservation.
- Example: One example of an implementation of one of the above-described benefits involves the Mississippi Choctaw Tribe, whose principles of business success include (1) a tribal land base under tribal government control, (2) a stable tribal government, and (3) an institutional structure designed to facilitate business decisions. In 1969, this tribe issued a tax-exempt bond to help fund the construction of an industrial park on the reservation. This project and the Choctaw's business development practices, in general, have been considered a great success.

In summary, when choosing a business classification, it is particularly important for an organization to think about how that classification will affect its eligibility for all of the above special tax treatments. For those projects where freedom from income taxation and, for example, ability to issue tax-exempt bonds, is most important, a tribe might prefer to directly own and operate the business.

10.2.2.2 Capital Investment Requirements[7]

Capital intensive projects often require financing from third parties. Typically, before investors bring capital to business investments, they consider whether the organization has a defined business plan, financial growth potential, reasonable business risks, and managers with excellent track records.

For tribal-businesses, these same criteria apply. However, in addition to the project's characteristics, investors might have a preference for certain organizational entities, as seen in Table 9-2. Investors might be concerned about investing in businesses operated by tribal governments, as they would businesses managed day-to-day by a state or municipal government. Such a concern could arise as a consequence of a belief that political considerations might unduly influence daily business decisions. This control might bring some concerns to third-party investors, who may be unfamiliar or uncomfortable with tribal rules and activities.

Other investor issues regarding funding tribal entities include the following:

- Disputes with tribes and with businesses operated as arms of tribal governments, including federally chartered tribal corporations, cannot be settled by courts, without an explicit waiver of sovereign immunity by the tribal entity. Non-tribal investors see this as an enormous risk, which

[7] Carey, Jeffrey, 2005. "Beyond Extraction: Maximizing the Value of Energy Resources for Tribes," a presentation by Merrill Lynch for Law Seminars International: *Tribal Energy Southwest Conference*, Las Vegas, Nevada, April 7-8, 2005.

may prevent them from investing in tribal enterprises. To allay this risk, however, tribes and investors can and do enter agreements that establish mutually accepted processes to resolve disputes, including the use of federal and state courts.

- Tribal trust land cannot be mortgaged, and a legal question exists as to whether land owned by a tribe in fee can be subject to mortgage. This can present a disadvantage to tribal enterprises seeking investment monies because such land is not available as collateral. Certain tribes have circumvented this problem by leasing property to third parties, either tribal or non-tribal, and permitting the leasehold, which is regarded by law as personal property rather than real property, to become the subject of a mortgage. The Mohegan Tribe of Connecticut used this arrangement when it obtained financing for its large Mohegan Sun Casino: the tribe leased the land on which the casino was to be built to a tribally created entity that, in turn, issued publicly traded bonds that were secured by a mortgage on the leasehold. The Navajo Nation has also participated in this sort of arrangement. More details about how this can be accomplished are illustrated below:

> Three tribes in the study (Citizen Potawatomi, Mississippi Choctaw, and Navajo Nation) reported they were able to induce banks to make loans to them using leasehold improvements as collateral. In each case, the tribe wanted to construct a building or to renovate an existing building needed to operate a tribally owned business or tribal program. A bank was willing to accept as collateral the improvements on the land (the new or renovated building) rather than the trust land.
>
> A leasehold improvement approach used by Navajo Nation can serve as a model for other tribes. This effort promoted entrepreneurial activities by tribal members, rehabilitated a building that had been long vacant, leveraged federal welfare reform funding, and provided facilities required to operate the federally funded program. A large building in one of the largest Navajo communities (Shiprock, New Mexico) was structurally sound but had remained abandoned for eight years after the manufacturing business using it was closed. When Navajo Nation took over operation of the TANF program, it sought to open several satellite offices throughout the reservation, including Shiprock. A construction firm owned by a tribal member negotiated a deal with Navajo Nation to rehabilitate the building in accordance with the specifications of the tribal TANF program. No TANF funds were expended to renovate the building—the TANF program signed a long-term lease with the construction company, which used the lease as collateral for a bank loan. The construction company used the loan to finance the rehabilitation needed by the TANF program. In addition, the builder was able to develop space in the renovated building for a restaurant and retail stores. [8]

The above example shows that there are ways to interest third-party investors and circumvent apparent investment barriers associated with tribal businesses.

To summarize, for those businesses that are particularly capital intensive, it is very important for the owners to choose a business classification that will be acceptable to outside investors. With regard to this study, as shown in the table below, IGCC and solar parabolic trough technologies appear to be the most capital intensive. Project financing for these particular technologies must be considered as part of the business classification decision.

Table 10-10 — Capital Costs of the Study's Technologies

Technology	Approximate Total Capital Investment ($/kW)
Solar Parabolic Trough with Storage	3,600
IGCC CO_2 Removal without Shift Conversion scenario	2,200
Solar Dish/Stirling Engine	1,500
Wind	1,700
Natural Gas Combined Cycle	600

10.2.2.3 Implementation of "Unproven" Technologies or Processes

When an organization chooses to finance a project that uses relatively new technologies or processes, the organization is taking on risk. There is performance risk (will the facility be as efficient as anticipated?); there is financial risk (will construction and operations cost more than expected?); and there is alternative technology risk (will a new, better, and less expensive technology come to the marketplace in the near future?). In addition to these kinds of risks, "unproven" technologies might require some sort of specialized expertise on the part of the employees and management.

It is easy to see how great responsibility and a high degree of comfort with risk are important in building and operating facilities using new technologies. With this in mind, it is important to consider the various business structures and their features. For certain business classifications, it is the tribe that retains authority and overall responsibility for day-to-day business decisions, as well as the attendant risks. With regard to this study, IGCC (especially with carbon capture) and solar dish/Stirling engine appear to be the most risky in terms of technical and financial performance. As such, should the tribes be wary of taking on risks, these technologies might be more suited to corporate structures, either tribal or state chartered. On the other hand, DSM, wind, and solar parabolic trough are established technologies, which might be more suited as tribal enterprises.

10.2.2.4 Ability to Control Jobs, Expand Tribal Knowledge Base, and Enhance Tribal Incomes

Certain business structures give tribes the authority to make decisions not only concerning day-to-day operations, but also concerning general business strategy. This can be extremely valuable to the tribes. For

[8] The Urban Institute, Inc., 2004.

instance, the tribe can put a strategy in place that protects its members from unemployment. The tribe might accomplish this by training member employees in practices that promise future growth potential on tribal lands. The tribe can also strive to expand its overall revenues. One way to accomplish this might be to become the industry leader in a specific sector. This might be achieved by becoming an expert in a new technology or process.

Some of the business classifications that have been discussed allow the tribes to retain more business strategy control than others. Specifically, structuring an enterprise as an arm of the tribal government gives the tribe direct control over jobs impacts and the ability to direct the businesses to follow the tribe's overall economic development and business strategy. For instance, tribal government enterprises can themselves decide whether to continue to run or to abandon an existing project. This would not be the case if the project was operated by a non-tribal or tribal corporation.

With regard to this study of generation alternatives, if the tribes are concerned with job impacts and long-term economic development of their tribes, they may choose to establish any technology options as tribal government organizations. In addition, some of the technology options may offer specific openings for long-term tribal development strategies. Wind, solar dish/Stirling, DSM, and possibly solar parabolic trough might fall under this category. For each of these technologies, there is great potential for the tribes to export their gained knowledge in construction and operation of such projects to new developments, both on and off reservation land.

10.2.2.5 Ability to Promote and Enhance Tribal Way of Life

Specific tribes have specific cultures or ways of life. Having businesses on their land that operate in tune with cultural preferences may be vital to the tribes in terms of respecting and preserving their culture.

With this in mind, certain business structures allow the tribes to retain more control over the principles under which a business operates than do others. Specifically, tribal government entities and unincorporated enterprises of tribal government give tribes overall authority concerning business operations and culture. Alternatively, some federally chartered tribal corporations (depending on the details of their charters), tribally chartered corporations, and state corporations allow the tribes a more passive role. In some instances, this might be preferred, as controlling a business might involve a great amount of tribal resources in terms of time and effort.

In summary, if consistency with cultural values is a key requirement for businesses on reservation lands, tribal government or unincorporated enterprises of tribal government would likely be the preferred organizational structure. With regard to this study, due to its aesthetic impacts, wind would likely be a key technology where cultural enforcement might be critical.

10.2.2.6 Royalty Potential vs. Direct Revenue Potential

In order to be approved for business activities on reservation land, some tribes require non-tribal businesses to pay them annual royalties and land and water use fees. Together, these fees can be significant and represent a very stable flow of income for the tribes. These fees are also independent of business risk. So, a tribe may benefit substantially if a successful non-tribal business, which was initially deemed risky, resides on their reservation land over the long-term.

On the other hand, all the revenue from a tribal government enterprise belongs to the tribe, but that revenue may be subject to uncertainties and business risk.

In terms of the generation options, IGCC on tribal land represents a technology that might provide large and long-term revenue streams in the form of royalties and permitting fees to the tribes if the facility is held by a non-tribal business. Also, as pointed out above, IGCC is also considered to be a somewhat risky technology in terms of performance characteristics at this time. Together these traits may imply that, currently, tribes may prefer to have an IGCC facility owned and operated by a state corporation rather than by a tribal business entity.

10.2.3 Study Technology Options and Recommended Organizational Structures

Table 10-11 summarizes the general findings regarding recommended ownership structures for the proposed technology options evaluated in this study. It is important to note, however, that these recommendations should be viewed simply as starting points, subject to reconsideration when a specific project and its details are fully available. It is premature to conclude that a particular technology is, or is not, suited to tribal ownership. Such decisions must, in the end, be made with full knowledge of the particular project and project financing options. However, the following reflects reasonable *generic* conclusions that can be considered as starting points, subject to reconsideration when a specific project and its details are ready to examine.

Table 10-11 — Generic Ownership Structures Recommendations for the Various Technology Options

Technology	Potentially Attractive as a Tribal Business?	Primary Reason for Recommendation
IGCC	Probably not	High capital cost; all-or-nothing investment; high business risk; high potential for royalty income from non-tribal enterprise.
NGCC	Not applicable	Proposed location is on private land.
Wind	Yes	Moderate and modular cost; low business risk; control is critical because of aesthetics; high potential to create future jobs for tribes, both on and off reservation. The Navajo Tribal Utility Authority is already taking action in wind development.
Solar/Parabolic trough	Maybe	High capital cost; low technology risk; medium potential to create future jobs for tribes, both on and off reservation.
Solar Dish/Stirling Engine	Maybe	Moderate and modular capital cost; moderate technology risk; moderate potential to create future jobs for tribes, both on and off reservation.
Biomass/Geothermal	Unclear	Information on project specifics, including proposed locations, job impacts, costs, business risks, etc. still pending
DSM/EE	Yes	Low and modular capital cost; low risk under sound management; no royalty potential from non-tribal business; high potential to create future jobs for tribes, both on and off reservation.

Based on these recommendations, the following conclusions may be drawn:

- **IGCC.** Due to its high capital costs, business risks, and high potential for royalty income from non-tribal enterprises, it would likely be in the tribes' best interests if the proposed IGCC facility were owned and operated by a non-tribal entity formed under state law.
- **Wind and DSM/EE Technologies.** For each of these, there is only moderate capital and operational costs, low technology risk, and a high potential to create future jobs for the tribes, both on and off of reservation territories. For all of these reasons, wind and DSM technologies might be attractive as tribal business entities.
- **Solar Dish/Stirling Engine Technology**. Business risks associated with this technology probably fall somewhere between those of IGCC and wind. Dish/Stirling engines systems have moderate, but modular capital costs. The technology may be a source of expanded jobs for the tribes in the future. Given these consideration, solar dish/Stirling engines may be potentially attractive to tribal businesses.
- **Solar Parabolic Trough Technology**. Solar parabolic troughs are usually very large projects; unlike solar Stirling technology, parabolic troughs are not generally built in a modular fashion

or to produce small amounts of energy. Parabolic troughs have high capital costs. Yet, they are a well-proven technology option. Given these factors, this technology may potentially be attractive to tribal businesses.

- **Natural Gas Combined-Cycle Facility.** At this time, no conclusions are offered with regard to NGCC. The proposed location of the natural gas plant is on private land. Therefore, whether or not it would potentially be attractive as a tribal business is a non-issue.
- **Other Renewables.** No conclusions can be made at this time regarding biomass or geothermal technologies. Information on proposed project specifics, including proposed locations, job impacts, costs, business risks, and so forth needed to make a solid conclusion regarding best business structure is still pending.

Again, it is important to reiterate that project specifics may alter the general conclusions above.

In addition, for the more modular technologies (wind, solar dish/Stirling, DSM/EE, other renewables), it might make sense for the tribes to consider the option of having a diversity of business entities on their lands. For example, it is certainly feasible for one wind site to be owned and operated by a tribal government, while another is owned and operated by a non-tribal entity. Such a scenario would allow both types of owners to benefit from each other's experiences with the technology.

10.3 HYPOTHETICAL PACKAGES OF INCENTIVES FOR SPECIFIC BUSINESS STRUCTURES

While the previous sections of this chapter separately examine financial incentives and business structures, this section combines the two concepts together and provides hypothetical packages of financial incentives that might apply to the capital costs of specific resources, owned by specific types of entities. The following packages are explored:

- IGCC without the sequestration option operated by non-tribal business owners at both the Black Mesa and Mohave sites.
- IGCC with sequestration option operated by tribal business owners at the Black Mesa site.
- DSM implemented in part by tribes on and near reservation land.
- Wind turbines at Gray Mountain operated by NTUA.
- Wind turbines at Aubrey Cliffs operated by Foresight.
- Solar dish/Stirling facility owned by tribes.
- Solar parabolic facility owned by non-tribal business entity.

With regard to the hypothetical packages, it is important to note that, in many cases, the owners of the facilities are not entitled to receive all of the hypothetical incentives simply by right; many of the incentives are competitive and require applicants to submit detailed paperwork in order to qualify and perhaps receive grant monies, tax breaks, loans, and/or other financial incentives. In addition, many incentives not only have annual distribution limits, but also a maximum that can be applied towards any individual project or owner. Furthermore, the ability of taxable corporations to take advantage of tax benefits depends on the details of the corporation's tax obligations and other factors.

For the hypothetical projects described below, a 35% federal income tax rate and a 10% nominal discount rate were assumed.

Table 10-12 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of IGCC without the Sequestration Option Operated by Non-Tribal Business Owners at Both the Black Mesa and Mohave Sites

IGCC without sequestration: Non-tribal ownership at Black Mesa Site			
IGCC capital cost at Mohave with No C02 removal and dry cooling			**$910,033,600**
Net reduction due to EPACT 2005, Section 1307, Credit for Investment in Clean Coal Facilities	Must apply for this incentive	Assumes 20% tax credit on investment available in year 1	$182,006,720
Net reduction due to EPACT 2005, Section 1301, Renewable Electricity Production Credit	Automatic incentive	7-year credit period: $2/ton indian coal; 5,930 tons/day of coal; $4,328,900 annually; NPV over 7 years starting in year 3:	$17,417,271
Net reduction due to Title 26. IRS tax code: Modified Accelerated Cost Recovery	Automatic incentive	20 year property can be deducted over 12 years; $26,542,647 annually; NPV of this incentive over years 3-14	$149,465,634
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic incentive	20% tax credit on first $20,000/tribal employee; 80% of 120 craft labor tribal employees assumed; $384,000 annually; NPV over 1st 2 years:	$666,446
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic incentive	20% tax credit on first $20,000/tribal employee; 80% of 206 tribal employees assumed; $659,200 annually; NPV over years 3-12:	$3,347,520
Total Cost After Incentives Applied			**$557,130,009**
% Capital Cost Saved			**38.78**

IGCC without sequestration: Non-tribal ownership at Mohave site			
IGCC capital cost at Mohave with No C02 removal and dry cooling			**$910,033,600**
Net reduction due to EPACT 2005, Section 1307, Credit for Investment in Clean Coal Facilities	Must apply for this incentive	Assumes 20% tax credit on investment available in year 1	$182,006,720
Net reduction due to EPACT 2005, Section 1301, Renewable Electricity Production Credit	Automatic incentive	7-year credit period: $2/ton indian coal; 5,930 tons/day of coal; $4,328,900 annually; NPV over 7 years starting in year 3:	$17,417,271
Total Cost After Incentives Applied			**$710,609,609**
% Capital Cost Saved			**21.91**

Notes:

An IGCC unit owned by a non-tribal business at Black Mesa could take part in the Title 26 Modified Accelerated Cost Recovery for property on tribal land. This is not the situation at the Mohave site, which is not located on tribal land. Table assumes no tribal employees at Mohave site.

Table above assumes construction over years 1 and 2, with a fully operational unit in Year 3.

Table 10-13 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of IGCC with Sequestration Option Operated By Tribal Owner at the Black Mesa Site

IGCC with Sequestration: Tribal ownership at Black Mesa Site			
IGCC capital cost at Black Mesa with 90% C02 removal and dry cooling			**$ 1,158,425,600**
Net reduction due to EPACT 2005: Section 2602: Indian Energy Education Planning and management Assistance	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$ 1,000,000
Net reduction due to Administration for Native Americans Program: Social and Economic Development Strategies	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$ 1,000,000
Total Cost After Incentives Applied			**$ 1,156,425,600**
% Capital Cost Saved			**0.17**

Notes:

The above assumes construction over years 1 and 2, with fully operational unit in Year 3.

Most of the financial incentives available for IGCC are tax credits. Because the tribes would not pay taxes, they would not benefit from the tax credits potentially available to non-tribal owners of an IGCC plant.

Table 10-14 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of DSM Implemented by Tribes On and Near Reservation Land

Cost of Energy Efficiency: Tribal Ownership			
Assume 50 MW savings total over 5 years			
Cost of 10% of EE that is implemented on or near the reservations			**$13,874,241**
Net reduction due to EPACT 2005, Section 2602, Indian Energy Education, Planning, and Management Assistance	Must apply for this incentive	Assume 5% of $20,000,000 available immediately	$1,000,000
Net reduction due to EPACT 2005, Section 126. Low Income Community Energy Efficiency Pilot Program	Must apply for this incentive	Assume 5% of $20,000,000 available immediately	$1,000,000
Net reduction due to USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Must apply for this incentive	$500,000 per project available immediately	$500,000
Net reduction due to Administration for Native Americans Program: Social and Economic Development Strategies	Must apply for this incentive	Assume 5% of $20,000,000 available immediately	$1,000,000
Net reduction due to New Mexico: House Bill 251, Clean Energy Grants Program	Must apply for this incentive	$200,000 per project available immediately	$200,000
Total Cost After Incentives Applied			**$10,174,241**
% Capital Cost Saved			**26.67**

Notes:

The EE budget for 50 MW savings is $30,520,000 per year for five years. For illustrative purposes, the Study assumes that 10% of the work and budget can be performed either on the reservation (a small part of that 10%) or on premises of electricity consumers near the reservation, but by enterprises based ON the reservation and staffed by tribal members. Workers would commute to job sites in places like Albuquerque, Flagstaff and so on.

Table 10-15 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of Wind Turbines at Gray Mountain Operated by NTUA

Wind at Gray Mountain: Owned by NTUA			
Cost of facility			**$237,068,532**
Net reduction due to EPACT 2005, Section 2602, Indian Energy Education, Planning, and Management Assistance	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$1,000,000
Net reduction due to EPACT 2005, Section 126. Low Income Community Energy Efficiency Pilot Program	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$1,000,000
Net reduction due to USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Must apply for this incentive	Assumes $500,000 per project available in year 1	$500,000
Net reduction due to DOE's Office of Energy Efficiency and Renewable Energy's Tribal Energy Program	Must apply for this incentive	Assumes $138,889 available in year 1 based on 2005 allottment of $2.5 million for 18 tribes	$138,889
Net Reduction due to EPACT 2005: Section 202, Renewable Energy Production Incentive Program	Automatic Incentive	465,896,224kWH/year; 1.5 cents/kWH, adjusted for inflation annually since '93;(Value = $9,317,924 annually);NPV of incentive over years 3-12:	$47,317,859
Net reduction due to Administration for Native Americans Program: Social and Economic Development Strategies	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$1,000,000
Total Cost After Incentives Applied			**$186,111,784**
% Capital Cost Saved			**21.49**

Notes:

Assumes construction in Years 1 and 2 and fully operational in Year 3.

In response to a stakeholder request, certain financial incentives were considered for the above hypothetical. However, some of them were not applicable. For instance, money from EPACT Section 2603 is earmarked for regulatory issues, not for capital costs. Similarly, the Indian Employment Tax Credit is not applicable to NTUA. In addition, while the idea of the New Market Tax Credit is an excellent one, 60% of funds must be directed towards serving tribal needs. The Gray Mountain wind farm would not meet this definition. Finally, the value of loan guarantees is discussed in a separate section of this chapter.

Table 10-16 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of Wind Turbines at Aubrey Cliffs Operated By Foresight

Wind at Aubrey Cliffs: Owned by Foresight			
Cost of facility			**$155,170,028**
Net reduction due to USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Must apply for this incentive	Assumes $500,000 available per project available in year 1	$500,000
Net reduction due to DOE's Office of Energy Efficiency and Renewable Energy's Tribal Energy Program	Must apply for this incentive	Assumes $138,889 available in year 1 based on 2005 allottment of $2.5 million for 18 tribes	$138,889
Net reduction due to EPACT 2005: Section 1301, Renewable Electricity Production Credit	Automatic Incentive	273,266,054 kWH/year; credit for 10 years for facilited placed in service after August 8, 2005; (=$5,465,321 annually); NPV over years 3-12.	$27,753,745
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic Incentive	20% tax credit on first $20,000/tribal employee; 80% of 95 tribal employees assumed; $304,000 annually); NPV over years 1 and 2 of construction	$527,603
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic Incentive	20% tax credit on first $20,000/tribal employee; 80% of 4 tribal employees assumed; (= $12,800 annually); NPV over years 3-12	$65,000
Net reduction due to AZ Statue ARS 42-5075, Title 42. Taxation, Arizona Solar and wind	Automatic Incentive	Assumes $5,000 per project available in year 1	$5,000
Total Cost After Incentives Applied			**$126,179,790**
% Capital Cost Saved			**18.68**

Note: Assumes construction in Years 1 and 2 and fully operational in Year 3.

Table 10-17 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of Solar Stirling Facility Owned by Tribes

Solar Stirling: Owned by tribes			
Cost of facility		**$1400/KW and 425MW facility**	**$595,000,000**
Net reduction due to EPACT 2005, Section 2602, Indian Energy Education, Planning, and Management Assistance	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$1,000,000
Net reduction due to EPACT 2005, Section 126. Low Income Community Energy Efficiency Pilot Program	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$1,000,000
Net reduction due to USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Must apply for this incentive	Assumes $500,000 available per project in year 1	$500,000
Net reduction due to DOE's Office of Energy Efficiency and Renewable Energy's Tribal Energy Program	Must apply for this incentive	Assumes $138,889 available in year 1 based on 2005 allottment of $2.5 million for 18 tribes	$138,889
Net Reduction due to EPACT 2005: Section 202, Renewable Energy Production Incentive Program	Automatic Incentive	Assumes 1,120,000 MWH/year; 1.5 cents/kWH, adjusted for inflation annually since '93 (=$22,400,000/year); NPV over years 4-13	$103,409,694
Net reduction due to Administration for Native Americans Program: Social and Economic Development Strategies	Must apply for this incentive	Assume 5% of $20,000,000 available in year 1	$ 1,000,000
Total Cost After Incentives Applied			**$487,951,417**
% Capital Cost Saved			**17.99**

Note: Assumes construction in years 1-3 and fully operational in year 4.

Table 10-18 — Hypothetical Package of Incentives to Reduce Initial Capital Cost of Solar Parabolic Facility Owned by Non-Tribal Business Entity

Solar Parabolic: Owned by non-tribal enterprise			
Cost of facility		**$3600/kw and 300MW facility**	**$1,080,000,000**
Net reduction due to EPACT 2005, Section 1336-1337. Business Solar Investment Tax Credit	Automatic Incentive	10% of captial cost can be taken as tax credit through 2008	$108,000,000
Net reduction due to USDA Renewable Energy Systems and Energy Efficiency Improvements Program	Must apply for this incentive	Assumes $500,000 available per project in year 1	$500,000
Net reduction due to Title 26. IRS tax code: Modified Accelerated Cost Recovery	Automatic Incentive	20 year property can be deducted over 12 years; Value is $31,500,000 annually; NPV over years 4-13	$145,419,883
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic Incentive	20% tax credit on first $20,000/tribal employee; 80% of 83 tribal employees assumed; NPV over 1st three years	$660,508
Net reduction due to US Treasury Indian Empoyment Tax Credit	Automatic Incentive	20% tax credit on first $20,000/tribal employee; 80% of 88 tribal employees assumed; $281,600 annually; NPV over years 4-13	$1,300,008
Net reduction due to AZ Statue ARS 42-5075, Title 42. Taxation, Arizona Solar and wind	Automatic Incentive	Assumes $5,000 available per project in year 1	$5,000
Total Cost After Incentives Applied			**$824,114,602**
% Capital Cost Saved			**23.69**

Note: Assumes construction in years 1-3 and fully operational in year 4.

10.3.1 Role of Loan Guarantees

The above packages of incentives do not factor in loan guarantees, which are available for many of the hypothetical facility/owner combinations. As an example, the EPACT 2005, Section 2602, Department of Energy Loan Guarantee Program was reviewed with regard to the Gray Mountain Wind facility, hypothetically owned and operated by NTUA. Section 2602 provides loans valued at no more than 90% of the project cost for projects that expand the provision of electricity on Indian lands. Table 10-19 shows the difference in cost of capital between being able to finance the project under EPACT 2005 Section 2602 and financing the project through more traditional means. Two factors add up to big savings: (1) A federal loan guarantee allows a greater percentage of the project cost to be funded by debt. This is important, because debt, in general, is less expensive than equity. (2) The cost of debt on a federally guaranteed loan is likely to be less than that of a standard loan instrument. As can be seen in the table below, there can be a tremendous reduction in weighted average cost of capital with use of federal loan guarantee programs. (In our hypothetical example, there is a 17% reduction in the weighted average cost of capital through use of Section 2602.)

Note that a tribal entity, which does not pay taxes, does not see any benefit from interest payment deductions. Therefore, tribal corporations, with the same capital structure and costs of debt and equity, will have a higher cost of capital than a non-tribal entity. However, both types of entities do benefit from loan guarantees.

Table 10-19 — Loan Guarantees That Could Drastically Reduce Cost of Capital for both Tribal and Non-Tribal Entities

EXAMPLE: Gray Mountain Wind Farm Guaranteed Loan		
	Without Low-interest Loan Guarantee	With Low-interest loan guarantee
Capital Structure		
% debt	45	65
% equity	55	35
Cost of debt:	8.40%	7.40%
Cost of equity:	16.0%	16.0%
Weighted average cost of capital for non-paying tax entity under EPACT section 2602:	12.6%	10.4%
Equivalent weighted average cost of capital for tax paying entity:	11.3%	8.7%

10.3.2 Value of Long-Term Contracts

In addition to other incentives, there are likely opportunities for underwriting investments in alternative energy generation through long-term procurement agreements with owners of Mohave and other utilities in the region. These opportunities may include purchase preferences for minority or economically depressed sources and for purchasing power from sources that meet California's newly adopted performance standards for reducing greenhouse gas emissions. Such opportunities can also be valuable to business owners looking to build new generation facilities.

10.3.3 Summary Regarding Hypothetical Packages of Incentives

From the preceding discussion, it is clear that there are a large variety of financial incentives that can potentially be used to offset the capital costs of new supply- and demand-side alternatives, both on and near tribal reservation land. Business owners, however, should not simply come to expect the realization of these incentives; many of them have strict requirements and many of them are competitive. Equally important, incentive availability changes over time; business owners should continually review available incentives to make sure they are aware of any changes or additions to offerings.

Last page of Section 10.

11. GENERATION AND DEMAND PROFILES

Another aspect of the Study was to evaluate the correlation between various potential Mohave alternatives/ complements and the SCE load and costs, identify possible alternative/complementary resource mixes, and calculate their benefit to meeting SCE load demand. Work on this task proceeded as follows:

- Collected information about SCE load profiles.
- Collected, analyzed, and converted profiles of complements/alternatives into comparable formats.
- Evaluated the correlation between various potential resources and SCE load and costs
- Identified possible resource mixes and calculating their benefit to meeting SCE load.

11.1 SCE LOAD DEMAND

For the demand profiles, hourly load and price data for SCE were collected for the year 2002 and for the more recent 12-month period from October 2004 through September 2005. A monthly summary of this information is shown in the graphs and table below. Note that the maximum loads occur in July, August, and September.

Figure 11-1 — Load Profile and Prices of Electricity for SCE by Month in the Year 2002

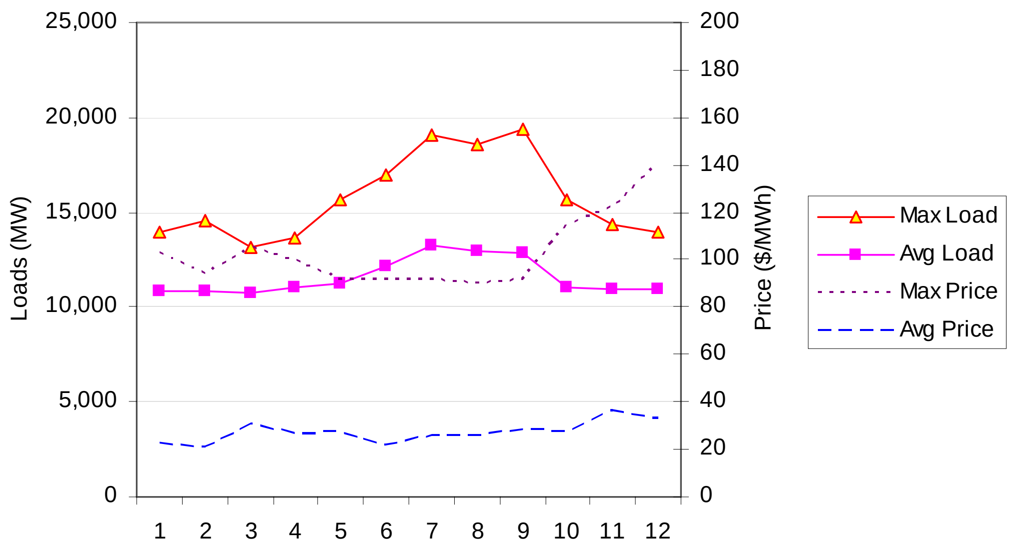


Figure 11-2 — California Monthly Loads and SCE Prices for October 2004 – September 2005

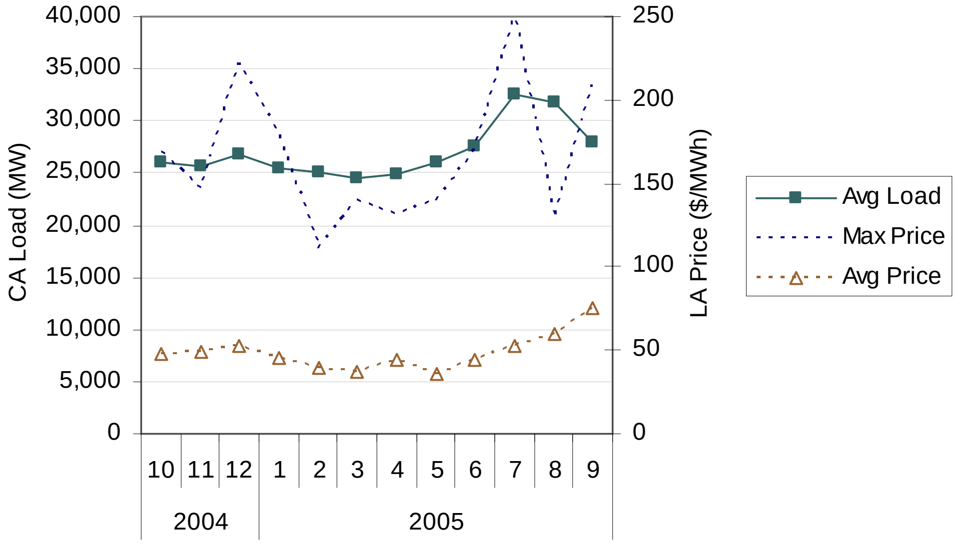


Table 11-1 — Load Profile and Prices of Electricity for SCE by Month in the Year 2002

Month	Avg. Load (MW)	Max. Load (MW)	Avg. Price ($/MWh)	Max. Price ($/MWh)
1	10,856	14,000	22.27	103.17
2	10,831	14,588	20.57	94.19
3	10,731	13,155	30.41	104.83
4	11,031	13,653	26.26	99.70
5	11,271	15,696	26.98	91.87
6	12,160	16,956	21.93	91.87
7	13,241	19,051	25.86	91.86
8	12,922	18,597	25.37	90.17
9	12,833	19,342	28.33	91.87
10	11,014	15,699	27.08	114.69
11	10,925	14,310	36.24	121.98
12	10,951	13,914	33.02	140.38

In addition, the two graphs below show the typical daily load and price patterns by season. The nighttime and evening loads are fairly consistent throughout the year. The big difference occurs in afternoon loads, which are much higher during July, August, and September, with June being a transitional month. The hourly prices show a similar, but much more erratic pattern. The relative price differences are much more extreme with afternoon and evening prices at roughly $35/MWh, which is over three times greater than the early morning prices of about $10/MWh. Thus, there are significant relative benefits for those resources that are available during the mid-day through evening period.

Figure 11-3 — Typical Hourly SCE Daily Price Pattern by Season

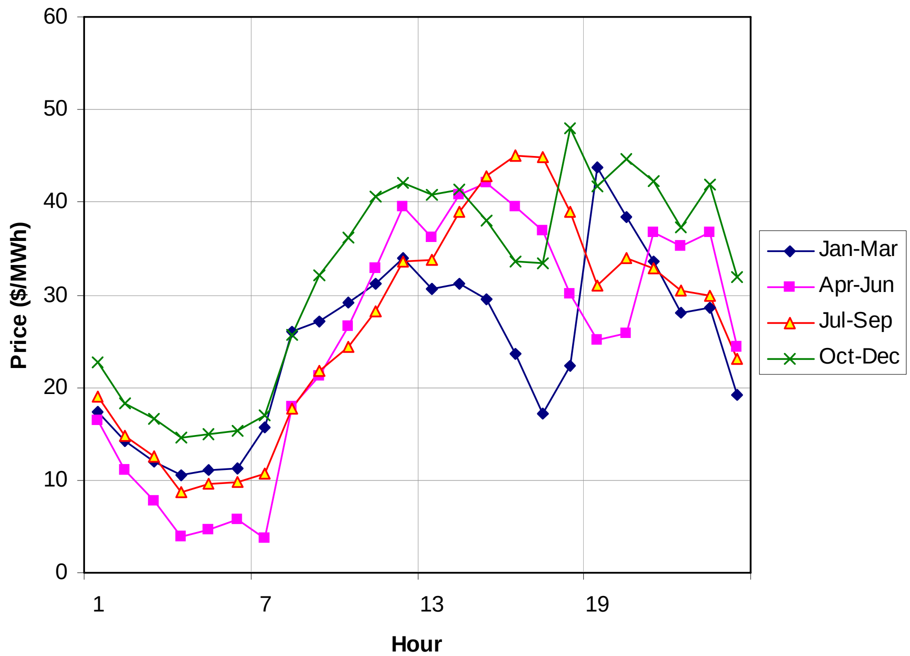
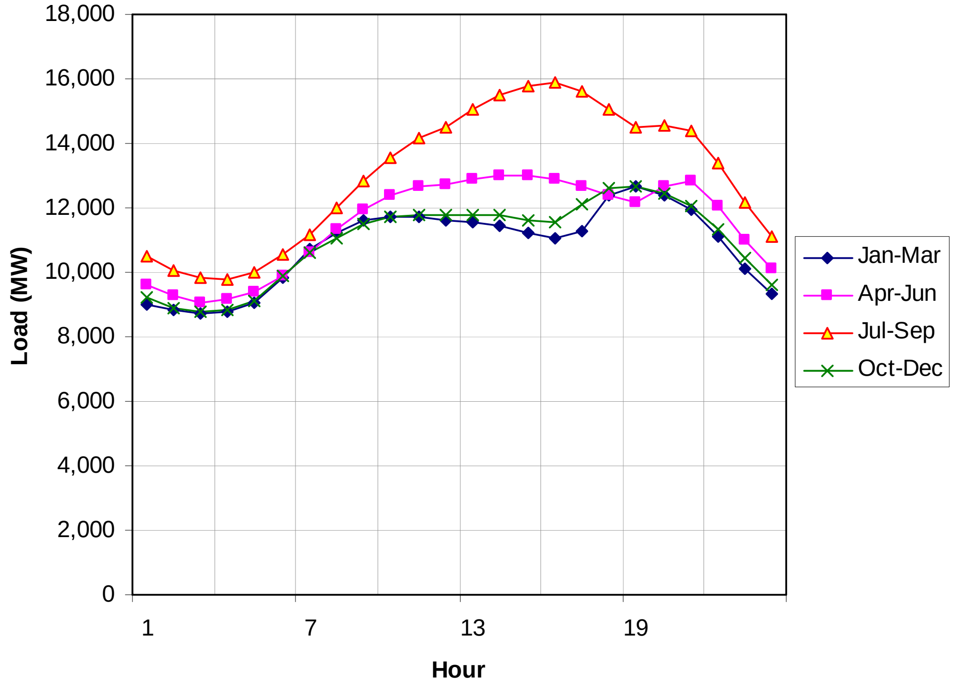
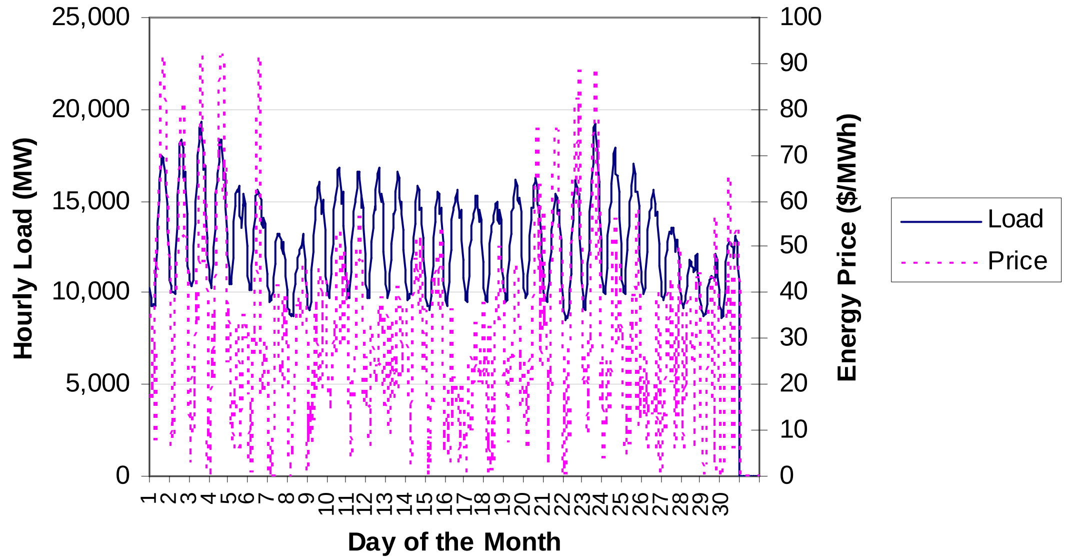


Figure 11-4 — Typical Hourly SCE Daily Load Pattern by Season



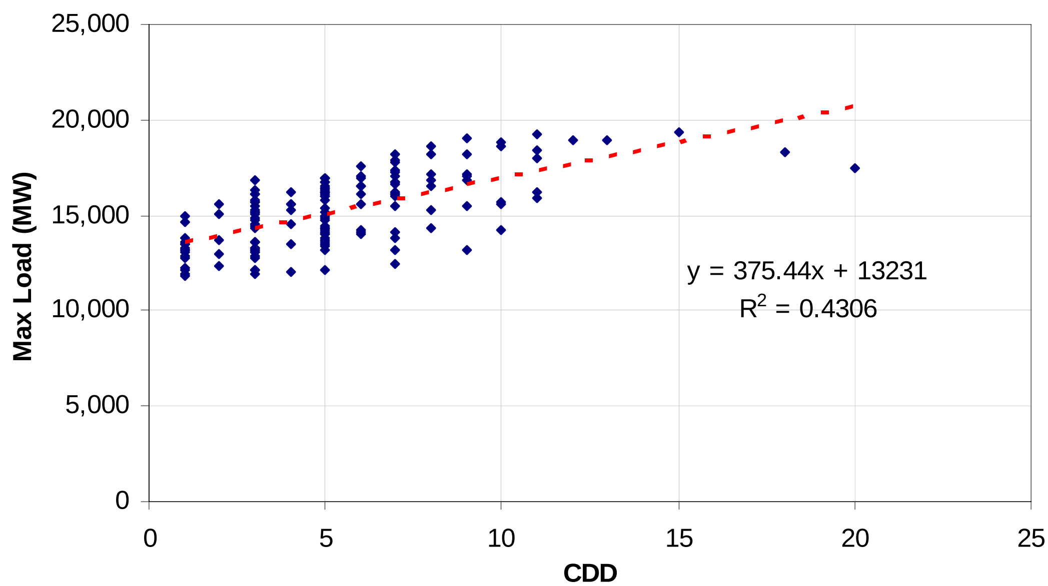
A more detailed look at loads and prices is shown in the following graph for September 2002, which shows that the highest prices are associated with the greatest loads. But that is not always the case; there are some days when loads are high but prices are not, and vice versa. Again, there is a very wide range of daily prices, with typical daily highs ranging from $40 to $90 per MWh, while daily lows are very often below $10/MWh.

Figure 11-5 — Hourly Price and Load Demand Correlation for September 2002



Based on this pattern, it seems likely that a portion of the peak daily loads are related to air conditioning. To determine this correlation, daily peak load and cooling degree days (CDD) was analyzed as shown below. This analysis shows a definite but modest relationship.

Figure 11-6 — Relationship between Daily Peak Energy and Cooling Loads



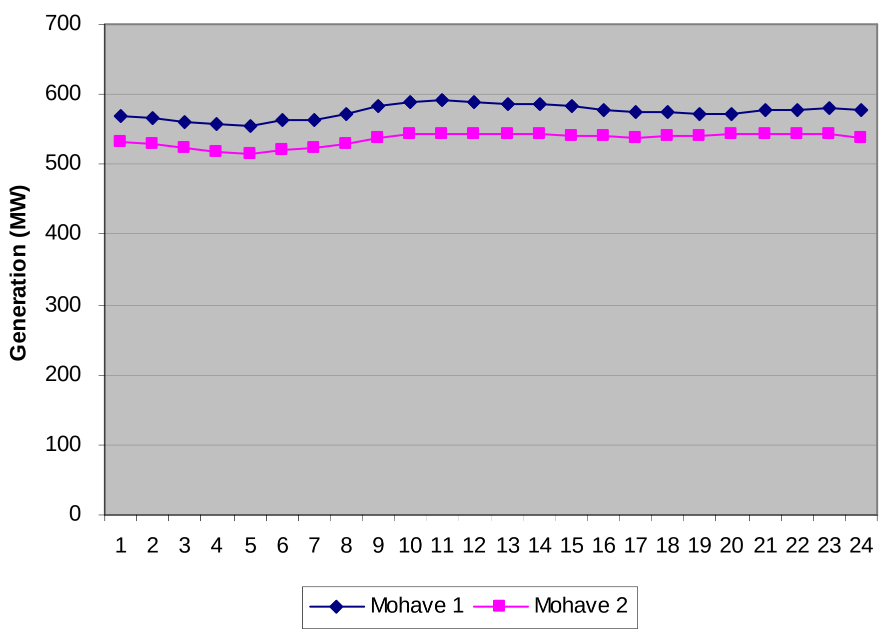
Note: Cooling degree days are those days where the average daily temperature is above 65 degrees Fahrenheit. The x-axis scale for CDD = average daily temperature minus 65 degrees.

11.2 ALTERNATIVE / COMPLEMENT PROFILES

The question that follows the preceding analysis is How well do the resources match up against the load? As discussed above, resources that preferentially provide more energy during the afternoon and evening hours and during the summer days would be of greater value. A description of the output profile of the existing plant and the various alternatives is provided below:

- **Existing Mohave Plant.** The daily generation profile for the existing Mohave station is very flat as shown in the following graph. Thus its most direct replacement would be another base generation resource. But a resource with a better match to the load profile would be even more valuable.

Figure 11-7 — Mohave Average Hourly Generation Profile for 2003



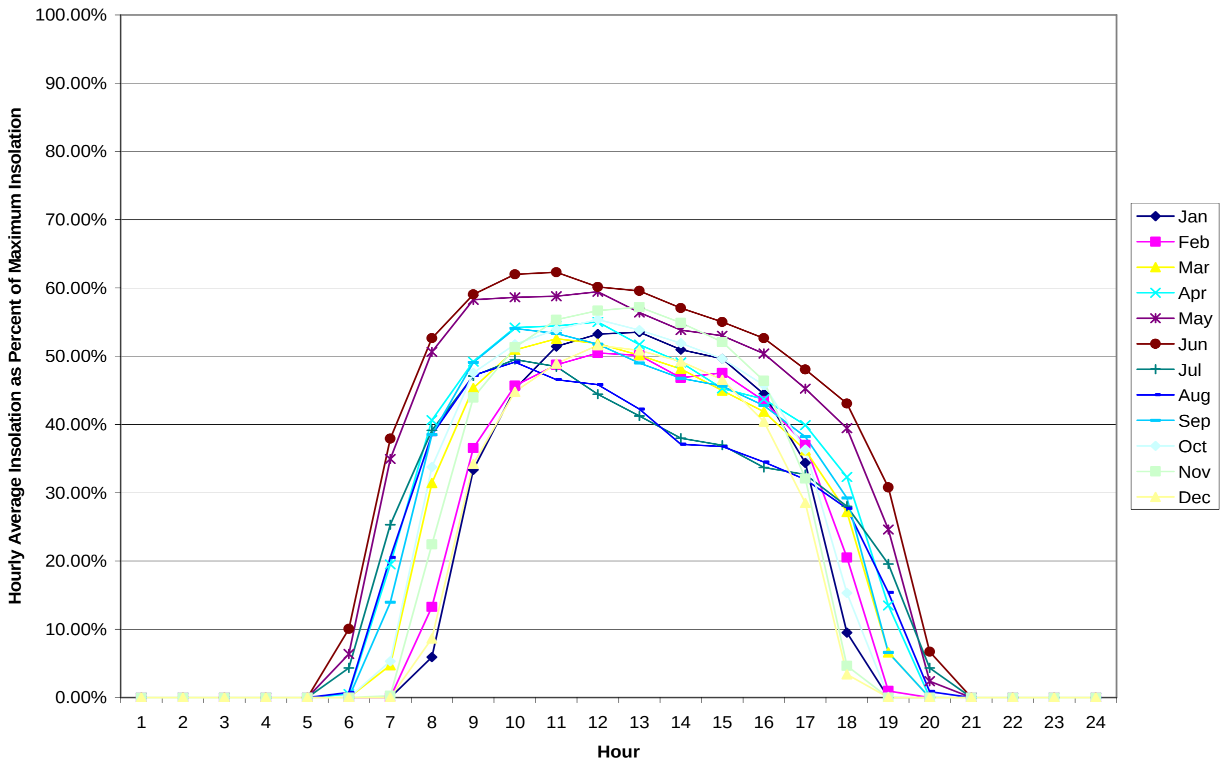
- **Integrated Gasification Combined Cycle.** An IGCC plant is a dispatchable resource that could be operated to some extent to match the loads. However, IGCC plants have very high fixed costs along with low fuel and operating costs. In addition, there may be operational limitations in the rate at which generation can be raised or lowered, especially in configurations that include carbon capture. Thus, an IGCC plant would most likely be run in a baseload pattern similar to Mohave and providing the same amount of energy at all load and price levels.

- **Natural Gas Combined Cycle.** These plants are dispatchable resources that could be run to match the load levels. NGCC plants have moderate capital costs and low emissions, but have fairly high fuel costs since natural gas prices on an energy basis have risen substantially in the last several years and are much greater than coal. These plants also tend to be fairly flexible in ramping up and down to match load. Given these characteristics, a NGCC plant would operate during higher load and price periods. Based on hourly prices shown previously, a plausible scenario would be that an NGCC plant would operate during the “peak” 16-hour period of each day and at additional times if needed for reliability or economy. An NGCC plant with carbon capture, however, may have operational constraints that limit ramp up and ramp down more tightly than for a basic NGCC plant. Also, NGCC plants with carbon capture would have higher capital costs. These factors may limit their dispatchability, either from engineering or economic considerations.

- **Solar.** Solar resources provide a good match, specifically with the daytime peak. However, as shown in the graph below, solar output peaks earlier than the SCE load does and falls off rapidly in the early evening. There is a further time offset since these data are for Flagstaff, Arizona, which is in a different time zone than California and physically farther east. The data also shows a significant afternoon decline in July and August when SCE loads are greatest. It is believed that this is a result of cloud cover conditions in Flagstaff. Such conditions are likely to vary by location and altitude, so the specific Solar 1 and 2 sites may present somewhat different conditions.

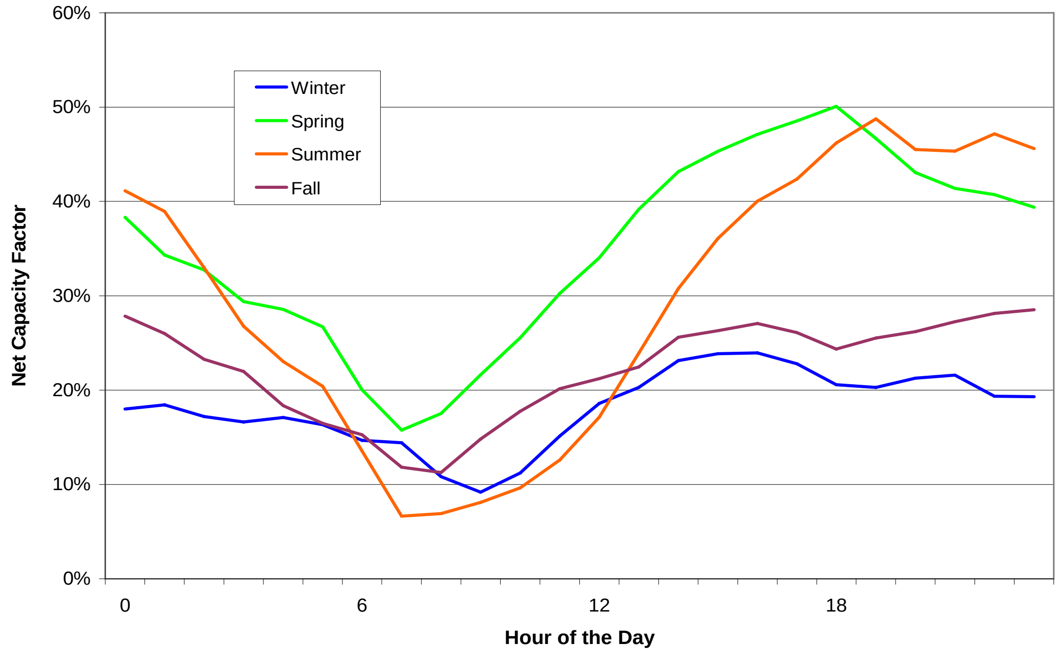
  The output for a photovoltaic device would closely follow this solar profile. A solar thermal device, depending on its design, might not generate at all below a threshold level. Of some of the designs being considered, a dish/Stirling engine with a parabolic reflector would best be able to provide power throughout the entire solar day, but at added expense. Systems with parabolic troughs would have lesser, but still good technical performance. Such a system with storage could shift the generation to later in the day and provide a better match with the SCE load.

Figure 11-8 — Hourly Solar Insolation in Flagstaff, Arizona, by Month



- **Wind.** Wind resources, while variable from one day to the next, show both positive and negative correlations with the SCE load. Seasonally, the wind energy is high in summer, as are loads. The daily pattern shows greater availability in the late afternoon and evening hours, which is a good complement to solar shown above. Generation is also high in the midnight to 6 a.m. period when loads and prices are lowest.

Figure 11-9 — Diurnal Wind Generation Output by Season at the Mogollon Rim in Northeastern Arizona



Note: Sites studied are Gray Mountain, Aubrey Cliffs, Clear Creek and Sunshine.

- **Demand Side Management (DSM) Resource.** The resource output of the DSM alternative or complement to Mohave cannot be described in the same terms as the resource output of the supply options because there are two separate components to the potential transaction. The DSM alternative being explored will consist of a power purchase agreement with SCE coupled with the implementation of DSM measures in a utility service territory located outside of SCE. The nature of the DSM portfolio is not yet known, and its actual physical characteristics (i.e., the hourly profile of energy and/or capacity savings resulting from a portfolio of installed DSM measures) will depend on the set of measures installed, which are yet to be determined with any specificity. However, it is likely that cost-effective DSM portfolios in New Mexico or Arizona, for example, will contain considerable peak load reduction characteristics. The predominance of air conditioning and commercial lighting measures, for example, usually found in such programs, ensures peak load reduction.

  Two broad approaches were considered to analyze the DSM alternative. With each approach, the DSM implementation is coupled with a power purchase agreement for physical flow into SCE's territory.

  The baseline quantitative example used in this analysis assumed that the power purchase contract, which will be coupled with the DSM implementation, will be of the same or similar profile as the current Mohave output, i.e., a baseload plant. (The actual profile used in the example was a flat, 24 x 7 shape power purchase.) In this way, the DSM "resource" can be more easily compared to other supply options. The actual cost, or price, of this resource might ultimately depend on negotiated arrangements between SCE and the neighboring utility supplier, or on results of a competitive solicitation. If the DSM measures being installed tended to focus on reduction of peak load, then the value of the DSM measures to the neighboring utility would be high, allowing for a lower “baseload” power purchase contract price (all else being equal). Conversely, to the extent that the DSM measures produced relatively “flat” savings (e.g., did not focus on daytime air conditioning uses or commercial lighting applications), the value to the host utility might be lower, and thus the purchase price for a “baseload” power flow to SCE would be higher.

A second approach could simply assume that the energy flows associated with the power purchase contract are of a similar shape as the actual DSM resource, or are shaped the same as the host utility’s load profile. In either instance, the price for such a resource would be higher than the price for a flatter-profile product, for the same quantity of energy.

11.3 SUMMARY AND FURTHER ANALYSIS

The SCE load demand shows a distinct seasonal and hourly variation. The variation in prices is even more dramatic than for load. Thus, some resources are more valuable than others depending on how they relate to load. Of course, one consideration is the economic value of the generation for the SCE system. Resources that provide more generation during the peak loads periods have greater energy value. Resources that provide greater reliable capacity during peak load periods are also of greater system value. However, there are also multiple other considerations having to do with locational economic and resource effects.

One of the study’s goals was to evaluate the correlation between various potential Mohave alternatives/ complements and SCE load and costs. SCE nighttime and evening loads are fairly consistent throughout the year. The big difference occurs in afternoon loads, which are much higher during July, August, and September. The data also indicate that a portion of the peak daily loads are related to air conditioning use. Based on this information, resources that preferentially provide more energy during the afternoon and evening hours and during summer days would correlate best with SCE loads and costs.

As it is a baseload generation facility, the daily generation profile for the existing Mohave station is very flat. Thus, its most direct replacement would be another base generation resource, such as an IGCC or NGCC plant. Solar resources, on the other hand, provide a good match specifically with the daytime peak. However, solar output peaks earlier than SCE’s load does and falls off rapidly in the early evening. Of some of the designs being considered, a dish/Stirling engine would best be able to provide power throughout the entire solar day. Systems with parabolic troughs would have lesser, but still good technical performance. Such a system with storage could shift the generation to later in the day and provide a better match with the SCE load.

As with solar, wind energy is high in summer, as are SCE loads. The daily wind pattern shows greater availability in the late afternoon and evening hours, which is a good complement to the solar option.

As for the resource output of the DSM alternative or complement to Mohave, it cannot be described in the same terms as the resource output of the supply options. The hourly profile of energy and/or capacity savings resulting from a portfolio of installed DSM measures will depend on the set of measures installed, which are yet to be determined with any specificity. As the DSM options being studied are in the Southwest, the available end uses would be, to some extent, similar to SCE's, and available savings would have a profile quite similar to SCE's, depending on the programs chosen. However, the commercial terms for such an exchange of DSM for power could shape the power provided in various ways to suit SCE loads.

The next step is to quantify the degree of fit between the various resources being considered and the SCE load profile. The approach used is to consider the relative value of energy from the different resources by matching their generation profiles with a SCE price profile. For each resource, the value of its generation is calculated by multiplying its hourly output by the hourly energy price for typical days to obtain a total avoided cost. Then, for comparison, the average energy value of a baseload resource (such as Mohave) is normalized to 1.0 and other resources (or resource portfolios) ranked relative to that.

Recent annual load and price profiles are shown in Figure 11-10 below. Figure 11-11 shows the average load profiles for various resources being considered.

Figure 11-10 — Average Hourly Load and Price Profiles for October 2004 – September 2005

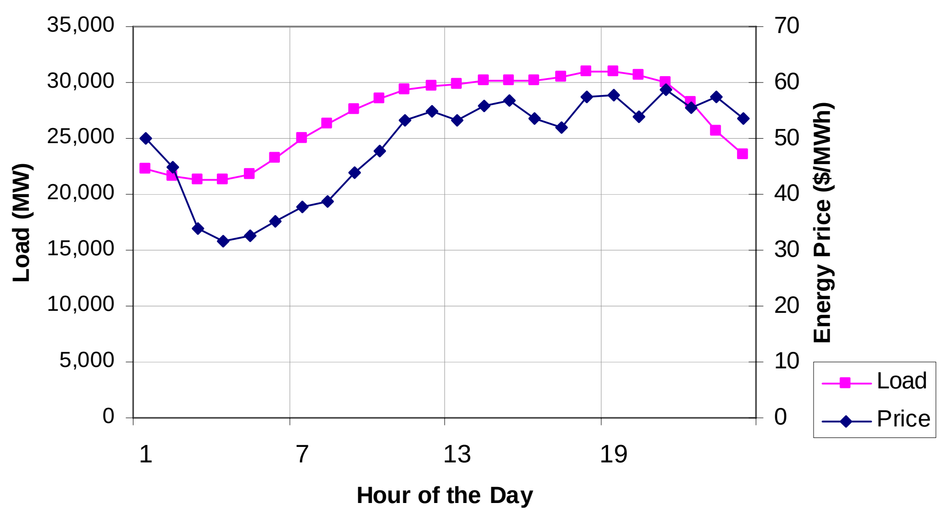
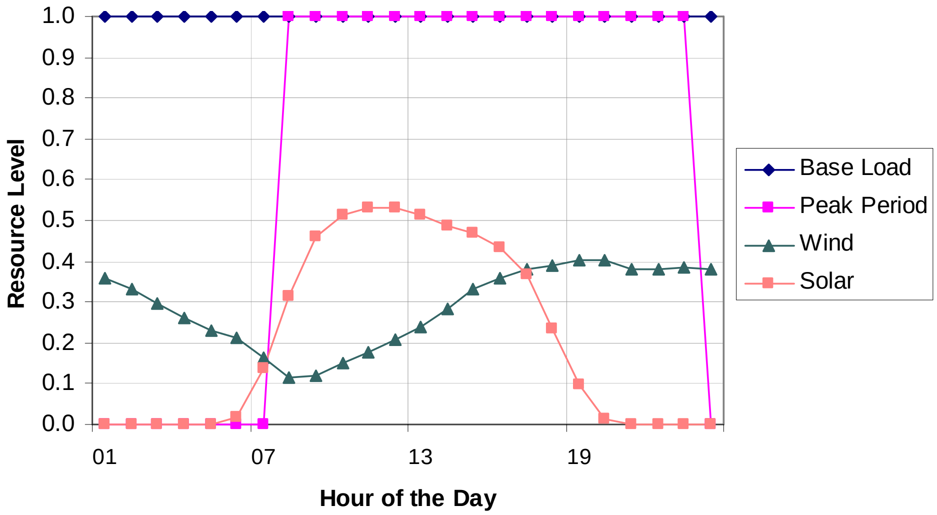


Figure 11-11 — Hourly Relative Resource Profiles



The results of this comparative analysis are shown in Table 11-2 below.

Table 11-2 — Relative Resource Energy Values

Resource Type	Baseload	Peak Period	Wind	Solar
Average Price, $/MWh	48.8	53.2	50.4	51.4
Price Premium	0.0%	9.1%	3.4%	5.5%

Based on recent price patterns, resources that more closely match load and price profiles can obtain average unit prices that are higher relative to baseload resources during the hours in which they operate. This is contrasted against the possible inability of these resources to serve load during other hours and obtain whatever premiums are available during those hours as, for example, in the case of certain solar resources during night hours. In order to characterize performance during both favorable hours and the rest-of-period hours, a more complete electric system operational modeling should be employed.

Last page of Section 11.

12. TRANSMISSION ISSUES

The original scope of work to determine transmission requirements for Mohave Alternatives and Complements included the following:

- Determine the status of transmission availability into the SCE region from the Study area.
- Use information available on the California ISO and wesTTrans OASIS sites to determine the nearer-term availability of transmission capacity into the SCE region.
- Review total transfer capability and available transfer capability to assess the near-term level of capacity availability. As necessary, information from the other western OASIS sites (the Northwest OASIS and the Rocky Mountain OASIS) will supplement data from California ISO and wesTTrans. This approach is to be supplemented with direct oral or written queries to transmission system operators in the Study Area to confirm or clarify the information obtained through OASIS queries.
- Review the information available from the California ISO on holders of existing transmission capacity, and holders of firm transmission rights (FTRs).
- Review existing studies conducted by the California ISO on transmission capability, and review California ISO market reports to determine which interfaces are more likely to be congested, and which interfaces are more likely to support additional capacity transfer into the SCE region. This includes California ISO Department of Market Analysis (DMA) annual and monthly reports and presentations.
- Review existing studies available from transmission owners in the Study Area, in particular those available from Nevada Power, Arizona Public Service, the Western Area Power Administration, the Salt River Project, and the Bonneville Power Administration. The estimates of existing transmission capacity determined through OASIS availability is to be confirmed by cross-checking those results against the transmission capacity information provided by these studies.

12.1 METHODOLOGY USED

The scope of work was limited to the desert southwest region and excluded assessment of transmission availability from the regions north of California. This limitation resulted from two factors: (1) confirmation that the group of supply alternatives and complements to be studied would be limited to locations in or near the Navajo and Hopi tribal lands and (2) the determination that DSM alternatives would focus on the desert southwest states. This was based on the greater level of utility-sponsored DSM already in place in Oregon and Washington, compared to the level of DSM activity and likely opportunities in the desert southwest regions. The methodology used focused on three specific sub-tasks:

- Review of OASIS data and determination of existing available transmission capability.
- Review of existing California ISO and desert southwest utility studies and consideration of future expected changes to the transmission system, focusing on the effect that major transmission upgrade proposals would have on changing (increasing) the level of transmission capacity available for transactions between the desert southwest and California.
- Completion of load flow studies.

12.2 BACKGROUND ON TRANSMISSION ACCESS IN THE REGION

Access to transmission in the desert southwest and the California regions occurs under two separate paradigms: one for users who take transmission service under the California ISO tariff structure and one for transmission service taken under all other transmission tariffs in the region. Many transmission users, especially those with loads in California, must work within both of these constructs to secure access to transmission. The transmission must be used to meet load obligations served by a variety of supply sources, often including those situated throughout the region and not limited solely to local (i.e., intra-state) resources. For example, customers of SCE receive power both from close-in sources of power that use transmission solely under the California ISO's purview (e.g., San Onofre Nuclear Generating Station) and also from more remote sources that rely on external transmission systems and transmission tariff structures (e.g., Four Corners Coal Generating Station, using Arizona Public Service transmission lines).

The California ISO coordinates all transmission use across the major investor-owned utility transmission systems in California, including those of SCE.[1] Users schedule transactions across and/or into the transmission system and pay usage charges based on the injection and withdrawal points of those transactions and based on the results of California ISO's daily and hourly assessments of transmission congestion across the system. The California ISO (1) uses a commercial network model of the transmission system (shown below), (2) defines major internal zones of use (NP15, SP15, and ZP26), and (3) separately models approximately 30 interchange tie points, including multiple tie points with the internal California regions of the Los Angeles Department of Water and Power, the Sacramento Municipal Utility District, and the Imperial Irrigation District. The California ISO tariff also includes a separate set of charges designed to recover the fixed costs of the transmission system.

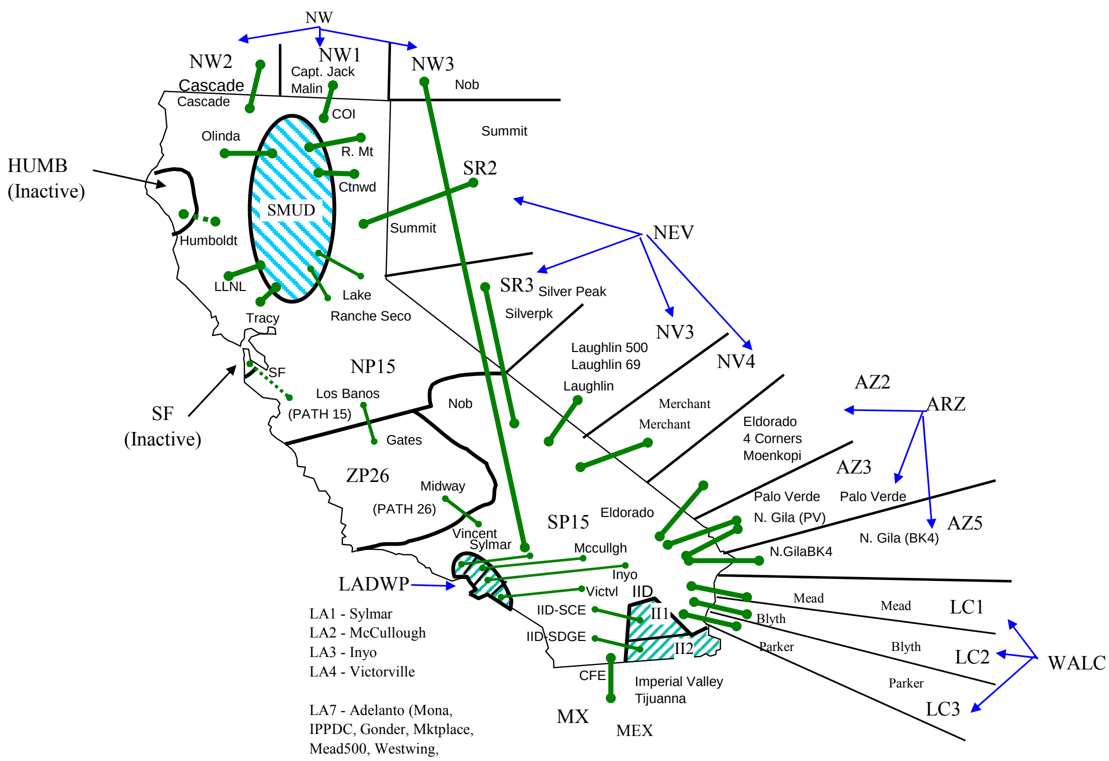
Users of the California ISO grid cannot reserve physical transmission capacity in advance of the day-ahead timeframe, except for uses associated with "Existing Transmission Contracts" (ETCs), which may represent on

[1] The rates, terms and conditions of transmission system use are contained in the current California ISO transmission tariff, available at http://www.caiso.com/pubinfo/tariffs/.

the order of 42% of the total California ISO peak grid use.[2] However, financially firm transmission rights (FTRs) are available for purchase through the California ISO's annual auction. These FTRs allow users to hedge the cost of congestion for one year between California ISO internal zones and between the internal zones and the interchange tie points. FTRs are not necessary in order to schedule energy into the California ISO internal zones.

Figure 12-1 — Congestion Zones and Pathways for California ISO Grid, 2004

Network Model, Effective 1/1/2005



Source: California ISO, Takeout Points, Network and Load Groups (effective January 1, 2005) available at http://www.caiso.com/marketops/technical/index.html.

In contrast to the California ISO tariff structure, the "contract path" paradigm, used by all transmission providers in the west except the California ISO, is best defined as a construct where all transmission is secured based on a fictional contract path from source point to sink point, for defined periods and defined quantities, with certain terms and conditions depending on the degree of "firmness" of the transmission. Individual transmission providers regularly compute the amount of transmission needed to serve native load uses, and then, based on

[2] The FERC Guidance Order in Docket No. ER02-1656-02 states the following: "On July 23, 2004, in Docket No. ER04-928-000, parties filed the requested information detailing approximately 64 contracts. Based on contract termination dates reported, 54 contracts representing approximately 19,000 megawatts

such computations, they determine the amount of transmission available for residual uses and thus offered for sale over OASIS. These computations are complex and are repeated at different intervals to determine the availability for different levels of service. For example, offerings for monthly transmission may be based on a computation performed once per week; offering for daily or hourly transmission service may be based on computations performed daily or several times during the day.

The structure used by the California ISO differs from that in use in the desert southwest in that physical transmission reservations in the California ISO cannot be made in advance;[3] instead, all users of the transmission system pay a usage charge based on computations of congestion derived from a simplified locational pricing model. This methodology implies that the energy output from a technology option can be imported into the SCE service territory if transmission can be secured from the option site to any of the California ISO interchange tie points.[4] While it is possible that physical curtailment of scheduled interchange can occur on an import path into California, it seems that this is a rare occurrence and that all users willing to pay congestion charges will be able to schedule energy into California.[5] For desert southwest regions, power can be delivered to any of the major Nevada or Arizona interchange tie points (NV3, NV4, AZ2, AZ3, or AZ5, via delivery over Arizona and Nevada transmission systems, as indicated on the network map above) or the remaining “lower Colorado” tie points (LC1, LC2, or LC3 via delivery over the Western Area Power Administration [WAPA] lower Colorado transmission system).

12.3 EXISTING AVAILABLE TRANSMISSION CAPACITY AS REFLECTED IN OASIS TRANSMISSION OFFERINGS

The Open Access Same-Time Information System (OASIS) is a transmission access and reservation construct mandated by the FERC through its open access Order 889 and its subsequent follow-on orders.[6] Order 889 was

(MWs) may still be in place upon implementation of MRTU in February 2007. These contracts may represent as much as 42 percent of the CAISO’s 2004 peak load of 45,000 MWs.” (paragraph 8).

[3] Transmission use under ETCs is scheduled with the California ISO in the day-ahead timeframe.

[4] The interchange tie zone “AZ2” includes a “pseudo” tie at Four Corners. This represents the ability to import certain generation at Four Corners directly into the California ISO control area, using existing transmission rights. It does not imply that new generation physically connected at Four Corners can automatically schedule into the California ISO control area; physical transmission to the California border points must first be obtained.

[5] An analysis of the magnitude of congestion charges for power flowing into California from desert southwest paths was beyond the scope of this project. However, California ISO reports that in 2004, the total congestion changes for imports from Palo Verde were $21 million, reflecting an average congestion charge of $6.10/MWh and path congestion for 22.3% of the hours in the year. Source: 2004 Annual Report on Market Issues and Performance, Table 5.2 and 5.3, pages 5-3 through 5-9.

[6] FERC Order 889 (April 24, 1996), 889-A (March 4, 1997), and 889-B (November 25, 1997), available at http://www.ferc.gov/legal/maj-ord-reg/land-ord.asp.

a companion Order to FERC's landmark Order 888[7], which promoted wholesale competition through open access to FERC-jurisdictional transmission systems. Many non-jurisdictional transmission system operators have also provided reciprocal open access on terms similar or identical to those reflected in Orders 888 and 889, including transmission systems used to supply power into California such as those operated by WAPA and the Bonneville Power Administration (BPA).

The promise of Order 889 is to provide transmission customers information about availability and pricing of transmission in a non-discriminatory fashion.[8] The OASIS structure facilitates this transparency by allowing customers to query the status of transmission availability on any given transmission provider's system,[9] and it also seeks to provide additional information, such as the results of system studies, that further informs transmission customers on the status of the transmission system robustness. A core purpose of the order is also to ensure that transmission providers do not grant preferential access to any user, including any affiliated company. Notably, however, "native load" uses of a transmission provider's system are considered outside the open access construct, and the information gleaned through OASIS reflects pricing and availability for uses incremental to native load.

Transmission owners in the Western U.S. initially provided open access reservation systems individually. Recently, many of the transmission-owning entities in the western region have coordinated their OASIS's under a single framework operating as the wesTTrans OASIS (http://www.westtrans.net/OASIS.html). The wesTTrans OASIS coordinates transmission reservation requests for the following transmission systems:

- Arizona Public Service
- Avista Corp. (formerly Washington Water Power)
- British Columbia Transmission Corporation (formerly, BC Hydro transmission)
- El Paso Electric
- Idaho Power Company

[7] FERC Order 888 (April 24, 1996), available at http://www.ferc.gov/legal/maj-ord-reg/land-ord.asp.

[8] FERC Order 889, "Under this final rule, each public utility (or its agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce will be required to create or participate in an OASIS that will provide open access transmission customers and potential open access transmission customers with information, provided by electronic means, about available transmission capacity, prices, and other information that will enable them to obtain open access non-discriminatory transmission service." (page i)

[9] FERC Order 889, "The second provision sets out basic rules requiring that jurisdictional utilities that own or control transmission systems set up an OASIS. Under these rules, the utilities are required to provide certain types of information on that electronic information system as to the status of their transmission systems and are required to do so in a uniform manner. With these requirements, we are opening up the "black box" of utility transmission system information. When in place, the OASIS will allow transmission customers to determine the availability of transmission capacity and will help ensure that public utilities do not use their ownership, operation, or control of transmission to deny access unfairly." (page xx)

- Imperial Irrigation District
- Los Angeles Department of Water and Power
- Nevada Power
- Northwestern Energy
- Portland General Electric
- Public Service of Colorado
- Public Service of New Mexico
- Puget Sound Energy
- Sacramento Municipal Utility District
- Salt River Project
- Sierra Pacific Power Company
- Southwest Transmission Cooperative
- Texas/New Mexico Power Company
- Tri-State Generation and Transmission Cooperative
- Tucson Electric Power
- Western Area Power Administration (Rocky Mountain and Desert Southwest regions)

In addition, Colorado Springs Utilities and Transmission Agency of Northern California will begin use of the wesTTrans OASIS platform in November and December 2005.

The transmission systems in the West are either individually or jointly owned by transmission providers, and those individually owned can include the existence of long-term ownership rights for transfers over designated paths. The Western systems continue to use the “contract path” approach, whereby transfer capability is allocated on a path- or line-specific basis to owners or rights holders. This system of ownership and rights allocation is reflected in the OASIS database, as queries to ascertain transmission availability result in “available transmission capability”[10] across any given path from one or more than one transmission owning entity. For example, the major lines transmission from Four Corners to Palo Verde are owned by Arizona Public Service,

[10] The wesTTrans OASIS system provides available transmission capacity in most cases on the “offerings” screen, rather than the “ATC” screen. The ATC screen often indicates the following, which accompanies a query to ascertain ATC: “Note: Your Provider may post ATC’s under Offerings”. We determined available transmission capacity using the values from the “offerings” screens.

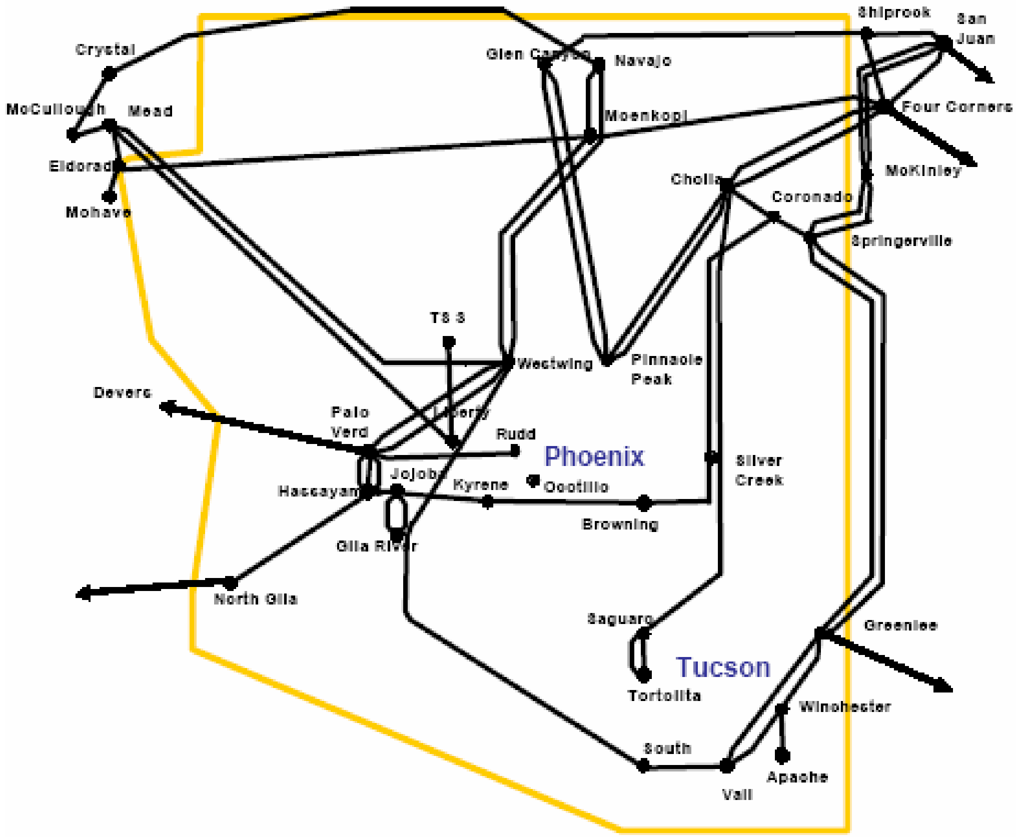
but the only "yearly" firm available transmission on that path is offered by Tucson Electric Power, which has rights to firm use for a portion of that path.

Synapse queried the wesTTrans OASIS platform during August and September 2005 to obtain information on the availability of transmission from the Study Area to SCE's service territory. The Study Area included central and northeastern regions of Arizona. For determining transmission availability, Synapse focused on a number of potential "source" points in the region, or "points of receipt" into the transmission system, into which a number of alternative supply sources could be connected or could have their power output flow. These source points included the following:

- The Four Corners/Shiprock region of northwestern New Mexico, a hub point for generation supply sources in the region;
- The Moenkopi and Navajo 500-kV connection points in north central Arizona; and
- The Cholla substation in eastern central Arizona, a connection point to the 500-kV system in the region.

The rough proximity of these source points is shown on the Arizona extra-high voltage transmission system map below.

Figure 12-2 — Arizona Extra-High Voltage Transmission Facilities



Note: This map is reproduced directly from the Arizona Corporation Commission Staff and KEMA Inc. report, "Third Biennial Transmission Assessment 2004-2013," November 30, 2004, filed in Docket No. E-00000D-03-0047 with the Arizona Corporation Commission.

The analysis assumes that any of the supply alternatives would be responsible for either connecting to the transmission grid at these locations or for securing adequate transmission to enable power injected at the supply point to flow to these locations. Transmission availability information for a number of lower voltage points on the transmission grid at locations closer to the exact locations of the supply alternatives was not obtainable through the OASIS system. These points include, for example, the Leupp, Seligman, and Coconino 230-kV connection points, and the 345 kV Flagstaff connection point, all of which are in the proximate north-central Arizona region.

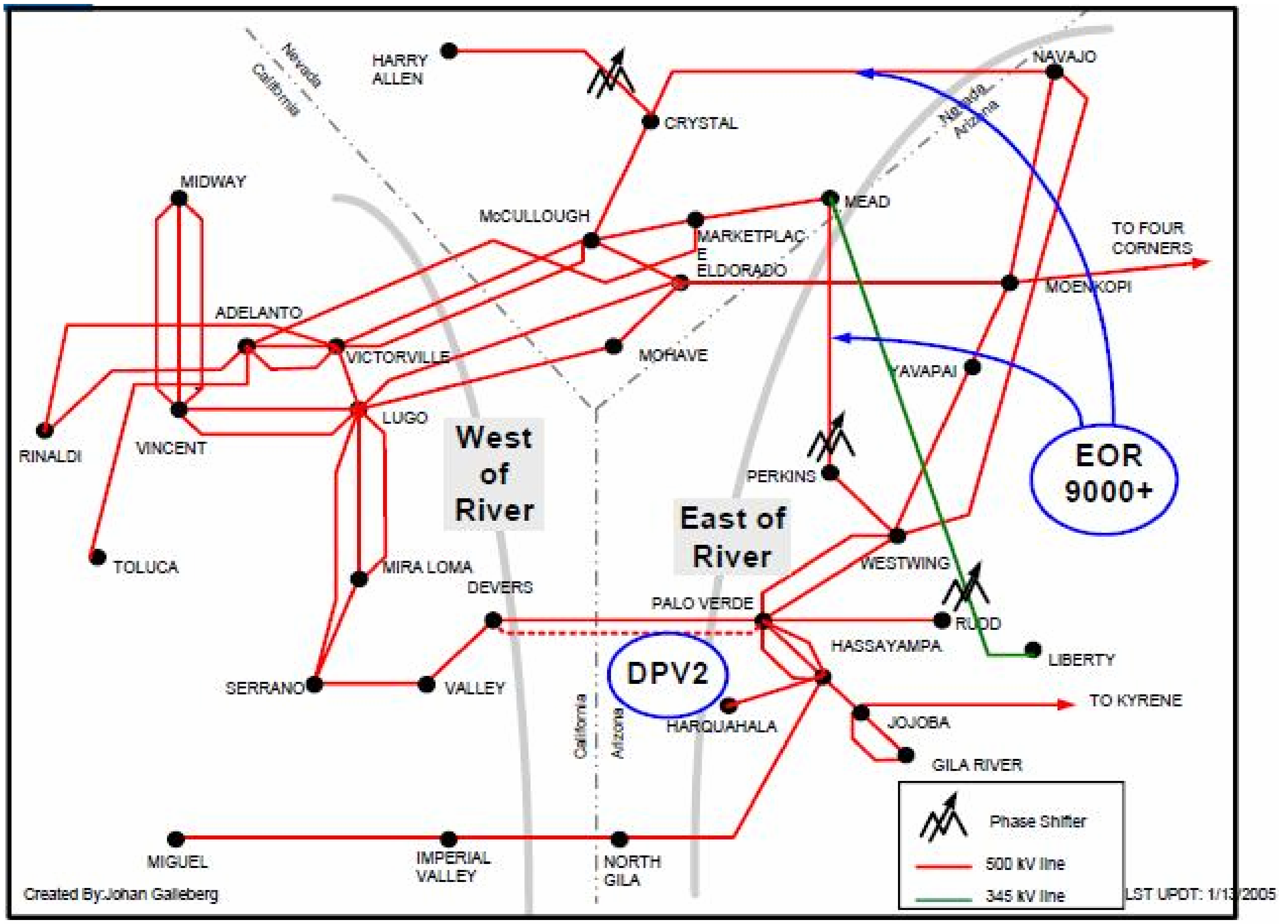
The following table maps the "source points" studied with regard to each of the different Mohave alternatives or complements. Unless otherwise indicated, all source points are located at the 500-kV level. In general, the methodology used to determine available transmission capacity was not tied directly to any particular technology option, but rather it established the level of capacity that remained available for any given power injection at the source point indicated. Thus, if capacity is (or is not) available for a transfer from Four Corners to Palo Verde, then that capacity could be used (up to the level available) for any number of alternatives that might connect via Four Corners, for example, an IGCC at Black Mesa, a wind plant at Black Mesa, or a Solar Site 1 plant.

Table 12-1 — Transmission System "Source" Points Associated with Each Technology Option

Technology Option	Transmission System Source Point
IGCC – at Black Mesa	Four Corners, Navajo, Moenkopi
Wind – Aubrey Cliffs	Hilltop (230 kV), Moenkopi
Wind – Gray Mountain	Moenkopi
Wind – Clear Creek / Sunshine	Cholla
Solar Site 1	Four Corners, Navajo
Solar Site 2	Moenkopi
DSM – New Mexico (PNM)	No transmission study conducted – coupled with purchased power at Palo Verde
DSM – Arizona (APS)	No transmission study conducted – coupled with purchased power at Palo Verde
IGCC at Mohave	No transmission study conducted – at CA border already
Combined Cycle at Mohave	No transmission study conducted – at CA border already

To serve SCE customers, electricity supply sourced from the Study Area would need to flow to California via any of two major transit paths and one minor transit path. The major transit paths include the Palo Verde-to-Southern California route, via two major 500-kV transmission lines, one from Palo Verde and one from its companion "switching station" at Hassayampa; and the set of 500-kV and 230-kV transmission lines emanating from the southern Nevada area at the McCullough, Marketplace, Eldorado, Mohave, and Mead substations. Those paths are schematically represented in the California ISO map below.

Figure 12-3 — Schematic of Major Transmission Infrastructure between Arizona, Nevada and California



Note: This map was produced by the California ISO and shows schematically the major constrained paths into California from the desert southwest, the "East of River (EOR)" and "West of River" paths indicated on the figure. This map also shows the location of two of the proposed new transmission projects designed to increase transfer capacity from Arizona into California: the "DPV2" or Devers-Palo Verde 2nd 500 kV line; and upgrades to increase the transfer capacity across the EOR path to 9,000 MW.

The third transit path includes access via the WAPA 230-kV facilities between the region west of Phoenix and the Parker dam facilities at the California border. Transit paths have been analyzed in this way in order to determine transmission availability to these "sink" points from the Study area.

Another way to characterize the routes into southern California would be to use the California ISO's set of interchange tie points with the region east and northeast of southern California, which includes the three transit paths described above. The California ISO models these interchange points as "branch groups" and computes congestion charges for import power flows sourced at any of these points.

The study sought to determine transmission availability from Arizona and Nevada to the California ISO border, to any of the physical interchange tie points, all of which are included as possible "sink" points or "points of delivery" in the OASIS database. The interchange tie points are listed in Table 12-2 below.

Table 12-2 — Interchange Tie Points between California and Arizona/Nevada

Interchange Tie Point	From	To	DESCRIPTION
ELDORD_5_MOENKP	AZ2	SP15	ELDORADO
PVERDE_5_DEVERS	AZ3	SP15	PALOVERDE
PVERDE_5_NG-PLV	AZ3	SP15	N.GILA (PV)
NGILA_5_NG4	AZ5	SP15	N.GILA (BK 4)
ELDORD_5_MCLLGH	LA2	SP15	MCCULLOUGH
MEAD_2_WALC	LC1	SP15	MEAD
BLYTHE_1_WALC	LC2	SP15	BLYTHE
PARKR_2_GENE	LC3	SP15	PARKER
MOHAVE_6_69KV	NV3	SP15	LAUGHLIN 69
MOHAVE_5_500KV	NV3	SP15	LAUGHLIN 500
MRCHNT_2_ELDORD	NV4	SP15	MERCHANT PLANT

Source: California ISO, Takeout Points, Network and Load Groups (effective January 1, 2005) available at http://www.caiso.com/marketops/technical/index.html. Note: Pseudo Ties are excluded from this listing.

Transmission availability was categorized according to the structure used by transmission providers offering access to their systems. Transmission can be obtained on a firm or a non-firm basis, and it can be obtained for varying time periods: hourly, daily, weekly, monthly, or yearly. Yearly transmission access is available only on a firm basis, and hourly transmission availability is generally available only on a non-firm basis, although OASIS entries do exist, indicating hourly firm transmission.

12.4 RESULTS OF THE OASIS QUERIES

The results of our OASIS queries are summarized in the tables below. The values listed in the tables are based on a careful examination of the results of numerous queries made through the wesTTrans OASIS system for various transmission paths. The maximum capacity available, the time frame, and the seller(s) are listed. For the paths reviewed, sellers include Tucson Electric Power (TEP), Arizona Public Service (APS), Los Angeles Department of Water and Power (LDWP), and Salt River Project (SRP). These entities either own the transmission assets in question or have rights to use the transmission. Appendix K contains more detailed data based on the OASIS queries that were used to develop these summary tables. The data in Appendix K reveal, for example, the pattern of available transmission across a succession of time periods and across different owners, from which the summary data were extracted based on maximum capacity available.

Table 12-3 — Summary of Transmission Availability "Into California" from Four Corners to Palo Verde

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Non Firm
Maximum Capacity Available	94 MW	104 MW	104 MW	104 MW	104 MW	117 MW	117 MW	422 MW
Time Frame	2007 and 2008	June – Aug 2006	June – Aug 2006	October 2005	October 2005	September 2005	September 2005	September 2005
Seller	TEP	TEP	TEP	TEP	TEP	TEP	TEP	APS

Notes:

Lower volumes of firm and nonfirm monthly transmission are available for the months November 2005 through February 2006, and September through October, 2006.

For hourly transmission, lower volumes are available for many hours; the maximum quantity listed is available for selected hours or groups of hours in the time period indicated.

Table 12-4 — Summary of Transmission Availability "Into California" from Four Corners to Mead

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Non Firm
Maximum Capacity Available	0 MW	0 MW	0 MW	1 MW	0 MW	1 MW	58 MW	211 MW
Time Frame				September 2005		September 2005	September 2005	September 2005
Seller				APS		APS	APS	APS

Note:

For hourly transmission, lower volumes are available for many hours; the maximum quantity listed is available for selected hours or groups of hours in the time period indicated.

Table 12-5 — Summary of Transmission Availability "Into California" from Navajo 500 to Palo Verde

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Non Firm
Maximum Capacity Available	169 MW	572/547 MW	572/547 MW	274 MW	234 MW	450 MW	390 MW	605 MW
Time Frame	2006	Jan – Sept 2006	Jan – Sept 2006	September 2005	September 2005	September 2005	September 2005	September 2005
Seller	TEP, APS	LDWP, APS, TEP	LDWP, APS, TEP	TEP, SRP, APS	TEP, APS	LDWP, APS, TEP, SRP	LDWP, APS, TEP	LDWP, SRP, APS

Notes:

125 MW of yearly transmission is available for 2007 and 2008 through TEP.

572 MW of monthly firm or non-firm transmission is available for January through March, 2006; 547 MW is available for April through September, 2006.

For hourly transmission, lower volumes are available for many hours; the maximum quantity listed is available for selected hours or groups of hours in the time period indicated.

Table 12-6 — Summary of Transmission Availability "Into California" from Cholla 500 to Palo Verde

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Non Firm
Maximum Capacity Available	0 MW	230 MW	115 MW	115 MW	69 MW	115 MW	115 MW	462 MW
Time Frame		Jan – Oct 2006	Jan – Oct 2006	September 2005	October 2005	September 2005	September 2005	September 2005
Seller		APS	APS	APS	APS	APS	APS	APS

Note:

For hourly transmission, lower volumes are available for many hours; the maximum quantity listed is available for selected hours or groups of hours in the time period indicated.

Table 12-7 — Summary of Transmission Availability "Into California" from Moenkopi to Palo Verde

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Firm*
Maximum Capacity Available	125 MW	641 MW	169 MW	463 MW	134 MW	663 MW	334 MW	538 MW
Time Frame	2006, 2007, 2008	Jan-Sept 2006	Jan-Oct 2006	September 2005	September 2005	September 2005	September 2005	September 2005
Seller(s)	TEP	SRP, TEP, APS	TEP, APS	SRP, TEP, APS	TEP, APS	SRP, TEP, APS	TEP, APS	SRP, APS

Note:
Hourly service is listed as available as firm for APS and SRP. Non-firm hourly maximum quantity is 334 MW, available from APS and TEP.

Table 12-8 — Summary of Transmission Availability "Into California" from Moenkopi to Eldorado, Mead, McCullough, or Marketplace

	Yearly Firm	Monthly Firm	Monthly Non Firm	Weekly Firm	Weekly Non Firm	Daily Firm	Daily Non Firm	Hourly Non Firm
Maximum Capacity Available	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW	0 MW

These results illustrate that current transmission system availability as reflected in the information posted on the OASIS site is limited and, in particular, that long-term firm transmission (e.g., yearly) is not available in the quantities needed for the supply alternatives other than those located at the existing Mohave site. However, the summary information does indicate that monthly period transmission service is often available in quantities approaching the approximate size of some of the technology options being considered (i.e., on the order of hundreds of megawatts). The summary information also indicates that paths originating at Moenkopi or Navajo appear to have greater shorter-term firm availability (e.g., monthly) than paths originating in the Four Corners area, likely reflecting the relative limitation on the first portion of the path from the Four Corners area. This implies that connection points at or around Navajo or Moenkopi locations may be preferable to those at the Four Corners area, all else being equal.

Lastly, it is important to note that this examination of transmission availability is based on current snapshots of the transmission system and does not take into account any of the transmission system upgrades under consideration for the region (discussed below). Use of OASIS data as an indicator of near-term transmission availability also presumes that the existing physical transmission reservation construct will continue to be used for power flowing to the California ISO grid border. However, if the desert southwest region were to implement a regional form of transmission access under an RTO-like structure with a form of financial transmission rights, a different approach to transmission use and scheduling could arise.[11] Under such a construct, Mohave technology options located in the Study Area might not need to secure physical transmission in the same manner as is currently contemplated, but rather might face a set of financial congestion charges for transshipment of power to the California ISO border.

12.5 EXISTING STUDIES OF TRANSMISSION CAPABILITY FOR THE ARIZONA–NEVADA–CALIFORNIA REGION

The following studies were reviewed to assist in determining the extent of available transmission capacity in the region:

- California ISO 2004 Annual Report on Market Issues and Performance
- California ISO CARTS/STEP (California Arizona Regional Transmission Study / Southwest Transmission Expansion Plan), various studies/presentations from the California ISO and transmission owners, including those associated with the following projects:
- Devers Palo-Verde #2 500-kV transmission line
- EOR 9000+ Upgrade Project
- SCE Short-term transmission projects – Devers area upgrades
- Path 46 West-of-River Phase I upgrades and path rating study
- Colorado River Transmission Planning Committee Status update
- STEP Expansion Plan Effects on Congestion Between Arizona, Nevada, and California
- 2004 California ISO Controlled Grid Study Report
- Arizona Public Service presentations – miscellaneous material available on APS's portion of the wesTTrans OASIS, including a presentation by Arizona Public Service at the WestConnect Transfer Capability Informational Conference.

[11] A number of transmission-owning utilities in the Arizona/New Mexico region have been considering a desert region RTO in various forms for numerous years. The current coordinated OASIS operation of wesTTrans represents the first phase of a multi-phased process that could result in an RTO with coordinated ATC computation or even an eventual common energy market platform. See, for example, the information available at www.westconnectrto.com or www.ssg-wi.com.

- Arizona Public Service Ten-Year Plan
- Arizona Corporation Commission (ACC)/KEMA 3rd Biannual Transmission Assessment
- Central Arizona Transmission System (CATS) Reports
- Conceptual Plans for Electricity Transmission in the West, Report to the Western Governors' Association, August 2001.

As a whole, the information contained in these studies indicated the following key points:

- Short-term upgrades to existing 230- and 500-kV transmission lines will increase the ratings of the major East-of-River and West-of-River transmission constraints and will help reduce near-term congestion costs for flows into the California ISO region.
- The planned addition of a second 500-kV transmission line between Devers (California) and Palo Verde (actually, just southwest of Palo Verde at the Harquahala Substation) along with the "East of River" upgrades to the existing 500-kV system "will eliminate the majority of the major path congestion in the STEP/SWAT [southwest transmission expansion plan/southwest area transmission] area."
- Transmission paths from Palo Verde east have been improved, and new transmission projects planned will continue to increase capacity east of the hub; however, paths west of the hub need to be upgraded to allow for full access of Palo Verde hub generation to the California market. The summary information in the above two points illustrates that capacity-increasing projects for paths west from Palo Verde are being examined.
- There remains an incremental amount of intra-Arizona transmission transfer capability available for firm sales, but the total amount is limited and is mostly on the order of a few hundred megawatts for different point-to-point paths.
- Consideration should be given to spreading the costs of new transmission system use across all users of the regional system, possibly through use of RTOs as the vehicle for cost recovery. Implementation of the "open season" model of the natural gas pipeline industry should be considered in order to provide capital for new construction.

A key summary point is notable, from the ACC/KEMA study:

> There is very little existing long-term firm transmission capacity available to export or import energy over Arizona's transmission system. Studies investigating transmission additions required between Arizona and California and between New Mexico and Arizona continue to explore the scope, participation and timing of alternative projects. [12]

[12] Arizona Corporation Commission Docket No. E-00000D-03-0047, *Third Biennial Transmission Assessment, 2004-2013*, November 30, 2004. Prepared by ACC Staff and KEMA Inc. Executive Summary, page iii.

Based on the information examined, it seems that there is little long-term firm capacity for increased Arizona–California flows, but increased capacity from proposed transmission projects will increase available transmission capacity.

12.6 PROPOSED MAJOR NEW TRANSMISSION PROJECTS

There are numerous transmission projects planned or proposed for the southern California and the desert southwest region. The following list includes four major projects that, if constructed, will affect transmission availability from western Arizona to the SCE service territory, and from the Study Area to the California border region:

- **East of Colorado River Path 49 Short Term Upgrades.** The major path limiting transfers to the California ISO control area from the Arizona/Southern Nevada region is the WECC Path 49, or “East of [Colorado] River” (“EOR”) path. Planned short-term upgrades to EOR Path 49 include installation of capacitors, phase-angle regulating transformers, and static VAR compensators on lines and substations in Arizona, California, and Nevada. These upgrades will increase the path rating from 7,550 MW to 8,055 MW in 2005 and 9,300 MW in 2006. These upgrades together are known as the EOR 9000 project.

- **Palo Verde – Devers #2 500 kV**. A second 500-kV line between Palo Verde and Devers is planned for operation in 2009. This line will increase the Path 49 rating by at least 1,200 MW and possibly by as much as 2,000 MW. As noted in a California ISO presentation (Jeff Miller, California ISO, Jan 2005 presentation)—

  > The EOR 9000 project and the Palo Verde-Devers #2 project are complimentary and function well together. The addition of both the PVD2 project and the EOR 9000 project would eliminate the majority of the major path congestion in the STEP/SWAT area.

- **Palo Verde – N. Gila – San Diego #2 500 kV.** This project is not as well-defined as the PV-Devers #2 line noted above. However, its addition will significantly increase the path rating of EOR.

- **Navajo Transmission Project.** The proposed Navajo transmission project is a 460-mile, 1,200 to 1,800-MW, 500-kV transmission line between the Four Corners/Shiprock region and the Las Vegas (McCullough substation) area. The project is planned for construction in three stages:
  - Shiprock (4 Corners) to Red Mesa;
  - Red Mesa to Moenkopi; and
  - Moenkopi to Las Vegas area (McCullough)

  The project is proposed by the Diné Power Authority, in conjunction with TransElect. The source of funding and likelihood of project implementation is unknown at this time. A 2008 operation is proposed. Additional information is available at the following sites:
  - http://www.cc.state.az.us/utility/electric/biennial/B-DNTP.ppt#258,1,Slide 1
  - http://www.trans-elect.com/navajo/navajo_background.htm.

- **Miscellaneous 500-kV Projects.** Increases to the major bulk transmission systems in the California-desert southwest region are likely to affect the ability of the Mohave technology options to move power to the California border, although some individual projects will not substantially change the transfer capability from the northeastern Arizona region to the California border. The Phoenix area is undergoing significant load growth, and substantial 500-kV system improvements are planned in the area. San Diego Gas and Electric and Southern California Edison are planning internal territory improvements that can affect the transfer rating across the major Arizona–Nevada–California paths.

12.7 TRANSMISSION INTERCONNECTION

This transmission evaluation analyzed the feasibility of adding generation at a number of sites in terms of upgrades required for transmission service. The interconnection cost is based on transmission upgrades required to relieve any overloaded facility that would prohibit the evacuation of power from the generation area. Upgrades required for interconnection allow the generator to inject power into the transmission system. However, this does not necessarily grant transmission service, allowing the generator to transfer power.

This transmission study reviews the impact of injecting power into the transmission network in 10 different generation scenarios. The 10 scenarios include 5 single-plant cases and 5 multiple-plant cases. The power flow studies were conducted using cases developed from the FERC 2005 summer case. The FERC case was modified for this analysis to incorporate the effect of capacity resources. Since information to distinguish capacity resources is not made public, capacity resources were accounted for by increasing the output of all generators within five buses of the new generation site to full capacity. In addition, newly completed generation projects and future generation projects with a high probability of completion were incorporated into the model. This resulted in the addition of eight generation projects, six that are completed and two that are expected to be in operation by 2010. Each of the 10 cases was then run two ways—first with existing transmission only, and then with two transmission projects that are scheduled for completion by 2010 for comparison.

Once the cases were developed for each scenario, our analysis identified overloaded transmission facilities for normal operation and for contingency conditions. The interconnection studies included contingencies for outages of transmission facilities above 100 kV and within four to five busses of the new plant. After the overloaded facilities were identified, a cost estimate was prepared for each case.

Our interconnection feasibility study for each case indicates that potential costs of interconnection vary between cases. Table 12-9 summarizes the interconnection cost estimates for each case both with and without the transmission upgrades.

Table 12-9 — Interconnection Cost Estimates

Case Number	Case Description	Estimated Cost *without* Path 49 Upgrades ($ in Millions)	Estimated Cost *with* Path 49 Upgrades ($ in Millions)
1	Black Mesa IGCC (500 MW)	$173.0	$48.0
2	Gray Mountain Wind (450 MW)	$0.0	$0.0
3	Solar Site 2 (425 MW)	$0.0	$0.0
4	Aubrey Cliffs (100 MW)	$60.0	$130.0
5	Clear Creek & Sunshine (135 MW)	$0.0	$0.0
6	Black Mesa IGCC & Solar Site 1 (925 MW)	$216.9	$158.7
7	Black Mesa IGCC & Gray Mountain Wind & Aubrey Cliffs (1050 MW)	$170.0	$195.0
8	Solar Site 2 & Gray Mountain Wind & Aubrey Cliffs (975 MW)	$272.5	$117.4
9	Solar Sites 1 & 2 (850 MW)	$214.5	$46.6
10	Gray Mountain Wind & Aubrey Cliffs & Clear Creek & Sunshine (685 MW)	$162.5	$70.0

By using the summer period load flow case, the transmission interconnection requirements identified for most of the supply-side technology options effectively provide firm transmission service during peak periods. However, use of existing regional grid capacity only (but including site-specific interconnection costs to get to the grid) could be considered if curtailing output for some periods proved economically viable, or if short-term transmission use in additional to what is transparently available through OASIS could be secured through negotiations with existing users who have rights to use the grid during peak periods. Thus, it is possible that the estimated costs for transmission system upgrade include certain regional grid upgrades that could be foregone in some instances, provided economic viability remained with reduced operation of the supply option. Detailed evaluation of these circumstances is beyond the scope of this study.

Furthermore, the regional grid upgrades identified for some of the supply options would have regional benefits; examining a likely or reasonable allocation of costs for those upgrades among the beneficiaries was beyond the scope of this project. However, when considering the individual projects that may require regional grid upgrades, it must be recognized that not all of the regional grid upgrade costs would likely be allocated solely to the supply option.

12.7.1 Methodology

The first task in evaluating a transmission system for a generation location is to develop the base case model. The FERC 2005 summer case was modified to include newly completed generation projects and future generation projects with a high probability of completion. The addition of newly operating plants near northern Arizona supplied 2,351 MW from six plants, all located in northern Arizona and Clark Country, Nevada. Next, two plants identified as having a high probability of completion by 2010 were included, namely Chuck Lenzie Generating Station and Copper Mountain Power, both in Clark County, Nevada, which added 1,700 MW of generation. Finally, Mohave Generating Station was turned off, resulting in a decrease in generation of 1,650 MW. Changes in generation output were accounted for by adjusting generation in surrounding areas to maintain the supply/demand balance. The FERC case was modified and analyzed using PowerWorld Simulator (Version 10.0) software, which is widely used by electric utilities, power developers, consultants, and reliability councils in the analysis of power flow cases.

To examine the effect of new transmission projects, a subcase was analyzed along with each numbered case. Of the new projects discussed in this report, the East of Colorado River Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 projects were identified as having a high probability of completion. The transmission upgrades were included in the subcases and the simulations were rerun. The differences between the main case and subcase results are highlighted.

Finally, developing the base case also includes preparation of one-line diagrams. One-line diagrams were prepared to show the topology of various voltage levels in the transmission system so that the direction and magnitude of transmission line loading, as well as areas with transmission congestion, can be understood visually. By analyzing the power flow paths, the one-line diagram can also display areas that contain large amounts of generating capacity and major load centers.

After the base case for each scenario was prepared, generation cases were developed by adding 100 to 1,050 MW at one to four generation busses to represent possible combinations of generation additions. In order to maintain the supply/demand balance, outputs in neighboring control areas were scaled down by an equal amount of generation as was added.

The base case and new generation case for each scenario were then compared by monitoring loading on transmission facilities under normal and contingency conditions. Transmission facilities that overload in the new generation case, but do not overload in the base case, will require mitigation. The transmission facility rating is based on the steady-state limit (A Limit) under normal operating conditions and the long-term emergency rating (B Limit) for contingency conditions. Only overloaded transmission facilities that have a distribution factor greater than 3% were deemed to require mitigation. The distribution factor indicates the percentage of the new generation that flows on a transmission facility. For example, if a 100-MW plant is added and the transmission line loading increases by 10 MW, then the distribution factor is 10%.

A summary of results is shown in Appendix K2 for all proposed generation scenarios. The summary sheets list all overloaded transmission facilities with a distribution factor greater than 0.1%. Summary tables shown in the body of this report include only transmission facilities with a distribution factor higher than the 3% threshold, that is, those that will require upgrades. Appendix K1 contains the list of contingencies run for each scenario.

12.7.2 Case 1: Black Mesa IGCC

Case 1 models 500 MW of new generation from one new plant: Black Mesa IGCC provides 500 MW via connection to a 500-kV bus between Four Corners and Moenkopi substations.

12.7.2.1 Normal Operating Conditions

The impact of adding 500 MW at Black Mesa is shown by comparing the base case against the new generation case shown as Appendixes K3-1 and K3-2, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation bus. Under normal operating conditions, two transmission facilities overload. Other facilities do not change significantly. Note that some transmission lines are modeled in segments in the system model, so that multiple bus-to-bus overloads indicate a single transmission line overload. For example, the second and third overloads in Table 12-10 represent one transmission line overload.

Table 12-10 — Overloads during Normal Operating Conditions: Case 1A

Transmission Facility	Base Case*	New Gen (500 MW)*
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	94.5	100.3
KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1	91.1	105.1
KAYENTA (79043) -> KAYENT&1 (79051) CKT 1	89.7	101.3

*Percent flow based on pre-contingency (normal) rating.

As indicated above, two transmission facilities (one 500-kV transmission line and one 230-kV transmission line) overload under normal operating conditions as a result of adding 500 MW at Black Mesa.

12.7.2.2 Contingency Conditions

The contingency analysis reviewed 116 independent outages centered on the new generation bus. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 500 MW at Black Mesa). A complete list of all contingencies reviewed is included in Appendix K1-1. The results of the contingency analysis are summarized Table 12-11 below:

Table 12-11 — Results of Contingency Analysis: Case 1A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (500 MW)*
_ L_14100CHOLLA-14101FOURCORNC&1-MS	NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO	94.7	107.1

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Black Mesa. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that one facility (a 230-kV transmission line) overloads due to the new generation.

12.7.2.3 Mitigation

The interconnection feasibility study indicates that three transmission facilities will require mitigation due to normal and contingency operating conditions. The following table lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-12 — Required Transmission Upgrades: Case 1A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Palovrde – N.Gila 500 kV	125 mi	$125.0
Kayenta – Shiprock 230 kV	90 mi	$45.0

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Glen PS – Navajo 230 kV	6 mi	$3.0
Total Cost		$173.0

The estimated cost figures in Table 12-12 include equipment, materials, labor, and contingency for rebuilding transmission lines and substations as required.

12.7.2.4 Case 1B: Differences Resulting from Path 49 Upgrades

Case 1 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. Results were similar to those presented above. Two of the overloads from Case 1A also appeared in Case 1B, but the third, Palo Verde to North Gila 500 kV, did not. The net change was a reduction of $125 M, resulting in a total cost for Case 1B of $48 M.

12.7.3 Case 2: Gray Mountain Wind

Case 2 models 450 MW of new generation from one new plant: Gray Mountain Wind provides 450 MW via connection to a 500-kV bus at Moenkopi Substation.

12.7.3.1 Normal Operating Conditions

The impact of adding 450 MW at Gray Mountain is shown by comparing the base case against the new generation case shown as Appendixes K3-3 and K3-4, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation bus. Under normal operating conditions, no transmission facilities experience significant load changes. Five facilities are overloaded, but they are also overloaded in the base case.

Table 12-13 — Overloads during Normal Operating Conditions: Case 2A

Transmission Facility	Base Case*	New Gen (450 MW)*
None	—	—

*Percent flow based on pre-contingency (normal) rating.

As indicated in Table 12-13, no transmission facilities overload under normal operating conditions as a result of adding 450 MW at Gray Mountain.

12.7.3.2 Contingency Conditions

The contingency analysis reviewed 141 independent outages centered on the new generation bus. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 450 MW at Gray Mountain). A complete list of all contingencies reviewed is included in Appendix K1-2. The results of the contingency analysis are summarized Table 12-14 below:

Table 12-14 — Results of Contingency Analysis: Case 2A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (450 MW)*
—	None	—	—

*Percent flow based on post-contingency (emergency) rating.

Table 12-14 shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Gray Mountain. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that no facilities overload due to the new generation.

12.7.3.3 Mitigation

The interconnection feasibility study indicates that no transmission facilities will require mitigation due to normal and contingency operating conditions.

12.7.3.4 Case 2B: Differences Resulting from Path 49 Upgrades

Case 2 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. No upgrades were required in Case 2A, and no new overloads were identified in Case 2B. Thus the total cost for Case 2B is $0 M.

12.7.4 Case 3: Solar Site 2

Case 3 models 425 MW of new generation from one new plant: Solar Site 2 provides 425 MW via connection to a 500-kV bus between Four Corners and Moenkopi substations.

12.7.4.1 Normal Operating Conditions

The impact of adding 425 MW at Solar Site 2 is shown by comparing the base case against the new generation case shown as Appendixes K3-5 and K3-6, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation bus. Under normal operating conditions, no transmission facilities experience significant load changes.

Table 12-15 — Overloads during Normal Operating Conditions: Case 3A

Transmission Facility	Base Case*	New Gen (425 MW)*
None	—	—

*Percent flow based on pre-contingency (normal) rating.

As indicated in Table 12-15, no transmission facilities overload under normal operating conditions as a result of adding 425 MW at Solar Site 2.

12.7.4.2 Contingency Conditions

The contingency analysis reviewed 104 independent outages centered on the new generation bus. A single contingency is defined as an outage of one transmission facility (e.g. transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 425 MW at Solar Site 2). A complete list of all contingencies reviewed is included in Appendix K1-3. The results of the contingency analysis are summarized Table 12-16 below:

Table 12-16 — Results of Contingency Analysis: Case 3A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (425 MW)*
—	None	—	—

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Solar Site 2. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that no facilities overload significantly due to the new generation. A number of transmission lines overload, but none carry 3% of the added generation, so no upgrades are required.

12.7.4.3 Mitigation

The interconnection feasibility study indicates that no transmission facilities will require mitigation due to normal and contingency operating conditions.

12.7.4.4 Case 3B: Differences Resulting from Path 49 Upgrades

Case 3 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. No upgrades were required in Case 3A, and no new overloads were identified in Case 3B. Thus the total cost for Case 3B is $0 M.

12.7.5 Case 4: Aubrey Cliffs

Case 4 models 100 MW of new generation from one new plant: Aubrey Cliffs provides 100 MW via connection to a 230-kV bus at Round Valley substation.

12.7.5.1 Normal Operating Conditions

The impact of adding 100 MW at Aubrey Cliffs is shown by comparing the base case against the new generation case shown as Appendixes K3-7 and K3-8, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation bus. Under normal operating conditions, no transmission facilities overload due to the added generation. Overloaded facilities were already overloaded without the additional generation.

Table 12-17 — Overloads during Normal Operating Conditions: Case 4A

Transmission Facility	Base Case*	New Gen (100 MW)*
None	—	—

*Percent flow based on pre-contingency (normal) rating.

As indicated in Table 12-17, no transmission facilities overload under normal operating conditions as a result of adding 100 MW at Aubrey Cliffs.

12.7.5.2 Contingency Conditions

The contingency analysis reviewed 112 independent outages centered on the new generation bus. A single contingency is defined as an outage of one transmission facility (e.g. transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 100 MW at Aubrey Cliffs). A complete list of all contingencies reviewed is included in Appendix K1-4. The results of the contingency analysis are summarized in Table 12-18 below:

Table 12-18 — Results of Contingency Analysis: Case 4A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (100 MW)*
T_19315PEACOCK345-19314PEACOCK230C1	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at PRESCOTT	117.3	135.2
T_19315PEACOCK345-19314PEACOCK230C1	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at TOPOCK	101.3	103.4

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Aubrey Cliffs. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that two facilities—two 230-kV transmission lines—overload due to the new generation.

12.7.5.3 Mitigation

The interconnection feasibility study indicates that two transmission facilities will require mitigation due to normal and contingency operating conditions. The following table lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-19 — Required Transmission Upgrades: Case 4A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Roundvly – Prescott 230 kV	75 mi	$37.5
Topock – Blk Mesa 230 kV	45 mi	$22.5
Total Cost		$60.0

The estimated cost figures in Table 12-19 include equipment, materials, labor, and contingency for rebuilding transmission lines and substations as required.

12.7.5.4 Case 4B: Differences Resulting from Path 49 Upgrades

Case 4 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. Results were similar to those presented above. No overloads were eliminated, but an additional overload was identified. The Imperial Valley to North Gila 500-kV line overloaded, requiring an additional $70 M in upgrades. The apparent inconsistency of increased cost with transmission upgrades is a result of base case loading. Lines that overload in the base case (without new generation applied) are not considered to require upgrades, because the new generation is not the cause of the line overload. In this case, the transmission upgrades in Case 4B relieved the Imperial Valley-North Gila line that was overloaded in Case 4A, so that it was no longer overloaded in the base case. When the new generation added load to the line, it caused the line to go over limit, and thereby require upgrades. The additional $70 M results in a total cost for Case 4B of $130 M.

12.7.6 Case 5: Clear Creek and Sunshine

Case 5 models 135 MW of new generation from two new plants: Clear Creek provides 75 MW via connection to a 230-kV bus at Leupp Substation and Sunshine provides 60 MW via connection to a 230-kV bus at Cococino Substation.

12.7.6.1 Normal Operating Conditions

The impact of adding 135 MW at Clear Creek and Sunshine is shown by comparing the base case against the new generation case shown as Appendixes K3-9 and K3-10, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation bus. Under normal operating conditions, no transmission facilities experience significant load changes.

Table 12-20 — Overloads during Normal Operating Conditions: Case 5A

Transmission Facility	Base Case*	New Gen (135 MW)*
None	—	—

*Percent flow based on pre-contingency (normal) rating.

As indicated in Table 12-20, no transmission facilities overload under normal operating conditions as a result of adding 135 MW at Clear Creek and Sunshine.

12.7.6.2 Contingency Conditions

The contingency analysis reviewed 115 independent outages centered on the new generation bus. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 135 MW at Clear Creek and Sunshine). A complete list of all contingencies reviewed is included in Appendix K1-5. The results of the contingency analysis are summarized Table 12-21 below:

Table 12-21 — Results of Contingency Analysis: Case 5A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (135 MW)*
—	None	—	—

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Clear Creek and Sunshine. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that no facilities overload significantly due to the new generation. Only slight loading changes were experienced.

12.7.6.3 Mitigation

The interconnection feasibility study indicates that no transmission facilities will require mitigation due to normal and contingency operating conditions.

12.7.6.4 Case 5B: Differences Resulting from Path 49 Upgrades

Case 5 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. No upgrades were required in Case 5A, and no new overloads were identified in Case 5B. Thus the total cost for Case 5B is $0 M.

12.7.7 Case 6: Black Mesa IGCC and Solar Site 1

Case 6 models 925 MW of new generation from two new plants: Black Mesa IGCC provides 500 MW of generation via connection to a 500-kV bus between Four Corners and Moenkopi substations and Solar Site 1 provides 425 MW via connection to a 230-kV bus at Kayenta Substation.

12.7.7.1 Normal Operating Conditions

The impact of adding 925 MW at Black Mesa and Solar Site 1 is shown by comparing the base case and new generation case, as shown in Appendix K3-11 and K3-12, respectively. The one-line diagrams show the change in loading on transmission facilities in the areas near the new generation busses. Under normal operating conditions, five facilities overload: four transmission lines and one transformer. Other lines in the area increase slightly but remain within acceptable limits. Table 12-22 below lists the base case and new generation case loading percentages for transmission facility overloads.

Table 12-22 — Overloads during Normal Operating Conditions: Case 6A

Transmission Facility	Base Case*	New Gen (925 MW)*
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	95.1	102.1
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	95.1	102.1
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	95.9	102.9
GLEN PS (79028) -> GLENCANY (79031) CKT 1	69.6	145.6
KAYENTA (79043) -> KAYENT&A (79055) CKT 1	67.9	136.7
NAVAJO (79093) -> LNGHOUSE (79096) CKT 1	62.1	131.2
KAYENT&A (79055) -> LNGHOUSE (79096) CKT 1	67.9	137.0
GLEN PS (79028) -> NAVAJO (79093) CKT 1	82.2	174.2

*Percent flow based on pre-contingency (normal) rating.

As indicated above, five transmission facilities would require mitigation. Mitigating these overloads would require upgrading one 500-kV transmission line, three 230-kV transmission lines, and one 230-kV transformer.

12.7.7.2 Contingency Conditions

The single contingency analysis reviewed 142 independent outages centered on the new generation busses. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case without new generation and then again for the new generation case with an additional 925 MW at Black Mesa IGCC and Solar Site 1. A complete list of all contingencies reviewed is included in Appendix K1-6. The results of the contingency analysis are summarized in Table 12-23 below:

Table 12-23 — Results of Contingency Analysis: Case 6A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (925 MW)*
L_79043KAYENTA-79096LNGHOUSEC&1-MS	KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1	18.5	120.3
L_79043KAYENTA-79096LNGHOUSEC&1-MS	KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA	10.9	123.5
T_79032GLENCANY-79031GLENCANYC2	GLENCANY (79031) -> GLENCANY (79032) CKT 1 at GLENCANY	81.6	114.2
T_79032GLENCANY-79031GLENCANYC1	GLENCANY (79031) -> GLENCANY (79032) CKT 2 at GLENCANY	81.6	114.2

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Black Mesa and Solar Site 1. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that three facilities overload due to single contingencies: one 230-kV transmission line and two 345-kV transformers.

12.7.7.3 Mitigation

The interconnection feasibility study indicates that eight transmission facilities will require mitigation due to normal and contingency operating conditions. Table 12-24 lists the transmission facilities requiring upgrades, with the estimated costs of the upgrades:

Table 12-24 — Required Transmission Upgrades: Case 6A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Palovrde – N.Gila 500 kV	125 mi	$125.0
Kayenta – Lnghouse 230 kV	25 mi	$12.5
Navajo – Lnghouse 230 kV	50 mi	$25.0
Glen PS – Navajo 230 kV	6 mi	$3.0
Glen PS – Glencany 230 kV	200 MVA	$3.2
Kayenta – Shiprock 230 kV	90 mi	$45.0
Glencany – Glencany Ckt 1 230/345 kV	100 MVA	$1.6

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Glencany – Glencany Ckt 2 230/345 kV	100 MVA	$1.6
Total Cost		$216.9

The estimated cost figures above include equipment, materials, labor, and contingency for upgrading transformers as required.

12.7.7.4 Case 6B: Differences Resulting from Path 49 Upgrades

Case 6 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. Results were similar to those presented above. Two important loading changes occurred. The Palo Verde to North Gila 500-kV line no longer required upgrades, reducing the overall cost by $125 M. However, the Imperial Valley to North Gila 500-kV line overloaded instead, adding $70 M to the total cost. The net change was a reduction of $55 M, resulting in a total cost for Case 6B of $161.9 M.

12.7.8 Case 7: Black Mesa IGCC and Gray Mountain Wind and Aubrey Cliffs

Case 7 models 1,050 MW of new generation from three new plants: Black Mesa IGCC provides 500 MW of generation via connection to a 500-kV bus between Four Corners and Moenkopi substations, Gray Mountain Wind provides 450 MW via connection to a 500-kV bus at Moenkopi Substation, and Aubrey Cliffs provides 100 MW via connection to a 230-kV bus at Round Valley Substation.

12.7.8.1 Normal Operating Conditions

The impact of adding 1,050 MW at Black Mesa, Gray Mountain Wind, and Aubrey Cliffs is shown by comparing the base case and new generation case, as shown in Appendix K3-13 and K3-14, respectively. The one-line diagrams show the change in loading on transmission facilities in the areas near the new generation busses. Under normal operating conditions, one transmission line overloads. Other facilities in the area increase but remain within acceptable limits. Table 12-25 below lists the base case and new generation case loading percentages for transmission facility overloads.

Table 12-25 — Overloads during Normal Operating Conditions: Case 7A

Transmission Facility	Base Case*	New Gen (1,050 MW)*
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	95.1	102.1
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	95.1	102.1
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	95.9	102.9

*Percent flow based on pre-contingency (normal) rating.

As indicated above, there is one transmission facility that overloads under normal operating conditions as a result of adding 1,050 MW at Black Mesa, Gray Mountain, and Aubrey Cliffs. Mitigating this overload would require upgrading one 500-kV transmission line.

12.7.8.2 Contingency Conditions

The single contingency analysis reviewed 202 independent outages centered on the new generation busses. A contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 1,050 MW at Black Mesa, Gray Mountain, and Aubrey Cliffs). A complete list of all contingencies reviewed is included in Appendix K1-7. The results of the contingency analysis are summarized in Table 12-26 below:

Table 12-26 — Results of Contingency Analysis: Case 7A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (1050 MW)*
L_14101FOURCORN-66235PINTOPSC1	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	91.0	101.0

*Percent flow based on post-contingency (emergency) rating.

The above table shows the change in load from the base case for overloaded transmission facilities under contingency conditions as a result of adding generation at Black Mesa, Gray Mountain, and Aubrey Cliffs. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that one 230-kV transmission line overloaded due to the new generation.

12.7.8.3 Mitigation

The interconnection feasibility study indicates that two transmission facilities will require mitigation for the addition of 1,050 MW at Black Mesa, Gray Mountain, and Aubrey Cliffs. Table 12-27 lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-27 — Required Transmission Upgrades: Case 7A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Palovrde – N.Gila 500 kV	125 mi	$125.0
Kayenta – Shiprock 230 kV	90 mi	$45.0
Total Cost		$170.0

The estimated cost figures above include equipment, materials, labor, and contingency for upgrading transformers as required.

12.7.8.4 Case 7B: Differences Resulting from Path 49 Upgrades

Case 7 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. Results were similar to those presented above, but with two changes. The Kayenta to Shiprock 230-kV line no longer overloads, which reduces the total cost by $45 M. However, the Imperial Valley to North Gila 500-kV line overloads in Case 7B, adding $70 M to the total cost. The apparent inconsistency of increased cost with transmission upgrades is a result of base-case loading. Lines that overload in the base case (without new generation applied) are not considered to require upgrades, because the new generation is not the cause of the line overload. In this case, the transmission upgrades in Case 7B relieved the Imperial Valley–North Gila line that was overloaded in Case 7A, so that it was no longer overloaded in the base case. When the new generation added load to the line, it caused the line to go over limit and, thereby, require upgrades. The net effect of the two changes is an increase of $25 M, yielding a total cost for Case 7B of $195.0 M.

12.7.9 Case 8: Solar Site 2 and Gray Mountain Wind and Aubrey Cliffs

Case 8 models 975 MW of new generation from three new plants: Solar Site 2 provides 425 MW of generation via connection to a 500-kV bus between Four Corners and Moenkopi substations, Gray Mountain Wind provides 450 MW via connection to a 500-kV bus at Moenkopi Substation, and Aubrey Cliffs provides 100 MW via connection to a 230-kV bus at Round Valley.

12.7.9.1 Normal Operating Conditions

The impact of adding 975 MW at Solar Site 2, Gray Mountain Wind, and Aubrey Cliffs is shown by comparing the base case and new generation case, as shown in Appendix K3-15 and K3-16, respectively. The one-line diagrams show the change in loading on transmission facilities in the areas near the new generation busses. Under normal operating conditions, one 500-kV transmission line overloads. Other facilities in the area increase slightly but remain within acceptable limits. Table 12-28 below lists the base case and new generation case loading percentage for transmission facility overloads.

Table 12-28 — Overloads during Normal Operating Conditions: Case 8A

Transmission Facility	Base Case*	New Gen (975 MW)*
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	95.1	100.8
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	95.1	100.8
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	95.9	100.8

*Percent flow based on pre-contingency (normal) rating.

As indicated in above, one transmission facility would require mitigation. Mitigating this overload would require upgrading one 500-kV transmission line.

12.7.9.2 Contingency Conditions

The contingency analysis reviewed 183 independent outages centered on the new generation busses. A contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case, without new generation and then again for the new generation case, with an additional 975 MW at Solar Site 2, Gray Mountain, and Aubrey Cliffs. A complete list of all contingencies reviewed is included in Appendix K1-8. The results of the contingency analysis are summarized in Table 12-29 below:

Table 12-29 — Results of Contingency Analysis: Case 8A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (975 MW)*
L_14003NAVAJO-14005WESTWINGC&1-MS	MOENKO&1 (14011) -> YAVAPAI (14006) CKT 1 at YAVAPAI	90.1	103.3
L_14003NAVAJO-14005WESTWINGC&1-MS	MOENKOPI (14002) -> MOENKO&1 (14011) CKT 1 at MOENKOPI	90.4	103.2
T_19315PEACOCK-19314PEACOCKC1	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	117.3	134.5

*Percent flow based on post-contingency (emergency) rating.

The above table shows the change in load on transmission facilities under contingency conditions as a result of adding generation at Solar Site 2, Gray Mountain, and Aubrey Cliffs. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that two facilities overload due to the new generation: one 230-kV and one 500-kV transmission line.

12.7.9.3 Mitigation

The interconnection feasibility study indicates that three transmission facilities would require mitigation due to normal and contingency operating conditions. Table 12-30 lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-30 — Required Transmission Upgrades: Case 8A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in millions)
Palovrde – N.Gila 500 kV	125 mi	$125.0
Moenkopi – Yavapai 500 kV	110 mi	$110.0
Roundvly – Prescott 230 kV	75 mi	$37.5
Total Cost		$272.5

The estimated cost figures above include equipment, materials, labor, and contingency for upgrading transformers as required.

12.7.9.4 Case 8B: Differences Resulting from Path 49 Upgrades

Case 8 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. For this case, the added transmission upgrades caused a new set of required transmission upgrades. The changes warrant a new table for Case 8B. As can be seen in Table 12-31 below, four facilities will require upgrades. The net change from Case 8A is a reduction of $155.1 M, yielding a total cost for Case 8B of $117.4 M.

Table 12-31 — Required Transmission Upgrades: Case 8B

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in millions)
Kayenta – Shiprock 230 kV	90 mi	$45.0
Eldor 1I – Eldordo 500 kV Ckt 1	100 MVA	$2.4
Eldor 1I – Eldordo 500 kV Ckt 2	100 MVA	$2.4
Imprlvly – N.Gila 500 kV	70 mi	$70.0
Total Cost		$119.8

The estimated cost figures above include equipment, materials, labor, and contingency for upgrading transformers as required.

12.7.10 Case 9: Solar Sites 1 and 2

Case 9 models 850 MW of new generation from two new plants: Solar Site 1 provides 425 MW of generation via connection to a 230-kV bus at Kayenta Substation and Solar Site 2 provides 425 MW via connection to a 500-kV bus between Four Corners and Moenkopi substations.

12.7.10.1 Normal Operating Conditions

The impact of adding 850 MW at Solar Sites 1 and 2 is shown by comparing the base case against the new generation case shown as Appendixes K3-17 and K3-18, respectively. The one-line diagrams show the change in loading on transmission facilities in the areas near the new generation. Under normal operating conditions, five transmission facilities overload: four transmission lines and one transformer. Other facilities in the area increase slightly but remain within acceptable limits. Table 12-32 below lists the base case and new generation case loading percentage for transmission facility overloads.

Table 12-32 — Overloads during Normal Operating Conditions: Case 9A

Transmission Facility	Base Case*	New Gen (850 MW)*
GLEN PS (79028) -> GLENCANY (79031) CKT 1	69.6	135.6
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	95.9	101.1
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	95.1	100.3
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	95.1	100.3
KAYENTA (79043) -> KAYENT&A (79055) CKT 1	67.9	127.5
KAYENT&A (79055) -> LNGHOUSE (79096) CKT 1	67.9	127.7
NAVAJO (79093) -> LNGHOUSE (79096) CKT 1	62.1	121.8
GLEN PS (79028) -> NAVAJO (79093) CKT 1	82.2	161.7

*Percent flow based on pre-contingency (normal) rating.

As indicated above, five transmission facilities would require mitigation. Mitigating these overloads would require upgrading one 500-kV transmission line, three 230-kV transmission lines, and one 230-kV transformer.

12.7.10.2 Contingency Conditions

The contingency analysis reviewed 135 independent outages centered on the new generation busses. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 850 MW at Solar Sites 1 and 2). A complete list of all contingencies reviewed is included in Appendix K1-9. The results of the contingency analysis are summarized in Table 12-33 below:

Table 12-33 — Results of Contingency Analysis: Case 9A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (850 MW)*
L_79043KAYENTA-79096LNGHOUSEC&1-MS	KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1	18.0	120.3
L_79043KAYENTA-79096LNGHOUSEC&1-MS	KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA	10.0	123.5
T_79032GLENCANY-79031GLENCANYC1	GLENCANY (79031) -> GLENCANY (79032) CKT 2 at GLENCANY	81.6	107.5
T_79032GLENCANY-79031GLENCANYC2	GLENCANY (79031) -> GLENCANY (79032) CKT 1 at GLENCANY	81.6	107.5

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at the Solar Sites 1 and 2. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that three facilities overload due to the new generation: one 230-kV transmission line and two 230/345-kV transformers.

12.7.10.3 Mitigation

The interconnection feasibility study indicates that eight transmission facilities will require mitigation due to normal and contingency operating conditions. The following table lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-34 — Required Transmission Upgrades: Case 9A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Palovrde – N.Gila 500 Kv	125 mi	$125.0
Kayenta – Lnghouse 230 kV	25 mi	$12.5
Navajo – Lnghouse 230 kV	50 mi	$25.0
Glen PS – Navajo 230 kV	6 mi	$3.0
Glen PS – Glencany 230 kV	150 MVA	$2.4
Kayenta – Shiprock 230 kV	90 mi	$45.0
Glencany – Glencany Ckt 1 230/345kV	50 MVA	$0.8

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Glencany – Glencany Ckt 2 230/345kV	50 MVA	$0.8
Total Cost		$214.5

The estimated cost figures in Table 12-34 include equipment, materials, labor, and contingency for rebuilding transmission lines and substations as required.

12.7.10.4 Case 9B: Differences Resulting from Path 49 Upgrades

Case 9 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. Results were similar to those presented above. No additional overloads were found, but five overloads that existed in Case 9A were relieved, namely Palo Verde to North Gila 500 kV, Kayenta to Longhouse 230 kV, Navajo to Longhouse 230 kV, Glen PS to Navajo 230 kV, and Glen PS to Glen Canyon 230 kV. The reduction in total cost was $167.9 M, resulting in a total cost for Case 9B of $46.6 M.

12.7.11 Case 10: Gray Mountain Wind and Aubrey Cliffs and Clear Creek and Sunshine

Case 10 models 685 MW of new generation from four new plants: Gray Mountain Wind provides 450 MW via connection to a 500-kV bus at Moenkopi Substation, Aubrey Cliffs provides 100 MW via connection to a 230-kV bus at Round Valley Substation, Clear Creek provides 75 MW via connection to a 230-kV bus at Leupp Substation, and Sunshine provides 60 MW via connection to a 230-kV bus at Cococino Substation.

12.7.11.1 Normal Operating Conditions

The impact of adding 685 MW at Gray Mountain, Aubrey Cliffs, Clear Creek, and Sunshine is shown by comparing the base case against the new generation case shown as Appendixes K3-19 and K3-20, respectively. Those one-line diagrams show the change in loading on transmission facilities in the area near the new generation busses. Under normal operating conditions, one transmission facility overloads. Other facilities do not change significantly.

Table 12-35 — Overloads during Normal Operating Conditions: Case 10A

Transmission Facility	Base Case*	New Gen (685 MW)*
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	95.9	100.5

*Percent flow based on pre-contingency (normal) rating.

As indicated above, one transmission facility, a 500-kV transmission line, overloads under normal operating conditions as a result of adding 685 MW at Gray Mountain, Aubrey Cliffs, Clear Creek, and Sunshine.

12.7.11.2 Contingency Conditions

The contingency analysis reviewed 181 independent outages centered on the new generation busses. A single contingency is defined as an outage of one transmission facility (e.g., transformer, line) taken out of service at a time. This set of contingencies was run for the base case (without new generation), then again for the new generation case (with an additional 685 MW at Gray Mountain, Aubrey Cliffs, Clear Creek, and Sunshine). A complete list of all contingencies reviewed is included in Appendix K1-10. The results of the contingency analysis are summarized in Table 12-36 below:

Table 12-36 — Results of Contingency Analysis: Case 10A

Contingency	Overloaded Transmission Facility	Base Case*	New Gen Case (685 MW)*
L_14002MOENKOPI-14006YAVAPAIC&1-MS	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	99.9	110.0

*Percent flow based on post-contingency (emergency) rating.

The above table shows the difference on overloaded transmission facilities under contingency conditions as a result of adding generation at Gray Mountain, Aubrey Cliffs, Clear Creek, and Sunshine. Line loading is recorded as a percentage of long-term emergency rating (B Limit), which is the threshold for post-contingency operations. This table indicates that one facility overloads due to the new generation: a 230-kV transmission line.

12.7.11.3 Mitigation

The interconnection feasibility study indicates that two transmission facilities will require mitigation due to normal and contingency operating conditions. The following table lists the transmission facilities requiring upgrades, with an estimated cost of each upgrade:

Table 12-37 — Required Transmission Upgrades: Case 10A

Transmission Facility	Circuit Miles or MVA Upgrade	Estimated Cost ($ in Millions)
Palovrde – N.Gila 500 kV	125 mi	$125.0
Roundvly – Prescott 230 kV	75 mi	$37.5
Total Cost		$162.5

The estimated cost figures in Table 12-37 include equipment, materials, labor, and contingency for rebuilding transmission lines and substations as required.

12.7.11.4 Case 10B: Differences Resulting from Path 49 Upgrades

Case 10 was also run with the East of Colorado Path 49 Short-Term Upgrades and the Palo Verde to Devers #2 transmission upgrades included in the model. The additional generation relieved the two overloads identified in Case 10A. However, a different line overloaded instead, namely the Imperial Valley to North Gila 500-kV line. The net change was a reduction of $92.5 M, resulting in a total cost for Case 10B of $158.7 M.

12.8 CONCLUSIONS

The following conclusions can be drawn from the transmission evaluation:

- **Long-Term Firm Service.** Existing conditions appear to limit the availability of long-term (e.g., yearly or multi-yearly) firm service from Arizona supply sources. Shorter-term service of more limited duration is available for some source-sink path combinations.
- **Short-Term Non-Firm Service.** Based on OASIS data, shorter-term firm, or non-firm service is available from most source points examined, but not necessarily during all periods. Thus, technology options located in the Study Area connecting up to the grid in the near-term might need to rely on shorter-term transmission availability. Note that SCE's ownership of rights for transmission service from their Four Corners generation share ownership were not considered as a possible source of transmission access for any of the Mohave alternatives or complements.
- **Tradeoffs between Increased Capacity for New Supply and Use of Existing Capabilities**. The transmission interconnection requirements identified for most of the supply-side technology options are based on provision of effectively firm transmission service during peak periods. Use of existing grid capacity could be considered if curtailing output for some periods proved economically viable, and/or if short-term transmission use in additional to what is transparently available through OASIS could be secured through negotiations with existing users who have rights to use the grid during peak periods.
- **OASIS Information.** The value of OASIS information is limited because of its time frame; it is not predictive beyond the near-term time periods, at most a few years out.

- **Proposed New Transmission Upgrades.** New transmission line proposals or works in progress add significant capacity to into-California (and likely intra-Arizona) transaction paths. To the extent these lines are built, it is possible that most technology options could secure access to import into SCE territory.

- **Alternative Locations of Alternatives.** Any technology options that source power from the existing Mohave site, or from the Palo Verde hub (e.g., the DSM alternative) will not face the transmission limitations identified in our review.

- **Effect of New Institutional Constructs.** The review did not assess the transmission availability under any new institutional constructs. If a West Connect RTO or similar regional transmission entity established coordinated transmission operations in the desert southwest area, the paradigm for transmission access and Available Transmission Capability (ATC) computation could change. One possible outcome of such arrangements is a lesser dependence on the need for source-to-sink physical transmission reservations in order to use the desert southwest grid to secure power flows into California from source points in the Study Area.

- **Wheeling Capability under Current Transmission Capacity**. The DSM and Mohave Combined Cycle technology options could each move Mohave-equivalent power into the SCE territory based on existing conditions. The California border location for these options allows this to occur during most if not all hours, although some congestion cost allocation from the California ISO would likely apply in some hours. The remaining Arizona area supply options would all be able to move power into the SCE territory for some hours of the year, based on securing available shorter-term firm or non-firm transmission, but it is unlikely they would be able to secure transmission for all hours, especially during peak periods, based on examination of the OASIS data. The latter assumes that minimal connection requirements to get to the regional grid are first made by the supply technology options in the Study Area.

- **Wheeling Capability with Reasonably Certain New Transmission Upgrades**. Most of the proposed new transmission projects that have a high likelihood of being built will result in increased transfer capability from western Arizona or southern Nevada into California, but they will not substantially affect the transfer capability from the northeastern Arizona area to the western portion of Arizona. There are numerous Arizona transmission upgrades proposed for the heavier load centers, such as Phoenix; these upgrades will not necessarily increase transfer capability over the major paths out of northeastern and north-central Arizona. Thus, even with implementation of certain new projects, it is not assured that the increased capacity will allow for Study Area technology options to secure firm, longer-term transmission service into the California border area. However, if intra-Arizona upgrades on the 500-kV system in the north and the northeast are realistically considered, then the increase in transfer capability from the Study Area to the California border would likely be on the order of the scale of output associated with SCE’s share of Mohave.

- **Wheeling Capability with Uncertain New Transmission Upgrades.** It is difficult to state with any certainty what the wheeling capability with new transmission upgrades might look like without conducting additional load flow studies and accounting for the location of new supply sources that might be considered if new transmission is built. This is beyond the scope of the project. For example, even if the Navajo Transmission Project is built, the potential for new generation in the northeastern Arizona region must be considered when assessing whether such new capacity might be available for the Mohave technology options. However, if any of the major northeastern/north-central Arizona to southwestern/northwestern Arizona paths are upgraded, the potential for transmission capacity increases on the order of SCE's share of Mohave output is likely.

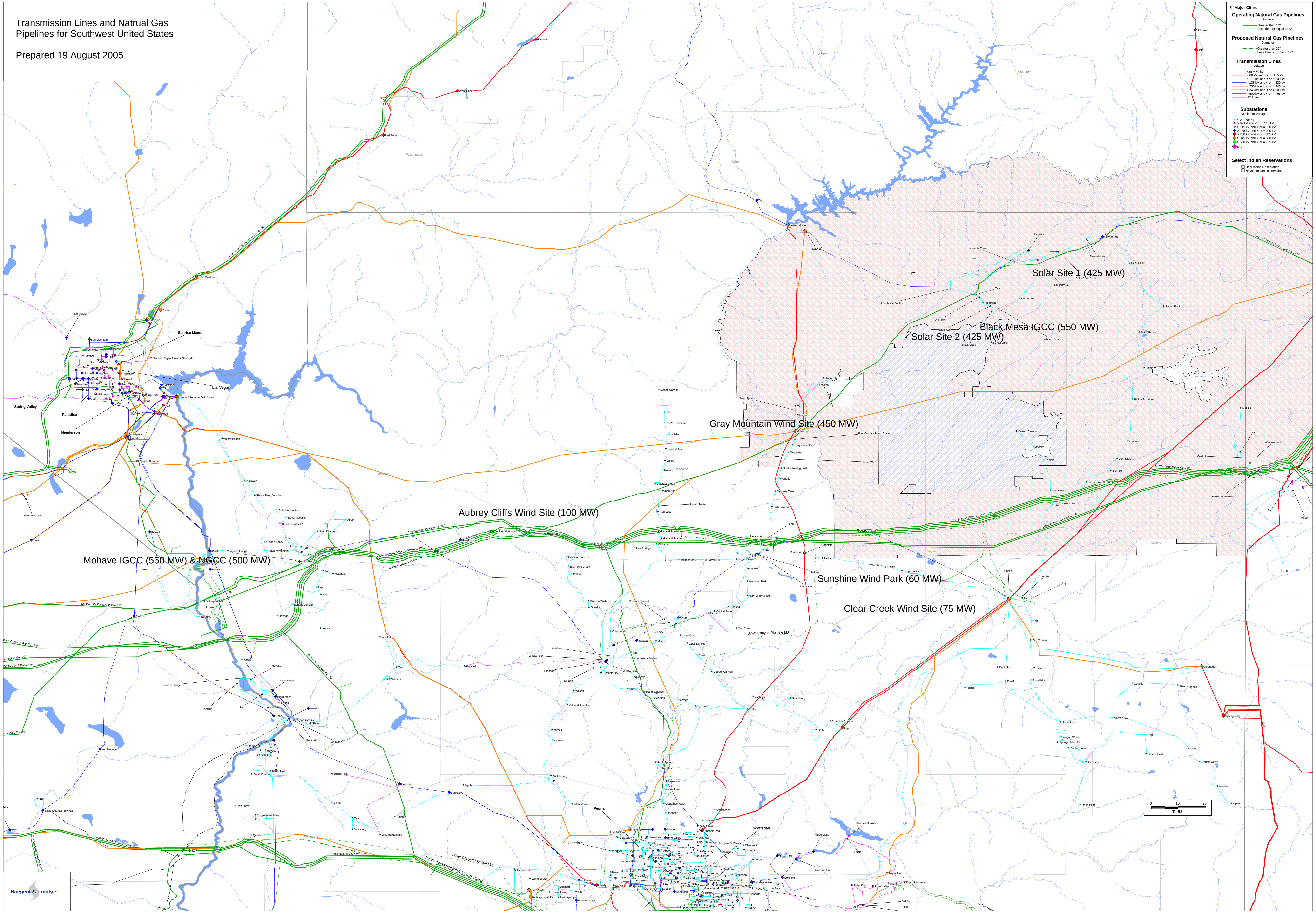
- **Load Flow Analyses.** The results of the load flow studies indicate that longer-term[13] firm transmission service is available in some cases without additional transmission system upgrades, but is not available in others without system upgrades. A summary of these cases and the estimated costs of required upgrades are provided in Table 12-9.

Last page of Section 12.

[13] Longer-term transmission service generally implies service of at minimum a years' duration. For example, Tucson Electric Power offered 125 MW of yearly transmission service for 2006, 2007, and 2008 on its rights to the Moenkopi–Palo Verde 500-kV path. Longer-term service can also imply transmission service available for many years into the future. Data on availability of such long-term transmission are not readily provided through the OASIS system. However, some of the utility documents available through the OASIS system indicated ongoing availability of longer-term transmission over specific, limited segments of the Arizona Public Service system.

Appendix A

General Location Map



Transmission Lines and Natrual Gas Pipelines for Southwest United States
Prepared 19 August 2005
Major Cities
Operating Natural Gas Pipelines
Proposed Natural Gas Pipelines
Transmission Lines
Substations
Select Indian Reservations
Solar Site 1 (425 MW)
Black Mesa IGCC (550 MW)
Solar Site 2 (425 MW)
Gray Mountain Wind Site (450 MW)
Aubrey Cliffs Wind Site (100 MW)
Mohave IGCC (550 MW) & NGCC (500 MW)
Sunshine Wind Park (60 MW)
Clear Creek Wind Site (75 MW)
Sunrise Manor
Las Vegas
Spring Valley
Paradise
Henderson
Peoria
Glendale
Scottsdale
Mesa
miles
Sargent & Lundy

Appendix B

IRP Data

Integrated Resource Plan Data

Input	Unit	Black Mesa IGCC (No CO_2 Removal)	Black Mesa IGCC (CO_2 Removal without Shift Conversion)	Black Mesa IGCC (Maximum CO_2 Removal)	Mohave IGCC (No CO2 Removal)	Mohave IGCC (CO2 Removal without Shift Conversion)	Mohave IGCC (Maximum CO2 Removal)	Mohave NGCC (Cooling Tower)	Mohave NGCC (Air-Cooled Condenser)
Capacity	MW	555	537	485	549	531	482	994	994
Outages									
Schedule Maintenance Rate	% of year	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%	6.5%
Forced Outage Rate	% of year	9.1%	9.1%	9.1%	9.1%	9.1%	9.1%	4.0%	4.0%
Average Heat Rates									
Full Load Heat Rate	BTU/kWh	9,927	10,421	11,751	9,909	10,402	11,730	7,070	7,070
Heat Rate Points									
75.0%	BTU/kWh	10,247	10,590	12,137	10,228	10,571	12,115	7,610	7,610
50.0%	BTU/kWh	10,578	10,932	12,529	10,559	10,912	12,507	7,080	7,080
25.0%	BTU/kWh	11,272	11,649	13,350	11,252	11,628	13,326	8,570	8,570
Heat Rate Capacity Points									
100.0%	MW	555	537	485	549	531	482	994	994
75.0%	MW	416	403	364	412	398	362	746	746
50.0%	MW	278	269	243	275	266	241	497	497
25.0%	MW	139	134	121	137	133	121	249	249
Costs									
Burnertip Fuel Price	$/MMBTU	1.15	1.15	1.15	1.15	1.15	1.15	8.64	8.64
Fixed O&M	$/kW-yr	49.59	67.45	80.98	49.59	67.45	80.98	1.97	1.77
Variable O&M	$/MWh	1.59	1.66	2	1.26	1.32	1.62	5.47	5.47
Emissions									
CO2 Emissions	lbs/MMBTU	200	142	17	200	142	17	114	114
NOx Emissions	lbs/MMBTU	0.022	0.022	0.021	0.022	0.022	0.021	0.037	0.037
SO2 Emissions	lbs/MMBTU	0.130	0.020	0.020	0.130	0.020	0.020	0.000	0.000
Repair Time									
Mean Time to Repair	hrs	144	144	144	144	144	144	20	47
Min Time to Repair	hrs	4	4	4	4	4	4	4	4
Max Time to Repair	hrs	720	720	720	720	720	720	720	720
Dispatch									
Ramp Rate	MW/hr	420	420	420	420	420	420	2,982	2,982
Run Up Rate	MW/hr	250	250	250	250	250	250	250	250
Min Up Time	hrs	4	4	4	4	4	0	0	0
Min Down Time	hrs	2	2	2	2	2	2	0	0
Start-Up Fuel	MMBTU	8,470	8,470	8,470	8,470	8,470	8,470	22,490	22,490
Expected Plant Life Time	years	30	30	30	30	30	30	25	25

Integrated Resource Plan Data

Input	Unit	Mohave NGCC (Cooling Tower and CO_2 Removal)	Mohave NGCC (Air-Cooled Condenser and CO_2 Removal)	Solar Site 1 (Trough)	Solar Site 2 (Trough)	Solar Site 1 (Dish)	Solar Site 2 (Dish)	Gray Mountain Phase 1	Gray Mountain Phases 1-3
Capacity	MW	846	846	300	300	425	425	150	450
Outages									
Schedule Maintenance Rate	% of year	6.5%	6.5%	1.0%	1.0%	1.5%	1.5%	3.0%	3.0%
Forced Outage Rate	% of year	4.0%	4.0%	1.5%	1.5%	2.0%	2.0%	3.0%	3.0%
Average Heat Rates									
Full Load Heat Rate	BTU/kWh	8,310	8,310	0	0	0	0	0	0
Heat Rate Points									
75.0%	BTU/kWh	8,945	8,945	0	0	0	0	0	0
50.0%	BTU/kWh	8,325	8,325	0	0	0	0	0	0
25.0%	BTU/kWh	10,075	10,075						
Heat Rate Capacity Points									
100.0%	MW	846	846	300	300	425	425	150	450
75.0%	MW	635	635	225	225	319	319	113	338
50.0%	MW	423	423	150	150	213	213	75	225
25.0%	MW	212	212	75	75	106	106	38	113
Costs									
Burnertip Fuel Price	$/MMBTU	8.64	8.64	0.0	0.0	0.0	0.0	0.0	0.0
Fixed O&M	$/kW-yr	2.32	2.08	33	33	3	3	55.32	53.05
Variable O&M	$/MWh	6.45	6.45	30	30	11	11	0.195	0.195
Emissions									
CO2 Emissions	lbs/MMBTU	114	114	11	11	0	0	0	0
NOx Emissions	lbs/MMBTU	0.037	0.037	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
SO2 Emissions	lbs/MMBTU	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Repair Time									
Mean Time to Repair	hrs	47	47	20	20	0	0	0	0
Min Time to Repair	hrs	4	4	4	4	0	0	0	0
Max Time to Repair	hrs	720	720	336	336	0	0	0	0
Dispatch									
Ramp Rate	MW/hr	2,538	2,538	0	0	0	0	0	0
Run Up Rate	MW/hr	250	250	250	250	0	0	0	0
Min Up Time	hrs	0	0	4	4	0	0	0	0
Min Down Time	hrs	0	0	2	2	0	0	0	0
Start-Up Fuel	MMBTU	22,490	22,490	0	0	0	0	0	0
Expected Plant Life Time	years	25	25	20	20	20	20	20	20

Integrated Resource Plan Data

Input	Unit	Aubrey Cliffs	Clear Creek	Sunshine Wind Park
Capacity	MW	100	75	60
Outages				
Schedule Maintenance Rate	% of year	3.0%	3.0%	3.0%
Forced Outage Rate	% of year	3.0%	3.0%	3.0%
Average Heat Rates				
Full Load Heat Rate	BTU/kWh	0	0	0
Heat Rate Points				
75.0%	BTU/kWh	0	0	0
50.0%	BTU/kWh	0	0	0
25.0%	BTU/kWh			
Heat Rate Capacity Points				
100.0%	MW	100	75	60
75.0%	MW	75	56	45
50.0%	MW	50	38	30
25.0%	MW	25	19	15
Costs				
Burnertip Fuel Price	$/MMBTU	0.0	0.0	0.0
Fixed O&M	$/kW-yr	31.91	32.24	33.33
Variable O&M	$/MWh	0.223	0.244	0.279
Emissions				
CO2 Emissions	lbs/MMBTU	0	0	0
NOx Emissions	lbs/MMBTU	0.0000	0.0000	0.0000
SO2 Emissions	lbs/MMBTU	0.000	0.000	0.000
Repair Time				
Mean Time to Repair	hrs	0	0	0
Min Time to Repair	hrs	0	0	0
Max Time to Repair	hrs	0	0	0
Dispatch				
Ramp Rate	MW/hr	0	0	0
Run Up Rate	MW/hr	0	0	0
Min Up Time	hrs	0	0	0
Min Down Time	hrs	0	0	0
Start-Up Fuel	MMBTU	0	0	0
Expected Plant Life Time	years	20	20	20

Appendix C

Technical Feasibility of CO_2 Sequestration

URS

TECHNICAL FEASIBILITY CARBON DIOXIDE SEQUESTRATION OPTIONS MOHAVE GENERATING STATION

For: Sargent & Lundy Engineers, Ltd

Job No. 28066931
January 24, 2006

URS

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ABBREVIATIONS AND ACRONYMS

API	American Petroleum Institute
AZGS	Arizona Geological Survey
bbl	Barrel
bgs	Below ground surface
CBM	Coal bed methane
CO_2	Carbon dioxide
CO_2-ECBM	Carbon dioxide enhanced coal bed methane recovery
CO_2-EOR	Carbon dioxide enhanced oil recovery
DOE	Department of Energy
ECBM	Enhanced coal bed methane
EOR	Enhanced oil recovery
GHG	Greenhouse Gas
IGCC	Integrated Coal Gasification/Combined Cycle
LLNL	Lawrence Livermore National Laboratory
Mscf	Thousand standard cubic feet
MMP	Minimum miscibility pressure
MW	Megawatt
NETL	National Energy Technology Laboratory
NGCC	Natural Gas-Fired/Combined Cycle
OOIP	Original oil in place
ORISE	Oak Ridge Institute for Science and Education
PC	Pulverized coal
ppm	Parts per million
psig	pounds per square inch gauge
PWCC	Peabody Western Coal Company
PUC	California Public Utilities Commission
SCE	Southern California Edison
S&L	Sargent & Lundy
Tcf	Trillion cubic feet
TDS	Total dissolved solids
TBEG	Texas Bureau of Economic Geology

1.0 INTRODUCTION

Southern California Edison's (SCE's) Mohave Generating Station is a coal-fired facility located in Laughlin, Nevada. The Black Mesa Mine complex consists of two open pit mines operated by Peabody Western Coal Company (PWCC): the Kayenta Mine, which supplies coal to the Navajo generating station in Page, Arizona, via an 83-mile-long electric railroad; and the Black Mesa Mine, which supplies coal via a buried slurry pipeline to the Mohave Generating Station. The station is some 300 miles from the numerous oil fields in Bakersfield, Kern County, California.

In recent years, numerous studies have been undertaken by various entities to evaluate the removal of greenhouse gas (GHG) from the atmosphere and sequestration of carbon compounds in the subsurface using a variety of technologies. Key participants in these studies include: U.S. Department of Energy (DOE), National Energy Technology Laboratory (NETL); Lawrence Livermore National Laboratory (LLNL); Texas Bureau of Economic Geology (TBEG); Sandia National Laboratory; Los Alamos National Laboratory; Oak Ridge Institute for Science and Education (ORISE); the U.S. Geological Survey, and state geological surveys in Pennsylvania, West Virginia, and Illinois; universities, such as Petroleum Technology Research Centre at the University of Regina, Saskatchewan, Pennsylvania State University, Columbia University, Ohio State University, University of Texas at Austin, West Virginia University, and Case Western Reserve University; and industry.

Several pilot projects have been undertaken by researchers and industry, and a few carbon dioxide (CO_2) sequestration projects are operational and have been for several years, such as the Sleipner West natural gas field under the North Sea, and the Weyburn oil field in Saskatchewan, Canada.

Five different types of geologic reservoirs are considered suitable for storing carbon: depleted oil and gas fields; unmineable coal seams; saline aquifers; oil shales; and mafic rock (Friedmann, 2003). This study is directed toward evaluation of the first three.

2.0 OBJECTIVES AND SCOPE OF WORK

Sargent & Lundy (S&L) was retained by SCE to explore the feasibility of various alternatives or complements to the existing Mohave Generating Station, as directed by the California Public Utilities Commission (PUC). Included in this scope was an evaluation of the feasibility of CO_2 sequestration from Integrated Coal Gasification/Combined Cycle (IGCC) or Natural Gas-Fired/Combined Cycle (NGCC) plants located at the existing site, and an IGCC plant located at the Black Mesa Mine site.

The objective of URS' consultation with S&L was to conduct a review of readily accessible literature in order to provide sufficient data for the following evaluation of sequestration options:

1. An evaluation and opinion regarding the feasibility of enhanced oil recovery through CO_2 injection at oil fields in Bakersfield, California; and

2. Identification of a suitable geologic formation for sequestration of CO_2 in the area of the Black Mesa Mine site in Arizona.

In order to achieve the stated objectives, URS has conducted the following scope of work:

- Collection and synthesis of recent available relevant technical literature in the public domain.

- Review of collected data for CO_2-enhanced oil recovery (EOR) and CO_2 sequestration and enhanced coal bed methane (ECBM) recovery.

- Interviews with appropriate researchers from government agencies, national laboratories, universities, and recognized authorities in the study of carbon sequestration in the private sector.

- Preparation of a report detailing the technical feasibility of the sequestration options evaluated.

3.0 BAKERSFIELD CO_2 – ENHANCED OIL RECOVERY

CO_2 has been injected into depleted oil fields to recover additional oil since the early 1970s, and CO_2 flooding is one of several technologies used by the oil industry to complete what is known as enhanced oil recovery (EOR). In the year 2000, a total of 84 commercial or pilot-scale EOR projects using CO_2 injection were operational worldwide. Of these 84 projects, 72 were operating in the U.S., and the majority of these were operating in the Permian Basin in west Texas and New Mexico.

A small proportion of oil, typically 20 to 40 percent of the original oil in place (OOIP), is recovered from oil reservoirs using traditional methods of recovery. EOR methods, including CO_2 injection, can allow for recovery of another increment of the OOIP.

A recent report completed by the DOE indicates that the OOIP in 172 of California's largest oil reservoirs equates to an estimated 83 billion barrels (DOE, 2005). Only 26 billion barrels of oil have been recovered or proved (will be recovered) from these fields to date. It is estimated that approximately 57 billion barrels of the OOIP will be remain in place without use of EOR methods, including CO_2 flooding.

A DOE study (DOE, 2005) concluded that an additional 1.7 to 3.8 billion barrels of oil may be recovered in California using miscible CO_2 flooding techniques. These estimates are based on $35 per barrel (bbl) oil prices and CO_2 costs of $0.50 to $1.25 per thousand standard cubic feet (Mscf).

The remainder of this section presents the following with regard to CO_2-EOR:

- CO_2-EOR processes;
- Screening of oil reservoirs in the San Joaquin Basin for CO_2 flooding;
- Sources of affordable CO_2;
- Transportation of CO_2;
- CO_2-EOR operations including "blow down" of the reservoir; and
- Long-term storage of CO_2 in petroleum reservoirs.

3.1 CO_2-EOR PROCESSES

CO_2-EOR can be used for miscible or immiscible oil recovery. Miscible CO_2-EOR has been the primary process used on commercial CO_2-EOR projects in the U.S. Miscible CO_2-EOR projects are implemented in oil reservoirs that contain light crude oil (crude oil that has an American Petroleum Institute (API) gravity of greater than 25 degrees), and at depths of at least 3,000 feet below ground surface (bgs). These conditions are required to achieve the minimum miscibility pressure (MMP) for the CO_2 and oil in the reservoir. A schematic illustration of the CO_2-EOR process is presented as Figure 1. The amount of oil recovered by miscible CO_2-EOR is dependent upon reservoir-specific characteristics, but can range from 10 to 15 percent of the OOIP.

The CO_2 that is used to initiate miscible floods must be greater than 95 percent CO_2. Nitrogen content in the CO_2 will affect the ability to achieve the MMP in a candidate petroleum reservoir, and will also increase the costs of compression and transport of CO_2.

CO_2-EOR projects can also be designed for immiscible applications. Immiscible projects can be applied to oil reservoirs that are shallower than 3,000 feet or on crude oils that are heavier (have an API gravity of less than 25 degrees). The MMP is not achieved in an immiscible process. Substantial incremental oil can be recovered from depleted oil reservoirs using immiscible CO_2-EOR.

3.2 SCREENING OF OIL RESERVOIRS IN THE SAN JOAQUIN BASIN FOR CO_2 FLOODING

Several large oil fields are present in the San Joaquin Basin in the vicinity of Bakersfield. The DOE (2005) identified 24 oil reservoirs within the San Joaquin Basin that may be technically and financially feasible for miscible CO_2-EOR projects. The largest fields that satisfy screening criteria for miscible CO_2-EOR, shown on Figure 2, include:

Field Name	Reservoir Name	Depth (Feet)	Oil Gravity (Degrees API)	Remaining Oil in Place (MM Bbls)
Elk Hills	Stevens	5,500	35	1,557
Coalinga, E. Extension	Nose Area	7,800	30	464
Kettleman, N. Dome	Temblor	8,000	36	891
Cuyama S.	Homan	4,000	32	605

Source: U.S. Department of Energy (2005)

Three other basins within California have also been identified as containing oil reservoirs with potential for CO_2-EOR, including the Los Angeles Basin, the Ventura Basin, and the Santa Rosa Basin.

Recent increases in world crude oil prices will result in improved economics for recovery of oil via CO_2-EOR and renewed efforts to implement enhanced oil recovery in California's oil fields, especially the larger fields.

3.3 SOURCES OF AFFORDABLE CO_2

A primary barrier for use of CO_2-EOR in California's oil fields has been lack of a secure and sufficient source of affordable CO_2. Carbon dioxide suppliers have reported that availability of CO_2 is currently limited. Additional natural and anthropogenic sources of CO_2 are available to be developed, but a substantial lead time of years will be required to construct the production and pipeline infrastructure to increase supplies to California oil fields.

Natural sources of CO_2 include reservoirs discovered and developed in Colorado, Arizona, or New Mexico. Local California sources include refineries, where CO_2 is produced in hydrogen plants. Pipelines are required to economically transport the CO_2 from these various sources to oil fields. The pipeline infrastructure required for transportation does not yet exist. Currently, it does not appear that economics justify construction of a pipeline to California from the developed natural resources in Colorado, New Mexico, and Arizona.

The long-term reliability of the refinery sources has been identified as a barrier to construction of pipeline infrastructure from the Wilmington refineries (in Southern California) to candidate reservoirs in the San Joaquin Basin (Friedmann, 2005; Personal Communication). Reliability of refineries as a long-term source of CO_2 may be affected by the economics of continued operation of the refinery and the continued use of specific refining processes that generate CO_2 as a by-product in the refinery. The recent increase in crude oil prices to approximately \$60/bbl will accelerate the construction of the pipeline infrastructure for use of the identified sources of CO_2. The timeframe for construction is still uncertain.

Potential future sources of CO_2 include fossil-fuel–fired electric power plants. A 1,000-megawatt (MW) pulverized coal (PC) power plant emits between 6 and 8 million tons of CO_2 per year (Herzog, 2004). Currently, the best technology for removing CO_2 from stack gas is absorption using diethanolamine scrubbers. One example of CO_2 recovery at a coal-fired power plant is the Warrior Run plant, located in Maryland, where 150 tons per day of CO_2 are recovered (Thambimuthu, 2002). The cost of CO_2 recovered from electric power plants in this manner is currently more expensive than CO_2 produced from natural sources. Future technical developments may decrease costs and improve the economics of recovering CO_2 from fossil-fuel–fired power plants for use in CO_2-EOR projects. No technical developments are foreseen that will allow for competitively priced anthropogenic CO_2 for EOR projects when compared to the cost of natural sources of CO_2 (Leppen, 2005; Personal Communication).

The overall market for CO_2 in California for CO_2-EOR has been estimated to be 18 trillion cubic feet [Tcf] (DOE, 2005). Much of this CO_2 will be recycled and reused after delivery to the regional market. CO_2 will be recovered and recycled after being injected either into the oil reservoir where it was originally injected or into another oil reservoir in the region.

The potential development of both natural and anthropogenic sources of CO_2 for use in California EOR projects remains uncertain. Increased world oil prices will drive new efforts to develop both supplies of CO_2 and EOR projects that may use those supplies.

3.4 TRANSPORTATION OF CO_2

CO_2 is usually transported as a compressed fluid in a supercritical phase where it behaves like a liquid with respect to density, but like a gas with respect to viscosity. The supercritical fluid is typically delivered to users in a mixture that is greater than 95 percent CO_2 and at pressures of approximately 1,500 pounds per square inch gauge (psig). The cost of transportation is substantial, and depends on construction of a regional pipeline or trunk line from the source to the location of use. This includes the use of compressor stations to maintain the CO_2 in a supercritical phase.

3.5 CO_2-EOR OPERATIONS INCLUDING “BLOW DOWN” OF THE RESERVOIR

Gases from CO_2-EOR projects are recovered and recycled into the oil reservoir during operation of the project. A typical project may operate from 10 to 30 years. Incremental oil may be recovered at the end of the project by “blowing down” the reservoir. During a “blow down,” the reservoir is slowly depressurized. Gases produced during the “blow down” may be compressed and transported to another CO_2-EOR project in the region, or they may be vented to the atmosphere.

A CO_2-EOR program was recently implemented in the Weyburn Field, located on the northern end of the Williston Basin in Saskatchewan, Canada (Torp, 2003). The project has been designed to be operated with no “blow down’ of the reservoir at the conclusion of the program. The Weyburn program includes a long-term study to demonstrate that the CO_2 injected there will remain in the reservoir for long time periods equivalent to geologic timescales.

3.6 LONG-TERM STORAGE OF CO_2 IN PETROLEUM RESERVOIRS

The length of time that CO_2 can be isolated in a petroleum reservoir is being studied by a variety of organizations. The DOE is providing funding to seven regional partnerships to develop and evaluate technologies for carbon, including CO_2 sequestration. Participants in the partnerships include universities, government agencies, Indian nations, and businesses.

The West Coast Regional Carbon Sequestration Partnership, lead by the California Energy Commission, is planning to conduct two projects in California and one project in Arizona to demonstrate and evaluate CO_2 storage in depleted gas reservoirs and other subsurface formations.

Weyburn is the first CO_2-EOR project to include a long-term study to demonstrate effective geologic isolation of CO_2 in a petroleum reservoir. Other operations that are valid analogs for evaluation of long-term sequestration of gases in petroleum reservoirs include acid gas injection projects, when the acid gas is produced from petroleum reservoirs as hydrogen sulfide and other related organic sulfur compounds. Acid gas injection has been implemented by petroleum producers since the 1970s.

3.7 SUMMARY

CO_2 sequestration via EOR has proven to be a viable technology. Furthermore, there are existing oil fields in the vicinity of Bakersfield, California that would be appropriate for CO_2 flooding. However, the EOR process requires a relatively pure source of CO_2, necessitating the treatment of flue gases from coal-burning power plants. This, coupled with the need for suitable CO_2 transportation via a pipeline, makes this sequestration option prohibitively expensive at this time. In fact, the reason that a pipeline to convey CO_2 to the Bakersfield area has not yet been built is because it has not been financially attractive to industry. However, the financial viability of this process will be significantly influenced by the price of oil, which is currently in a state of flux.

A variation of the use of CO_2 for EOR purposes is the sequestration of CO_2 in naturally occurring reservoirs which form the source of CO_2 for other applications, in essence a recycling of the resource. This possibility was evaluated (Allis, et al., 2001) for reservoirs on the Colorado Plateau and in the southern Rocky Mountains. About ten natural CO_2 fields in this region have been tapped for some time as a source of CO_2-EOR. Ultimate sequestration of CO_2 back into one or more of these reservoirs would depend upon the potential for trapping of the CO_2 in the subsurface, e.g., minimal leakage to the surface, as well as economic considerations. Gas storage options and an evaluation of possible leakage is being conducted. The economic viability of this option would depend upon the infrastructure required, as well as the willingness of the field operator to accept the CO_2 for injection back into the field, which is unknown at this time.

4.0 BLACK MESA CO_2 SEQUESTRATION

CO_2 sequestration refers to the long-term storage of CO_2, generally on the order of thousands of years. As the idea of CO_2 sequestration in geologic receptors gained interest, many types of geologic rock bodies, called formations, were examined as potential hosts for CO_2 generated by man-made processes. Host geologic formations considered for CO_2 sequestration include oil and/or gas reservoirs, deep saline formations, deep unmineable coal deposits, massive dome-shaped salt features and bedded salt formations, coal-bearing shales, and even dark-colored magnesium-rich silicate (mafic) rocks that are low in quartz.

Two types of geologic formations were immediately recognized for the value-added economic benefits that could be realized by CO_2 injection and sequestration: enhanced oil and/or gas recovery in depleted or depleting oil and/or gas reservoirs (CO_2-EOR), and enhanced coal-bed methane recovery in deep unmineable coal deposits (CO_2-ECBM). Opportunities for CO_2-EOR in oil reservoirs were discussed earlier in this report. This section focuses on deep saline formations and deep CO_2-ECBM.

4.1 SCREENING CRITERIA FOR GEOLOGIC FORMATIONS

Various researchers have developed physical, chemical and economic criteria to screen geologic formations suitable for CO_2 sequestration (Stevens et al., 1999; Frailey et al., 2005; White et al., 2003; Herzog and Golomb, 2004; GEO-SEQ, 2004; UTBEG, 2005). This section will evaluate the suitability of geologic formations for CO_2 sequestration based on the following physical and chemical criteria:

- Sequestration must occur at depths greater than approximately 800 meters (2,620 feet), which places CO_2 above its critical point. The critical temperature at which CO_2 exists as a dense gas is 304ºK (88ºF) (White et al., 2003). At that temperature, CO_2 is a gas with such high density that it cannot mix with formation fluids. Furthermore, under these conditions it is less viscous than the surrounding brine, so it behaves as a gas compared to the brine (GEO-SEQ, 2004).

- A maximum depth of 2,000 meters (6,560 feet) is suggested to limit the required wellhead injection pressure, and also cap the cost to drill an injection well (Allis et al., 2003).

- The storage capability of the formation must be prolonged for hundreds to thousands of years. The overlying formation, or cap rock, that seals in the CO_2

must be thick and impermeable to gas. The structural integrity of the formation and the horizontal extent of the formation must be intact; no large faults, structural breaches, or outcrops can exist as pathways that allow CO_2 to escape from the formation.

- Sequestration must target porous formations having saline fluids that generally feature greater than 3,000 parts per million (ppm) total dissolved solids (TDS). Porous water-bearing formations (aquifers) that contain fresh water are economically valuable sources of water for domestic, agricultural, and industrial uses. Conversely, saline water has no economic value, and as a result, porous saline formations are suitable hosts for CO_2 sequestration.

4.2 SUITABLE GEOLOGIC FORMATION TYPES

4.2.1 Deep Saline Formations

Characteristics

The ideal deep saline formation target for CO_2 sequestration is a thick, laterally continuous and relatively homogeneous sandstone or carbonate (limestones and dolomites) with high porosity and permeability. The advantages of deep saline formations include:

- Generally high porosity and moderate to high permeability for sandstones, and moderate porosity and permeability for carbonates—the high porosity in a thick formation provides a large capacity for CO_2 storage, and moderate permeability reduces the potential for clogging the narrow passageways connecting pore spaces by precipitation of carbonate minerals.

- The depth and high salinity result in few competing uses for the formation (GEO-SEQ, 2004).

- Deep, laterally extensive formations provide a long, slow flow path for CO_2 migration back to the biosphere.

- CO_2 is less dense than the saline formation fluid and will rise to the top of the formation like a gas cap (Benson, 2003).

The disadvantages of deep saline formations are a result of their depth and lack of economic value:

- Deep saline formations are not well characterized because they are not targets for oil and gas exploration and little or no reservoir characterization has been completed (Orr, 2003).

- The thickness and quality of the cap rock or seal may be unknown.

- Monitoring of the CO_2 injection and migration, and fluid/rock interaction processes will be difficult at depth because monitor wells are expensive to install and other monitoring methods have less resolution at depth.

Sequestration in deep saline formations has been proven effective in Statoil's Sleipner West Field in the North Sea. The CO_2 is separated from gas production and injected in the Utsira sandstone formation using a horizontal well. The horizontal well is used to avoid corrosion by CO_2 of adjacent wells by directing the CO_2 away from those wells. The project began in 1996 and stores CO_2 at a depth of 1,000 meters (3,280 feet) in the sandstone, which is 15 to 75 meters (50 to 250 feet) thick. About 2,800 tons of CO_2 are injected into the formation each day (Torp and Brown, 2003).

Trapping Mechanisms

There are three processes for long-term CO_2 trapping in saline formations (Herzog and Golomb, 2004; White et al., 2003): hydrodynamic, solution, and mineral. Each process is discussed below.

Hydrodynamic – Saline formations need an impermeable cap rock to seal in the CO_2, which is less dense than the brine. This will force the CO_2 to become entrained in the groundwater and trapped hydrodynamically. The CO_2 moves away from the well under the influence of the injection pressure, but eventually migrates outside the influence of the well and flows with the natural hydraulic gradient. This may occur within a few kilometers of the injection well.

Solution – CO_2 also can be trapped by dissolution into the brine. Dissolved CO_2 is not subject to buoyancy and is not so dependent on the cap rock for trapping. Injection of CO_2 lowers the pH of the formation brine and increases mineral dissolution in sandstone formations. Mineral dissolution has a buffering effect that increases the solubility of CO_2 in the brine. This buffering effect does not occur in carbonate formations because dissolution of the mineral matrix does not increase the solubility of CO_2 or solution trapping.

Mineral – Mineral trapping occurs when CO_2 reacts with minerals present in the formation rock to form stable solids that are not subject to leaking. Mineral trapping is prevalent where +2 valence ions such as Mg^{2+}, Ca^{2+}, and Fe^{2+} are present to precipitate magnesium, calcium, and/or iron carbonates, respectively.

There is, however, a tradeoff in the effectiveness of mineral trapping. If the mineral trapping occurs early in the life of the injection near the injection well, passageways between the pores will clog and severely reduce the permeability and effective storage capacity of the formation. White et al. (2003) envisions a cyclical process of precipitation and re-dissolution in saline formations, as well as in coal seams. They hypothesize that the drop in CO_2 partial pressure as the CO_2 moves away from the injection well will cause mineral precipitation and permeability reduction. The reduction in permeability will cause the partial pressure of CO_2 to increase and re-dissolve the precipitated minerals, opening pore spaces for increased CO_2 movement away from the injection well. This cyclical process could continue until CO_2 equilibrates with the formation and is neutralized, or until CO_2 contacts the low pressure at a gas production well and forms carbonate scale in the well casing.

Formations Near Black Mesa Mine

This study identified and evaluated geologic formations in the Black Mesa Mine area suitable for CO_2 sequestration. A geologic report prepared by Peabody Coal Company (Peabody, 2004) mapped the sedimentary formations underlying the Black Mesa Mine. The deep formations include thick, porous sandstones such as the Wingate, Coconino, De Chelly, and Cedar Mesa Sandstones; and thick porous carbonates such as the Redwall and Muav Limestones. Formations found suitable for CO_2 sequestration include the Coconino Sandstone and Redwall Limestone.

Sandstones – Although there are no reported deep saline formations beneath the Black Mesa Mine, a suitable saline formation is located approximately 72 kilometers (45 miles) south of the mine. Peabody (2004) mapped the sedimentary formations underlying the mine. The deep, thick sandstones include the Wingate, Coconino, De Chelly, and Cedar Mesa Sandstones. Unfortunately, those sandstone formations contain fresh water in the immediate vicinity of the mine (Robson and Banks, 1995). However, the Permian-age Coconino Sandstone does have a region of high salinity south of the mine, where salinity ranges from 3,000 to more than 25,000 ppm (Figure 3). In this area, the Coconino Sandstone is 2,500 to 3,500 feet deep, from 500 to 800 feet thick, has moderate to high porosity, and is in a geologically stable area with little faulting or folding. The high salinity aquifer encompasses an area approximately 50 miles long and 20 miles wide. This formation dips upward and thins to the south away from Black Mesa.

URS contacted Steven L. Rauzi, Oil and Gas Administrator at the Arizona Geological Survey (AZGS). As a member of the Southwest Region Geological Sequestration Partnership, the

AZGS conducted an inventory of formations that may be suitable for CO_2 sequestration near coal-fired power plants in northern Arizona. The AZGS recognized the Coconino Sandstone as a suitable sink for CO_2 in northern Arizona (Mahan, 2005). This area is within the Navajo and Hopi Indian Reservations, and permitting for an injection well will require their approval. State agencies (Arizona Department of Water Resources; Arizona Department of Environmental Quality) also would require an aquifer protection permit to inject CO_2 into deep saline formations.

Limestones – The Mississippian-age Redwall Limestone also was recognized as a good candidate formation in northern Arizona for CO_2 sequestration (Allis et al., 2003; Mahan, 2005). The Redwall Limestone is a thick, massive dolomite (calcium magnesium carbonate) and dolomitic limestone at sufficient depth for CO_2 to reach the critical point. Variations in reservoir porosity can result from depositional environment changes and/or recrystallization of carbonate minerals that have enhanced porosity. In the Grand Canyon, 114 kilometers (70 miles) west of Black Mesa, Redwall Limestone outcrops display large, cavernous dissolution features, confirming that high porosity can be present (Utah Geological Survey, 2003). Regional and local structures have relatively gentle dips, and faulting is not extensive (Peabody, 2004). Thick shale in the Permian Organ Rock Formation provides an effective cap rock. The geologic structure beneath Black Mesa resulted in deposition of a thick Redwall Limestone section.

There is, however, limited information on the groundwater quality in the Redwall Limestone. A wireline geophysical log was run in the Sinclair #1 Navajo well, located 30 miles west of the Black Mesa Mine. The log response indicates that the upper 280 feet of the Redwall are limestone and contains fresh formation water. The lower 140 feet are mostly dolomite and contain saline formation water. Saline water also is present in a dolomitic zone in the upper 65 feet of Muav Limestone below the Redwall. Water samples collected from Redwall-Muav springs in Grand Canyon, 114 kilometers (70 miles) west of Black Mesa, contained fresh water (Monroe et al., 2004).

URS interviewed James A. Drahovzal at the Kentucky Geological Survey, who has studied deep carbonate reservoirs for CO_2 sequestration. He agrees that carbonate formations are generally not well characterized both for storage capacity and formation salinity, and that greater emphasis should be placed on evaluating deep carbonate reservoirs for CO_2 sequestration. Carbonate reservoirs also should be good candidates for sequestration because the CO_2-carbonate fluid-rock interactions will not have a significant impact on reservoir porosity and permeability.

Alluvial Aquifers – Deep sand and gravel (alluvial) basins contain aquifers near the Arizona-California border. There can be a wide variation in aquifer salinity in these formations, and most of the deep aquifers have not been penetrated or tested at the depth necessary for CO_2

sequestration. Robson and Banks (1995) reported that alluvial basins in the Mohave-Kingman area have groundwater with salinity generally less than 1,000 ppm. Beneath the shallow non-saline alluvial formations, deeper saline alluvial formations may exist that have not been tested.

URS contacted Steve Rauzi of the AZGS for information on deep alluvial aquifers. Because oil and gas exploration has not targeted those deep formations, there is no information on aquifer thickness and areal extent, and no groundwater quality data. If no suitable formations can be found for CO_2 sequestration near the Black Mesa Mine, exploration of deep alluvial aquifers near the Arizona-California border may be warranted.

4.2.2 Deep Unmineable Coal Deposits

Characteristics

The ideal coal deposit target for CO_2 sequestration contains thick, laterally extensive and deep unmineable coal seams that have already produced coal bed methane (CBM) by dewatering the formation. The application of CO_2 injection and sequestration to CBM production is a value-added benefit. CBM production combined with CO_2 injection and storage expands the use of a coal resource by providing multiple benefits: (1) increased methane recovery; (2) ECBM drainage of a resource area; and (3) long-term CO_2 storage (Stanton et al., 2001). The advantages of using deep unmineable coal deposits include:

- CO_2 displaces methane gas that is adsorbed within coal. This process releases methane gas to production, while at the same time capturing and storing CO_2. Depending on coal quality, two or more molecules of CO_2 are captured for each methane molecule displaced (Stanton et al., 2001).

- Coal cleats (small fractures in the coal seams) provide porosity and permeability in the coal seams and increase the capacity for CO_2 capture.

- CO_2 accelerates gas recovery. Higher injection rates often result in higher methane production.

- The injected gas can be a mixture of nitrogen (N_2) and CO_2, such as is found in smokestack (flue) gases, that need not be purified prior to injection (White et al., 2003). This advantage can significantly reduce the cost of separating and cleaning CO_2 from flue gases.

The disadvantages of using deep unmineable coal deposits include:

- A limited depth range of 800 to 1,600 meters (2,600 to 5,200 feet) for optimum performance of CO_2 injection. Below that depth, coal cleats begin to close up, reducing porosity (Stevens et al., 1999).

- Uncertain sensitivity of the coal seams to ECBM depending on the coal rank (purity). A sensitivity study by Reeves et al. (2004) concluded that ECBM is more favorable in higher rank coal seams that have lower permeability.

- With CO_2 injection there is a general decline in coal permeability and injectivity as coal cleats dry out and begin to close up (Klara et al., 2003).

Burlington Resources has been injecting CO_2 into CBM wells at their Allison Unit in southwestern Colorado since 1995. The CO_2 is obtained from a natural source and is technically not a CO_2 sequestration project, although it has proven the viability of the process by injecting more than 300,000 tons of CO_2. This ECBM operation has lost some injectivity over time because the coal swells when it is contacted by CO_2 (Klara et al., 2003).

Trapping Mechanisms

Very little is understood about what happens to CO_2 when it is injected into a coal seam. Most understanding of the trapping and reaction processes is theoretical and is being evaluated using models. The theory and understanding of these physical, chemical, and thermodynamic processes are complex, and at least 10 hypotheses have been formulated to develop models. The reader is referred to White et al. (2003) for a discussion of these hypotheses.

Formations Near Black Mesa Mine

There are no deep unmineable coal deposits near the Black Mesa Mine. The Black Mesa Mine strips coal from the shallow Cretaceous-age deposits of the Mesaverde Group (Nations et al., 2000). Unmineable coal seams in the Black Mesa Basin are found at depths less than approximately 330 meters (1,000 feet) and are too shallow for optimum CO_2 sequestration. In addition, the coal seams are generally thin and do not extend laterally for more than about 5 miles to outcrops at the edge of Black Mesa.

There are deep unmineable coal deposits in the San Juan Basin, which is located about 150 miles east of the mine in New Mexico. CBM production is from multiple thick coal seams in the Cretaceous-age Mesaverde Group (Fassett, 2000). The San Juan Basin has several thousand CBM production wells and is one of the most prolific CBM production areas in the world. ECBM is in the beginning stages in the San Juan Basin, and there are many opportunities for

CO_2 injection in multiple coal seams throughout the basin. At this time the basin is served by one CO_2 pipeline from a natural deposit in Colorado. There is the potential for piping CO_2 from another natural source located in the St. Johns area of east-central Arizona.

4.3 SUMMARY

There are no deep unmineable coal deposits near the Black Mesa Mine suitable for CO_2 sequestration. Accordingly, this option is not considered viable. However, the Coconino-DeChelly sandstone of the Black Mesa Basin, south of the Black Mesa Mine, seems to be an appropriate receptor for CO_2 sequestration in a deep saline aquifer. As mentioned above, additional subsurface exploration and testing would be required to verify this possibility.

5.0 LIMITATIONS

Professional opinions expressed herein are based upon a limited scope of work, review of readily available and relevant technical literature, and interviews with cognizant professionals, and should not be construed as legal opinions. Other interpretations are possible based on information not reviewed by URS.

6.0 REFERENCES

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Appendix D
Emissions Valuation
Final Draft

Note:	This Appendix D differs from the version included in the February 2006 report.

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March 29, 2006

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1. Introduction

The quantity and cost of pollution emissions should be considered in any analysis of generation resource alternatives. As the dominant source of electricity in the U.S., fossil fuel-fired power plants generate comparatively large amounts of pollution compared with other generation technologies, such as renewable sources. [1] Because power plants are stationary, they are more easily regulated and monitored than small, mobile sources. Thus, pollution-emitting plants are often the object of regulations to reduce air pollution levels.

Pollution has negative effects on human health and the environment, a key component of the cost burden imposed on society, often called social costs. Rather than merely prescribing pollution controls, regulation of pollutants often seeks to attach economic significance to them so that emitters must factor these social costs into their operating decisions.[2] Generation owners incur tangible direct costs of compliance (e.g., the capital and operating costs of pollution control technology; reduced net plant output due to pollution controls; emissions allowance expense[3]; transaction costs), but they also face certain risks associated with pollution control regulation (e.g., fines for non-compliance, uncertainty about future standards). When offered a choice for how to comply with emission standards, generators must weigh the risk and costs of different options—including switching to generation technologies that generate less or no air pollution—to be competitive.

This section considers the economic impacts and projected market prices of five pollutants typically emitted by fossil fuel-fired power plants: Oxides of Nitrogen (NOx), Particulate matter (PM), Sulfur Dioxide (SO_2), Mercury (Hg), and Carbon dioxide (CO_2).[4] Particulate matter (PM) is further divided into coarse (PM_{10}), fine ($PM_{2.5}$), and ultrafine particulates (UFP). Through chemical reactions, these pollutants can form Ozone (O_3), which is therefore also a concern for the power generation sector. For purposes of discussing why these pollutants were selected for coverage in this report, they are divided into the Criteria Air Pollutants (and precursors to criteria air pollutants), Mercury, and Greenhouse gases.

In addition to producing few or no emissions, renewable resources may provide value by creating tradable renewable energy credits (RECs). Many states in the West have established renewable portfolio standards (RPS) that require load serving entities to ensure that renewable generation makes up a certain portion of their total resource mix. RECs are a means of tracking and accounting for renewable generation for compliance with renewable portfolio standards, and thus have a market value and can create additional revenues for their owners. The amount of value created by RECs for any one renewable facility will depend upon many factors, including

[1] Coal, natural gas, and petroleum accounted for about 70% of net electricity generation in the U.S. in 2003. EIA. See http://www.eia.doe.gov/neic/infosheets/electricgeneration.htm.
[2] One example of such a measure is the tradable allowance system established for sulfur emission under the Clean Air Act Amendments of 1990. (See section 3.1, Acid Rain Program.)
[3] An emissions allowance is a legal and transferable right to emit a quantity of emissions (e.g., pound, ton). Sources are required to use allowances to cover the actual amounts emitted during the compliance period (month, year). Burtraw, Dallas, David A. Evans, Alan Krupnick, Karen Palmer, and Russel Toth (Resources for the Future). *Economics of Pollution Trading for SO_2 and NOx.* May 2005.
[4] http://www.eia.doe.gov/cneaf/pubs_html/rea/feature1.html

the type of renewable generation, the RPS target in any given year, the availability of other renewable resources to meet the RPS target, and the ability to trade RECs within and across state borders. Section 5 of this Appendix provides a discussion of how the renewable options under consideration in this study might provide additional value from the generation and sales of RECs.

1.1. Criteria Air Pollutants

EPA regulates six of these pollutants, including CO, Lead (Pb), Nitrogen Dioxide (NO_2), O_3 (which is controlled in part through NOx regulations), PM, and SO_2, under the National Ambient Air Quality Standards (NAAQS) established by the 1970 Clean Air Act (CAA). EPA developed health-based criteria to form the basis of specific ambient standards (primary NAAQS) for these six 'criteria air pollutants.' Secondary standards were developed based on protection of property and the environment.

Table 1 shows the effects of pollutant exposure on human health, as well as damage to property, natural resources, and ecosystems.

Table 1. Health and Environmental Effects of Criteria Air Pollutants.

Pollutant	Human Health Effects	Environmental Effects
SO_2	Exposure to SO_2 has been associated with premature death and respiratory illness. It may aggravate existing heart disease and asthma. In addition, SO_2 can undergo chemical reactions in the air to form PM, another criteria pollutant.	SO_2 is a component of acid rain, which damages forests and crops, changes the makeup of soil, and makes lakes and streams acidic and unsuitable for fish. Continued exposure to acid rain changes the natural variety of plants and animals in an ecosystem and accelerates the decay of building materials and paints. SO_2 is a precursor to PM and also a component of regional haze, which reduces visibility in urban areas and in national parks.
NOx	NOx exposure can cause or worsen respiratory disease such as emphysema and bronchitis, and can aggravate existing heart disease. It is associated with premature death. NOx can also form PM (see below).	NOx also contributes to acid rain, is a component of regional haze, and forms ozone when it reacts with volatile organic compounds (see O_3). NOx is also a precursor to fine particulates. NOx affects water quality, leading to oxygen depletion and declines in aquatic life.
O_3	Ozone irritates lung airways, aggravates existing asthma, and can cause permanent damage with repeated exposure. Even at very low levels, ground-level ozone triggers reduced lung capacity and increased susceptibility to respiratory illnesses like pneumonia and bronchitis.	Ground-level ozone interferes with the ability of plants to produce and store food, which makes them more susceptible to disease, insects, other pollutants, and harsh weather. It damages the leaves of trees and other plants and reduces crop and forest yields. O_3 is a component of regional haze.
PM	Exposure to particulate matter is associated with bronchitis and asthma, decreased lung function, heart disease, and premature death.	PM is the major cause of regional haze. It also makes lakes and streams acidic, changes the nutrient balance in coastal waters and large river basins, depletes the nutrients in soil, damages sensitive forests and farm crops, affects the diversity of ecosystems; and can damage stone and other materials.
CO	CO exposure reduces oxygen delivery	CO contributes to the formation of smog—ground-

Pollutant	Human Health Effects	Environmental Effects
	to the body's organs (like the heart and brain). Effects are most serious for those with heart disease. It may lead to development of vision problems, reduced ability to work or learn, reduced manual dexterity, and difficulty performing complex tasks.	level ozone (see O_3).
Pb	Lead exposure can damage the nervous system, kidneys, liver, and reproductive system; it may also lead to osteoporosis, high blood pressure, heart disease and anemia. At high levels, it causes seizures, mental retardation, and behavioral disorders. Fetuses and young children are particularly vulnerable, even at low levels.	Lead has similar effects on wild and domestic animals as it does on people. It slows vegetation growth and can cause reproductive damage, blood and neurological changes in some aquatic life.

Source: U.S. EPA. Six Common Air Pollutants. See http://www.epa.gov/air/urbanair/.

The CAA requires EPA to reevaluate NAAQS standards every five years.[5] EPA draws on peer-reviewed, scientific studies of the health and environmental effects of exposure, ensuring that standards more-or-less reflect current or recent scientific developments. Studies continue to indicate that the damages that these pollutants cause to human health and/or the environment are significant and serious.[6] Historical experience suggests that future environmental requirements will be even more stringent than they are today.[7]

Criteria air pollutants continue to be common in the U.S. Although EPA has been regulating criteria air pollutants since 1970, many urban areas are still classified as non-attainment for at least one criteria air pollutant. About 90 million Americans live in non-attainment areas. EPA has responded with tighter or different regulatory mechanisms, for example the NOx SIP Call in 1998. Unable to comply with ozone standards, a number of states have pushed EPA to regulate interstate pollution that contributes to their non-attainment status. Given the continued pressure states and the public put on EPA, it is unlikely that the NAAQS will be loosened—or even remain at current levels—over the period covered by this analysis.

The criteria pollutants of primary concern for coal-fired plants include SO_2 and PM. Likewise, coal plants emit NOx (a precursor to another criteria pollutant, O_3) in significant quantities. Air quality issues tend to differ between the western and eastern parts of the country, with emphasis on SO_2 in the west and on NOx in the east, due to its contribution to widespread non-attainment of the NAAQS for ozone. Differing concerns about the environmental impact of SO_2 and NOx

[5] While EPA's analysis and assessment are frequently contested by stakeholders, the regulatory mechanisms embodied in the NAAQS (including the process of evaluation and revision to the standards) have withstood litigation. These legal precedents suggest that the regulatory framework is fairly well-established.
[6] See, e.g., Northeast States for Coordinated Air Use Management (NESCAUM). *Mercury Emissions from Coal-Fired Power Plants: The Case for Regulatory Action*, Oct., 2003. http://bronze.nescaum.org/airtopics/mercury/rpt031104mercury.pdf.
[7] Bolinger, Mark and Ryan Wiser. *Balancing Cost and Risk: the Treatment of Renewable Energy in Western Utility Resource Plans*. Ernest Orlando Lawrence Berkeley National Laboratory (LBNL-58450). August 2005. p. viii. http://eetd.lbl.gov/EA/EMP/rplan-pubs.html.

on either side of the Rockies are reflected in recent policy developments (e.g., the Clean Air Interstate Rule only applies to the eastern states.) See section 3.1.[8]

Of the criteria air pollutants, this report focuses on SO_2, because it is likely the most economically significant to a generator in the West. NOx is also considered, mainly for its role in the creation of regional haze. (See Regional Haze, section 3.1.) Although we report qualitative considerations, a lack of active markets and data for O_3 CO, and particulates prevent thorough quantitative analysis. Because fossil-fired electric power plants emit only trace amounts of Pb,[9] we do not focus on it here.

1.2. Mercury

The health and environmental effects of exposure to mercury are frequently in the news. These effects, including neurological and developmental impairment to both humans and other animals, are severe and widely documented. As early as 1998, EPA reported to Congress that mercury is the Hazardous Air Pollutant (HAP) with the greatest concern for public health. Public awareness remains heightened due to recent and serious state and local advisories about contaminated water bodies and fish populations unsafe for consumption.

Table 2. Health and Environmental Effects of Mercury.

Human Health Effects	Environmental Effects
Mercury, at high levels, may damage the brain, heart, kidneys, lungs, and immune system of people of all ages. Methylmercury may harm the developing nervous system of unborn babies and young children.	Mercury exposure may cause mortality, reduced fertility, slower growth and development, and abnormal behavior. Fish, fish-eating animals, and predators higher up the food chain are at risk for higher exposure.

Source: http://www.epa.gov/mercury/about.htm.

Concerns about the effects of mercury on public and environmental health prompted EPA's recent rulemaking on mercury emissions from electric steam generating units. In 2000, the EPA issued a determination that generation plants should be regulated under Section 112 of the CAA, which would require application of a Maximum Achievable Control Technology (MACT) standard. Despite the MACT determination, EPA issued two final rules this year: one delisted mercury as a pollutant that was "appropriate and necessary" to regulate under Section 112, and the other promulgated regulation of mercury under Section 111 of the Clean Air Act, which allows for a cap and trade regulatory mechanism. Numerous environmental interest groups, attorneys general, politicians, and others decried EPA's decision and immediately challenged it in court. Regulators, legislators, and the public may hear about this high-profile decision for some time to come.

A large portion of mercury emissions are attributed to electricity generation. Coal-fired utility boilers account for 41% of U.S. anthropogenic emissions.[10] Hg is a major emissions concern for

[8] PacifiCorp 2004 IRP, Appendix A, p. 19.
[9] http://www.eia.doe.gov/cneaf/pubs_html/rea/feature1.html
[10] Northeast States for Coordinated Air Use Management (NESCAUM). *Mercury Emissions from Coal-Fired Power Plants: The Case for Regulatory Action*, Oct., 2003.

coal-fired plants. Given the current state of scientific knowledge, these stationary sources are an essential and practical target for regulation.[11]

1.3. Greenhouse Gases

The earth's climate is partially determined by concentrations of greenhouse gases in the atmosphere. International scientific consensus, expressed in Third Assessment Report of the Intergovernmental Panel on Climate Change (IPCC), is that climate is changing due to anthropogenic emissions of greenhouse gases. While uncertainty remains about the magnitude of these effects, there is widespread consensus that continued greenhouse gas emissions will have serious consequences for socio-economic systems, human health and the environment.[12]

Table 3. Health and Environmental Effects of Greenhouse Gases.

Human Health Effects	Environmental Effects
Nitrous oxide, a greenhouse gas, also has direct effects on human health (see NOx, Table 1). Exposure to CO_2 is not associated with direct effects on human health. However, humans will be indirectly affected by climate change through changes in ranges of disease, water-borne pathogens, water quality, and air quality.	Changes in regional climate will disrupt many physical, biological, social, and economic systems. There are preliminary indications that these systems have already been affected. • Global mean surface temperatures are projected to increase by 1.4–5.8 °C by 2100. • Snow cover and ice extent, both polar and in glaciers, have decreased. The arctic is warming almost twice as fast as the rest of the world. • Mean sea levels are expected to rise by 9–88 cm by 2100. • Rainfall patterns will change. • Variability of the climate will increase, resulting in greater threat of extreme weather events including maximum temperatures, precipitation events, drying and drought, cyclone intensity, and precipitation intensities. • Climate change will affect food availability and quality.

Source: Johnston, Lucy, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value.

These facts have made greenhouse gas emissions the focus of much policymaking on various scales, from local to international. [13] International markets for carbon allowances are operational and have experienced steady growth in trading volumes.[14,15] Regional carbon markets, including

[11] PacifiCorp 2004 IRP, Appendix A, p. 19.

[12] In 2001 the IPCC issued its Third Assessment Report. The Report states that the earth's climate will change more rapidly than previously expected, and that most of the warming observed over the last 50 years is attributable to human activities. Johnston, Lucy, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, *Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value*.

[13] For example, in June, 2005, the U.S. Conference of Mayors voted unanimously to support the Climate Protection Agreement sponsored by Seattle Mayor Greg Nickels. The agreement adopts the Kyoto Protocol's goal of reducing GHG emissions 7% below 1990 levels by 2012. "U.S. Mayors Endorse Nickels' Climate Protection Agreement" June 13, 2005. http://www.seattle.gov/news/detail.asp?ID=5260&Dept=40.

[14] The principal anthropogenic greenhouse gases include carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O); hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6) are also greenhouse gases. A carbon allowance on the international market, expressed in terms of tons of CO_2 equivalent, will be categorized by emissions-reduction methodology and may include any of these gases. The Chicago Climate Exchange trades reductions in any of the following: CO_2; CH_4; N_2O; HFCs; PFCs; and SF_6. http://www.chicagoclimatex.com/about/program.html

the Regional Greenhouse Gas Initiative (RGGI), are developing in the U.S. While the U.S. has yet to address global warming on a national scale, there are many indications that carbon regulation is inevitable. In June of 2005, the U.S. Senate passed a resolution on global warming calling for a "national program of mandatory, market-based limits and incentives on greenhouse gases."[16]

Investors are increasingly demanding that U.S. businesses incorporate carbon costs and opportunities into their business plans.[17] A 2002 report from the investment community identifies climate change as a potential multi-billion dollar risk to some U.S. businesses and industries. Given its continued growth in emissions, the electric sector is likely to be a prime target of future greenhouse gas regulation. Moreover, electric utilities face large risks from climate policy, which is likely to have important consequences for power generation costs, fuel choices, wholesale power prices and the profitability of utilities. Even under conservative scenarios, additional costs could exceed 10% of 2002 earnings.[18]

Although not currently regulated under federal law, the risk of carbon regulation in the U.S. is significant over the 20-year horizon considered in this analysis.[19] Moreover, the risk of future carbon regulations dominates regulatory compliance risk from other pollutants, even assuming a modest cost per ton of CO_2. Future carbon regulations represent a growing concern for coal-fired plants, which could see a $10/MWh increase in the cost of coal power as a result.[20],[21]

1.4. Organization of This Appendix

The next section, Section 2, discusses the economic significance of emissions. Section 3 describes current and future regulations that allow for emissions trading or will otherwise impact allowance clearing prices in the southwest. Section 4 sets forth methodology for determining emissions trading values, as incorporated into each of the technology options examined in this study. Section 5 examines the value of renewable energy credits.

[15] Despite not being launched until 2005, the Emissions Trading Scheme saw carbon trading as early as 2003 and has experienced growth up to the present. Johnston, Lucy, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, *Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value*.

[16] Eilperin, Juliet. "Senators Struggle to Act on Global Warming." *Washington Post*. Friday, July 22, 2005; Page A03. http://www.washingtonpost.com/wp-dyn/content/article/2005/07/21/AR2005072102235.html

[17] Johnston, Lucy, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, *Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value*.

[18] Ibid.

[19] Bolinger, Mark and Ryan Wiser. *Balancing Cost and Risk: the Treatment of Renewable Energy in Western Utility Resource Plans*. Ernest Orlando Lawrence Berkeley National Laboratory (LBNL-58450). August 2005. p. viii. http://eetd.lbl.gov/EA/EMP/rplan-pubs.html. Also see PacifiCorp 2004 IRP, Appendix A, p. 19.

[20] Ibid., p. 19.

[21] Based upon the US EPA's eGRID data for the year 2000, the CO_2 emissions coefficient (in short tons of CO_2 per MMBTU) are 0.1026 for coal, 0.0604 for natural gas, and 0.0798 for oil combustion. "Review of PSI Energy Environmental Compliance Plan Filing: Testimony of Bruce E. Biewald, prepared on behalf of the Citizens Action Coalition of Indiana and Environmental Council." Synapse Energy Economics, Inc. Cause No. 42622. March 17, 2005. See http://www.synapse-energy.com/publications.htm#mony.

2. Economic significance of pollutants

2.1. Risk

The health and environmental effects of exposure to pollutants, described in the previous section, will impose costs on society. Through regulation, these social costs may be partially or wholly incorporated into the production costs of the polluter. An unregulated pollutant will incur a cost to society but not to the producer of the pollution. However, presently uncontrolled emissions have the potential to be regulated in the future and therefore represent risk. Regulation or legislation can shift an unpriced externality into a priced one, creating tangible costs and opportunities. A generator must consider, even anticipate, the possibility of new or changing regulations to be competitive over the long term.

Environmental regulations are generally revised to reflect scientific developments in pollution release, dispersal, ambient transformation, population exposure, and epidemiological effects. Regulation may occur on a number of scales, as health problems vary in terms of the characteristics of populations affected, geographical scope, and other factors. Regulations are overseen by governmental bodies with varied jurisdictions, and under authority of many different laws and statutes that often arise in response to the specific effects of each pollutant.

2.2. Regulatory Mechanisms

Pollution can be subject to numerous regulatory mechanisms, including ambient standards, restrictions on release, or a combination of the two. Ambient standards set a limit for the concentrations of a pollutant in the air in a specific area. For example, under Title I of the CAA, EPA sets ambient air quality standards for criteria pollutants. States implement the standards through State Implementation Plans (SIPs), and Tribes that elect to participate in programs submit Tribal Implementation Plans (TIPs). In turn, the state may use a different regulatory mechanism to achieve compliance with federal ambient standards,[22] or to achieve state-mandated pollution reductions above and beyond those required by federal law (see Section 3 below for further discussion of regulations on different levels of government).

Release-based regulation seeks to limit the amount of emissions from a specific source. Costs may include mitigation technologies, incremental costs for cleaner-burning fuel, or alternately, penalties incurred for non-compliance.[23] Technology-driven regulations, a type of release-based regulation, designate criteria for defining sources that are subject to the rule and establish an abatement technology for that class of sources. By design, technology-driven regulations must change over time to keep up with innovation in emissions control. Technology driven regulations are often contrasted with risk based regulations, because the former does not generally promote innovation, whereas the latter provides incentives for polluters to find new

[22] Release-based regulation is often the means for a state to comply with federal ambient standards. For example, to allow economic growth in localities in violation of ambient standards, the 1977 CAAA added a provision for release-based emissions offsets. Offsets allow new sources to pay existing sources to reduce emissions, such that the overall quantity of emissions in the locality does not increase (see NAAQS in section 3.1). Burtraw, Dallas, David A. Evans, Alan Krupnick, Karen Palmer, and Russel Toth (Resources for the Future). *Economics of Pollution Trading for SO_2 and NOx.* May 2005. p. 4.

[23] Regulations that use technology-driven standards include Maximum Available Control Technology (MACT), Best Available Control Technology (BACT), New Source Review (NSR), and Best Available Retrofit Technology (BART).

ways to reduce emissions. Risk-based regulations require that total emissions must go down to a defined level or reduce emissions by a specific amount.[24]

An emission limit places a threshold on the amount of emissions from a source but allows the producer to determine the most economical way to achieve that reduction (i.e., it is risk-based).[25] There is no economic motivation for the producer to reduce emissions below the emissions limit.

Under cap and trade regulation, each unit of emission, or allowance, has monetary value. Emissions choices are tied to economics both above and below the cap, because an emitter must buy allowances if the emitter uses more than it is allocated or has banked, or it can collect revenue by selling allowances if he emits less than the cap. Emissions falling into this category include: sulfur dioxide (SO_2) under Title IV of the Clean Air Act (U.S. EPA); mercury under the Clean Air Mercury Rule; NOx under the SIP Call; and CO_2 pursuant to the Kyoto Protocol and RGGI, if enacted.

3. Regulations by Pollutant

Air emissions are generally regulated under both federal and state law and, in some instances, tribal law. EPA oversees implementation of the CAA, although Nevada (like most states) has authority to administer the federal laws within their borders.[26] A polluter may be subject to regulations at different levels, and federal and state laws can overlap with each other. Federally-recognized tribes, such as the Navajo Nation, generally have the option of implementing U.S. air pollution regulations. Tribes do not face federally-mandated planning or compliance deadlines in the absence of a legally binding agreement with the U.S. EPA.[27]

3.1. Multi-Pollutant Regulations

Acid Rain Program

Sulfur Dioxide (SO_2)

Title IV of the 1990 Clean Air Act Amendments established a cap and trade program for SO_2 allowances, allocated to electricity-generating facilities based on heat input over a historical base period (1985-1987). Known as the Acid Rain program, Title IV allowed sources to “bank” unused allowances for future use. Over the first phase of implementation, which began in 1995,

[24] For example, New Source Review standards are technology-based. NAAQS are an example of risk-based regulation. NAAQS and New Source Review are discussed in section 3.1.
[25] The Prevention of Significant Deterioration program, which applies to sources in NAAQS attainment areas, incorporates limits on emissions increases. See section 3.1.
[26] The Nevada Bureau of Air Pollution Control (BAPC) has jurisdiction over all fossil fuel-fired units that generate steam for electrical production, even in Washoe and Clark counties. http://ndep.nv.gov/bapc/index.htm.
[27] The Director of the Navajo Nation Environmental Protection Agency can set “air quality standards, emissions limitations and standards of performance for prevention, control and abatement of air pollution in the Navajo Nation. In prescribing regulations, the Director shall give consideration to but shall not be limited to the relevant factors prescribed by the Clean Air Act and the regulations hereunder, except that the regulations prescribed by the Director shall be at least as stringent as those promulgated under the Clean Air Act.” Navajo Nation Environmental Policy Act § 1103.

generators have built up allowances. As of 2000, Phase II capped total emissions at 8.95 million tons. EPA expects that generators will draw on and deplete banked allowances by 2010.[28]

Mohave units 1 & 2 are allocated 26,437 and 26,336 SO_2 allowances, respectively, through 2009. Thereafter, unit 1 is allocated 26,165, and unit 2 is allocated 26,059.[29] The Mohave plant has had more allowances allocated to it than it used in past years. For instance, through March 1, 2004, it transferred 6407 allowances (2003 vintage) from unit 1 and 6014 from unit 2. These allowances will provide a stream of future revenue, discussed further in section 4.4.

Oxides of Nitrogen (NOx)

In addition to the SO_2 cap and trade program, Title IV of the CAAA required reductions in the NOx emission rates of two groups of coal-fired boilers.[30] Although technology-based, the limits were applied on an average, company-wide basis, therefore allowing compliance flexibility within a firm. Title I required states to implement additional NOx and volatile organic compounds (VOC) regulations on large point sources in ozone non-attainment areas. The Title I requirements went into effect sooner and generally allowed less flexibility.

Title I of the 1990 CAAA also responded to ozone non-attainment in areas significantly affected by upwind emissions by establishing the Ozone Transport Commission (OTC) in the eastern US. Out of the OTC came the NOx Budget Program, a trading program that began in 1999 and featured a unified market, state-level budgets and state-determined allowance allocations to individual sources.[31] NOx policy further evolved from the NOx Budget Program to the NOx SIP call. The SIP Call took the form of an opt-in regional cap and trade program, or alternatively a command-and-control mechanism with state-determined limits for individual sources. Effective May of 2004, the NOx SIP call is expected to reduce national emissions by 22% from a baseline level.[32] Most recently, NOx regulations have come under CAIR (described below). But while regional cap and trade systems have been implemented in the East, no such mechanism currently exists in the West, other than on a local basis (see RECLAIM, below).

Although it seems unlikely that NOx will be a major regulatory concern in the west for the near term, nitrogen deposition is a significant problem for forested areas such as the Colorado Front Range and San Gabriel, Klamath, and San Bernadino Mountains and is expected to get worse.[33]

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[28] Phase I applied to specific units, the 110 dirtiest coal-fired electricity generators. Phase II expanded affected units to include all other coal-fired electricity-generating facilities over 25 MW in capacity, as well as smaller units burning high-sulfur fuel. Burtraw, Dallas, David A. Evans, Alan Krupnick, Karen Palmer, and Russel Toth (Resources for the Future). *Economics of Pollution Trading for SO_2 and NOx.* May 2005. p. 8.
[29] EPA ATS – Allowances Held Report. See http://www.epa.gov/airmarkets/tracking/ats/allheld.html.
[30] Group 1 consists of dry bottom wall fired & T-fired boilers. Group 2 includes cell burners, cyclones, wet bottoms, vertically fired boilers.
[31] Allocation rules set by individual states are described in Burtraw, Dallas, David A. Evans, Alan Krupnick, Karen Palmer, and Russell Toth. RFF. *Economics of Pollution Trading for SO_2 and NOx*. May 2005, p. 30-33.
[32] Ibid., p. 36.
[33] http://www.fs.fed.us/psw/topics/air_quality/cl/meetings/ppt/07_haeuber_sandiford_epa_cl.ppt#294,9,Nitrogen Deposition in the High Elevation West

Regional Haze

Regional haze is the impairment in visibility that results from ambient pollutants, emitted from numerous sources over a large geographic area. The solid or liquid particles that contribute to regional haze include $PM_{2.5}$, SO_2, NOx, and ozone.

The 1977 CAAA established a goal to reduce visibility impairment due to regional haze in Class I areas, including national parks and wilderness areas. Pursuing progress towards this goal, Congress created the Grand Canyon Visibility Transport Commission (GCVTC) in 1991 to advise the U.S. EPA on protecting the visual air quality in 16 Class I areas on the Colorado Plateau.[34] In 1996, GCVTC issued a report recommending strategies for addressing regional haze in this region.

The 1999 Regional Haze rule marked a change in EPA's approach, expanding coverage of the rule to all states, not just those with Class I areas within their borders. In addition, it required states to establish emission reduction targets and strategies for protecting visibility in Class I areas. On September 29, 2000, the Western Regional Air Partnership (WRAP) appended GCVTC's 1996 report in order to place the GCVTC recommendations within the framework of the national Regional Haze rule. The Annex to the GCVTC report contains a set of recommended regional emissions milestones that address emissions of SO_2 between 2003 and 2018.

Under 40 CFR 51.309, the nine western Transport Region States (Arizona, California, Colorado, Idaho, Nevada, New Mexico, Oregon, Utah, and Wyoming), and eligible Tribes within that geographic area, were given the option of implementing regional plans based on the recommendations made in the WRAP Annex. WRAP members developed a model compliance plan, establishing regional SO_2 emissions milestones and a SO_2 backstop cap and trade program for states choosing to participate.[35] Five states—Arizona, New Mexico, Oregon, Utah and Wyoming—opted in.[36] Arizona's SIP, submitted on December 23, 2003, addresses reasonable progress at the Class I areas on the Colorado Plateau from year-end 2003 through year-end 2018.[37] The State of Arizona determined that NOx and PM strategies were not needed at the time that its SIP was submitted to the EPA, but it committed to revise its SIP in 2008 if the state determines that emission control strategies are needed.

Table 4. Regional Haze Milestones.

Year	Base regional SO_2 milestone (tons)
2003	682,000
2004	682,000

[34] http://www.wrapair.org/WRAP/reports/GCVTCFinal.PDF

[35] Wilson, James H. Jr., Manish Salhotra, and Erica J. Laich. *Historic and Future SO_2 Emissions Analysis – 9 State Western Region*. http://www.epa.gov/ttn/chief/conference/ei10/poster/wilson.pdf. Accessed Sep 23, 2005. Last modified Apr 21 2001.

[36] http://www.wrapair.org/309/index.html

[37] Arizona Department of Environmental Quality Air Quality Division. December 23, 2003. *Regional Haze State Implementation Plan for the State Of Arizona*. http://www.azdeq.gov/environ/air/haze/download/2sip.pdf.

2005	682,000
2006	682,000
2007	682,000
2008	680,333
2009	678,667
2010	677,000
2011	677,000
2012	677,000
2013	659,667
2014	642,333
2015	625,000
2016	625,000
2017	625,000
2018	480,000
2019 forward, until replaced by an approved SIP	480,000

Until the program has been triggered and source compliance is required, the State of Arizona submits annual emissions reports to the WRAP and all participating states and tribes. First submitted in September 2004, the report documents actual SO_2 emissions for all stationary sources subject to the Milestone Inventory requirements.[38]

Table 5. State-by-State Comparison of 1990 and 2000 Stationary Source SO_2 Emissions in the 9 GCVTC Transport Region States (tons per year)

States	1990	2000
Arizona	185,398	99,133
California	52,832	38,501
Colorado	95,534	99,161
Idaho	24,652	27,763
Nevada	52,775	53,943
New Mexico	177,994	117,344
Oregon	17,705	23,362
Utah	85,567	38,521
Wyoming	136,318	124,110
Totals	828,775	621,838

Although a participant in WRAP, Nevada chose not to implement the Section 309 plan. Consequently, it must draft and implement a SIP under 40 CFR 51.308 individually. Nevada plans to have a draft implementation plan by late 2006, stakeholder feedback through the middle of 2008, and a final SIP to EPA by December of 2008.[39] Under section 51.308(e), a state must either require BART on qualifying sources, or implement an emission trading program or other alternative measure that will achieve greater reasonable progress than would be achieved by

[38] Ibid.
[39] http://ndep.nv.gov/baqp/stakeholders%203_05/AoH_IWG.ppt#260,26,Slide 26

implementation of BART at qualifying sources. This provision appears to leave the door open for Nevada to implement a state-level emissions cap and trade program as a part of its long-term strategy.[40] An emission trading program or alternative measure program adopted in lieu of BART must be fully implemented within the period of the first long-term strategy or by 2018. In addition,

- The program must, as a minimum, include all the sources in the region subject to BART.[41]
- The reductions in emissions required of BART sources must be surplus to other Federal requirements as of the baseline date of the SIP, that is, the date of the emissions inventories on which the SIP relies (51.308(e)(2)(iv)).
- The regional trading program may include sources not subject to BART such as area and mobile sources as well as major stationary sources that are not BART-eligible sources.

While Nevada has the option of implementing a state-level cap and trade program, it is not likely to do so. The benefits of participating in the regional cap and trade program are potentially much greater than a state-level one. A single-state market for those credits may be more volatile and possibly produce higher prices than in the multi-state Section 309 region, as sources in Nevada will have fewer options for trading.

Hypothetically, SCE could have emissions credits to sell if Mohave is shut down, depending on how Nevada chooses to structure its compliance plan. Under the Regional Haze rule, states must identify major stationary sources of air pollution that are eligible for best available retrofit technology (BART).[42] WRAP identified the Mohave Generating Station as BART-eligible. BART is likely to be required for the facility, pursuant to a study by EPA that found SO_2 emissions from the Mohave Generating Station are transported to the Grand Canyon, and that "no other single source is likely to have as great an impact on visibility in the Park."[43]

The Navajo Nation has also participated in WRAP. It has not elected to submit a Section 308 or 309 plan at present, and is not required to do so under the deadlines set for U.S. states.

Regional haze is comprised of pollutants, including $PM_{2.5}$, its precursors (SO_2, NOx), and other pollution (e.g., ozone), that are controlled under other regulations. Implementation of regulations under the Regional Haze rule could put downward pressure on the price of allowances regulated under other programs (e.g., Acid Rain) by increasing the number of allowances on the market. Similarly, changes to other air regulations, such as the Ozone and $PM_{2.5}$ NAAQS, will have a benefit on regional haze. Conversely, a market created by Nevada to

40 WESTAR Regional Haze SIP Workgroup, for the Western Regional Air Partnership. *Regional Haze State Implementation Plan Templates*. Jun 29, 2001. Appendix A: Section-by-Section 308 Templates. http://www.westar.org/RHSIP/Final%20Documents/308%20templates.doc

41 The one exception to this applies to sources that have previously installed BART-level controls, and the emissions limitations are federally enforceable. A state can allow these sources the option of not participating in the trading program. WESTAR Regional Haze SIP Workgroup, for the Western Regional Air Partnership. *Regional Haze State Implementation Plan Templates*. Jun 29, 2001. (51.308(e)(2)(ii)). Appendix A: Section-by-Section 308 Templates. http://www.westar.org/RHSIP/Final%20Documents/308%20templates.doc

42 http://www.wrapair.org/forums/ssjf/documents/bart/Executive_Summary.pdf

43 U.S. EPA. Final Project MOHAVE Report Fact Sheet. May, 2004. http://www.epa.gov/region09/air/mohave/mofact.html, accessed May 31, 2005.

comply with the Regional Haze rule would certainty interact with other local, regional, and national markets. If other programs (aside from Regional Haze) impose more stringent standards on even some of the Nevada sources, the clearing prices in a regional haze market could go down.

NAAQS

EPA established NAAQS for CO, Pb, NO_2, O_3 (which is regulated in part through limits on NOx emissions), PM_{10}, $PM_{2.5}$, and SO_2. Strictly speaking, the NAAQS are ambient standards. While not changing the spirit of the law, amendments to the CAA in 1977 increased flexibility by allowing limited trading through emission offsets—also called emission reduction credits (ERCs)—to prevent ambient standards from stunting local economic growth.[44] Under this provision, an increase in a qualified criteria air pollutant can be offset with a reduction of the pollutant from some other stack at the same plant, from another plant owned by the same company, or from sources owned by some other company in the area. Existing major permitted facilities in non-attainment regions create ERCs by permanently curtailing of operations, voluntarily controlling emissions above and beyond what is required, or shutting down. The value of an ERC is unique to each county, and offset trading is largely bilateral, intermittent, and not standardized,[45] as is necessary to be traded on an open market. Because of the lack of availability of these data, we did not quantify the value of offsets.[46]

NAAQS impose a cost on individual firms for emitting various pollutants. To the extent that states impose limits or technological standards on individual units to comply with NAAQS, they affect the value of emissions allowances. Emissions sources must comply with local standards, reflecting the area's attainment status under the NAAQS, in addition to cap and trade program requirements.[47] This ceiling would lessen the potential for sources in a highly-polluted area to further degrade air quality by buying allowances from an area with good air quality.

[44]. Dallas Burtraw, David A. Evans, Alan Krupnick, Karen Palmer, and Russell Toth. RFF. *Economics of Pollution Trading for SO_2 and NOx*. May 2005, p. 4-5.
[45] http://www.evomarkets.com/emissions/
[46] Although offsets for CO and Pb could potentially have some value, we do not estimate them here for this reason.
[47] Dallas Burtraw, David A. Evans, Alan Krupnick, Karen Palmer, and Russell Toth. RFF. *Economics of Pollution Trading for SO_2 and NOx*. May 2005, p. 12.

Table 6. NAAQS Thresholds and Classifications.[48]

Criteria Pollutant	Standard (not to exceed)		Laughlin, NV Status	Black Mesa, AZ/ Navajo Nation Status
SO_2	Primary:	0.03 ppm (80 µg/m3), annual arithmetic mean 0.14 ppm (365 µg/m3), 24-hr level	Attainment	Attainment
	Secondary:	0.50 ppm (1300 µg/m3), 3-hr level		
NO_2	0.053 ppm (100 µg/m^3), annual arithmetic mean		Attainment	Attainment
O_3	Subpart 1:	4th-highest daily max. 8-hr average measured ozone level in a region over a 3-yr period	Attainment[49]	Attainment
PM_{10}	150 µg/m3, 24-hr average concentration 50 µg/m3, annual arithmetic mean concentration		Non-attainment: Serious	Attainment
$PM_{2.5}$	65 µg/m3 24-hr average concentration 15.0 µg/m3 annual arithmetic mean concentration		Attainment/ unclassifiable	Attainment

Source: EPA. Currently Designated Nonattainment Areas for All Criteria Pollutants, As of April 11, 2005. Accessed Sept. 13, 2005. http://www.epa.gov/oar/oaqps/greenbk/ancl.html.

The locations currently under consideration for the IGCC technology option are Black Mesa, AZ or Laughlin, NV (Clark County). Black Mesa, under the jurisdiction of the Navajo Nation, is in attainment for all criteria pollutants. This status is unlikely to change in the near term.[50] Both Arizona and Nevada are subject to NAAQS. The Navajo Nation can participate in this program by submitting a list of attainment, nonattainment, and unclassifiable areas to the Administrator of the U.S. EPA, as well as a Tribal Implementation Plan for the implementation, maintenance and enforcement of NAAQS and visible air quality.[51]

The NGCC option, as is studied in this report, is located on the existing Laughlin, NV coal plant site. Where Clark County does not have attainment status with federal NAAQS, the possibility of ERCs having value exists. Clark County has non-attainment status for PM_{10} NAAQS. The subsection of Clark County containing Laughlin is currently in attainment with SO_2, NO_2, $PM_{2.5}$, and O_3. Loss of attainment status for any of these NAAQS is unlikely to spur a market for offset credits, given the small number of emitters in the area and continued efforts to comply with other environmental regulations. Depending on prevailing winds and other factors, Mohave's compliance with Acid Rain, Regional Haze, and CAMR may help reduce the County's total ambient levels of SO_2, NOx, and $PM_{2.5}$.

[48] Both Laughlin, NV and Black Mesa, AZ are in attainment of CO NAAQS, defined as 9 ppm 8-hr non-overlapping average. Clark County's non-attainment status (serious) for CO applies to Las Vegas Valley, Hydrographic Area 212. Serious status indicates that an area has a design value of 16.5 ppm and above. The standard for Pb is 1.5 µg/m3, quarterly average. Both areas are in attainment for Pb. The standard for Pb is 1.5 µg/m3, quarterly average. A change in Pb NAAQS status seems highly improbable, given that only two areas in the U.S. have non-attainment status.

[49] That portion of Clark County that lies in hydrographic areas 164A, 164B, 165, 166, 167, 212, 213, 214, 216, 217, and 218 (Las Vegas) but excluding the Moapa River Indian Reservation and the Fort Mojave Indian Reservation is in non-attainment for 8-hr ozone (subpart 1).

[50] Personal communication with Colleen McKaughan, U.S. EPA, Region 9. Nov. 10, 2005.

[51] Navajo Nation Environmental Policy Act. N.N.C. § 1111-1112.

Anticipated changes to NAAQS

NAAQS standards are based on health and environmental effects of exposure. The EPA is required to reevaluate these standards every five years to reflect changes in scientific knowledge.[52]

Sulfur Dioxide (SO_2)

The standards for SO_2 were last affirmed in 1996.[53] We do not anticipate additional rules in the short term for SO_2. Aside from indirect effects from exposure to PM, the body of knowledge on health and environmental effects of direct SO_2 emissions has not changed substantially in recent years. In addition, states and counties will put pressure on sources to keep SO_2 emissions down to preserve $PM_{2.5}$ NAAQS attainment or achieve PM_{10} attainment. Implementation of other rules, such as CAIR and Regional Haze, could alleviate some of the most chronic air quality problems associated with SO_2 and reduce the possibility that more long-term health or environmental effects would come to light. These factors could preempt the need for tightened SO_2 NAAQS.

Nitrogen Dioxide (NO_2)[54]

As with SO_2, if impending regulations succeed in lowering levels of ambient NO_2, policy will have less need to respond. We do not anticipate changes to the NO_2 NAAQS for non-attainment areas in the short term.

Ozone (O_3)

In 1971, EPA established the first ozone NAAQS—a 1-hour standard for ambient concentrations. EPA repromulgated the ozone NAAQS in 1997, adopting an 8-hour average standard in addition to the 1-hour standard. The most recent Air Quality Criteria Document (AQCD) for ozone, assessing up-to-date information on ozone air quality, exposure, and health and ecological effects, was released in January 2002.[55] The attainment date for Subpart 1 is June 2009.[56] In 2005, the 1-hour standard expires, and the review process starts over. We expect that the standard will not be revised; however, a criteria document, due in February of 2006, should provide a stronger indication.

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[52] This report does not quantify the value of CO and Pb and therefore excludes these criteria pollutants from this discussion.

[53] http://www.state.nj.us/dep/cleanair/powerpoint/Kelly%20Status%20of%20Air%20Quality%20Standards.ppt#261,16, Slide 16

[54] While direct NO_2 is less of a concern for power plants, NO_2 is formed from NO, which is created during combustion. Stationary fuel combustion sources, such as electric utility and industrial boilers, are major NO emissions sources. http://www.epa.gov/oar/oaqps/greenbk/o3co.html#Nitrogen%20Dioxide.

[55] http://www.epa.gov/sab/02project/proj02-06.htm

[56] 8-Hour Ozone Areas Listed by Category/Classification, As of April 11, 2005. http://www.epa.gov/oar/oaqps/greenbk/gnc.html

Coarse Particulates (PM_{10})

The NAAQS for PM were most recently revised in July 1997. A new review of the PM NAAQS is underway. The Clean Air Scientific Advisory Committee (CASAC) reviewed the revised, draft Staff PM Paper in Winter 2002.[57]

Fine Particulates ($PM_{2.5}$)

As required by the Clean Air Act, EPA reviews NAAQS standards every five years. EPA is currently reviewing standards, and the Administrator will issue the official standard by October, 2006. In all likelihood, the standards will be tightened. Clark County may not be affected, however, as Las Vegas[58] was within the strictest parameters considered.[59] The Navajo Nation is in attainment for the $PM_{2.5}$ NAAQS.

Ultra-fine Particulates (UFP)

Ultra-fine particulates are a subset of $PM_{2.5}$ smaller than 0.1 micrometer in diameter. Although they are not currently regulated as a class, scientific evidence is mounting that these particles pose serious health threats and need to be addressed apart from coarser ones. Motor vehicle emissions are perceived as the primary source of UFPs, especially in urban areas and along highly used traffic routes. Nonetheless, the issue is of particular concern to the electric generating sector, because all fossil-fuel power plants, whether fired by coal, oil, or natural gas, emit UFPs. Combustion of natural gas—commonly perceived as clean-burning, and often favored in policy—results in high UFP emissions. Equally problematic, a study in East Germany indicates that optimized combustion processes may have caused an increase in UFP concentrations while simultaneously effecting an overall decrease in $PM_{2.5}$ mass concentration.[60] More research is needed in monitoring ambient concentrations and chemical composition of the particles, developing dispersion and formation models, and further exploring health effects, before policy will respond. However, attention to this issue will increase, and a regulatory paradigm shift cannot be ruled out over the long term.

[57] http://www.epa.gov/sab/02project/proj02-02.htm

[58] Las Vegas is the closest Metropolitan Area considered in OAQPS Staff's *Review of the National Ambient Air Quality Standards for Particulate Matter: Policy Assessment of Scientific and Technical Information*. It is also in Clark County, but it is 95 miles away from Laughlin.

[59] EPA is considering a 15 $\mu g/m^3$ annual standard with a revised 24-hour standard between 35 and 25 $\mu g/m^3$. Alternately, it is considering a 14 to 12 $\mu g/m^3$ annual standard with a revised 24-hour standard between 30 and 40 $\mu g/m^3$, or a 12 $\mu g/m^3$ annual average, combined with 30 $\mu g/m^3$ in any 24 hours. The maximum $PM_{2.5}$ 3-year annual mean at any of the five testing sites in the Las Vegas-Paradise-Pahrump, NV metropolitan area was 11 $\mu g/m^3$. The 24 hour data show a maximum average difference (90^{th} percentile) between the readings at any two sites in this MA to be 17.6 $\mu g/m^3$. This suggests that Las Vegas may also pass the standard.

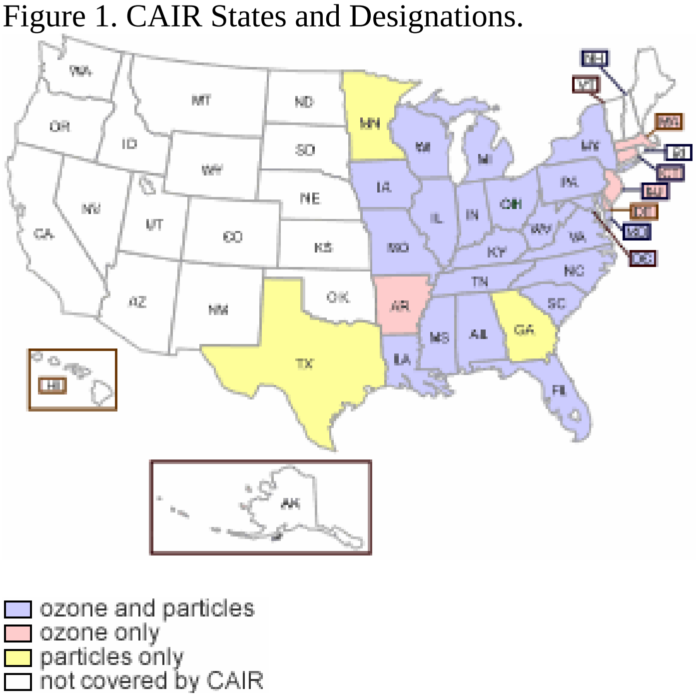
[60] During a six-year investigation into UFPs in the former East Germany, researchers collected ambient air quality data on particulate matter and correlated the findings to the modernization of combustion technology in coal-fired industry and power generation, automobiles, and home heating. The findings indicate that while the overall mass concentration of fine particles decreased, the UFP concentrations increased. Optimized combustion processes may have led to an increase in UFP concentrations from direct emissions as well as diminished coagulation of particles (larger particles may not penetrate as deeply into the lungs). See http://enhs.umn.edu/5103/particles/character.html.

CAIR (Clean Air Interstate Rule)

In March, 2005, EPA finalized the Clean Air Interstate Rule (CAIR). This rule places additional restrictions on the SO_2 and NOx emissions of 28 eastern states and the District of Columbia, to reduce their contributions to $PM_{2.5}$ and 8-hour ozone non-attainment in downwind areas. Under CAIR, states can achieve the required emissions reductions by either requiring power plants to participate in an interstate cap and trade system, or meeting individual state air emission limits through state-defined measures.[61] The final rule requires states to amend and submit their SIPs by September of 2006. Limits on emissions go into effect in two stages. Phase I of CAIR NOx programs begins in 2009; Phase I for SO_2 starts in 2010. Phase II for both SO_2 and NOx commences in 2015. The CAIR rule will eventually replace the requirements of the OTC NOx Budget Program and the NOx SIP Call.

Figure 1 shows the states covered by CAIR and their designations as “ozone and particles,” “ozone only” or “particles only.” “Ozone only” states are subject to CAIR’s seasonal NOx emission standard but not the annual NOx or SO_2 standards.[62] “Particles only” states must comply with both the annual NOx and SO_2 standards.

Figure 1. CAIR States and Designations.



Although the final rule applies only to eastern states, EPA has indicated that it may propose to extend CAIR to the West at some future point and even conducted an analysis of NOx controls under this scenario. However, NOx is less of a concern in western states. Moreover, to comply

[61] http://yosemite.epa.gov/opa/admpress.nsf/d9bf8d9315e942578525701c005e573c/5af79c40e7ba7f2685256ffe00642ad3!OpenDocument

[62] EPA. *Technical Support Document for the Clean Air Interstate Rule Notice of Final Rulemaking: Regional and State SO_2 and NOx Emissions Budgets*. March 2005. Available at http://www.epa.gov/interstateairquality/pdfs/finaltech06.pdf

with CAMR (see below) some power plants will rely on emissions controls that have ancillary NOx and SO_2 reduction benefits. For these reasons, there may not be need to subject the western states to CAIR regulations. Tightening or modifying an existing program, such as the Regional Haze rule, is more likely, and may have more support from stakeholders.[63]

CAIR is currently under litigation, with lawsuits raised from both environmental groups and power companies.[64] If implemented, CAIR will certainly affect the national SO_2 market. As opportunities for low-cost emissions controls decrease in the eastern U.S., sources there may find it more cost-effective to buy allowances for compliance with the Acid Rain program on the national market. The increase in demand will push up the price of national SO_2 allowances.

New Source Review (NSR)

To ensure attainment of national ambient air quality standards, the 1977 CAAA established the New Source Review (NSR) program. NSR is a permitting program for major new or substantially modified air pollution sources. This program covers criteria air pollutants (but not hazardous air pollutants, including Hg) in non-attainment areas. Sources are required under the NSR program to meet a stringent technology-based standard, the Lowest Achievable Emission Rate (LAER).

Increasing enforcement and tightening of NSR rules could have an effect on total emissions and the supply of allowances. Faced with NSR rules, owners of facilities needing substantial modification can install emissions-control equipment. Owners can also retire them, if the cost of emissions controls is high enough to make the plant uneconomic to run. In both of these scenarios, total emissions would likely go down. Alternately, facility owners may decide to put off modifications to circumvent the rule. If owners neglect maintenance of the facility and the efficiency of the plant declines as a result, emissions per unit of electricity output could increase. A NSR enforcement initiative, begun under the Clinton administration but more recently losing momentum, has the potential to effect emissions reductions; however, it is unclear whether reductions have been realized because individual cases can be caught up in litigation for years.[65]

Areas that meet the NAAQS standard (such as Clark County) are regulated under the Prevention of Significant Deterioration (PSD) program.[66] Attainment areas are regulated using the BACT standard.[67] Under PSD regulations, any Major Stationary Source is subject to the most stringent of the federal regulations in 40 CFR Part 60, the state's SIP Call, or that source's permit. 40 CFR Section 52.21 (PSD) clearly defines Mohave as a Major Stationary Source because it has the

[63] WRAP intends to develop regional and state approaches that can be implemented in the next round of regional haze plans, which are due to EPA by December 2007, to address EPA's concerns. 2004 Annual Report. Western Governors' Association. p. 12. http://www.westgov.org/annrpt04.pdf.
[64] Darren Samuelsohn. "Industry files 12 lawsuits against EPA's CAIR rule." *Greenwire*. July 12, 2005. http://www.eenews.net/Greenwire/include/print.php?single=07120501. See also "N.C. groups challenge CAIR." *Argus Air Daily*. Vol. 12, 131. July 11, 2005, p. 1.
[65] Industry advocates argue that EPA shifted to a more stringent interpretation of the NSR rules regarding power plant maintenance and replacement projects, which previously did not trigger NSR. PacifiCorp 2004 IRP, Appendix A, p. 20.
[66] http://netl.doe.gov/coal/E&WR/nox/regs.html
[67] http://netl.doe.gov/coal/E&WR/nox/regs.html

potential to emit more than 100 tons of pollutants per year and uses more than 250 BTUs of heat input per hour.

EPA is considering revising NOx PSD regulations. It proposed three mechanisms: increment-based approach, cap and trade in lieu of the increment-based approach, and a state planning approach. The cap and trade approach would create a market for NOx credits. The other two approaches would affect the price of NOx credits, provided that Mohave is eligible to trade in another NOx allowance market (e.g., a potential Regional Haze market).[68] WRAP proposed that EPA allow mitigation to concurrently satisfy PSD and Regional Haze requirements.[69]

RECLAIM (Southern California)

The Regional Clean Air Incentives Market (RECLAIM) program started in 1994.[70] Geographically, RECLAIM covers the South Coast Air Basin in California.[71] RECLAIM trading credits (RTCs) cover SO_2 & NOx, and Emission Reduction Credits (ERCs) exist for PM_{10}, NOx, and SOx.[72] Allowances allocated under the RECLAIM program must be used in the compliance year in which they are allocated. This design feature contributed to low levels of trading and low prices in early years.[73] Trading has become more active but prices more volatile, owing to the large number of small sources, tight emissions caps, and substantial regional load growth,[74] with no set-asides for new sources.[75]

Responding to a 30-fold increase in the price of NOx RTCs during the California Energy Crisis, the South Coast Air Quality Management District (SCAQMD) rescinded generators' ability to participate in the program. This change increased volatility and reduced liquidity in the market, although a requirement for compliance plans leveled prices at around $1.00/lb, close to the pre-crisis average. On January 7, 2005, SCAQMD lowered the NOx cap and approved participation by large electricity generators on a limited basis.[76] This move will increase liquidity.

The Mohave Generating Station is currently subject to the national SO_2 cap and trade program (Acid Rain). For SO_2, we focus on Acid Rain credit prices because they will be valid and tradable wherever an alternative power source is located. Moreover, it is unlikely that RECLAIM will have a material effect on allowance prices for the nation-wide Acid Rain program.

Although the geographic scope is limited, RECLAIM has a fairly active market for NOx RTCs that can inform an exploratory analysis of willingness-to-pay to offset emissions, given

[68] See docket IS OAR-2004-0013
[69] WRAP, June 6, 2005 comments to EPA in case # OAR-2004-0013
[70] http://www.epa.gov/airmarkets/trading/basics/index.html
[71] This basin includes portions of Los Angeles, Riverside and San Bernardino counties and all of Orange County. Within Riverside County, the AQMD also has jurisdiction over the Salton Sea Air Basin and a portion of the Mojave Desert Air Basin. http://www.aqmd.gov/map/MapAQMD1.pdf
[72] ERCs also exist for Volatile Organic Compounds (VOC) and CO.
[73] Burtraw, Dallas, David A. Evans, Alan Krupnick, Karen Palmer, and Russel Toth (Resources for the Future). *Economics of Pollution Trading for SO_2 and NOx.* May 2005. p. 29.
[74] http://www.evomarkets.com/emissions/
[75] "RECLAIM: 2004 credits decline" *Argus Air Daily*. Vol 12, 160, August 19, 2005. p. 4.
[76] Unger, Samantha. "Back to the Future for RECLAIM." *Evolution Markets Executive Brief*. Jan. 10, 2005.

expectations about future fuel prices and regulations. RECLAIM's applicability to Nevada or Arizona is limited, however. If Nevada implemented a cap and trade program for NOx (either to comply with the Regional Haze rule or revised PSD rules for NOx), it would likely feature less stringent emissions limits and greater trading flexibility than RECLAIM allows; thus, RTC prices could be much higher than the price of emissions allowances under the hypothetical program in Nevada.

3.2. Regulations of Individual Pollutants

Mercury (Hg)

Clean Air Mercury Rule

EPA issued the final Clean Air Mercury Rule (CAMR) on March 15, 2005, establishing the first limit on mercury air emissions by power plants. CAMR sets "standards of performance" limiting mercury emissions from new and existing coal-fired power plants and creates a market-based cap-and-trade program that will reduce nationwide utility emissions of mercury in two distinct phases. Effective in 2010, the first phase cap is 38 tons. During Phase I, emissions will be reduced by taking advantage of "co-benefit" reductions—that is, mercury reductions achieved by reducing sulfur dioxide (SO_2) and nitrogen oxides (NOx) emissions under CAIR. In the second phase, due in 2018, coal-fired power plants will be subject to a cap of 15 tons.

Under CAMR, states have the discretion to participate in the federal cap-and-trade program or to meet the required reductions through other options, including facility-based limits and trading restricted to inside of state borders. Because allowance banking is permitted, Hg emissions will probably not reach the level of the cap until the late 2020s at the earliest.

CAMR would allow states to allocate emission allowances among the point sources according to their own methodology. Nevada's budget is 0.285 tons through 2017, & 0.112 tons after 2018. At present, it is not clear how Nevada will allocate its budget among sources. The Navajo Nation has a state trading budget of 0.601 tons per year, to cover two major coal-fired power plants, Four Corners and Navajo Generating Station. Arizona is allocated 0.454 tons per year.[77]

On May 31, 2005, EPA received petitions for reconsideration of the mercury rule, maintaining that EPA should not have decided to delist this pollutant. Instead, the petitions seek coverage of Hg by the maximum achievable control technology (MACT) standard. In response to these requests, EPA decided to initiate a reconsideration process on June 24, 2005. EPA will not stay the rule pending the reconsideration process.[78] Observers of are confident that this review will not result in any changes to the final rule.

Although it is likely that CAMR, not MACT, will be imposed, which regulatory model is adopted over the long term depends in part on whether hotspots of mercury develop. While there is strong scientific evidence that exposure is hazardous to human health, how mercury will be dispersed under a cap and trade mechanism is unclear. Economic logic suggests that hotspots should not occur, because the dirtiest facilities are likely to have the lowest emission control

[77] Title 40 § 60.4140
[78] http://www.epa.gov/mercury/control_emissions/decision.htm#June

costs. However, mercury has non-uniform dispersion properties that may call for additional limits.[79]

Carbon Dioxide (CO_2)

A regional carbon market, the Regional Greenhouse Gas Initiative (RGGI), is in development in the Northeast U.S.[80] The RGGI Staff Working Group is currently finalizing its recommendations to RGGI Agency Heads, and Agency Heads are meeting next week in hopes of finalizing a Memorandum of Understanding and Model Rule. Following that agreement, states would initiate legislative and/or agency proceedings as necessary. Despite much serious negotiation, the Agency Heads are likely to reach agreement and move on to the state proceedings. The outcome of the state proceedings is far from certain, however, especially if legislatures get involved. In addition to serving as a model process for other states or coalitions of states, if implemented, RGGI could lead the way for federal legislation and provide valuable data on costs of CO_2 reductions in the U.S.

On the other side of the country, the Governors of Washington, Oregon, and California expressed interest in establishing carbon policy through the West Coast Governor's Climate Change Initiative, one of the leading state-level efforts on global warming in the country. In November 2004, the Governors approved a series of detailed recommendations to reduce global warming pollution.[81] While this initiative is not very far along, it holds promise by recognizing that global warming will have serious adverse consequences on the economy, health and environment of the West Coast states; that states must act individually and regionally to reduce greenhouse gas emissions; and that the region can achieve economic benefits from lower dependence on imported fossil fuels and greater investments in clean energy technologies.

On the state level, the California PUC recently required investor owned utilities (IOUs) to factor a carbon cost adder, from $8 to 25 per ton of CO_2, into investment decisions for all new fossil-fuel fired power plants.[82] IOUs are required to justify their choice of cost, from $8 to 25 per ton

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[79] Hotspots are spikes in pollution levels at specific locations and/or during specific time periods. These could occur if a small number of facilities purchase a large portion of allowances, or if prevailing winds carry and deposit emissions in specific areas. Evidence on the creation of new hotspots, or change in existing hotspots, as a result of SO_2 and NOx trading programs is ambiguous. Burtraw, Dallas, David A. Evans, Alan Krupnick, Karen Palmer, and Russel Toth (Resources for the Future). *Economics of Pollution Trading for SO_2 and NOx.* May 2005. p. 11, 14, 37, 46.

[80] Currently, nine states—Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island and Vermont—are participating in RGGI. In addition, Maryland, the District of Columbia , Pennsylvania, the Eastern Canadian Provinces and New Brunswick are observers in the process. http://www.rggi.org/states.htm

[81] These include: 1. Establishing new targets for improvement in performance by state fleets; 2. Collaborating on the purchase of hybrid vehicles; 3. Developing a plan for deploying electrification technologies at truck stops; 4. Implementing strategies and incentives to increase retail energy sales from renewable resources by one percent or more annually in each state through 2015; 5. Establishing a cost-effective efficiency threshold for all products sold on the West Coast; 6. Incorporating aggressive energy efficiency measures into state building energy codes, and 7. Organizing a conference in 2005 to inform policymakers and the public of climate change research concerning the West Coast states.

[82] Johnston, Lucy, Amy Roschelle,Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value."

of CO_2. It is not clear whether this applies to power sources located outside of California borders. A similar carbon planning requirement is in effect in Oregon.[83] New Mexico Governor Bill Richardson signed an Executive Order in June, 2005, setting the state's targets at achieving 2000 emissions levels by 2012, 10% below 2000 levels by 2020, and a 75% reduction below 2000 emission levels by 2050.

Arizona is also taking steps towards responding to climate change, creating an advisory group to inventory and recommend policies to reduce greenhouse gas emissions in the state by July, 2006.[84] Technical work groups provide technical analysis and policy options for consideration by the advisory group. The Arizona Department of Environmental Quality is coordinating the stakeholder process, with facilitation and technical support provided by the non-profit Center for Climate Strategies. The workgroups created by the advisory group are in the process of prioritizing design variables for evaluating which of many policy options will receive further study.[85] Other states have taken similar steps,[86] including the California Public Utilities Commission's June, 2005 "Policy Statement on Greenhouse Gas Performance Standards." This policy statement follows the groundbreaking initiative by the governor's office seeking to reduce California's greenhouse gas emissions to 1990 levels by 2020. Nevada does not show signs of following suit with a state-level greenhouse gas emissions policy at present.[87]

Although ratification of the Kyoto Protocol by the U.S. is doubtful, national-level regulation seems more and more likely. A 2004 study showed that 60% of power-generating companies participating in the survey believed that Congress would enact mandatory carbon limits within a 10-year horizon.[88] In *Electric Power, Investors, and Climate Change: A Call to Action*, a diverse group of experts from the power sector, environmental and consumer groups, and the investment community agreed that greenhouse gas emissions (GHG), including CO_2, will be regulated in the U.S.; the only remaining issue is when and how. Participants also agreed that regulation of greenhouse gases poses significant financial risks and opportunities for the electric sector.[89] A

[83] Since 1993, the Oregon Public Utilities Commission mandated that regulated electric utility IRPs include analysis of a range of carbon costs, from $10 to $40 (in 1990 dollars) per ton of CO_2. "State and Local Net Greenhouse Gas Emissions Reduction Programs: Oregon Carbon Adder." http://www.pewclimate.org/states.cfm?ID=57

[84] The advisory group has many regulatory and policy variants to consider, including mitigation options in all sectors and for all greenhouse gases; voluntary and mandatory approaches for unilateral and multi-state actions; and actions to cover future time periods of 2010, 2020 and a third period, to be determined. The advisory group will also consider policy overlap with air quality, energy, land use, and economic development. *Role of the Arizona Climate Change Advisory Group* at http://www.azclimatechange.us/background-ccagrole.cfm. See also "Arizona addresses global warming" *Argus Air Daily*. Vol. 12, 131. July 7/11, 2005, p. 5 and Executive Order 2005-02: Climate Change Advisory Group. http://www.governor.state.az.us/eo/2005_02.pdf.

[85] Personal communication, Kurt Maurer, Arizona Dept. of Environmental Quality, 10/28/2005.

[86] Amending several air pollution control rules, New Jersey recently adopted regulations classifying carbon dioxide as an air contaminant. "Codey Takes Crucial Step to Combat Global Warming" October 18, 2005. See http://www.state.nj.us/cgi-bin/governor/njnewsline/view_article.pl?id=2779.

[87] In the late 1990s, Nevada and Utah, like many states, saw bills urging Congress and the President not to ratify the Kyoto Protocol. http://yosemite.epa.gov/oar/globalwarming.nsf/content/ActionsStateLegislativeInitiatives.html#NV

[88] 19 companies participated, representing 29% of power generation in the U.S. in 2003. Bolinger, Mark and Ryan Wiser. *Balancing Cost and Risk: the Treatment of Renewable Energy in Western Utility Resource Plans*. Ernest Orlando Lawrence Berkeley National Laboratory (LBNL-58450). August 2005. p. viii. http://eetd.lbl.gov/EA/EMP/rplan-pubs.html.

[89] Johnston, Lucy, Amy Roschelle,Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, *Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value*.

group of investors recently called on 43 investor-owned utilities to conduct climate risk analyses as common practice and disclose how they are preparing for future regulations of GHGs within a year.[90]

Indeed, Congress is paying increasing attention to the threat of global warming. A bill that would create a cap & trade system for greenhouse gas emissions, co-sponsored by Senators McCain (AZ) and Lieberman (CT), failed to pass the Senate,[91] but other initiatives followed quickly on its heels. The most recent movement towards regulating carbon dioxide in the U.S. saw the passage of the non-binding resolution passed by the Senate agreeing that mandatory caps would be needed at some point in the future. As a part of the Energy Policy Act, Congress passed an amendment proposed by Sen. Hagel (R-NE) that authorizes voluntary measures for control of greenhouse gases.

Binding federal legislation will almost certainly take the form of a cap and trade system. Questions and conflicts regarding rulemaking details could, however, delay final implementation of climate change policy. For example, a cap and trade regime would almost certainly give rise to debate about allowance allocation and baseline levels.

3.3. Regulations Applicable to the Sites Studied in this Report

		Laughlin, Nevada		Black Mesa, Arizona	
Regulation	Pollutant	Currently in Force in Area	Area in Attainment?	Currently in Force in Area	Area in Attainment?
Acid Rain Program	SO_2	Yes	N/A	Yes	N/A
	NOx	Yes	N/A	Yes	N/A
Regional Haze	Multiple	TBD	N/A	Yes	N/A
NAAQS	SO_2	Yes	Yes	Yes	Yes
	NO_2	Yes	Yes	Yes	Yes
	O_3	Yes	Yes	Yes	Yes
	PM_{10}	Yes	No (serious)	Yes	Yes
	$PM_{2.5}$	Yes	Yes (unclassifiable)	Yes	Yes
	CO	Yes	Yes	Yes	Yes
	Pb	Yes	Yes	Yes	Yes
CAIR	Multiple	No	N/A	No	N/A
NSR	Multiple	Yes	N/A	Yes	N/A
RECLAIM	Multiple	No	N/A	No	N/A
CAMR	Mercury	No	N/A	No	N/A
Climate Protection	CO_2	No	N/A	No	N/A

[90] "Investors ask emitters to disclose risks." Argus Air Daily. Vol. 12, 131. July 11, 2005, p. 5.
[91] The Climate Stewardship Act, originally introduced in 2003, was reintroduced in June 2005 but failed to pass with a vote of 38-60.

4. Emissions Valuation

4.1. Control technologies

If polluters face different costs associated with their various opportunities to reduce emissions, cap and trade regulation can produce lower net compliance costs than technology-driven regulation or fixed emissions limits will. With cap and trade regulations, polluters with relatively low-cost abatement options have the incentive to install control technology, so that they can earn revenue from the sale of the emissions allowances created by that reduction. A polluter facing relatively high costs to reduce emissions can buy allowances as long as the cost of those allowances is lower than the levelized cost of installing pollution controls. If the market for emissions credits is competitive, the price of an allowance reflects the cost to abate an additional unit of emissions—i.e., the marginal cost of abatement.

The cost of emissions controls varies widely, depending on the type of emissions being controlled and the level of removal required, as well as the plant's configuration, operations, fuel mix, age, and the ambient characteristics under which it operates. Even for the same type of technology, control costs depend on whether the plant can accommodate mass-produced bolt-on units or requires structural changes.

The pollutants addressed in this analysis frequently come from the same processes, such as fossil fuel combustion. In addition, some post-combustion controls will reduce more than one pollutant. A 1999 study by EPA found that pollution control strategies to reduce emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, and mercury are highly inter-related, and that the costs of control strategies are highly interdependent.[92] For example, wet flue gas desulfurization (FGD) units effectively capture SO_2, PM, and oxidized mercury. Over time, technological improvements will reduce the cost of compliance. Emissions trading programs may spur generators to search for low-cost ways to reduce emissions, beyond what would occur in the absence of the program.[93]

Fuel switching will also reduce emissions of more than one pollutant, e.g., from oil or coal to natural gas, or from any fossil fuel to a renewable source. The economics of fuel-switching can have a large impact on allowance prices. For example, over much of the 1990s, actual Acid Rain allowance prices were well below levels forecasted by EPA. A 2000 study found that generators' ability to burn low-sulfur coal to comply with the Acid Rain program accounted for roughly 80% of the difference between actual SO_2 allowance prices and forecast levels. Technological change only accounted for 20% of the difference.[94]

Technologies and resource options to reduce emissions of one pollutant (e.g., efficiency, renewables, as well as fuel switching) can significantly reduce emissions of others. The addition

[92] Johnston, Lucy, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, *Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value*.
[93] For example, implementation of cap and trade under the Acid Rain program was accompanied by increases in scrubber efficiency and reliability, thus lowering costs. Burtraw, Dallas, David A. Evans, Alan Krupnick, Karen Palmer, and Russell Toth. *Economics of Pollution Trading for SO_2 and NOx*. RFF. May 2005. p. 17, 23.
[94] Ibid., p. 17.

of clean generating technologies will change the capacity factors for existing units. In addition, control costs can add significantly to the forward-going costs of operating existing units, potentially decreasing operations of these units and increasing the supply of allowances across the board. For all of these reasons, issues of compliance with regulations dealing with the criteria pollutants, Hg, and CO_2 are highly interconnected.

4.2. Historical, current, and forward allowance prices

For emissions that have been actively traded for long periods of time, market data can provide a valuable tool for projecting future allowance prices. Market participants and brokers assess the opportunity cost of holding onto allowances, taking into account regulatory risk, projected compliance costs, and fuel price forecasts, when bidding into the allowance market. However, participants may assess risks differently. Regulatory uncertainty (new or changing programs) could lead to volatile market prices for allowances. Conversely, well-established programs may produce more stable prices.[95]

The market for emissions allowances is subject to considerable volatility and price risk. Unexpected plant outages and high summer temperatures can cause sudden and dramatic increases in NOx allowance prices. Changes in fuel prices will also reduce price stability, in spite of how mature the cap and trade program is. For example, the market for SO_2 allowances has experienced highly volatile prices recently. Likewise, "overinvestment" in reduction measures by affected utilities can cause significant reductions in allowance prices, although the change in price will probably be less dramatic than weather-related volatility.

All of the pollutants considered in this analysis can result from fossil-fuel combustion. In addition, some pollutants (e.g., PM) can be formed when other pollutants undergo chemical reactions in the air (e.g., SO_2, NOx). Because the formation of the different pollutants is often related, the behavior of the markets for those emissions will be correlated. For example, an increase in coal-fired generation will tend to drive up the prices of all emissions associated with coal combustion (including Hg, CO_2, SO_2). Likewise, anything that increases the supply of allowances for one pollutant (e.g., Hg, due to stricter regulations) can dampen prices for another commodity (SO_2) if both emissions are commonly controlled with the same technology. In this case, the total cost of allowances for the concomitantly-controlled emissions (both Hg and SO_2) will go up.

Regulations can have a disproportionate effect on the operating costs of plants burning certain fuels. If stringent enough, or if the emissions are very expensive to control, these regulations could affect plant operations. Potentially, regulations could result in reduced operations, mothballing, and shutdowns of plants. For example, implementation of CO_2 regulations would tend to drive down the price at the margin for tons of SO_2, NOx, and Hg [96], because the cost of

[95] Mary Jo Krolewski and Andrew S. Mingst. Clean Air Markets Division, Office of Atmospheric Programs, U.S. EPA, Washington, D.C. ICAC Forum 2000. *Recent NOx Reduction Efforts: An Overview.* p. 9. (\\Server\Lib-Docs\Emissions\NOx\nox-options.pdf)

[96] Models of SO_2, NOx, and Hg prices that do not include CO_2 regulation in the analysis could overstate prices. As long as the probability of CO_2 regulations is greater than zero, then the risk-adjusted price of these emissions is lower.

renewable technologies would decrease dramatically relative to fossil-fired ones. Net displacement of existing fossil-fired generation will free up allowances for sale on the market, driving prices down.

The value of an emission allowance reflects many factors, including the timeframe, penalty for non-compliance, and other regulatory parameters as they impact the entire set of possible buyers; growth in emissions by the source and by other sources in the area; season; the wide range of other existing and potential regulations on that pollutant, its precursors, or the secondary pollutants that arise from it; and the cost of emissions controls, which varies on a plant-by-plant basis. While the value of an allowance will be determined by these factors, available data do not always reflect these locational differences, especially when the location of the emissions reduction (the origin of the allowance) is not covered by liquid markets.

This section provides the historical, current, and forward allowance prices for each pollutant. Historical prices are provided as context only, to show consistency with past market behavior and regulatory changes. Historical prices are not intended as forward looking statements in and of themselves.

4.3. Price Projections

Environmental regulators routinely model the costs of policies when considering rules to set limits on emissions. For the electric power industry, modeling usually takes into account some of the factors that affect the price of allowances, including projected fuel prices, increase in electricity demand, and the cost of control. These models require simplification of the many variables and massive amounts of data that determine prices, including the cost of retrofitting existing units, transaction and compliance costs, regulatory barriers or incentives to trade, future changes in policy, and many others. For each pollutant, this section will discuss the models employed by regulators, intervenors in regulatory or legal proceedings, and in utility resource plans, as well as the assumptions that shape the results of model runs.

4.4. Markets for Emissions by Pollutant

Carbon Dioxide (CO_2) and Carbon

Control technologies

The cost of CO_2 emissions abatement is broken down into three parts: capture, transport, and storage (sequestration). Capture can occur pre- and post-combustion. The captured CO_2 is then transported by pipeline or some other mechanism to depleted oil or gas fields, saline reservoirs, or another facility for sequestration. CO_2-capture technologies have only been applied to boilers at small scales. In addition to the type of capture technology, costs are based on application in other settings but will vary based on plant efficiency, plant lifetime, capacity factor, the quality of fuel, among others. Given these uncertainties, a Carnegie Mellon study estimates IGCC capture, transport, and storage at about \$27/short ton CO_2, versus \$53 for NGCC applications.[97] See section 8 of the report for more information about the costs of CO_2 sequestration.

It is important to note, however, that capture and storage systems demand energy input and increase the energy input per unit of output. The Carnegie Mellon case study estimates that IGCC applications would require 16% additional energy per MWh, while NGCC would require 18% more.[98] Likewise, emissions of other pollutants—including SO_2, NOx, and NH3—per MWh increase relative to a plant without capture and storage systems.

Allowance prices

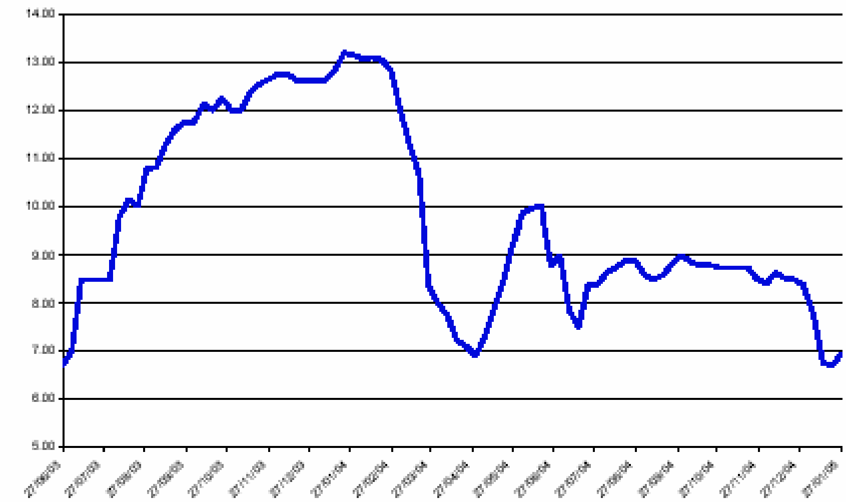
Historical price trends

Implementation of the Kyoto Protocol moved forward with great progress in recent years. Countries in the European Union (EU) are now trading carbon in the first international emissions market, the EU Emissions Trading Scheme (ETS), which officially launched on January 1, 2005. This market, however, has been going strong since before that time – Shell and Nuon entered the first trade on the ETS in February 2003. Traded volumes in the EU ETS totaled approximately 600,000 tons of CO_2 in 2003, with prices ranging from about 5-13 euros per ton CO_2. Most of these trades were on a forward basis with payment on delivery. Trading volumes have increased steadily throughout 2004 and totaled approximately 8 million tons CO_2 in that year.[99]

Eight exchanges and 11 brokerages are planning to take active roles in the acceleration of the carbon market. One financial index for EU allowances (EUA) is called the Carbon Market Index. Figure 2 shows Carbon Market Index data as of January 27, 2005. For most of 2004, carbon trades have ranged between 6.75 to just over 13 euros per ton CO_2, equivalent to approximately \$8–17 US.

[97] Costs given in terms of metric tons were converted to short tons using this factor: 1 metric ton = 1.102 short tons (or, 1 short ton = 0.907 metric tons). There are 12 g of carbon in 44 g of carbon dioxide.
[98] Rubin, Edward S. April 12, 2005. "Costs and Impacts of CO_2 Capture at Power Plants." Presentation to the MIT Laboratory for Energy and the Environment, Cambridge, MA.
[99] "What determines the Price of Carbon," *Carbon Market Analyst*, Point Carbon, October 14, 2004.

Figure 2. EU Allowance Prices, June 2003 to January 2005 (€/ton-CO_2)



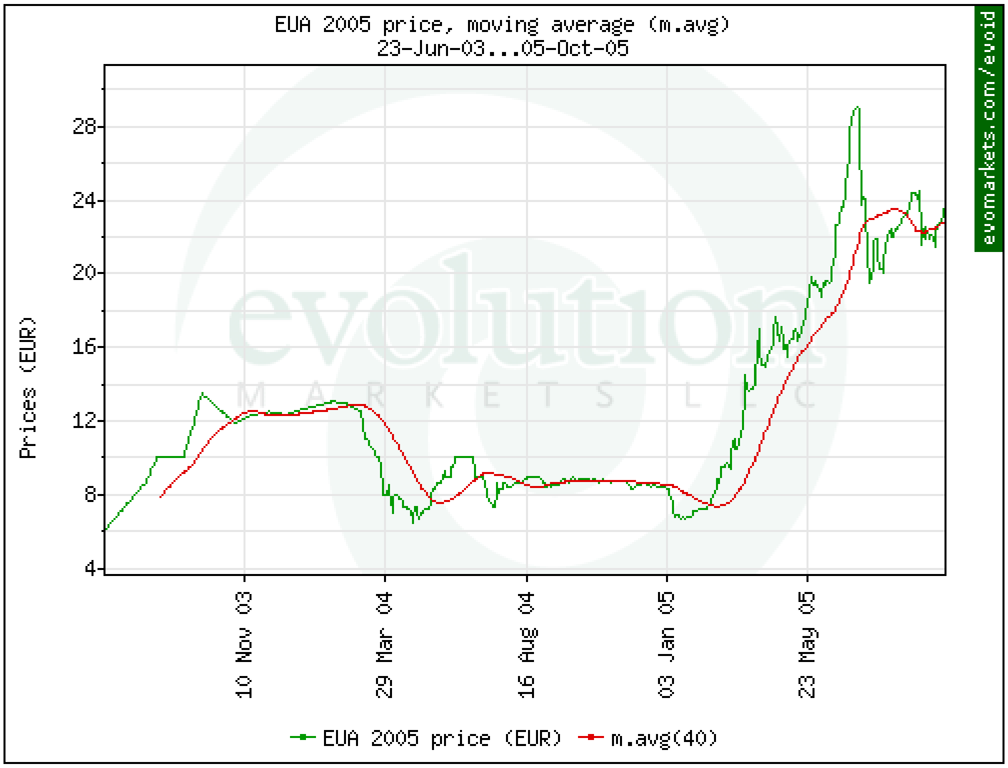
Source: Johnston, Lucy, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value.

Current prices

Trading volume in carbon OTC markets has experienced significant growth, with 14 to 16 million EUAs traded monthly as of the beginning of this year. While the number of active participants in the markets is growing at a slow pace, brokers expect large numbers of companies to become active in the near term.[100] A number of policy details are now in place, including the initiation of the Emissions Trading Scheme, approval of many member states' National Allocation Plans, and approval of baseline methodologies for Clean Development Mechanism projects. The increased regulatory certainty has led to growth in trading. Aside from regulatory certainty, the main drivers of EUA prices include oil and gas prices, power prices, and weather data. As shown in figure 3, EUA prices for current vintage allowances (2005) are in the range of 23 to 24 euros, up considerably from prices of 7 to 9 euros at the start of the year.[101]

[100] "Monthly Market Update: Greenhouse Gas Markets" Evolution Markets LLC. April 2005. http://www.evomarkets.com/assets/mmu/mmu_ghg_apr_05.pdf, accessed Oct. 6, 2005.
[101] EU Markets on 10/05/2005. Evomarkets.com. See also "Monthly Market Update: Greenhouse Gas Markets" Evolution Markets LLC. April 2005. http://www.evomarkets.com/assets/mmu/mmu_ghg_apr_05.pdf, accessed Oct. 6, 2005.

Figure 3. 2005 EU Allowance Prices, June 2003 to October 2005 (Nominal €/ton-CO_2)



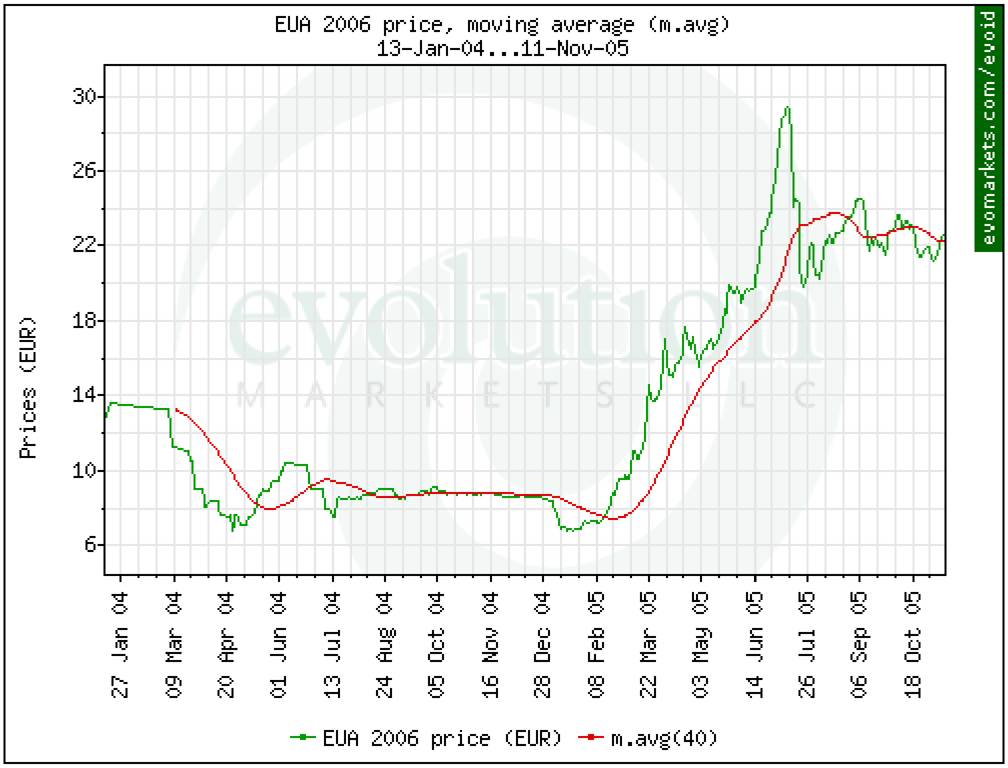
Source: "Monthly Market Update: Greenhouse Gas Markets" Evolution Markets LLC. April 2005.

Forward markets

Trading volume is most liquid in the near term. EUA prices for forwards (2006-2007) are in the range of 23 to 24 euros, consistent with current vintage (2005) allowance prices and movement.[102] Prices are likely to go up much higher in 2008. The penalty for exceeding individual company targets rises to roughly 90 euros per ton-CO_2 for each ton above the cap, from the phase-in penalty of 36 euros per ton effective 2005 to 2007.

[102] EU Markets on 10/05/2005. Evomarkets.com

Figure 4. 2006 EUA prices, January 2004 to November 2005 (Nominal €/ton-CO_2)



Source: http://www.evomarkets.com/, accessed Nov. 11, 2005.

Price Projections

The uncertainty surrounding the form and breadth of national climate protection legislation in the U.S. creates substantial difficulties in modeling allowance costs. Analyses of state and regional programs in development become germane to a projection of federal carbon prices, because these smaller initiatives may provide a model for federal ones.

One of the largest programs under development in the U.S., the Regional Greenhouse Gas Initiative (RGGI) was the subject of a recent study by ICF. ICF estimated CO_2 prices under a range of scenarios, including 25% to 35% cuts in emissions below 1990 levels, currently under consideration by RGGI. Under the 35% reduction scenario, CO_2 allowances would initially trade at $4.40/short ton and rise to $12/short ton by 2024. In a scenario with a lower reduction (25%), CO_2 prices would range from $2.50 to $6.80 ($2003) in the RGGI area.[103]

The California Public Utilities Commission (CPUC) opened an avoided cost rulemaking in 2004 and commissioned Energy and Environmental Economics (E3) to develop methodology and standard avoided costs for the evaluation of energy efficiency programs. E3 put forth values of

[103] RGGI members include New York, Massachusetts, Connecticut, New Jersey, Delaware, New Hampshire, Maine, Vermont, and Rhode Island. CO_2 cap would boost Northeast US power price $4/MWh. Platts Electricity Alert. Apr 6, 2005.

$5/ton-$CO_2$ in the short term (2004), $12.5 by 2008 and $17.5 by 2013, with a levelized value of this stream (in 2004 dollars) of about $8/ton-$CO_2$.[104]

A number of projections were submitted in response to the CPUC's decision to require utilities to consider CO_2 in their plant investment decisions. The NRDC submitted a value of $12/ton-$CO_2$ starting in 2008. EIA's analysis of proposed federal legislation, the Clean Power Act (S.556 and S.366) reflects higher rates, from $15-$25/ton-CO_2 in 2010 to $14-$36 in 2020.[105] EIA's analysis of the Climate Stewardship Act (S.139) projects CO_2 allowances to be in the range of $22 to $49 per ton, over the period 2010-2020 (in 2001 dollars). Likewise, the Massachusetts Institute of Technology's Joint Program on the Science and Policy of Global Change produced similar results from its model of S.139.[106]

Electric utilities have incorporated slightly lower values into their long-term planning, as shown in Table 7.

Table 7. Summary of CO_2 Allowance Assumptions.

Party	**CO_2 emissions trading assumptions for various years**	**$/metric ton carbon**[107]
PG&E	$8/ton (2008)	$29
Avista	$1-11/ton (2004-2023)	$5-40
Portland's General Electric	$10/ton (2010)	$37
Xcel	$6-12/ton (2009)	$22-44
Idaho Power	$12.30/ton (2008). Also evaluated scenarios with carbon dioxide at $12.30 per ton and $49.21 per ton.	$45. Highest scenario is $180
PacifiCorp	$8/ton in 2003 IRP, also evaluated scenarios with carbon dioxide at $2, $25, and $40/ton.	$29 up to a high of $147

[104] E3 escalated the baseline price for CO_2 credits by 5% annually. We note that E3 uses the term "present value" to describe the stream of benefits but feel that "levelized" price more accurately describes the $8/ton value presented in its study. Energy and Environmental Economics, Inc. *Methodology and Forecast of Long Term Avoided Costs for The Evaluation of California Energy Efficiency Programs*. October 25, 2004.
[105] Johnston, Lucy, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, *Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value*.
[106] Ibid.
[107] There are 12 g of carbon in 44 g of carbon dioxide.

Source: Johnston, Lucy, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value.

Figure 5. Comparison of CO_2 Cost Estimates, Reductions in Emissions to 1990 Levels (2004$/ton-$CO_2$).

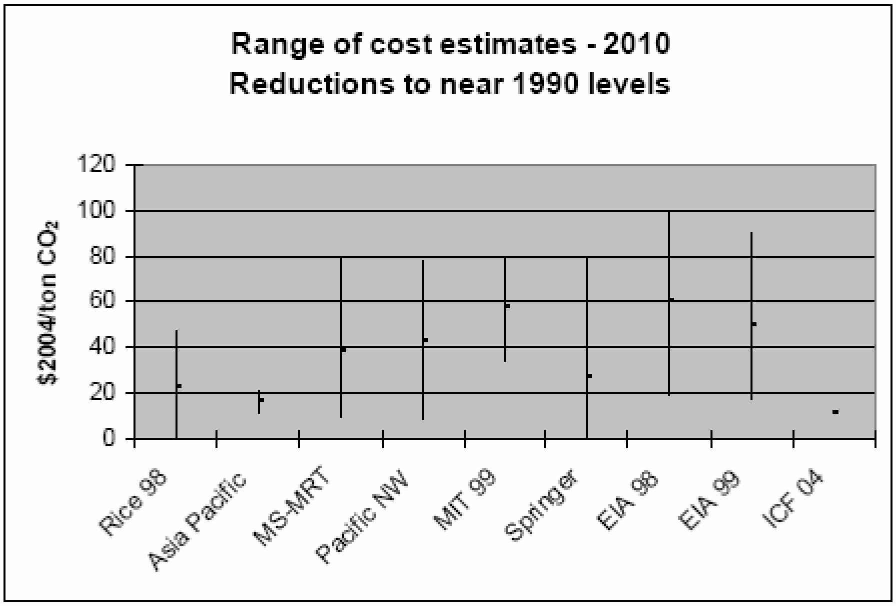


Figure 6. Comparison of CO_2 Cost Estimates, Reductions in Emissions to 2000 Levels (2004$/ton-$CO_2$).

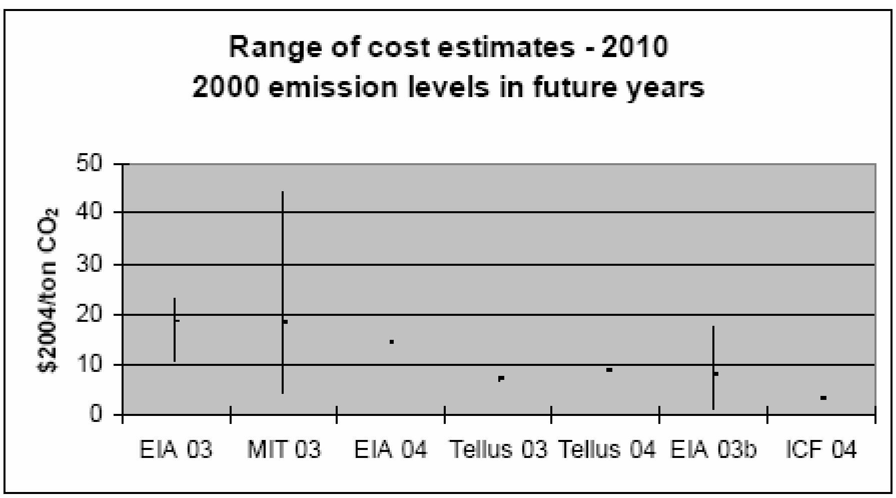
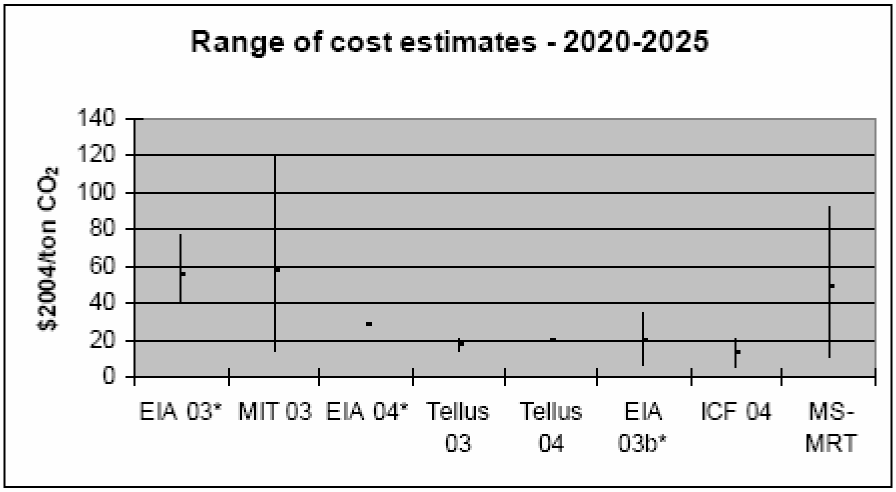


Figure 7. Comparison of Long Term CO_2 Cost Estimates (2004$/ton-$CO_2$).



Source: Johnston, Lucy, Amy Roschelle, Ezra Hausman, Anna Sommer and Bruce Biewald. Synapse Energy Economics, Inc., September 30, 2005, Considering Climate Change in Electric Resource Planning: Zero is the Wrong Carbon Value.

In its 2004 Integrated Resource Plan (IRP), PacifiCorp projects the cost of carbon allowances, as well as SO_2, NOx, and Hg compliance costs. The model assumed that national CO_2 emissions limits would be set at 2000 levels, starting in 2010, based on the proposed (but failed) legislation of Senators Lieberman and McCain.[108] PacifiCorp models a base case and multiple alternative scenarios with different assumptions for the cost of CO_2. The base case CO_2 cost is set at an inflation-adjusted price, $8/ton-$CO_2$ (2008$), consistent with the upper range of offsets emerging and currently available internationally. PacifiCorp conducted other scenario risk simulations, including $0, $10, $25, and $40 per ton of CO_2. Initial CO_2 costs are probability-weighted to reflect the uncertainty about when regulations will be passed. In 2010, costs are adjusted by a probability of 0.5, 2011 prices are multiplied by 0.75, and 2012 prices are not adjusted (with an implied probability of 100%).

PacifiCorp anticipates that, as CO_2 allowance costs increase, its new and existing coal and natural gas units will operate less. Base-load coal generation produces more CO_2 and other air emissions per megawatt-hour of energy. Increasing the cost of emissions reduces the cost advantage of coal.[109]

A recent review of western utility integrated resource plans found that estimates of levelized compliance costs varied widely—from $0 to $58 per ton of CO_2.[110] The wide range of projections for carbon allowance prices owes to uncertainty about fuel prices, capital costs for different kinds of plants and different emissions control technologies, and electricity demand. Perhaps the most significant contributor to this variance is uncertainty about how and when regulations will be implemented. These uncertainties are reflected in the different assumptions in

[108] McCain-Lieberman bill would impose less stringent limits than the Kyoto Protocol.
[109] PacifiCorp Integrated Resource Plan, 2004.
[110] Bolinger, Mark and Ryan Wiser. *Balancing Cost and Risk: the Treatment of Renewable Energy in Western Utility Resource Plans*. Ernest Orlando Lawrence Berkeley National Laboratory (LBNL-58450). August 2005. p. 58. http://eetd.lbl.gov/EA/EMP/rplan-pubs.html.

price models, which produce different results and ranges. Projections of carbon prices can be asymmetrical in relation to a base case, with greater high side potential.

Summary

Using the currently available information from carbon trading markets, utility planning and regulatory commission decisions, and computer modeling studies presented above, we forecast a mid-case of roughly \$5/ton-CO_2 (2006\$) in 2010 increasing to \$26/ton-CO_2 (2006\$) in 2025. In the mid-case, the 2010 price is lower than recent actual trading prices for CO_2 in markets where such carbon trading has been established, most notably the marked increase in EUAs over the last few months. The figure of \$26/ton-CO_2 is a reasonable expectation for the year 2025 assuming that the target emission level for that year is in the neighborhood of year 2000 emissions. It is somewhat higher than the prices from scenarios that assume factors such as a high degree of flexibility in compliance options or aggressive policies to promote clean energy development. It is lower than the prices from scenarios that include factors such as strictly limited flexibility, lack of complementary clean energy policies, or high baseline emissions growth.

It is important to note that this forecast depends on many uncertain factors, most significantly regulatory and political uncertainty. Our analysis estimates the opportunity cost of CO_2 emissions by projecting CO_2 allowance prices under probable federal policy scenarios, and drawing on available and analyzed scenarios.[111]

The forecast of beginning and end values for low, mid, and high-price scenarios is as follows:

[111] In contrast, the policy development in California involves considerable uncertainty (the policy statement was posted very recently—Oct. 6, 2005—and directs Staff to investigate numerous aspects of the standard). For this reason, we do not address this initiative quantitatively. However, it is reasonable to expect that the policy statement will drive national policy.

Table 8. Projection of CO_2 Allowance Prices (2006$/ton)

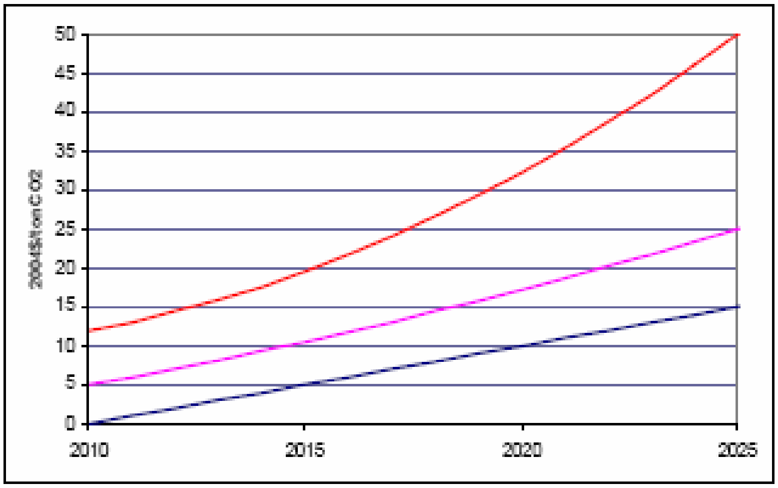
	CO_2 ($/Ton)		
Year	Low	Mid	High
2006	-	-	-
2007	-	-	-
2008	-	-	-
2009	-	-	-
2010	-	5.3	12.6
2011	1.1	6.3	13.8
2012	2.1	7.5	15.1
2013	3.2	8.6	16.7
2014	4.2	9.8	18.5
2015	5.3	11.1	20.6
2016	6.3	12.4	22.8
2017	7.4	13.8	25.2
2018	8.4	15.2	27.9
2019	9.5	16.6	30.8
2020	10.5	18.1	33.9
2021	11.6	19.6	37.2
2022	12.6	21.2	40.7
2023	13.7	22.9	44.4
2024	14.7	24.6	48.4
2025	15.8	26.3	52.6
Levelized	6.4	13.0	25.2

These projections are based on a reasonable, smooth and gradually increasing slope (except for the low case) that fits the starting and ending values. The low case increases linearly from zero in 2010 to almost $16/ton-$CO_2$ (2006$) in 2025. The high case increases from about $13 (2006$) in 2010 to $53/ton-$CO_2$ in 2025. These forecasts are defined according to the following equations, where t = year, starting with 2010 set equal to $0/ ton-$CO_2$:

Low case: $Price_L = t$
Mid case: $Price_M = 5 + t + 0.022\, t^2$
High case: $Price_H = 12 + t + 0.102\, t^2$

Intermediate years were derived by linearly increasing the price or smoothly increasing the slope to reflect increases in demand for energy. These estimates are not the result of statistical analysis but are rather an attempt to make reasonable projections for planning purposes for a parameter that is crucially important but highly uncertain.

Figure 8. Forecasted CO_2 Prices in the U.S. (2004 dollars per ton of CO_2)



While it is informative to consider the fuel prices in forecasting carbon emissions prices, the natural gas market (which will partially determine the extent that fuel switching from coal will be a viable strategy, but may also encourage renewables) has been highly volatile over the last three decades.

Sulfur Dioxide (SO_2)

Control technologies

The most widely used control application for sulfur dioxide is flue gas desulfurization (FGD) technology, often referred to as "scrubbers." FGDs employ a sorbent, normally lime or limestone, to remove sulfur dioxide and other particles from flue gas streams. There are two types of FGD: wet and dry. The first and most common type involves mixing the sorbent with water and injecting the slurry into a scrubber through which the flue gas passes.[112] Wet scrubbing is approximately 90% efficient. Dry FGDs inject the sorbent directly into the flue gas duct or a spray dryer and are less efficient at removing sulfur dioxide.

In determining regulatory impact of the Acid Rain program, EPA used long-run marginal abatement costs ranging from $579 to $760/ton (1995$). More recent estimates of long run marginal abatement costs have been similar ($560/ton), assuming higher costs for low-sulfur coal versus high sulfur coal than existed in the mid 1990s.[113] Currently, SO_2 abatement using wet scrubbers costs between $200 and $5,000 per ton, while dry spray ranges from $150 to $4,000 per ton (2001$).[114] Many applications cost around $600 per ton. However, SO_2 removal

[112] Cooper, David C. and F.C. Alley. *Air Pollution Control: A Design Approach.* Waveland Press: Prospect Heights, Illinois, 2002.
[113] Burtraw, Dallas, David A. Evans, Alan Krupnick, Karen Palmer, and Russell Toth. *Economics of Pollution Trading for SO_2 and NOx*. RFF. May 2005. p. 17.
[114] U.S. EPA. *CICA Fact Sheet: Flue Gas Desulfurization*. EPA-452/F-03-034. See http://www.epa.gov/ttn/catc/dir1/ffdg.pdf, posted 7-15-03.

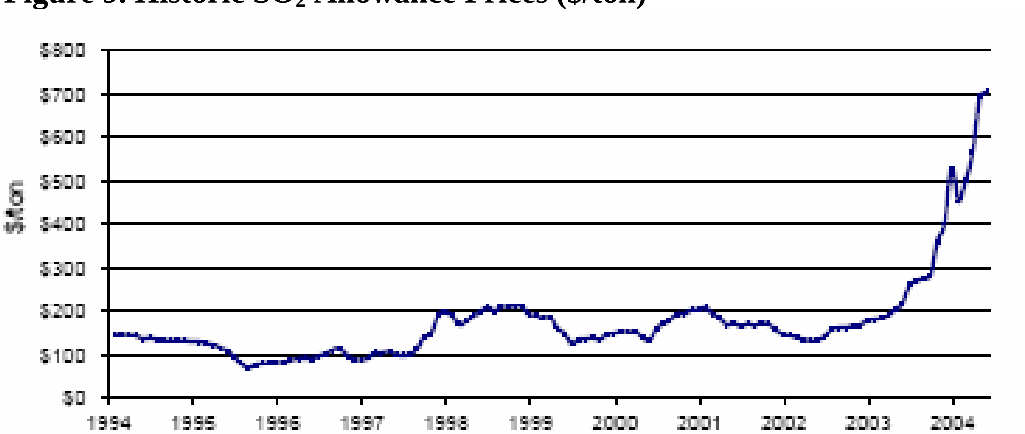
costs are projected to increase, as demand from developing countries is raising the price of raw materials.[115]

Allowance prices

Historical price trends

SO_2 allowances have been traded for more than a decade. Through much of the first decade of the Acid Rain program, allowance prices remained below forecast values, reflecting the decline in the delivered cost of low-sulfur coal and natural gas. Starting in 2000, Phase II of the program set a permanent cap of 8.95 million tons on emissions. Allowance prices have escalated since that time, most notably from 2003 to present. The rise in natural gas prices pushed up the demand for coal-fired generation, and SO_2 allowance prices shot up to $700/ton in 2004.[116] Figure 9 shows allowance prices from the inception of the program to 2004.

Figure 9. Historic SO_2 Allowance Prices ($/ton)



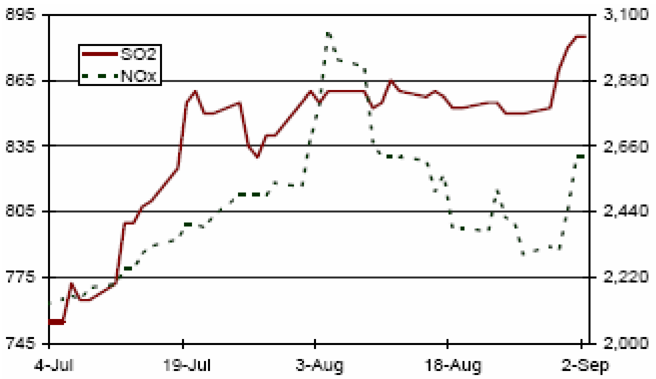
Source: Economics of Pollution Trading for SO_2 and NOx. Dallas Burtraw, David A. Evans, Alan Krupnick, Karen Palmer, and Russell Toth. RFF. May 2005.

Early on, regulatory uncertainty dampened trading under the program. Studies have indicated that state legislation and regulatory commission policy tended to undermine market efficiency, as uncertainty about how allowance transactions would be handled in rate case proceedings lessened utilities' willingness to participate. Nonetheless, SO_2 markets have historically been relatively efficient, and market efficiency will continue to increase over time.[117]

As shown in Figure 10, recent movement in the SO_2 allowance market has followed the upward trend of the past two years. The rise in allowance prices may reflect an increase in the spread between high- and low-sulfur coal prices. Generators using cheaper, high-sulfur coal will emit more SO_2, use more credits, and as a result, reduce the supply of allowances.[118] In addition, natural gas prices have continued to escalate in the recent past, favoring operation of sulfur-emitting coal-fired generators and creating greater need for SO_2 allowances.

[115] "SO_2: Spot consolidates at lower end." *Argus Air Daily*. Vol. 12, 160. August 19, 2005, p. 2-3.
[116] Burtraw, Dallas, David A. Evans, Alan Krupnick, Karen Palmer, and Russell Toth. *Economics of Pollution Trading for SO_2 and NOx*. RFF. May 2005. p. 16.
[117] Ibid., p. 18-20.
[118] PacifiCorp 2004 IRP, p. 34

Figure 10. SO_2 and NOx Allowance Prices, 2006 Term, July to September 2005 Trading (2005$/ton)



Source: Argus Air Daily. Volume 12, 170, September 2, 2005.

Current prices

Currently, SO_2 markets are very liquid, seeing active daily trading.[119] Data on SO_2 markets are relatively abundant.

EPA held its annual Acid Rain allowance auction on March 28, 2005. This auction yielded a final weighted average price of $702.51 for SO_2 allowances first useable in 2005.[120] This average is consistent with brokerage-reported trades for 2005 in late March, ranging from $705-$730/ton ($2005).

Reported allowance prices are relatively consistent between brokerages, and they reflect a continuation of the upward trend of the past two years.

[119] http://www.evomarkets.com/

[120] Winners of the EPA auction pay as bid. See http://www.epa.gov/airmarkets/auctions/2005/index.html.

Table 9. SO_2 Allowance Prices, 2005 Term (2005$/ton)

	Evolution Markets Weekly Market Update [121]	Argus Air Daily [122]	Platts[123]	Cantor-Fitzgerald[124]
Publication date	09/02/05	09/02/05	09/02/05	09/01/05
2005	885.00	885.00	882.50	880.00

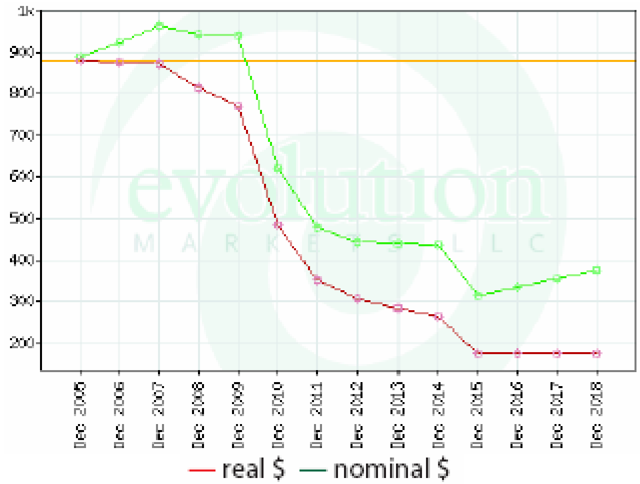
Forward markets

CAIR's tighter emissions standards, going into effect in 2009, will push national SO_2 allowance prices up. In addition, banked Acid Rain allowances are projected to be depleted by 2010, putting additional upward pressure on SO_2 prices.[125] An uncertain regulatory future—due to, for example, litigation of CAIR, PM NAAQS reevaluation (for $PM_{2.5}$ and UFP), and Regional Haze SIP development—can cause allowance prices to swell, because allowance holders are reluctant to give them up in the face of uncertainty. Regulatory risk will also increase allowance-price instability.[126]

In real dollars, the broker-reported price of SO_2 rises over the next four years and plunges in 2009.

[121] Weekly Market Update: Sept. 2, 2005. Nr 35/2005. Evolution Markets LLC. http://www.evomarkets.com.
[122] Argus publishes daily SO_2 allowance prices for current vintage (spot). Forward SO_2 prices, reflecting the range within which deals traded or could have traded at the close of the trading day for that particular vintage, are published weekly, on Fridays. Argus assesses the midpoint of the bid/ask range at the timestamp of 5:00pm Eastern Time, taking into account deals done, bids, offers, spreads between current and future vintages, and other assessments of the market gathered through a wide survey of participants. See http://www.argusonline.com/wwwroot/pa-html/methodology/argus_air_daily.htm.
[123] Platts Broker-Based Indexes for US Coal and Emissions for Sept 12. http://www.platts.com/Coal/News/6082163.xml?p=Coal/News&S=n
[124] Trade price represents actual trades. The Market Price Index is calculated at the end of each business day using an average of, where available, recent trade price(s), lowest offer price, and highest bid price. Recent trade price(s) include all transactions occurring that day (sales, swaps, and options) executed by Cantor Fitzgerald and, in some cases those reported to Cantor Fitzgerald. If there are several qualifying transactions, a weighted average of the transactions is used. Fees and commissions are not factored into the MPI. Cantor Environmental Brokerage Market Summary. http://www.emissionstrading.com/MarketData/mpi.asp?mpi=1.
[125] Burtraw, Dallas, David A. Evans, Alan Krupnick, Karen Palmer, and Russell Toth. RFF. May 2005 *Economics of Pollution Trading for SO_2 and NOx*. p. 8.
[126] PacifiCorp 2004 IRP, p. 34

Figure 11. Forward SO_2 Allowance Prices, Real and Nominal $.



Source: Evolution Markets LLC. An Overview of Trading Activity and Structures in the U.S., presented at the NYMEX Futures Seminar, New York, July 28, 2005.

Table 10. Forward SO_2 Allowance Prices (2005$/ton)

	Evolution Markets Weekly Market Update [127]	Argus Air Daily [128]
Publication date	09/02/05	09/02/05
2006	882.79	883.00
2007	879.69	880.00
2008	820.57	840.00
2009	776.59	790.00
2010	486.75	480.00
2011	354.00	400.00
2012	309.75	

In recent years, allowance prices have risen for near term forwards but start to fall off for forwards six years in advance. Current trades reflect a rapid decline in prices for five-year advance terms. Likewise, the results of the Acid Rain auction held by EPA in March show a 62% difference between the price of SO_2 allowances for the current year versus 2012 advance

[127] Weekly Market Update: Sept. 2, 2005. Nr 35/2005. Evolution Markets LLC. http://www.evomarkets.com.
[128] Argus publishes daily SO_2 allowance prices for current vintage (spot). Forward SO_2 prices, reflecting the range within which deals traded or could have traded at the close of the trading day for that particular vintage, are published weekly, on Fridays. Argus assesses the midpoint of the bid/ask range at the timestamp of 5:00pm Eastern Time, taking into account deals done, bids, offers, spreads between current and future vintages, and other assessments of the market gathered through a wide survey of participants. See http://www.argusonline.com/wwwroot/pa-html/methodology/argus_air_daily.htm.

allowances. This ratio is 10% larger than the ratio of the weighted averages of prices from 2000 to present.[129]

Table 11. Spot and Forward SO_2 Allowance Prices (2005$/ton)

EPA Acid Rain Auction	Quantity Sold	Clearing Price*
Spot (First Usable in 2005)	125,000	$690.00
7 Year Advance Bids (First Usable in 2012)	125,000	$260.00

**Winners of the EPA auction pay as bid. Source: http://www.epa.gov/airmarkets/auctions/2005/index.html.*

In addition, this decline may be attributed to the EPA's rulemaking for CAIR, which cuts the regional budget for Acid Rain allowances in half by 2010 in the eastern states.[130] Beginning in 2015, the allowance retirement ratio applied to existing Acid Rain Program allowances is 65 percent.[131] Acid Rain allowances issued in 2010 and beyond will only cover ½ ton of SO_2. Allowances issued prior to 2010 will still cover a whole ton of emissions.[132]

This decline may also reflect expectations about allowance markets after the implementation of CAMR and an increase in the opportunity cost of holding allowances.[133] Because generators can control for both Hg and SO_2 effectively through scrubbers, SO_2 and Hg allowance prices are interdependent. Theoretically, SO_2 allowance prices (as well as Hg allowance prices) will reflect the ratio of SO_2 to Hg removal achieved by the marginal control technology, e.g., scrubbers.[134]

Unabated, coal-fired generation generally results in substantially more Hg, CO_2, and SO_2 emissions than generation powered by other means, including natural gas and renewables. Although CAMR will increase the cost of emitting Hg, it is unlikely to increase the cost of coal-plant operations enough to substantially affect their economics.[135] In contrast, carbon regulations could have a large effect on coal plant deployment, depending on the price of CO_2 allowances.

[129] The number of allowances from 2000 to 2005 remained relatively constant, as did the ratio of total spot allowances to total 7-year advance allowances over the same period. The ratio of spot to 7-year advance allowances has been fairly constant from 2000 to 2005, with a weighted average of -56% over that period.

[130] The emissions budget for the region covered by CAIR was derived from the Acid Rain budgets for the states in each program. To determine the 2010 cap, the emissions budgets for the states included were totaled and reduced by half for the 2010 cap and by 65 percent for the 2015 cap. The 2010 cap for SO_2 is, therefore, 3.6 million tons in the 23 state + D.C. region ("particles only" states) and for 2015 is 2.5 million tons. EPA. "Technical Support Document for the Clean Air Interstate Rule Notice of Final Rulemaking: Regional and State SO2 and NOx Emissions Budgets." March 2005. Available at http://www.epa.gov/interstateairquality/pdfs/finaltech06.pdf.

[131] U.S. Environmental Protection Agency Office of Air and Radiation. *Technical Support Document for the Clean Air Interstate Rule, Notice of Final Rulemaking, Regional and State SO_2 and NOx Emissions Budgets*, March 2005, p. 2.

[132] As a result, holders of banked allowances are saving them for compliance with CAIR. "SO_2: Spot consolidates at lower end." *Argus Air Daily*. Vol. 12, 160. August 19, 2005, p. 3.

[133] CAMR could increase the supply of SO_2 allowances (and decrease SO_2 prices) if polluters choose to install mercury-abatement technology that has ancillary benefits in SO_2 reductions. However, EPA does not project that the cap on Hg emissions will significantly reduce SO_2 and NOx emissions *beyond emissions levels projected to result from CAIR alone.* U.S. EPA. *Regulatory Impact Analysis of the Clean Air Mercury Rule: Final Report*. EPA-452/R-05-003. March 2005. p. 7-5.

[134] A control technology's relative efficiency of SO_2 and Hg removal may vary over different operating conditions.

[135] U.S. Environmental Protection Agency. *Regulatory Impact Analysis of the Clean Air Mercury Rule: Final Report*. March 2005. EPA-452/R-05-003. P. 7-9.

Price Projections

In its 2004 Integrated Resource Plan (IRP), PacifiCorp projects the cost of SO_2 allowances relative to carbon compliance costs. The IRP projects that, as CO_2 allowance costs increase, the company's new and existing coal and natural gas units will operate less. A decrease in fossil-fired generation would also reduce SO_2 emissions—and increase the supply of SO_2 allowances.[136] In this model, future SO_2 (and NOx) prices were adjusted to reflect their inverse correlation with CO_2 allowance costs. PacifiCorp derived its base assumptions for SO_2 prices from PIRA projections, assuming full implementation of tighter SO_2 limits from the failed Clear Skies bill and CAIR by 2010. Although the Clear Skies bill did not pass, PacifiCorp correctly notes that any regulatory future with emissions limits lower than today see a tightening of the market for SO_2 allowances.

The SO_2 projections PacifiCorp used in its 2004 IRP are shown in Table 12.

Table 12. Projected Spot SO_2 Allowance Prices in PacifiCorp's 2004 IRP ($/ton)

Carbon Cost	*0.00*	*8.00*	*10.00*	*25.00*	*40.00*
SO_2 ($/Ton)					
Calendar Year					
2005	395	395	395	395	395
2006	481	481	481	481	481
2007	559	559	559	559	559
2008	686	648	584	441	257
2009	797	753	679	512	299
2010	928	877	791	596	348
2011	951	899	811	611	357
2012	974	921	830	626	366
2013	998	944	851	642	375
2014	1,023	967	872	658	384
2015	1,055	997	900	678	396
2016	1,088	1,028	927	699	408
2017	1,123	1,061	957	722	421
2018	1,160	1,096	989	745	435
2019	1,199	1,133	1022	771	450
2020	1,240	1,172	1057	797	465
2021	1,282	1,212	1093	824	481
2022	1,327	1,254	1131	853	498
2023	1,373	1,298	1171	883	515
2024	1,421	1,343	1212	914	533
2025	1,471	1,391	1254	946	552

Source: PacifiCorp 2004 Integrated Resource Plan, p. 34.

[136] PacifiCorp 2004 IRP.

The price streams begin to vary in 2008, when the model incorporates 50% probability-weighted carbon prices. After 2010, SO_2 prices diverge more radically.[137] While PacifiCorp's analysis is fairly comprehensive, its analysis was conducted while SO_2 prices were relatively modest. PacifiCorp's projections do not reflect the recent increase in SO_2 allowance prices, driven partially by escalating natural gas prices.

A more recent model of SO_2 prices was developed by the EPA in support of its proposed Clean Air Mercury Rule. These projections were published in its Regulatory Impact Analysis (RIA).

Using IPM to model the market impacts of the rule, EPA projected that Hg reductions would be achieved by coal-switching, dispatch changes, running existing SCR units year-round,[138] and installing control technology on existing coal-fired units. The emissions control technologies assumed in the model include additional FGD installations for SO_2 control, additional SCR installations for NOx control, and activated carbon injection for Hg-specific control. Notably, the generation mix under EPA's model does not change substantially, with only a 0.8% decrease in coal plant output in 2020 with CAMR relative to the base case.

The RIA accounts for the effect Hg regulations will have on SO_2 and NOx allowance prices, due to the fact that generators can combine control technology to effectively reduce all three pollutants. EPA concludes that CAMR does not substantially effect SO_2 (and NOx) emissions when compared to a CAIR-only scenario.[139]

The RIA makes some critical assumptions that reduce its predictive value. Firstly, the analysis includes the Acid Rain program, NOx SIP call, and state rules finalized prior to March of 2004. Missing are the effects of advances and cost reductions in abatement technology, very recent increases in natural gas prices relative to coal, the Regional Haze rule, and most importantly, the potential for carbon regulations in the future. [140] To address one of these shortcomings, EPA conducts a sensitivity analysis with a higher fuel price differential between natural gas and coal, as forecasted by EIA in its 2004 Annual Energy Outlook.

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[137] PacifiCorp 2004 Appendix 103-106

[138] Units in the NOx SIP Call region run only during ozone season, but can be run the rest of the year for little additional cost. P. 7-8.

[139] U.S. Environmental Protection Agency. *Regulatory Impact Analysis of the Clean Air Mercury Rule: Final Report*. March 2005. EPA-452/R-05-003. p. 7-5.

[140] EPA expects that the current level of research into mercury control technologies will depress the cost of emissions controls. A cap and trade market structure may also promote research into alternative abatement methods. EPA conducted a sensitivity analysis to account for the effect of improvements in Hg emissions control technology. The advanced-technology scenario assumes that a second ACI option is available in 2013: brominated sorbents & no fabric filter (80 to 90% removal, and lower capital costs). This is compared to the scenario where conventional sorbents with fabric filter achieve 90% removal. EPA did not model a case with higher fuel-price differentials and technological improvements, which would account for fuel and technology market interactions (e.g., improvements in low-cost Hg control technology would improve the economics of operating coal-fired plants, increasing demand for coal). As a result, the extent to which fuel price-differentials, favoring coal and pushing up allowance prices, would offset the effects of technology improvements is unknown. Total compliance costs are greater with the alternative technology assumptions (RIA, table 7-19) than with the EIA fuel price assumptions (RIA, table 7-28). The incremental costs for CAMR over the CAIR-only, base-case scenario have a present value of $3.9 billion (2007-2025). Assuming advanced technology, the present value over the same period is $2.2 B. For the EIA fuel price scenario, the incremental costs of the EIA assumptions are $3.1 B. Ibid, at 7-6, 7-7.

Table 13. Marginal Cost of SO_2 Reductions, CAMR Base Case, with EPA and EIA Assumptions for Natural Gas Prices and Electric Growth ($1999)

	Year	2010	2015	2020
EPA Assumptions	SO_2 ($/ton)	700	900	1,200
EIA Assumptions	SO_2 ($/ton)	800	1,000	1,300

Source: U.S. Environmental Protection Agency. Regulatory Impact Analysis of the Clean Air Mercury Rule: Final Report. March 2005. EPA-452/R-05-003. Tables 7-8 and 7-29.

EPA did not model a case with higher fuel-price differentials and technological improvements, nor did it consider carbon legislation in any case. As discussed previously, we expect that relative fuel prices and carbon regulation would have a significant impact on SO2 prices.

Summary

Because ambient SO_2 is a precursor to PM, states and counties will put pressure on sources to keep SO_2 emissions down to preserve $PM_{2.5}$ NAAQS attainment status, and to achieve PM_{10} attainment. In addition, Regional Haze and CAIR will go into effect over the next five to ten years. Tighter regulations on regional haze will tend to drive up SO_2 prices. Although it applies to eastern states only, CAIR will exert upward pressure on national SO_2 credit prices. Depletion of banked Acid Rain allowances in 2010 also points to increases in SO_2 allowance prices.

CAMR will likely result in an absolute decline in SO_2 prices, despite pushing up the overall cost of compliance for all affected pollutants (Hg, SO_2, NOx). SO_2 (and NOx) allowance prices will be inversely related with the cost of complying with carbon regulations.[141] A downward trend could reflect anticipation of new carbon regulations in the mid- to long-term, which would decrease operation of coal plants, thereby increasing the amount of SO_2 allowances on the market.

Excluding carbon regulations, CAIR's upward pressure in phases I (2010) and II (2015) will partially offset the absolute reduction in SO_2 prices due to CAMR's two stage implementation (in 2010 and 2018).

Implementation of CO_2 regulations on any scale would drive down the price at the margin for tons of SO_2.[142] High costs of carbon compliance will displace existing fossil-fired generation, freeing up SO_2 allowances (as well as for Hg and NOx) for sale on the market and depressing market prices for SO_2. The magnitude of this effect reflects the uncertainty associated with carbon compliance costs and the relative cost of carbon abatement (which will not necessarily coincide with a reduction in SO_2 emissions) versus switching to non-fossil fuels (which would entail lower SO_2 emissions). In turn, carbon allowances costs are highly dependent on when regulations are enacted, how stringent the controls are, what methods emitters can use to comply,

[141] Bolinger, Mark and Ryan Wiser. *Balancing Cost and Risk: the Treatment of Renewable Energy in Western Utility Resource Plans*. Ernest Orlando Lawrence Berkeley National Laboratory (LBNL-58450). August 2005. p. 61. http://eetd.lbl.gov/EA/EMP/rplan-pubs.html.

[142] Models of SO_2, NOx, and Hg prices that do not include CO_2 regulation in the analysis could overstate prices. As long as the probability of CO_2 regulations is greater than zero, then the risk-adjusted price of these emissions is lower.

who is subject to the regulations, and so on. The current range of CO_2 price estimates is fairly wide. Accordingly, when weighted by probabilities of CO_2 compliance, the range of SO_2 values is very large. Further research will be needed when the form and breadth of climate change legislation becomes clearer. Accordingly, the SO_2 price projections shown in Table 14 are not adjusted for the effect of CO_2 compliance costs.

Holding other variables constant, an increase in natural gas prices relative to coal should increase the price of SO_2 allowances, as coal-burning plants become relatively less expensive to operate, move up in the dispatch order, and create a greater demand for SO_2 allowances. However, the downward pressure of carbon regulations on SO_2 allowance prices would likely be much greater than the effect of the current price spread between natural gas and coal. We did not adjust SO_2 prices for the fuel-price effect on the grounds that it would be misleading given the high risk of carbon regulations.

Table 14. Projection of SO_2 Allowance Prices (2006$/ton)

Year	SO_2 ($/Ton)
2006	880
2007	861
2008	794
2009	835
2010*	937
2011	984
2012	1,031
2013	1,078
2014	1,125
2015	1,172
2016	1,242
2017	1,312
2018	1,383
2019	1,453
2020	1,523
2021	1,523
2022	1,523
2023	1,523
2024	1,523
2025	1,523

** SO_2 allowances issued in 2010 and beyond will cover only half of the emissions covered by allowances issued prior to that time. The market price of an allowance will be half of the projected prices shown above, which are stated in $/ton rather than $/allowance.*

For 2006 to 2009, these figures are calculated using forward prices averaged over the years for which data are available and reported by more than one source. Later years are based on EPA Regulatory Impact Analysis, using the EIA-price forecast scenario, and smoothed out between 2010, 2015, & 2020. From 2020 to 2025, forecasted prices are assumed to remain flat, reflecting emissions reductions from increased energy efficiency and renewables. The levelized value of

SO_2 allowances is $1,239/ton (2006$), based on a real discount rate of 7% and a levelization period of 2010 to 2025.[143]

Oxides of Nitrogen (NOx)

Control technologies

The most common control for nitrogen oxides at power plants is a low-NOx burner. NOx is formed during combustion via reactions between nitrogen and oxygen. A low-NOx burner regulates the mixing of fuel and air thus inhibiting NOx formation and is approximately 40-60% effective.[144] If a post-combustion flue gas treatment is also needed, two methods are commonly employed in the U.S.: selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR). Both reduce nitrogen oxides to nitrogen gas. SCR uses a catalyst and achieves an 80% reduction in NOx, whereas SNCR only achieves a 40-60% reduction.

Table 15. SCR Costs (1999$/ton)

Unit Type	Cost per Ton of Pollutant Removed
Industrial Coal Boiler	2,000 - 5,000
Industrial Oil, Gas, Wood	1,000 - 3,000
Large Gas Turbine	3,000 - 6,000
Small Gas Turbine	2,000 - 10,000

Source: U.S. EPA. CICA Fact Sheet: Selective Catalytic Reduction. EPA-452/F-03-032. See http://www.epa.gov/ttn/catc/dir1/fscr.pdf, posted 7-15-03.[145]

SNCR costs tend to be slightly cheaper. For annual control, total SNCR costs range from $400 and $2,500/ton of NOx removed. Seasonal control is more expensive, between $2,000 and $3,000 per ton.[146]

Allowance prices

Historical price trends

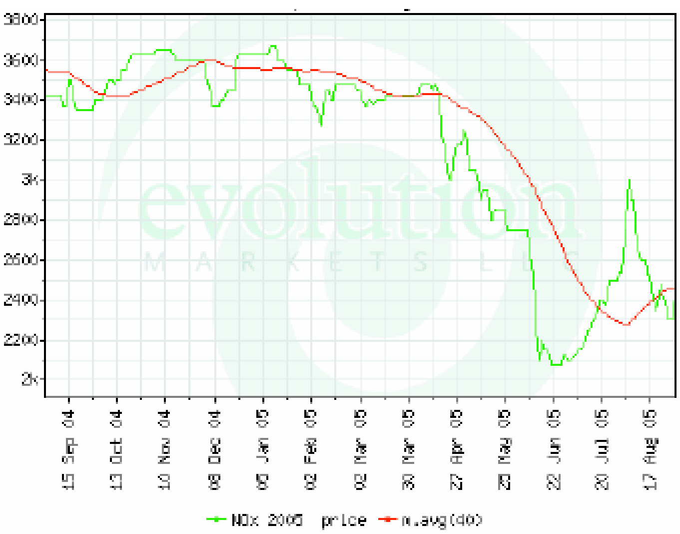
Neither Arizona nor Nevada currently participates in NOx trading programs. However, both states have developed or will develop a SIP for the federal Regional Haze rule. A regional or state-level cap and trade program would certainly reflect local conditions not modeled in this

[143] All emissions allowance prices were levelized over the years 2010-2025 to reflect the earliest feasible in-service-date for an IGCC or NGCC plant. Note that SO_2 (Acid Rain) allowances are currently available, applicable, and represent an opportunity cost for existing generation resources in Nevada and Arizona, including the Mohave Generating Station.
[144] Cooper, David C. and F.C. Alley. *Air Pollution Control: A Design Approach.* Waveland Press: Prospect Heights, Illinois, 2002.
[145] These calculations assume a 85% capacity factor and annual NOx control. Wood-fired units are assumed to have hot side electrostatic precipitators for particulate removal. Coal and oil O&M and annual costs are based on a 350 MMBtu boiler. Gas turbines' costs are based on 75 MW (large) and 5 MW (small) turbines. U.S. EPA. *CICA Fact Sheet: Selective Catalytic Reduction*. EPA-452/F-03-032. See http://www.epa.gov/ttn/catc/dir1/fscr.pdf, posted 7-15-03.
[146] *Ibid*.

analysis. Nevertheless, to the extent that NOx prices in other areas reflect national fuel prices and costs of abatement technology, these allowances provide a benchmark for understanding how a NOx allowance market in Arizona, Nevada, or the region is likely to behave.

Figure 12 shows recent NOx allowance prices under the NOx SIP Call program, effective in the eastern U.S. The compliance period for NOx runs from May through September. A dip in the end-of-season market is consistent with a glut of banked allowances from 2003 and 2004 and the flow control provision, which devalues a majority of banked allowances held-over from prior years by 50%.[147]

Figure 12. Historic NOx Allowance Prices, 2005 Term, Sept 2004 to Aug 2005 moving average (Nominal $/ton).



Source: Evolution Markets. Monthly Market Update: NOx Markets. August 2005. http://www.evomarkets.com/assets/mmu/mmu_nox_aug_05.pdf

Table 16. NOx Allowance Prices, 2003-2005 (Nominal $/ton).

Publication date	Aug 2003	Aug 2004	Aug 2005
Term			
2003	2625		
2004	2400	2100	1950
2005	2850	3425	2425
2006	N/A	2700	2650
2007	N/A	2450	2550

Source: Evolution Markets. Monthly Market Update: NOx Markets.

[147] In 2004, the eleven new participants in the NOx SIP Call had a four month compliance period, compared with the current five-month period. This shortened compliance period reduced emissions last year, because pollution controls were not operated during May. "NOx: Low Q2 output drags down prices." *Argus Air Daily*. Vol. 12, 160. August 19, 2005, p. 3.

Table 17. Recent NOx SIP Call Average Assessments, 2005 Term (2005$/ton).

Assessment Period	NOx
Sept. 2005 (to date)	2,625.00
Aug. 2005 average	2,567.39
3rd quarter 2005 average (to date)	2,464.17
2nd quarter 2005 average	2,844.14

Source: Argus Air Daily. Volume 12, 170, September 2, 2005.

Southern California has an active market for discrete (marginal) NOx trading credits (RECLAIM). Although specific to California, the RECLAIM trading credit (RTC) market provides a barometer of what generators in the region are willing to pay to offset their emissions in the current regulatory climate. A program implemented in Arizona or Nevada would probably see much lower allowance prices than in the RTC market, which is shaped by strict state-level emissions limits, allowances that cannot be banked for use in future years, and weather patterns conducive to local pollution accumulation.[148] Despite the differences, California's RTC markets can provide an upper boundary for what NOx allowance costs could be were Nevada or Arizona to participate in NOx trading.

Current prices

NOx spot market prices, trading at around $2,600/ton currently, are consistent with prices over the last few months.

Table 18. NOx Allowance Prices, 2005 Term (2005$/ton).

	Argus[149]	Platts	Cantor Fitzgerald	Evolution Markets
Publication date	09/02/05	09/02/05	09/02/05	09/02/05
2005	2,625	2,540	2,413	2,625

Forward markets

Most forward price data on NOx is based on eastern markets, including the NOx SIP call. As with current and historic prices, these data are not adjusted for economic conditions in the southwest. Generally, east-coast forwards show a slight decline in prices over the next couple of years.

[148] Moreover, regulations in California exacerbated market volatility, particularly during the energy crisis. NOx RTCs increased exponentially—over a 4,600-fold increase in prices from year-end 1999 to year-end 2000. Although the RTC market prices appear to have leveled off somewhat, this past volatility calls into question the validity of these data for assessing future NOx market trends in the west. U.S. Department Of Energy, National Renewable Energy Laboratory. *Power Technologies Data Book: 2003 Edition*. June 2004. NREL/TP-620-36347. Table 11.4. http://analysis.nrel.gov/databook/tables.asp?chapter=7&table=41

[149] Argus publishes daily NOx allowance prices for current vintage (spot), forward market prices for three additional years and previous year (banked) allowances. It also publishes spreads between the spot and forward and banked allowances.

Table 19. NOx Allowances (2005$/ton)

	Argus	Platts	Cantor Fitzgerald	Evolution Markets
Publication date	09/02/05	09/02/05	09/02/05	09/02/05
2006	2,900	2,650	2,650	2,650
2007	2,700	N/A	2,700	2,550
2008	2,025	N/A	2,500	N/A

Sources: Argus Air Daily. Volume 12, 170, Sept. 2, 2005; Platts Broker-Based Indexes for US Coal and Emissions for Sept 12. http://www.platts.com/Coal/News/6082163.xml?p=Coal/News&S=n; Cantor Fitzgerald Market Summary, http://www.emissionstrading.com/; Weekly Market Update: Sept. 2, 2005. Nr 35/2005. Evolution Markets LLC. http://www.evomarkets.com.

Applicable to sources in the Los Angeles basin, RECLAIM has a fairly active market for NOx RTCs. Table 20 provides current prices and future NOx RTC prices through 2011.

Table 20. Final NOx RECLAIM RTC Prices, June 14 2005 Auction (2005$/lb).

Compliance Year Beginning	Compliance Year Ending	Original Zone (Coastal or Inland)	Quantity (Pounds/year)	Price ($/Pound)
12/31/2005	Single Year Trade	Coastal	116,000	$4.7970
12/31/2006	Single Year Trade	Coastal	116,000	$4.7970
12/31/2007	Single Year Trade	Coastal	102,000	$4.7970
12/31/2008	Single Year Trade	Coastal	86,000	$4.7970
12/31/2009	Single Year Trade	Coastal	71,000	$4.7970
12/31/2010	Single Year Trade	Coastal	55,000	$4.7970
12/31/2011	All Years After	Coastal	40,000	$4.7970

Source: Evolution Markets – NOx Reclaim Auction Summary. June 14, 2005 steam auction. http://www.evomarkets.com/assets/EvolutionMarketsNOxRECLAIMAuctionSummary.pdf

Prices in RECLAIM are steady through 2011. Current forwards deviate somewhat from forward prices one year ago (shown in Table 20), which climbed through 2007.

Price Projections

As discussed in section 4.4, Sulfur Dioxide, the EPA used IPM to project NOx allowance prices for the CAMR RIA.

Table 21. Marginal Cost of NOx Reductions, CAMR Base Case, with EPA and EIA Assumptions for Natural Gas Prices and Electric Growth (1999$/ton)

Assumptions	2010	2015	2020
EPA	1,200	1,500	1,300
EIA	1,200	1,600	1,300

Source: U.S. Environmental Protection Agency. Regulatory Impact Analysis of the Clean Air Mercury Rule: Final Report. March 2005. EPA-452/R-05-003. Tables 7-8 and 7-29.

The model of CAMR's market impacts assumes that mercury reductions would be achieved by coal-switching, dispatch changes, running existing SCR units year-round,[150] and installing

[150] Units in the NOx SIP Call region run only during ozone season, but can be run the rest of the year for little additional cost. P. 7-8.

control technology on existing coal-fired units. SCR installations, one of the emissions control technologies included in the model, have co-benefits for NOx and Hg control. The RIA accounts for the effect Hg regulations will have on NOx and SO_2 allowance prices, due to the fact that generators can combine control technology to effectively reduce all three pollutants. EPA concludes that CAMR does not substantially effect NOx emissions when compared to a CAIR-only scenario.[151]

As discussed in section 4.4, Sulfur Dioxide, the RIA does not include assumptions about the potential for carbon regulations in the future, but it includes a sensitivity analysis to account for the higher fuel price differential between natural gas and coal forecasted by EIA in its 2004 *Annual Energy Outlook*. The increase in natural gas prices relative to coal over the last year is likely to increase the effect captured in the EIA price scenario.[152]

Table 22. Projected Spot NOx Allowance Prices in PacifiCorp's 2004 IRP ($/ton)

Carbon Cost	*0.00*	*8.00*	*10.00*	*25.00*	*40.00*
NOx ($/Ton)					
Calendar Year					
2005	--	--	--	--	--
2006	--	--	--	--	--
2007	--	--	--	--	--
2008	--	--	--	--	--
2009	--	--	--	--	--
2010	2,105	2,105	2105	345	345
2011	2,158	2,158	2158	354	354
2012	2,210	2,210	2210	362	362
2013	2,265	2,265	2265	371	371
2014	2,321	2,321	2321	381	381
2015	2,393	2,393	2393	393	393
2016	2,468	2,468	2468	405	405
2017	2,547	2,547	2547	418	418
2018	2,631	2,631	2631	431	431
2019	2,720	2,720	2720	446	446
2020	2,813	2,813	2813	461	461
2021	2,908	2,908	2908	477	477
2022	3,010	3,010	3010	494	494
2023	3,115	3,115	3115	511	511
2024	3,224	3,224	3224	529	529
2025	3,337	3,337	3337	547	547

Data from the NOx RTC market provides the foundation for the avoided cost figures used by the state of California for assessing the value of energy efficiency programs. Another model of SO_2

[151] U.S. Environmental Protection Agency. *Regulatory Impact Analysis of the Clean Air Mercury Rule: Final Report*. March 2005. EPA-452/R-05-003. p. 7-5.
[152] Ibid, at 7-6, 7-7.

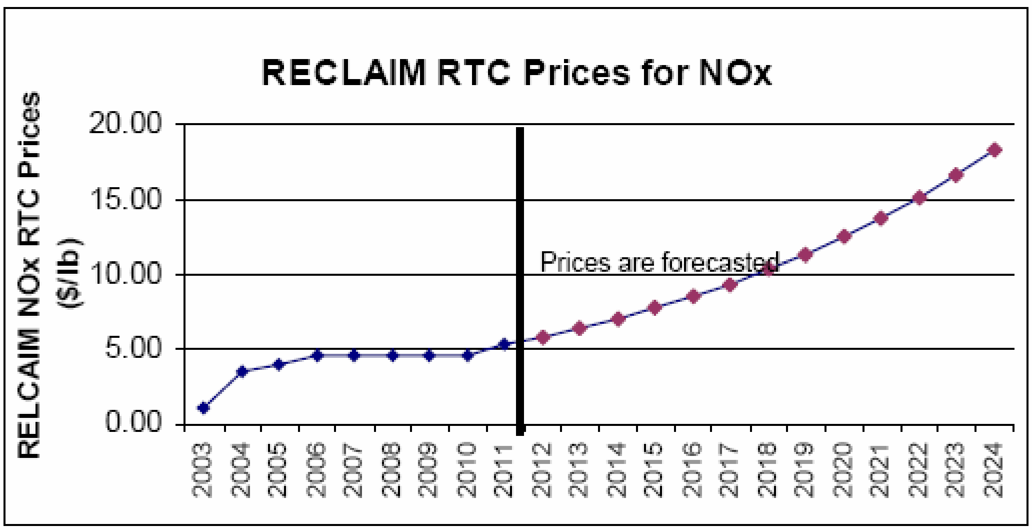
prices was developed by E3, which forecasted the growth of the RTC prices from 2011 (the end of active forward trading on RECLAIM) through 2024.

Table 23. NOx RECLAIM RTC prices through 2010 ($/lb).

Year	2004	2005	2006	2007	2008	2009	2010
($/lb)	$ 3.50	$ 3.94	$ 4.55	$ 4.63	$ 4.63	$ 4.63	$ 4.63

Source: Energy and Environmental Economics, Inc. Methodology and Forecast of Long Term Avoided Costs for The Evaluation of California Energy Efficiency Programs. October 25, 2004, p. 76-77 & 81.

Figure 13. AQMD RECLAIM RTC prices ($/lb).



Emission credits do not yet trade on a liquid futures market. Data on the RECLAIM market ends in 2011. E3 used an annual projected growth in the NOx RECLAIM RTC market price, on average over 12% per year, as proxy for future growth. This growth level was adjusted for a significant price spike in near-term years, down to 10% annually.[153] As discussed above, eastern and RECLAIM NOx allowance prices have limited relevance to the West for the short term.

Summary

Nevada's Regional Haze SIP will be implemented the next five to ten years and may include tighter regulations on NOx emissions. If, in the unlikely case that the state plan involves a cap and trade mechanism, NOx prices will tend to increase. The co-benefits of emissions control technology installed to comply with CAMR could depress prices on this local market but would increase total cost of compliance.

Like SO_2, ambient NOx is a precursor to PM. Pressure to reduce emissions will be most acute in areas that are not in attainment for PM.

[153] Energy and Environmental Economics, Inc. *Methodology and Forecast of Long Term Avoided Costs for The Evaluation of California Energy Efficiency Programs*. October 25, 2004, p. 81

We expect that NOx allowance prices will be negatively correlated with the cost of complying with carbon regulations.[154] Carbon regulations would decrease operation of coal plants, thereby increasing the amount of NOx allowances on the market. A downward trend could reflect anticipation of carbon regulations in the next five to ten years. However, as discussed in section 4.4, Sulfur Dioxide, the price projections for NOx shown in Table 24 are not adjusted for the effect of CO_2 compliance costs. Note that we do not anticipate that Arizona or Nevada would be subject to NOx trading programs over the next five to ten years.

Table 24. Projections of NOx Allowance Prices in the Eastern U.S. (2006$/ton)

Year	NOx ($/Ton)
2006	2,650
2007	2,641
2008	2,152
2009	1,779
2010	1,406
2011	1,500
2012	1,594
2013	1,687
2014	1,781
2015	1,875
2016	1,805
2017	1,734
2018	1,664
2019	1,594
2020	1,523
2021	1,523
2022	1,523
2023	1,523
2024	1,523
2025	1,523

For 2006 to 2009, these figures are calculated using forward prices averaged over the years for which data are available and reported by more than one source. Later years are based on EPA Regulatory Impact Analysis, using the EIA-price forecast scenario, and smoothed out between 2010, 2015, & 2020. From 2020 to 2025, forecasted prices are assumed to remain flat, reflecting emissions reductions from increased energy efficiency and renewables. The levelized value of NOx allowances in the East is $1,617/ton (2006$), based on a real discount rate of 7% and a levelization period of 2010 to 2025.

[154] Bolinger, Mark and Ryan Wiser. *Balancing Cost and Risk: the Treatment of Renewable Energy in Western Utility Resource Plans*. Ernest Orlando Lawrence Berkeley National Laboratory (LBNL-58450). August 2005. p. 61. http://eetd.lbl.gov/EA/EMP/rplan-pubs.html.

Mercury (Hg)

Control technologies

Two types of mercury can be expelled from coal-fired power plants: elemental and oxidized (ionic) mercury. Some mercury will be captured by electrostatic precipitators (ESPs) and fabric filters if it is bound to particles. The combination of SCR and FGD at coal-fired power plants has been shown to reduce mercury emissions since elemental mercury is converted to oxidized mercury by SCR. Oxidized mercury is water-soluble and therefore, capturable via wet scrubbing.[155]

Despite implementation of CAMR, there is still uncertainty in the cost of mercury controls. Western coals are likely to be much cheaper to control than high-sulfur bituminous coals, per pound of mercury removed. Experts estimate costs of around $5,000/lb to remove 70 percent of the mercury from Western coals with electrostatic precipitators (ESPs); to achieve 90 percent, control costs around $10,000/lb. Mercury control for Eastern coals may cost twice as much as for Western coals.[156]

Allowance prices

Historical, Current, and Forward Prices

Because mercury has not been regulated via a cap and trade mechanism in the past, data on historical and current prices are not available. Forward prices are not likely to be available for several years, due to litigation and the lack of regulatory details at this point.

Price Projections

In its 2004 IRP, PacifiCorp considers both CO_2 and Hg in its base case, with a price of $8/ton-$CO_2$.

Table 25. Projected Hg Allowance Prices in PacifiCorp's 2004 IRP (2004$/lb)

Year	Hg ($/lb)
2010	40,934
2011	41,958
2012	42,965
2013	44,039
2014	45,140
2015	46,539
2016	47,982
2017	49,517
2018	51,151
2019	52,890
2020	54,689

[155] Feeley, et.al. "Field Testing of Mercury Control Technologies for Coal-Fired Power Plants." National Energy Technology Laboratory, May 2005. Available at http://www.netl.doe.gov/coal/E&WR/pubs/mercuryR&D-v4-0505.pdf.
[156] "Tech firms: W. coal mercury bias unfair" *Argus Air Daily*. Vol. 12, 205. October 24, 2005, p. 4.

2021	56,548
2022	58,527
2023	60,576
2024	62,696
2025	64,890

Source: PacifiCorp. Technical Appendix for the Integrated Resource Plan. 2004. p. 36.

The effect of CO_2 prices on Hg prices cannot be readily extrapolated from PacifiCorp's analysis, because it does not incorporate Hg allowance projections into its alternative CO_2 cost scenarios. Further, PacifiCorp drew on PIRA's forecast for a cap-and-trade policy beginning in 2010 with a safety valve price of $35,000/lb, adjusted for inflation. Because the safety valve was not included in the final version of CAMR, Hg allowance prices could be higher than those shown.

EPA modeled Hg allowance prices as a part of its regulatory impact analysis for CAMR.[157] EPA projected that Hg reductions would be achieved by coal-switching, dispatch changes, running existing SCR units year-round,[158] and installing control technology on existing coal-fired units (such as activated carbon injection for Hg-specific control). Under EPA's model, total coal plant output decreases by only 0.8% in 2020 with CAMR relative to the base case (CAIR only). As discussed in section 4.4, Sulfur Dioxide, the analysis does not include the effect of potential carbon regulations in the future.[159]

In addition, EPA's analysis uses conservative assumptions for future technological improvements. EPA expects that the current level of research into mercury control technologies will depress the cost of emissions controls. A cap and trade market structure may also promote research into alternative abatement methods. To address some of these shortcomings, EPA conducts two sensitivity analyses. The first scenario reflects the effect of improvements in Hg emissions control technology. The advanced-technology scenario assumes that a second ACI option is available in 2013: brominated sorbents & no fabric filter (80 to 90% removal, and lower capital costs). This is compared to the scenario where conventional sorbents with fabric filter achieve 90% removal.

EPA's second sensitivity analysis assumes a higher fuel price differential between natural gas and coal, as forecasted by EIA in its 2004 *Annual Energy Outlook*.[160]

[157] In addition, other parties submitted analyses during the public comment period.
[158] Units in the NOx SIP Call region run only during ozone season, but can be run the rest of the year for little additional cost. P. 7-8.
[159] Ibid, at 7-6, 7-7.
[160] EPA did not model a case with higher fuel-price differentials and technological improvements, which would account for fuel and technology market interactions (e.g., improvements in low-cost Hg control technology would improve the economics of operating coal-fired plants, increasing demand for coal). As a result, the extent to which fuel price-differentials, favoring coal and pushing up allowance prices, would offset the effects of technology improvements is not known. Total compliance costs are greater with the alternative technology assumptions (RIA, table 7-19) than with the EIA fuel price assumptions (RIA, table 7-28). The incremental costs for CAMR over the CAIR-only, base-case scenario have a present value of $3.9 billion (2007-2025). Assuming advanced technology, the present value over the same period is $2.2 B. For the EIA fuel price scenario, the incremental costs of the EIA assumptions are $3.1 B.

Table 26. Marginal Cost of Hg Reductions with CAMR: Base Case, High Gas Price, and Advanced Technology Scenarios (1999$/lb.)

Technology Scenario	Gas Price Scenario	2010	2015	2020
Current Technology	EPA	23,200	30,100	39,000
Current Technology	EIA	26,400	34,200	44,400
Sorbent Sensitivity	EPA	11,800	15,300	19,900

Source: U.S. Environmental Protection Agency. Regulatory Impact Analysis of the Clean Air Mercury Rule: Final Report. March 2005. EPA-452/R-05-003. Table 7-8.

In its comments on the January 30, 2004, Notice of Proposed Rulemaking, the Edison Electric Institute submitted analysis forecasting lower prices than those projected by EPA. This analysis finds that the marginal cost of control (i.e., Hg allowance price) will not reach $35,000/lb, the "safety valve" price cap originally proposed by EPA.[161] Under different technological change assumptions (1.5, 2.5, and 4.0% annual rates of technological improvement in Hg control technology), modeled prices remained below $35,000 (2004$) for all but one year.[162]

Summary

As discussed in section 4.4, Sulfur Dioxide, the price projections for Hg shown in Table 26 are not adjusted for the effect of CO_2 compliance costs.

The levelized value of Hg allowances is $42,036/lb (2006$), based on a real discount rate of 7% and a levelization period of 2010 to 2025. Our forecast of mercury allowance prices is as follows:

[161] The safety valve provision was not included in the final rule.
[162] The periods under consideration include 2010, 2012, 2015, 2018, and 2020. have been projected by Smith, Anne, Scott J. Bloomberg, John L. Rego, and John H. Wile. *Projected Mercury Emissions and Costs of EPA's Proposed Rules for Controlling Utility Sector Mercury Emissions*. June 10, 2004, p. 42.

Table 27. Projection of Hg Allowance Prices ($2006/lb.)

Year	Hg ($/lb.)
2006	-
2007	-
2008	-
2009	-
2010	30,937
2011	32,766
2012	34,594
2013	36,422
2014	38,250
2015	40,078
2016	42,469
2017	44,859
2018	47,250
2019	49,640
2020	52,031
2021	52,031
2022	52,031
2023	52,031
2024	52,031
2025	52,031

PM_{10}, $PM_{2.5}$, UFP

Control technologies

Wet scrubbers, such as those used to control for sulfur dioxide (see section 4.4, Sulfur Dioxide), also control particulate matter. They are more costly to build and operate, however, than two other, common particulate controls: electrostatic precipitators and fabric filters (or baghouses). Electrostatic precipitators (ESPs) use electrical force to remove particles from a flue gas stream. As the flue gas passes between oppositely-charged electrodes, particulate matter adopts a charge and is attracted to the oppositely charged plate.[163] Dry ESP applications—typically used for utility boilers—cost between $35 and $236/short ton.[164]

Fabric filters are akin to large vacuum cleaner bags. The flue gas stream is forced through the cloth, which traps the dust. The dust can be removed by shaking the filter or reversing air flow. Fabric filters have a higher rate of particulate removal than ESPs, but they are more costly—

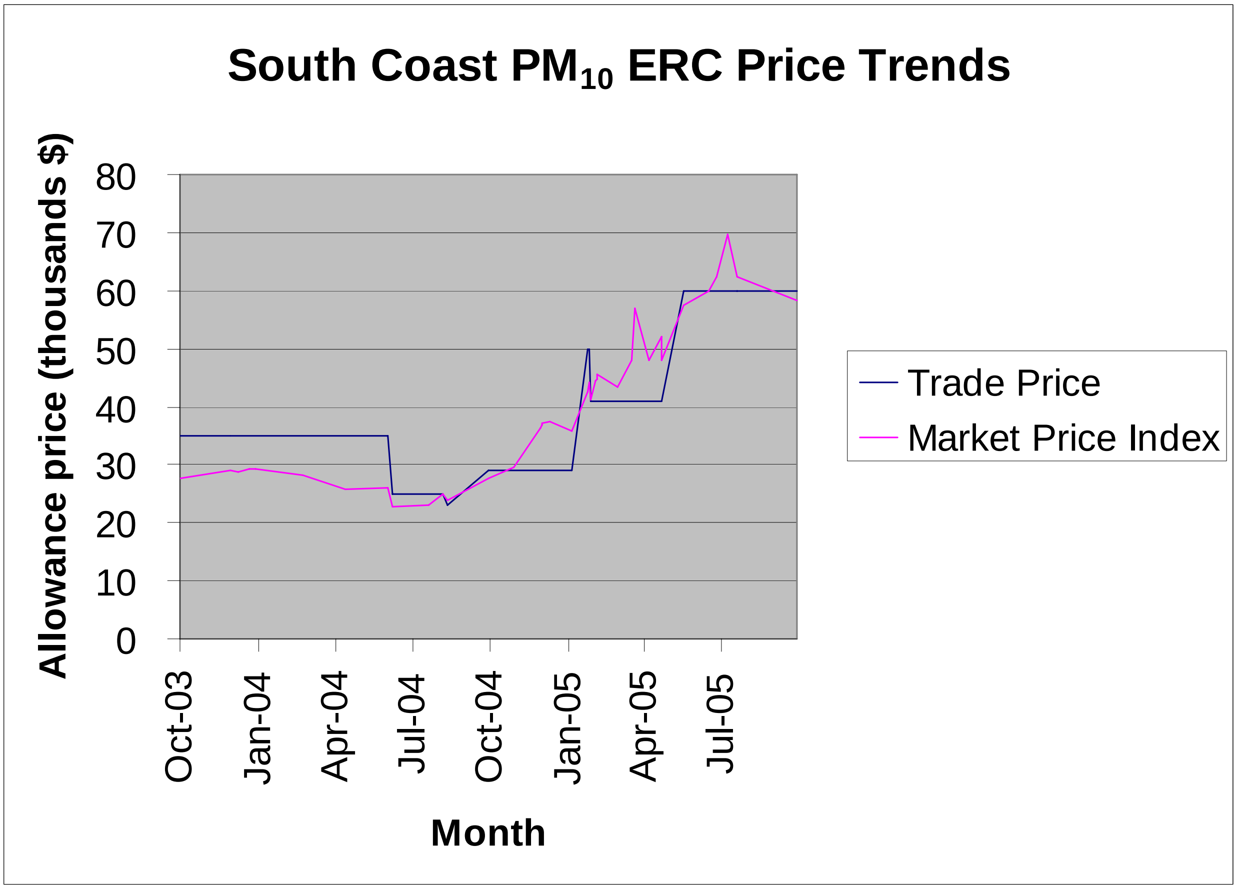
[163] Cooper, David C. and F.C. Alley. *Air Pollution Control: A Design Approach.* Waveland Press: Prospect Heights, Illinois, 2002.
[164] U.S. EPA. *CICA Fact Sheet: Dry Electrostatic Precipitator (ESP) - Wire-Plate Type.* EPA-452/F-03-028. See http://www.epa.gov/ttn/catc/products.html. Posted 7-15-03.

between about $37 to $337/ton (2002$), depending on the way that dust is removed from the filter. As a result, fabric filters are relatively common in coal-fired power plants.[165]

Emission Reduction Credits

Liquid markets do not currently exist for particulate emission reduction credits in Nevada or Arizona. In California, RECLAIM has a PM_{10} market; however, the data are not as transparent as the prices for NOx RTCs.

Figure 14. Historical South Coast PM_{10} ERC Prices.



Over the past two years, the price of PM_{10} ERCs initially fell slightly but increased dramatically in the last 12 months.

Projections

As a part of its projections for the state of California, E3 estimated PM_{10} prices using NOx as a proxy. E3 collected market data for PM_{10} emissions values from the California Air Resources

[165] U.S. EPA. *CICA Fact Sheet: Fabric Filter – Mechanical Shaker Cleaned Type, Pulse-Jet Cleaned Type, and Reverse-Air/Reverse-Jet Cleaned Type*. EPA-452/F-03-024 to EPA-452/F-03-026. See http://www.epa.gov/ttn/catc/products.html. Posted 7-15-03.

Board (CARB) and regional air district offset transaction market. As noted by E3, the offsets do not represent discrete quantities of emissions credits for a particular vintage but rather are valid credits for permanent reductions in emissions. Because this value does not easily translate into the marginal value of PM_{10}, E3 averaged CARB emission reduction credit (ERC) prices as a baseline price for both PM_{10} and NOx. E3 then applied the ratio of PM_{10} to NOx ERC prices to NOx RTC values, to approximate a discrete price for a pound reduction in PM_{10}.

Table 28 shows the resulting values of the annualized PM_{10} prices through 2010.

Table 28. Annualized PM_{10} Prices through 2010 ($/lb).

Year	2004	2005	2006	2007	2008	2009	2010
($/lb)	$ 4.90	$ 5.51	$ 6.37	$ 6.47	$ 6.47	$ 6.47	$ 6.47

Source: Energy and Environmental Economics, Inc. Methodology and Forecast of Long Term Avoided Costs for The Evaluation of California Energy Efficiency Programs. October 25, 2004, p. 77- 78.

E3 applied the estimated 10% growth in NOx prices to the PM_{10} prices after 2011, when future RTC credit prices are no longer observable.

Summary

The geographic scope of the market for PM_{10} ERCs reduces its value as a proxy for the value of these emissions offsets in Nevada or Arizona. In addition, PM_{10} trading in California is somewhat limited, and the average cost of these credits has experienced large fluctuations over the last 10 years.[166] The data presented above is intended to inform an exploratory analysis of willingness-to-pay to offset emissions but should not be considered as a projection of future values.

Ozone (O_3)

Currently, there is no market for ozone allowances in Nevada or Arizona. There is the possibility of a market for offset credits or allowances for compliance with the Regional Haze rule; more likely, however, is that it would continue to be controlled by regulating its precursors. For this reason, O_3 offset prices would be codependent with NOx allowances, and as with PM, any measure of O_3 prices would need to take this into account. Because there are no existing or proposed markets, and given the lack of data, we do not estimate the value of O_3 as an emissions allowance.

5. Valuation of Renewable Energy Attributes

To date twenty one states, plus Washington, D.C., have implemented a policy often called a Renewable Portfolio Standard (RPS) (See Figure 16). An RPS generally requires investor owned utilities (IOUs) or retail providers (and sometimes municipal utilities and rural electric cooperatives) to procure electricity from qualified renewable generation facilities at a gradually

[166] State of California Environmental Protection Agency, Air Resources Board. March 2004. *Emission Reduction Offsets Transaction Cost Summary Report for 2003*.

increasing percentage of their retail sales.[167] In this section, we explore RPS regimes in the Western states surrounding the current SCE Mohave facility. Specifically, we investigate RPS targets and rules by different states in the West and explore various opportunities regarding how Mohave renewable facilities that are examined under this study can provide values to SCE or the owners of the facilities.

5.1. Background on RPS

A RPS is often combined with a trading program involving renewable energy certificates or credits (RECs). Generally, one REC is produced per MWh of renewable electricity generation and sometimes per kWh of generation. Utilities are allowed to trade certificates with one another in order to meet their own renewable generation requirements. Trading can take place within states, across states within a region, or sometimes across regions, depending on each program's policies.[168] Many RPS policies rely upon state-wide or region-wide REC tracking systems. REC tracking systems currently operate within the New England Power Pool, Texas, and Wisconsin. A few other regions including Midwest ISO, PJM and New York ISO are also developing or recently have developed a certificate tracking system.

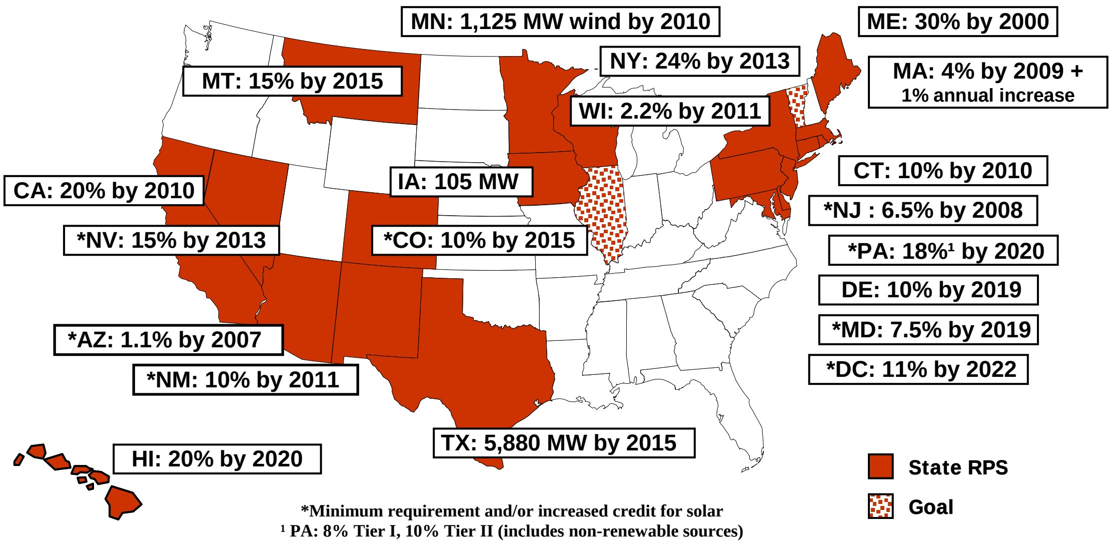
In addition, the Western Governors' Association and California Energy Commission (CEC) have been working together to develop a regional renewable energy tracking system called the Western Renewable Energy Generation Information System (WREGIS). WREGIS is an accounting system that is intended to track and verify renewable energy generation and certificates in the Western Electricity Coordinating Council geographic region, including California and all its neighboring states.

The California Energy Commission expects WREGIS to be fully operational by late 2006 or early 2007. By fully operational, we mean that those states that opt to participate in REC trading system in this region will be able to do so; the WREGIS is not a mandatory system for the region. However, several states in the region that have RPS regulation are considering future WREGIS participation.

[167] The renewable generation that "qualifies" under the various state RPSs varies among the states and is quite different from that which "qualified" as a Qualifying Facilitiy under PURPA. PURPA Qualifying Facilities area not considered further in this assessment and typically do not qualify under RPSs.

[168] Note that no RECs are generated under California RPS rules. Further no RECs are generated by renewable generators in Arizona; instead RECs are generated once they are purchased by utilities. However, for the sake of convenience we use the term "RECS" for all renewable attributes traded with or without the associated power in our study.

Figure 16. Map of Renewable Energy Portfolio Standards



Source: The Database of State Incentives for Renewable Energy (DSIRE)

5.2. RPS Targets in Western States

In the Western states for which WREGIS is mainly designed, Arizona, California, Colorado, New Mexico, Nevada, and Montana have established RPS policies. While many of these states RPS rules remain somewhat undefined, each does have clearly established renewable targets (See Table 5.1). All RPS rules applied to investor owned utilities, while some of them are also applied to other types of retail electricity providers such as energy service providers, community aggregators, municipalities, and/or rural electric cooperatives. (State specific RPS rules are summarized at Table 5.2. at the end of this section.)[169] It is important to note that California's RPS target is much higher than other states and its impact is far greater than all other states' RPS combined. In 2010, California aims to procure around 55,000 GWh of renewable energy, while other states are to procure around 9,000 GWh combined.

Table 29. State RPS Targets in the Western Region

Year	AZ		CA	CO		MT	NM	NV			
	All*	Solar		All	Solar			All	RE*	Solar	EE***
2005	1.0%	0.6%	15.0%					6.0%	4.5%	0.30%	1.5%
2006	1.05%	0.6%	16.0%				5.0%	6.0%	4.5%	0.30%	1.5%
2007	1.1%	0.7%	17.0%	3.0%	0.1%		6.0%	9.0%	6.8%	0.45%	2.3%
2008	1.1%	0.7%	18.0%	3.0%	0.1%	5.0%	7.0%	9.0%	6.8%	0.45%	2.3%
2009	1.1%	0.7%	19.0%	3.0%	0.1%	5.0%	8.0%	12.0%	9.0%	0.60%	3.0%
2010	1.1%	0.7%	20.0%	3.0%	0.1%	10.0%	9.0%	12.0%	9.0%	0.60%	3.0%
2011	1.1%	0.7%	21.0%	6.0%	0.2%	10.0%	10.0%	15.0%	11.3%	0.75%	3.8%
2012	1.1%	0.7%	22.0%	6.0%	0.2%	10.0%	10.0%	15.0%	11.3%	0.75%	3.8%
2013			23.0%	6.0%	0.2%	10.0%	10.0%	18.0%	13.5%	0.90%	4.5%
2014			24.0%	6.0%	0.2%	10.0%	10.0%	18.0%	13.5%	0.90%	4.5%
2015			25.0%	10.0%	0.4%	15.0%	10.0%	20.0%	15.0%	1.00%	5.0%
2016			26.0%	10.0%	0.4%	15.0%	10.0%	20.0%	15.0%	1.00%	5.0%

[169] Some states establish different RPS rules and targets for different types of retail providers.

2017			27.0%	10.0%	0.4%	15.0%	10.0%	20.0%	15.0%	1.00%	5.0%
2018			28.0%	10.0%	0.4%	15.0%	10.0%	20.0%	15.0%	1.00%	5.0%
2019			29.0%	10.0%	0.4%	15.0%	10.0%	20.0%	15.0%	1.00%	5.0%
2020			33.0%	10.0%	0.4%	15.0%	10.0%	20.0%	15.0%	1.00%	5.0%

* All eligible resources
** Renewable energy resources
*** Energy efficiency resources

In addition to their general renewable generation targets, Arizona, Colorado and Nevada have set-aside targets for solar electric power. These set-asides produce entirely different REC markets which often have higher REC prices reflecting higher costs of photovoltaic technologies than other renewables. Nevada has amended its RPS this year, renaming it the Energy Portfolio Standard (EPS) and including energy efficiency as one of resources eligible to meet its annual requirement. IOUs in Nevada are allowed to meet a maximum 25 percent of their annual EPS requirements through energy efficiency. Given that energy efficiency is the least expensive source of energy, investor-owned utilities are most likely to procure energy efficiency to this maximum.

5.3. Opportunities for Selling and Trading RECs in Neighboring States

RPS rules regarding selling and trading RECs or renewable attributes are quite complex and differ widely among states. Here we describe for each state if and how renewable energy attributes are sold and traded within each state and across the state boundaries. The rules in each state will determine the extent to which renewable options under consideration in this study will be able to sell RECS within the neighboring states. We expect that the renewable options being considered in this study will most likely be located in Arizona. Thus, rules regarding in-state sales in Arizona, and the rules requiring cross-state sales in neighboring states, are particularly relevant for the purposes of this study.

Arizona

RECs are generated in Arizona according to the amount of bundled renewable energy that utilities procure. However, Arizona RECs cannot be traded separately from that energy, although the energy (with accompanying Arizona RECs) can be traded between utilities in Arizona.[170] In general, utilities in Arizona have to make long term power purchase contracts with renewable generators for meeting their RPS targets. Such purchases may also be made from customers who produce renewable energy. Further, utilities need to conduct competitive solicitations to procure renewable energy from developers. Approximately 70 percent of the utilities' RPS obligation is expected to be met through a competitive solicitation process (or Request for Proposal) for third-party grid-side resources (as opposed to customer-sited resources).[171] According to Arizona Public Service Company's (APS) recent RFP, the price of power is capped at a level equal to 125 percent of the cost of conventional resource alternatives. Typically this conventional resource is natural gas-fired units, but the market price differs depending on the type of renewable energy projects (e.g., patterns of energy output and different levels of predictability).[172]

[170] The rule in Arizona is called the Environmental Portfolio Standard or EPS. For convenience, we use the term RPS for all similar rules.
[171] Personal contact with Ray Williamson (Arizona Corporation Commission) on October 14, 2005
[172] APS's Request for Proposal, available at http://www.aps.com/aps/rfp/renewable/default.html

The same deliverability and other RPS rules are applied to out-of-state facilities. Arizona currently limits eligible resources from out-of-state facilities to solar. However, the Arizona Corporation Commission is considering expanding this eligibility to other renewable energy resources. According to the Commission staff, this change might happen as early as next year.[173]

Colorado

RECs may be used and traded between entities such as utilities, marketers, and generators to satisfy RPS obligation to the extent that utilities cannot generate or procure enough renewable electricity to meet their obligation. Colorado Public Utilities Commission (PUC) will develop a credit tracking system or consider utilizing WREGIS.

Colorado's RPS rule has not addressed how out-of-state facilities can enter the Colorado's RPS market although the rule favors in-state renewable facilities by valuing one kWh from in-state facilities as 1.25 kWh toward meeting RPS requirements. Currently stakeholders are debating issues regarding out-of-state facilities. Renewable advocates and electric utilities have proposed to the Commission that unbundled REC from out-of-state facilities be eligible to meet Colorado's RPS targets.[174]

Nevada:

RECs are generated by renewable generators and may be traded between entities such as utilities, marketers, and generators under RPS rules. The commission is considering establishing a certificate tracking system and is also examining feasibility of utilizing WREGIS.

Of the western states that have adopted an RPS, Nevada seems to have the most restrictive rules on renewable energy trading from out-of-state facilities. Nevada's rule only allows for out-of-state facilities connected via dedicated power line to a facility owned, operated or controlled by a Nevada Utility.[175] This rule excludes most of renewable energy projects out-side of the state.

New Mexico

RECs are generated by renewable generators and may be traded between entities such as utilities, marketers, and generators under RPS rules. REC trading can be conducted without physical delivery of the associated electricity if a facility is located within the state.

New Mexico's RPS has a provision that treat in-state facilities preferably if all other things are equal. Currently out-of-state facilities are required to deliver RECs with the associated electricity. This deliverability requirement may change once WREGIS is established because the State's RPS rule, NMAC 17.9.572, provides that electricity needs to be delivered to New Mexico "unless the commission determines that there is a regional market for exchanging renewable energy certificates."[176]

[173] Personal communication with Ray Williamson (Arizona Corporation Commission) on September 27, 2005
[174] Personal communication with Rick Gilliam, Western Resource Advocates, Sept. 27, 2005.
[175] NRS 704.7815
[176] New Mexico Administrative Code 17.9.572, B(2)

Montana

RECs are generated by renewable generators and may be traded between entities such as utilities, marketers, and generators under RPS rules. Utilities need to conduct solicitations to obtain RECs with or without the associated power, and may not resell RECs.

Out-of-state facilities need to deliver electricity into the state to be eligible for the states' RPS requirements.

5.4. Opportunities for Selling and Trading RECs in California

Renewable Energy Procurement Process under California RPS

California currently has very strict, complex rules on renewable energy sales and trading. A voluntary REC market exists in California and is administered by the CEC. However, RECs are not generated and traded for the purpose of RPS compliance in California. In general, utilities in California have to make long-term power purchase contracts with renewable generators for meeting their RPS targets. Further, utilities need to conduct competitive solicitations, using a using least-cost best-fit methods defined by the Commission in order to select renewable energy projects. The least-cost best-fit methods allow a utility to identify least-cost resources that "best meet utility's energy, capacity, ancillary service, and local reliability needs."[177] Any proposed contracts are subject to CPUC approval.[178]

The same rules apply to an out-of-state renewable facility wishing to comply with the California RPS requirements. That is, an out-of-state facility such as a wind or solar facility examined in this study needs to go through a utility's competitive solicitation, and also to deliver both renewable attributes and their associated electricity into California.

At present the CEC and stakeholders are discussing pros and cons of relaxing these strict rules of California RPS, including allowing unbundled REC trading. As a result of stakeholders' inputs, the CEC recommended experimenting with unbundled REC trading on a limited basis.[179] The creation of WREGIS will create RECs in California, which might relax deliverability rules of RECs further and allow trading of unbundled RECs within the state and across the boundaries.

Supplemental Energy Payments

A renewable energy facility, including an out-of-state facility, can be eligible to receive supplemental energy payments (SEPs) under RPS rules. SEPs are set equal to any costs of the qualified renewable facility above the market price referent (MPR, reflecting the estimated all-in

[177] California Energy Commission (CEC), 2004, , *New Renewable Facilities Program*, page 3; California PUC, 2003, Decision 03-06-071, *Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program*, June 19, 2004, page 28.
[178] CEC, 2004, , *New Renewable Facilities Program*, page 3; California PUC, 2003, Decision 03-06-071, *Order Initiating Implementation of the Senate Bill 1078 Renewable Portfolio Standard Program*, June 19, 2004, page 28.
[179] CEC, 2005, *2005 Integrated Energy Policy Report*, September 2005

cost of baseload and peaking gas-fired generation) covered by the state's renewable energy fund.[180] SEPs may be paid for a maximum of 10 years. Contracts for shorter periods will receive payments for the duration of contract. Further, the Energy Commission may impose a cap on the amount of SEP.[181] The renewable energy fund is collected from ratepayers in proportion to their electricity consumption.

Baseload MPRs are applied to estimating SEPs for baseload renewable energy facilities, and peaking MPRs for peaking renewable energy facilities. Baseload MPRs recently determined by California PUC are set at 6.05 cents/kWh for resources with contract periods of 10, 15, and 20 years.[182] This means that the costs of eligible renewable generation above 6.05 cents/kWh are paid through supplemental energy payments (SEPs) to the extent that renewable energy funds are available. Peaking MPRs recently issued by the PUC are set at approximately 11.42 cents/kWh. To date no SEPs have been paid to utilities because the costs of renewable generation submitted to CPUC have been lower than MPRs.[183]

Lastly, it is important to note that although the commission decided to use the methodologies described here, there is great uncertainty whether California will continue using them in the future. The study conducted by KEMA and XENEGY revealed that nearly half of the study respondents proposed eliminating MPRs and SEPs due to their complexity. The study suggested eliminating these approaches. In response to this study, the CEC recommended that California PUC in collaboration with the CEC "investigate options for developing an alternative RPS framework and propose legislation that would adopt a simpler and more transparent RPS process by next year."[184]

California RPS Target

In 2004, California IOUs as a whole provided approximately 11 percent of their electricity from renewable energy, below the annual procurement target set by the government (13 percent in 2004, See Table 5.1).[185] Utilities are allowed to carry over a maximum deficit of 25 percent of annual requirements to the following years up to three years. If utilities fail to meet their requirements, they must to pay a penalty of $0.05/kWh of renewable energy supply shortage.[186]

In contrast to this state-wide supply shortage, SCE currently procures a significant amount of renewable energy, representing approximately 18 percent of its retail sales as of 2005. It is well on its way to achieving the 20 percent target before 2010. Given this condition, the CEC proposed creating a utility-specific goal for SCE. The goal is set at 25 percent by 2010, 30

[180] Ryan Wiser, Mark Bolinger, Kevin Porter, Heather Raitt, 2005, *Does It Have to Be This Hard? Implementing the Nation's Most Aggressive Renewable Portfolio Standard in California*, August 2005, prepared for Lawrence Berkeley National Laboratory, page 3.
[181] CEC, 2004, *New Renewable Facilities Program*, page 7
[182] California Utilities Commission (PUC), 2005, Resolution E-3942, filed on July 21, 2005.
[183] KEMA-XENERGY Team, 2005, *Preliminary Stakeholder Evaluation of the California Renewables Portfolio Standard*, June 2005, Page 19.
[184] CEC, 2005, *2005 Integrated Energy Policy Report*, September 2005, page 94.
[185] CEC, 2005, *Implementing California's Loading Order for Electricity Resources*, July 2005.
[186] California PUC, D.03-06-071.

percent by 2015, and 35 percent by 2020.[187] If this proposal is adopted, it would be an incentive for SCE to develop or purchase additional renewable energy.

5.5 Opportunities for Renewable Energy Attributes or RECs from SCE Renewable Facilities

It is likely that the renewable options being considered in this study will be able to obtain some additional value for the RECS they generate. In general, renewable developers will seek the market where they can get the highest price for their product; and the REC opportunities might dictate which market and which state that is.

It is beyond the scope of this study to estimate which market and at which price RECs from the Mohave renewable facilities will be sold. Such an estimate would require detailed assessment of the supply and demand for renewables in several neighboring states. Furthermore, the RPS rules in the region are not fully developed and in flux, making it especially challenging to estimate the potential value of RECs.

Nevertheless, we describe some scenarios for how and where such renewable options might be able to capture additional value from the sale of RECS. In all of the scenarios, we assume that power associated with the generation from those renewable options flows into SCE's territory– either directly or through a power swap with another source of power. The differences across the scenarios are based on (1) whether the RECs remain bundled with that power, and if not, where the RECs will be sold; and (2) whether SCE is able to make a power swap that replaces power from the renewable options.

If SCE owns the renewable facility, then the additional value of the RECS will flow to SCE. If SCE instead purchases the energy from some other entity that develops the renewable resources, including the tribes, then the value of the RECS will either flow to SCE if they are included in the terms and prices for the power, or to the renewable developer.

Scenario 1: Renewable attributes remain bundled with electricity and sold to SCE

In this scenario where the RECs remain bundled with the renewable power, the only applicable market will be SCE's service territory. Further assuming that the renewable energy projects pass a competitive solicitation and meet the least-cost best-fit standard, SCE (or the renewable developers) may receive SEPs, for the costs above the market price referent (e.g., 6.05 cents/kWh), so long as SEP funding is available.

Under current California rules, SCE would not be able to sell the RECs from power delivered into its territory to other California utilities. If the CEC decides to create a specific target for SCE, then the RECs may have considerable value to SCE. If not, then they may have little value because SCE is likely to be able to easily meet the current state-wide target.

[187] CEC, 2004, 2004 Integrated Energy Policy Report Update.

Scenario 2: Renewable attributes remain bundled with power and sold to utilities outside of SCE territory

This case assumes that SCE could sell the renewable power, bundled with the RECs, to other utilities in California or other states in the region. Ideally, the power and the RECS would be sold to the utility or the state that offers the highest value.

If some power may need to flow to SCE's service territory, SCE would have to replace the renewable generation with a purchase from another source. Thus, there would have to be two transactions in order for this scenario to work: (1) the renewable developer sells the renewable power and bundled RECs to the market offering the highest prices and (2) SCE purchases an equal amount of energy from another source that is not necessarily renewable.

Currently all states in the region except Nevada accept RECs bundled with the associated power. (As discussed above, Nevada only accepts bundled RECs with the power sold into the state from a facility that is directly connected to a transmission or distribution system owned by a Nevada utility.) Therefore, the states where power could be sold under this scenario include California, Arizona, Colorado, New Mexico, and Montana.

Among these markets, New Mexico appears to be an attractive place to sell RECs because its RPS values certain resources higher than others. For example, one kWh of solar is valued at three kWh, which provides higher values for utilities and thus higher payments for solar power generators. The Colorado market appears to be less attractive because in-state resources are treated better by receiving 1.25 kWh worth of RECs per one kWh. The Arizona REC market does not look as attractive as New Mexico because the payment for renewable energy there is capped at 125 percent of conventional resources.

Scenario 3: Renewable attributes are unbundled from the associated power

In this case, RECs are unbundled from the associated power, the power goes into SCE's territory, and the renewable developers sell the RECs to those states that accept unbundled RECs and offer the highest prices for RECs. Unfortunately, at this point in time, there are no state RPSs in the region that accept unbundled RECs.

However, some states such as Colorado and New Mexico are likely to accept unbundled RECs in the near future. As discussed above, the Colorado RPS does not address this issue, but utilities and environmental groups in the state have proposed to accept unbundled REC from out-of-state facilities. New Mexico is likely to allow unbundled RECs from out-of-state once WREGIS becomes operational. Other states might also allow unbundled RECs to be used to comply with renewable portfolio standards once WREGIS becomes operational.

Scenario 4: Unbundled RECs are sold into voluntary markets

When RECs are unbundled, voluntary REC markets – where customers voluntarily pay an additional cost for purchasing Green Power – are another opportunity for renewable developers to sell RECs. Numerous green marketing programs and tariffs exist in a variety of states. Voluntary markets do not typically restrict location of renewable facilities as much as RPS rules do. Environmental attributes traded in voluntary markets are mostly certified by Green-e program nationally. Given the small size of the voluntary markets relative to mandatory RPS markets, REC values in the voluntary markets are likely to be correspondingly lower.

Table 30. RPS Rules by Western States

	AZ	CA	CO	MT	NM	NV
Applicability	IOUs and Coops.	IOUs, energy service providers, community aggregators (POUs implement themselves)	All retail customers with more than 40,000 customers	IOUs (munis and rural coops with more than 5,000 customers implement themselves)	All retail electricity providers except coops or minus	All retail electricity providers except coops, munis or general improvement districts
REC Trading	No RECs traded, but eligible "kWhs" can be traded.	No RECs traded, but eligible "kWhs" can be traded.	Yes	Yes, but utilities may not resell RECs.	Yes	Yes
Certificating and tracking	No specific provisions	CEC shall certify eligible resources and verify compliance with RPS	The Commission is evaluating certificate tracking systems including a regional tracking system	The Commission shall adopt a rule regarding resource verification and certificate tracking system by June 2006.	The Commission tracks renewable certificate trading.	The Commission may establish a certificate tracking system.
Out-of-state purchase	Only solar providing electricity to AZ	Yes if out-of-state facilities sell electricity into CA	not addressed, but has a provision to favor in-state renewables (counted as 1.25 kWh per 1 kWh of in-state generation)	Yes if out-of-state facilities deliver electricity into MT	All other things being equal, renewable generation in NM is treated preferably. Renewable electricity must be delivered in-state.	Yes, only if a facility is connected via dedicated power line (or shared with 1 nonrenewable generator) to a facility owned, operated or controlled by a NV utility
Eligible resources/technologies	Solar Water Heat, Solar Thermal Electric, PV, Landfill Gas, Wind, Biomass, Solar Air Conditioning Systems	Solar Thermal Electric, PV, Landfill Gas, Wind, Biomass, Hydroelectric (30 MW or less), Geothermal Electric, Municipal Solid Waste, Digester Gas, Tidal Energy, Wave Energy, Ocean Thermal, Fuel Cells (renewable fuels)	PV, Landfill Gas, Wind, Biomass, Geothermal Electric, Anaerobic Digestion, Small Hydro (10 MW or less), Fuel Cells (renewable fuels)	Solar Thermal Electric, PV, Landfill Gas, Wind, Biomass, Hydroelectric (10 MW or less), Geothermal Electric, Anaerobic Digestion, Fuel Cells (renewable fuels)	Solar Thermal Electric, PV, Landfill Gas, Wind, Biomass, Small hydro (under 5 MW), Geothermal Electric, Anaerobic Digestion, Fuel Cells (renewable fuels)	Solar Water Heating, Pool Heating, Space Heating, Thermal Electric, and Thermal Process Heating, PV, Landfill Gas, Wind, Biomass, Hydroelectric(30 MW or less)(, Geothermal Electric, Municipal Solid Waste, Certain Energy Efficiency, Anaerobic Digestion, Biodiesel

Eligibility Date and other conditions	On or after January 1, 1997	Generally old facilities are eligible for RPS with some conditions, but only new facilities (operational after January 1, 2002) are eligible to receive SEP which is the payment above the market price referent.	Not specified	Facilities must be either (1) located within Montana; or (2) must be a new facility (beginning operation after 1/1/2005) in another state delivering electricity into Montana.	Hydroelectric generation is limited to new facilities	Not specified
Resource preference	At least 50% of the annual target must come from solar in 2001, increasing to 60% in 2004-2012.		One kWh of in-state renewables is valued as 1.25 kWh. At least 4% of the annual requirements must come from solar and at least half of it from customer-sited solar.		One kWh of biomass, geothermal, landfill gas, or fuel cell power is worth two kWh for the RPS, and one kWh of solar worth three kWh for the RPS	A kWh from solar is valued as 2.4 Renewable Energ Credits (RECs) and a kWh from customer-maintained renewable DG is valued as 1.15 RECs. These two characteristics can be combined and are valued as 2.55 RECs.

Source: Database for State Incentive for Renewable Energy; Renewable Energy Policy Project; Union of Concerned Scientists, "State Minimum Renewable Electricity Requirements (as of June 2005)"

6. Summary

The health and environmental effects of exposure to pollutants will impose costs on society. Through regulation, these social costs may be partially or wholly incorporated into the production costs of the polluter. An unregulated pollutant will impose a cost on society but not to the producer of the pollution. However, presently uncontrolled emissions have the potential to be regulated in the future and therefore represent risk. Regulation or legislation can shift an unpriced externality into a priced one, creating tangible costs and opportunities. A generator must consider, even anticipate, the possibility of new or changing regulations to be competitive over the long term.

With this in mind, our assessment of emissions valuation considered the economic impacts and projected market prices of seven pollutants typically emitted by fossil fuel-fired power plants. Those considered most relevant in terms of current or near-future regulations include $SO_{2,}$ NOx, Hg, and CO_2.

SO_2 allowances have been traded for more than a decade. Allowance prices have escalated since 2000 and most dramatically from 2003 to present. The rise in natural gas prices pushed up the demand for coal-fired generation, and SO_2 allowance prices shot up to $700/ton in 2004. Recent movement in the SO_2 allowance market has followed the upward trend of the past two years. The rise in allowance prices may reflect an increase in the spread between high- and low-sulfur coal prices.

Pollution regulations are likely to get tighter and put upward pressure on the price of emissions, assuming positive electric load growth. Although CAIR only applies to eastern states, it will drive up the price of Acid Rain SO_2 credits nation-wide. The five-state (AZ, NM, OR, UT, WY) backstop cap and trade program for SO_2 under the Regional Haze rule should likewise increase the price of SO_2, as well as NOx, PM, and ozone (where these markets exist). SO_2 forwards indicate a price rise over the next four years, with a plunge starting in 2009. Because SO_2 is a precursor to PM, the near-term price rise reflects the fact that states and counties will put pressure on sources to keep SO_2 emissions down to preserve $PM_{2.5}$ NAAQS attainment status. In addition, tighter regulations on regional haze will tend to drive up SO_2 prices. The plunge starting in 2009 reflects the change in definition of Acid Rain allowances, which cover only half a ton. In addition, anticipation of new carbon regulations in the mid- to long-term, which would decrease operation of coal plants, are increasing uncertainty and the amount of SO_2 allowances on the market. We project a levelized value of SO_2 emissions at $1,239/ton (2006$), based on a real discount rate of 7% and a levelization period of 2010 to 2025.

Neither Nevada nor Arizona currently participates in NOx trading programs. A cap and trade mechanism seems unlikely in the near- to mid-term, although regional haze compliance could force the states to respond over the long term. Most historic, current, and forward price data on NOx are not adjusted for economic conditions in the southwest. East-coast forwards show a slight decline in prices over the next couple of years, but the value of these data here are limited by many factors.

The co-benefits of emissions control technology installed to comply with the Clean Air Mercury Rule (CAMR) could depress NOx prices in the east but would increase total cost of compliance for NOx, SO_2, and mercury combined. Like SO_2, ambient NOx is a precursor to PM. Pressure to reduce emissions will be most acute in areas that are not in attainment for PM_{10}, and surrounding upwind areas. Based on these factors, we project a levelized value of NOx emissions at $1,617/ton in the East (2006$), based on a real discount rate of 7% and a levelization period of 2010 to 2025.

In addition, we expect that NOx, SO_2, and Hg allowance prices will be negatively correlated with the cost of complying with carbon regulations. Carbon regulations would decrease operation of coal plants, thereby increasing the amount of NOx allowances on the market, and decreasing their price. However, we have not adjusted the levelized price of NOx emissions for carbon regulatory risk, due to the wide range of values these projections would necessarily entail.

Because mercury has not been regulated via a cap and trade mechanism in the past, data on historical and current prices are not available. However, projections for Hg allowance prices do exist. These show an almost 2-fold increase in prices per pound between 2010 and 2020. Hg emissions have a projected levelized value of $42,036/lb., based on a real discount rate of 7% and a levelization period of 2010 to 2025.

The United States does not currently regulate carbon dioxide emissions. However, there are some indications that this situation is likely to change sometime in the next decade. As an indicator of what prices might look like here in the states, should that happen, we see that the European Union's market for carbon dioxide allowances has ranged between 6-13 Euros/ton CO_2 over the last couple of years. Closer to home, in December 2004, the California Public Utility Commission ruled to require utilities to consider CO_2 regulation risk in all future plant investment decisions. Specifically, the Commission ruled to require California utilities to factor in an expected regulation cost of $8-25/ ton of carbon dioxide to any new fossil-fuel resources. Federal carbon policy would drive up the price of CO_2 emissions credits, which are currently voluntary in the U.S. CO_2 values in the U.S. are assessed at $13/ton (2006$), based on a real discount rate of 7% and a levelization period of 2010 to 2025.

More stringent regulations may change the economics of different fuels. The Regulatory Impact Analysis for EPA's final version of CAMR shows a slight reduction in coal as a percent of the generation mix relative to scenarios without CAMR (p. 7-9). EPA does not project significant changes in coal plant operations with CAMR versus operations without CAMR. Although CAMR is currently under litigation, in all likelihood CAMR will stand up to the challenge.

6.1. Illustrative example

Table 31. Cost of IGCC Emissions[188]

		Emissions rate (lbs/ MMBTU)	Heat Rate (MMBTU/ MWh)	Emissions per unit of output (lbs/MWh)	Levelized allowance price (2006$/ton)	Levelized emissions cost (2006$/MWh)
No CO_2 Removal	SO_2	0.126	9.91	1.247	$ 1,239	$ 0.77
	NOx	0.022	9.91	0.215	$ 1,617	$ 0.17
	CO_2	199.573	9.91	1,978.164	$ 13	$ 12.85
	Hg	0.0000005	9.91	0.000005	$ 84,072,200	$ 0.19
No-Regrets CO_2 Removal	SO_2	0.020	10.24	0.208	$ 1,239	$ 0.13
	NOx	0.022	10.24	0.223	$ 1,617	$ 0.18
	CO_2	142.277	10.24	1,457.449	$ 13	$ 9.47
	Hg	0.0000005	10.24	0.000005	$ 84,072,200	$ 0.20
90% CO_2 Removal	SO_2	0.020	11.74	0.239	$ 1,239	$ 0.15
	NOx	0.021	11.74	0.252	$ 1,617	$ 0.20
	CO_2	16.852	11.74	197.846	$ 13	$ 1.29
	Hg	0.0000005	11.74	0.000005	$ 84,072,200	$ 0.23

[188] Calculation assumes plant operation at 100% capacity, 100% load. Emissions costs in the above table are priced at the levelized projected allowance costs. Allocations of emissions allowances are not reflected in these figures. Also note that the costs of emissions controls (e.g., scrubbers or carbon capture) are not included here. Levelized allowance prices and levelized emissions costs are presented in 2006 dollars and are levelized over the period from 2010 to 2025, using a real discount rate of 7%.

Table 32. Cost of NGCC Emissions[189]

		Emissions rate (lbs/ MMBTU)	Heat Rate (MMBTU/ MWh)	Emissions per unit of output (lbs/MWh)	Levelized allowance price (2006$/ton)	Levelized emissions cost (2006$/MWh)
Cooling Tower	CO_2	114.389	7.07	808.731	$ 13	$ 5.25
	NOx	0.037	7.07	0.262	$ 1,617	$ 0.21
Air-Cooled Condenser	CO_2	114.389	7.07	808.731	$ 13	$ 5.25
	NOx	0.037	7.07	0.262	$ 1,617	$ 0.21
Cooling Tower and CO_2 Removal	CO_2	11.439	8.31	95.057	$ 13	$ 0.62
	NOx	0.037	8.31	0.308	$ 1,617	$ 0.25
Air-Cooled Condenser and CO_2 Removal	CO_2	11.439	8.31	95.057	$ 13	$ 0.62
	NOx	0.037	8.31	0.308	$ 1,617	$ 0.25

[189] Calculation assumes plant operation at 100% capacity, 100% load. Emissions costs in the above table are priced at the levelized projected allowance costs. Allocations of emissions allowances are not reflected in these figures. Also note that the costs of emissions controls (e.g., scrubbers or carbon capture) are not included here. Levelized allowance prices and levelized emissions costs are presented in 2006 dollars and are levelized over the period from 2010 to 2025, using a real discount rate of 7%.

Appendix E

Stakeholder Comment Matrix

Comment Matrix for MACS Preliminary Report Issued September 30, 2005, Rev. 2 dated November 21, 2005 with stakeholder follow-up

Org.	Report Chapter	Ind	Comment	Sargent & Lundy/Synapse Reply	Stakeholder Follow-up (NRDC)	Stakeholder Follow-up (SCE)
			COMMENTS OF THE NATURAL RESOURCES DEFENSE COUNCIL ON THE PRELIMINARY DRAFT MOHAVE ALTERNATIVES STUDY (CPUC Docket R.04-04-003)			
NRDC	ES	1	ES-2: The heat rate for IGCC of 9,912 – 11,740 btu/kWh is significantly greater than expected. The Northwest Power Planning Council has estimated IGCC heat rates at 7915 btu/kWh without sequestration and 9290 btu/kWh with sequestration. See: http://www.nwcouncil.org/energy/powerplan/plan/(05)%20Generating%20Resource.pdf. NRDC recommends that the study team evaluate IGCC using the heat rates used by the Northwest Power Planning Council.	A review of the NWPower Council Appendix for Power Generation indicates that they used an old EPRI report for their Cost & Performance Basis. This report assumes the use of the GE-H turbine which is not yet widely used. As indicated in the report, due to features in the IECM model we could reasonably expect an improvement of about 2% in Efficiency or 70 Btu/kw. Improvements beyond this level require widespread deployment of advanced turbine technologies such as the 7B, H, and G model engines. Procurement of these limited production engines increases the project risk at this time. NW Power Council Staff out of office all week, and could not respond to questions.	NRDC believes it is likely that the H-turbine will be available in the time horizon of the proposed project.	
NRDC	ES	2	ES-2: The difference in construction costs between wet cooling and dry cooling is so small that it would seem logical to choose dry cooling at either location, given the expiration of Colorado River cooling water contract at Laughlin in 2026. NRDC recommends that dry cooling be recommended for future project planning.	The performance is very similar under average conditions, but at peak temperatures will be degraded, which is not fully shown by the model. Hybrid systems can be considered that would provide the best attributes of both. This type of design consideration is usually considered during detailed design studies. However, in general we concur that a dry system should be considered in this case.		
NRDC	ES	3	ES-2 (and elsewhere): It is important to express all generation and demand side management ("DSM") alternatives in common economic terms. NRDC recommends $/mWh, levelized over the remaining life of the water supply contract at Laughlin (for resources that would require renewal or replacement during the 17-year study period, or the measure life of longer-lived resources, whichever term is greater).	We will use estimates of resource costs and benefits in 2006 dollars. O&M costs will be provided in $/kW-yr for fixed costs and $/MWh for variable costs. Levelized generation costs over project or contract lives are outputs of the integrated resource plan process and are, as such, outside the scope of the current effort.	At a minimum, then, expected project lifetimes and expected equivalent availability factors for each resource are needed, so that the stakeholders can independently estimate project output costs for comparative purposes.	
NRDC	ES	4	ES-4: The Gray Mountain capital costs are shown for 150 mW, not for 450 mW. The site is identified as a 450 mW site. The economics and generation profile of this resource are so exemplary that this is an example of a resource that should probably move forward regardless of the future of Mohave. NRDC recommends that the capital costs be provided for a 450mW site.	The decision to move forward with any project is the subject of the Integrated Resource Plan of SCE pursuant to CPUC requirements. The total costs for 450 MW's are shown by phase in Section 4.4.1The total cost is merely the sumo f those 3 phases.		
NRDC	ES	5	ES-8: The total water requirements for each type of thermal plant should be expressed in common terms: acre-feet per year is the measure used to date for Mohave slurry and cooling water.	We will conform the presentation of this data to employ both the customary units and acre-ft per year.		
NRDC	ES	6	ES-14: SO2 credit prices should be provided for a recent historical (2-5 year) period. The value of sulphur credits from closing Mohave should be treated as an opportunity cost of continued operation.	Recent historical SO_2 credit prices are discussed in more detail in Section 4.2 of Appendix I.		
NRDC	ES	7	ES-15: The Draft Report cites prices for CO2 allowances in the European Union at 6-13 Euros/ton in recent years. EU CO2 emission permits are now substantially more expensive; recent prices have been over $25/ton CO2. The October 11, 2005, closing price was 23.15 euro or $27.78 at an exchange rate of 1.2 $/euro	Forward market prices for CO_2/carbon were not provided in the PD but will be included in the final report.		
NRDC	ES	8	ES-19: The recognition of greater value associated with on-peak resources is well-stated. There does not appear to be any utilization of this, except on page 11-9, where there is discussion of multiplying the hourly generation for each option by the SCE marginal cost for each hour. This is an appropriate way to recognize these differential values, but this methodology should be more clearly developed in the Draft Report so it is clearly understood.	The calculation of the value of the generation is constrained by the level of detail of the generation data. Based on the data that is available, the hourly generation for an average day in each season will be matched with the average hourly price to calculate the average value of the energy provided.		
NRDC	ES	9	ES-20 It is not really clear whether the transmission issues have been addressed on a contract path or flow-based approach. For some resources, particularly wind, it may be better to consider flow-based transmission availability, and recognize that the resources may not be able to reach market for a few hours per year when multiple contingencies exist on the transmission system. As we discuss below, the transmission cost estimates in Chapter 12 appear to look at retrofits required to maintain full current reliability with full dispatch of the identified resources. It may be cheaper to "underbuild" transmission and shut in supply for a few hours per year; only analysis can show which is the most cost-effective option. NRDC recommends that the Report clearly state the assumptions about transmission costing methodology, and any required retrofits.	The assessment of near-term transmission system availability between the Study Area and SCE's border uses strictly a contract-based approach. The OASIS system from which the data was obtained is based on contract path, although the ATC is based in part on the results of flow-based analyses undertaken by individual utilities. The load flow studies associated with the "Interconnection" section do use a flow-based approach. Load flow studies have been performed for a range of options with capacities roughly approximating the SCE share of the existing plant. This was the primary criterion for such groupings. We do not imply with those groupings that they are appropriate for development as a group. The load flow analysis is simply an analysis of the injection of a certain amount of power at certain buses in the transmission system and does not consider the source of such generation. The size of the groupings and the location of the power injections is simply meant to be representative of possible alternatives and used to give an idea of the required transmission system upgrades. Whether equity or debt, investors and lenders are going to want some contractual assurances for investing the magnitude of dollars involved. If some large portion of the capacity on the transmission system can be contracted for such that economics are viable, and some small portion is left "risk" to technical flow,perhaps this could be further explored, but is beyond the scope of this study.		
NRDC	ES	10	ES-20: The "Conclusions" require some sort of benchmark cost for Mohave to allow for rational comparison of the alternatives and complements. NRDC understands that this is not part of the scope of the study. However, if in the future the technologies in the report are being compared against the cost of ongoing operation of Mohave, the Mohave costs should include, among other things, the opportunity cost of using SO2 credits instead of selling them, carbon costs associated with ongoing plant operation, and a plant life reflective of Colorado River water for plant operation being unavailable after 2026.	As has been conceded this is not part of the current scope and should be supplied by others.	NRDC believes it would be helpful for SCE to revise the estimates it prepared in the proceeding (for which many of the stakeholders have workpapers) to reflect the two key changes: project life amended to conform to the cooling water supply contract, and CO2 emission costs to conform to CPUC decisions. This would provide a framework for evaluation of the	

					alternatives and complements.	
NRDC	2	1	Overall, Sargent & Lundy conclude that IGCC is feasible at either Black Mesa or Laughlin. The elevation at Black Mesa is not a problem – the lower average temperature more than makes up for the slight derating due to altitude. Water use is dramatically lower for a plant built at Black Mesa using a dry feed gasifier and dry cooling: approximately 1500 acre-ft/yr versus 6800 acre-feet/yr, or almost an 80% reduction in water use.	Dry cooling significant reduces water usage.		
NRDC	2	2	Sargent & Lundy's capital cost estimates are, however, very high. This is in part because they assume the need for a redundant gasifier to ensure 90% plant availability. The final study should present alternative cost estimates assuming that a redundant gasifier is not needed, either because natural gas is used as a backup fuel or because SCE can use system purchases in case of unplanned outages. This should reduce capital costs by roughly $180/kW or about 9%.	The cost of spare systems for improved performance can range from 5 – 10% depending on the degree to which employed. Your assumption is appropriate on the range of costs. As a conservative designer of generating systems, and based on the recommendations from technology suppliers for currently proposed systems, our recommendation for installed systems stands. Elimination of spares to increase risk is an owner's decision.	NRDC noted at the Oct. 21, 2005, meeting that with a spare gasifier, it probably also makes sense to include duct firing in any IGCC system design, so that when loads (and prices) are high, and all gasifiers are working, additional output can be generated.	
NRDC	2	3	Also, Sargent & Lundy notes that they did not receive vendor data as of the time of this writing. Vendor data must be incorporated into the final report, and NRDC is working with Sargent & Lundy to encourage vendors to respond.	We have still not received any input from Vendors. We have contacted both GE and Conco/Phillips again this week w/ no response.		
NRDC	2	4	The Draft Report says that Sargent & Lundy's cost estimate is similar to values reported in the literature. The final report should make an explicit comparison. Values in the literature typically range from about 1400-1700 $/kW rather than the ~2000 $/kW given in the draft for IGCC without CO2 sequestration. (Part of the difference between this figure and $2000/kW estimated by S&L may be the inclusion of 12.5% EPC fees, the type of coal, and the assumption of a spare gasifier, but in any case, the differences should be explained).	The base estimate is indeed within the range. We will provide additional clarification in the text. Most estimates that are published do not provide owners costs which are a part of all completed projects. The costs published are in line with "in-house" estimates conducted for confidential clients. We also have compared these costs with well known costs for PC-Generation which most experts acknowledge range from 15 – 20% less than IGCC. Current cost estimates for PC units fall in the proper range for our findings.		
NRDC	2	5	2-5: The list of IGCC Demonstration Plants on this page does not include the Beulah, North Dakota plant mentioned on page 8-2 of the Report. This table should list all gasification projects in the U.S. currently operating, along with their output. If some are gasification without combined-cycle generation (simple cycle, or no generation) this can be indicated. The in-service date for each should be shown.	We can provide a more complete listing of Gasification plants in the USA or the world. Beulah is a gasification plant but is not an IGCC plant. Note that there are many key issues that are different for IGCC that are not faced in the design of gasification for syngas generation only. These include the demands of demands for wide variation on load over an hourly basis, and this implication to integration of design and performance.	A list of gasification plants would be useful.	
NRDC	2	6	2-13: Characterizing the Black Mesa coal as sub-bituminous when it has a heat rate of 10,834 btu/lb seems a bit unusual – that is a heat content well within the range of bituminous coal. Obviously the low moisture content affects the HHV, but not the LHV. From the USDOE Virtual Museum of Coal Mining:	The Black Mesa coal is designated as sub-bituminous by the USGS and USBM.		
NRDC	2	7	"The four major types of coal are: 1. Lignite - Brownish black coal with generally high moisture and ash content, and the lowest carbon content and heating value (heating value of 4,000-8,000 Btu per pound). 2. Subbituminous - A dull black coal with a higher heating value (heating value of 8,300-10,000 Btu per pound). 3. Bituminous - A soft intermediate grade of coal that is the most common and widely used in the United States (heating value of 10,000-14,000 Btu per pound). 4. Anthracite - The hardest type of coal, consisting of nearly pure carbon. It has the highest heating value and lowest moisture and ash content (heating value of 14,000-15,000 Btu per pound)."2	The Black Mesa coal is designated as sub-bituminous by the USGS and USBM.		
NRDC	2	8	2-14: The table of water demand is confusing. The total water use for IGCC at Black Mesa with the Shell (dry) gasifier appears to be 282 af/yr for Boiler Feedwater Makeup, and 282 af/yr for Misc. Plant Uses, but the total is shown as 1,476 af/yr. It appears that it should be 564 af/yr. One can get this by adding 282 and 282, or by subtracting the coal slurry feed requirement of 1,356 from the wet total of 1,919.	There is an error in the calculation spread sheet used for this and it will be corrected.		
NRDC	2	9	2-15: Salvage value of the Mohave site may be a complicated issue, but the inclusion of land for alternatives and complements should also recognize the sale value of land at Laughlin if the plant is replaced.	This is an owner's issue.		
NRDC	2	10	2-16: IGCC Performance reflects a much higher heat rate than was expected. See comment and reference to the Northwest Power Planning Council above.	See response to comment NRDC-ES-1		
NRDC	2	11	2-18: The combined effect of higher elevation on plant performance is not obvious. Clearly the capital cost of the turbine will be higher at the higher elevation, and that presumably is captured by the IECM model. Then there is a performance penalty at altitude, offset by a performance benefit from cooler temperatures. It might be more useful to show a year-round weighted heat rate at the hotter and lower (Laughlin) and cooler and higher (Black Mesa) locations.	The capital cost in $ remains essentially the same for differing plant locations. The difference is in performance (heat rate) and output. As these values change, the normalized cost/kW will change. Typically this is prepared for the Average conditions. As indicated in the graphs, output is sensitive to ambient temperature which can have an impact on dispatch planning.	It would be useful to have the adverse impact on capacity, and the beneficial impact on heat rate associated with higher altitude recognized separately. They appear to virtually offset one another.	

NRDC	2	12	2-22: The note on this page says that high CO2 removal is not feasible until 2020 because of the need for turbines that burn pure H2. This is not correct. BP has announced plans to build an H2 burning turbine system with carbon capture in the UK: http://www.bp.com/genericarticle.do?categoryId=97&contentId=7006978	The reference provided does not provide a detailed technology description for the project. Using the links from the site, the International CO2 Capture program site was found. BP, Shell, and other major oil producers are participants. They are evaluating an array of CO2 capture and enabling technologies that dovetail with EOR that can be used to extend oil reserves and benefit the environment. A key note in their discussions on Barriers states: "**Turbine Vendors not willing to engage in very expensive development without clear market perspectives.**"		
NRDC	2	13	H2 can be diluted with NOx or flue gas recirculation to provide H2 dilution. Ed Lowe of GE said publicly that H2 combustion is not a problem for GE turbines at an EPRI workshop, August 2005. Sargent & Lundy should contact GE and other turbine vendors and report their comments on this issue.	Dilution in the turbine is typically with N_2 and/or H_2O.		
NRDC	2	14	2-25: The table appears to assume that the current contract rate for water at Laughlin would continue beyond 2026. That is unlikely. The assumptions for the cost of water at both Black Mesa and Laughlin should be made explicit, on a $/acre-foot basis. Allowing only $350,000 per year for slurry water and $90,000/year for cooling water seems implausible. The current use at Laughlin, 14,000 acre-feet per year has a market value of over $6 million per year at $400/acre-foot. That is an opportunity cost associated with continued use of that amount, and any lesser amount carries a proportionate opportunity cost. Similarly, the cost of development of C-Aquifer water is expected to be quite significant, and these magnitudes do not appear to capture a plausible level.	S&L was given the costs for water at: $20/acreft for Colorado River Water and $200/acreft for Slurry Water from the reservation. No time limit was provided. Adjustments can be made to these values by SoCal if needed in their dispatch model.	At the October 21, 2005, meeting, SCE indicated that these values are substantially out of date. Colorado River water has an opportunity cost in the $400 range, and slurry water is apparently costing $1,000.	The cost for water to be used in the economic model would be better represented at $200/acreft for the Colorado River Water and $1,000/acreft for the Slurry Water from the Reservation. This is typical of the numbers utilized when comparing alternatives until actual numbers are developed or needed for fine tuning a final design package.
NRDC	2	15	2-26: The table of projects costs should culminate in $/mWh.	Calculation of levelized $/MWh costs is beyond the scope of the current study.		
NRDC	2	16	2-28: It is not clear if duct firing of the system is contemplated or plausible. This is typically a very cheap way to add capacity to a combined cycle coal turbine, and may be applicable (using natural gas, if gasification products are not appropriate) for economies associated with this low-cost capacity. The final report should include an analysis of duct firing.	Duct firing will indeed allow for additional capacity. This is at the expense of efficiency, since the gas does not contribute to the CT output. This concept would require additional capacity in the gasification plant and would add somewhat to the overall capital cost. This is beyond the scope of IECM. S&L can provide an estimate for this approach but we would need a target for additional MW. Such a study is typically performed in later phases of design.	The cost and heat rate impacts for duct firing should be included. Duct firing at NGCC units typically involves an incremental heat rate of about 9,000 btu/kwh, which is BELOW the average heat rate of the IGCC as estimated by S&L. Therefore, it would appear that duct firing not only WOULD reduce the average cost/kw of an IGCC, but MIGHT improve the average heat rate of an IGCC.	
NRDC	3	1	No comments on non-Stirling options; not the cost-effective options.	In light of the Renewables Portfolio Standards, the Chapter 3 discussion focused on the four CSP technologies being promoted internationally: • Parabolic-trough • Power Tower • Dish/Stirling engine • Photovoltaics Of these four technologies, Parabolic Trough technology was included as a viable CSP complement generation based on currently being the most proven solar thermal electric technology and the technology with the highest degree of confidence for the capital cost estimate. Dish/engine systems were included as a viable CSP compliment generation based on having demonstrated the highest solar-to-electric conversion efficiency (29.4%), and therefore have the potential to become one of the least expensive sources of renewable energy. It is noted in the report the dish/engine capital costs are highly speculative since current dish/ engine plants are small demonstration plants. Dish/engine capital costs are projected based on the use of experience curves. The experience curve describes how unit costs decline with cumulative production. For the $1,500/kW capital cost noted in the report, production of 17,000 dish/engines would be required. The report cautions that use of experience curves is not an established method, but a correlation that has been observed for several different technologies. The report also shows the current capital of a single dish/engine is approximately $5,000/kW.		
NRDC	3	2	3-27: The discussion of storage to match the Mohave plant load profile is inappropriate. The methodology discussed at page 11-9 is a more appropriate way of valuing resources with different generation profiles.	The basic intent of Chapter 3 was to determine if concentrating solar power (CSP) technology could feasibly replace or compliment the Mohave generation. To this end the load profile of the Mohave Plant was used to determine ***how much*** generation would have to be replaced or complemented. Chapter 3 shows CSP technology is not a logical alternative to ***totally replace*** the electrical generation of the Mohave Generating Station. One point stated in the report is that CSP is not a logic Mohave generation replacement since thermal storage or a hybrid configuration would be necessary to match the existing Mohave Generating Plant load profile. However, CSP technology is shown to be a potential alternative to ***complement*** the electrical generation of the Mohave Generating Station, both as Dispatchable Power Systems and Distributed Power Systems. The capital cost estimate for the Parabolic Trough 100 MW Plant provides a breakout cost for storage – the storage cost can be deducted to obtain the capital cost for a 100 MW Parabolic Trough Plant without storage. The correct mix of generation will have to be determined from a Resource Planning Study, which is beyond the scope of this report.		
NRDC	3	3	3-28: The economic data shown indicates that the Parabolic Trough is not a cost-effective option and should not be studied further.	See previous response to comment NRDC-3-1.		
NRDC	4	1	4-3: The development of 450 mw of highly cost-effective wind generation appears to be possible at Grays Mountain by the Navajo Tribe prior to the date when Mohave could re-enter service. It may be desirable to fast-track this resource.	We cannot comment definitively on the feasibility of completing the entire Gray Mountain development before the restart of Mohave. The development on Navajo lands requires permitting approvals by that entity. Fast-track development would require their concurrence. We leave it to the Navajo Nation to reveal whether fast-track development is possible. The largest projects in the world on flat farm land are 400 MW projects taking 2 years minimum just for		

				construction. It takes 2 years on average to develop a project, and one has never been done of this magnitude on Sovereign Native lands, much less on an elevated plateau with some construction and logistics challenges.		
NRDC	4	2	4-6: NRDC questions the advisability of constructing a cement batch plant ON TOP of the mountain. Due to high winds in this area, it might make more sense to find a more sheltered nearby spot.	While the wind velocities are high in certain areas, nevertheless since cost savings are enabled by producing cement at the site rather than trucking it up, a suitable area for the plant on top of the mountain needs to be found. The wind on this plateau will not effect either the physical integrity or ability of a batch plant to make cement. The very reason the plant needs to be on the mountain is to minimize the transportation distance and time so that the cement will not prematurely set or coagulate in such a way that it becomes defective when delivered to foundation forms.		
NRDC	4	3	Also on p. 4-6, NRDC questions whether a 34.5 kv line from Grays Mountain to Moenkopi would be adequate for 450 megawatts of wind-generated capacity. Typical loadings on 34.5 kv lines are well under 100 megawatts. Either multiple 34.5 kv lines or a single larger line would appear to be more appropriate. The final report should address this issue.	NRDC's comment is appropriate. However, output from wind installations is typically at the 34.5 kV level. We would expect a multiple circuit transmission line to be required for transport of all three phases of the project and will reflect this in the final report.		
NRDC	4	4	4-12: The estimated cost of output appears to be based on conventional independent power plant financing. There is no discussion of the financing options available to the Navajo Transmission Utility Authority ("NTUA"). These options might bring down the cost significantly below the levels shown (or bring up the net revenue to the Tribe). The extensive discussion in Chapter 10 identifies many incentives available to tribal developers that do not appear to be reflected here.	Cost estimates already include both the costs for conventional project financing (levered costs), and the unlevered costs, with the eonomic assumptions assumptions provided. The unlevered costs represent the amounts to be financed and the converntional project financing costs are provided as an example only. We will present the unlevered construction costs only in the final report. Choosing the proper incentives or the proper way to finance any of these projects is not within the scope of this study, and at any rate depends on a multitude of unknowns that directly flow out of who the participants, investors, and lenders will be, what structure is ultimately chosen for ownership, etc.	NRDC believes that the combination of tribal incentives available to the Navajo, and their ability to leverage those incentives with debt financing may make the Grays Mountain project much more cost-effective than a non-tribal and non-renewable resource with otherwise similar cost fundamentals. NRDC thinks it would be unfortunate if this report did not do a case study of a tribally-owned resource taking advantage of the tribal energy incentives, renewable energy incentives, and tribal job creation tax credit incentives that could be available for this type of project. NRDC sees this option as having great potential to meet the SCE needs while providing tribal revenue and tribal employment that are crucial to the Navajo and Hopi people.	
NRDC	4	5	4-23 It would be useful to combined the load profiles of the Stirling Dish, DSM, and Wind resources to see how, combined, they compare to the SCE system load profile.	The comparison of output and load profiles is the subject of Chapter 11. We can provide a depiction of the combined data in the next draft.		
NRDC	5	1	NRDC has no comments on NGCC.	We have provided details of NGCC as requested in the scope of work.		
NRDC	6	1	6-2: Attachment 1 is information that relates to footnote 2, BPA / Snohomish PUD / Puget Sound Energy conservation transfer.	The footnote will be expanded to more clearly address the "conservation transfer" between PSE and Snohomish, Mason and Lewis county PUDs.		
NRDC	6	2	6-3: NRDC considers the energy efficiency estimate used in the report to be extremely conservative. First, the SWEEP report itself was conservative. Second, the consultants determined that only one-half of the amount identified in the SWEEP study is assumed to be available for development. Third, the benefit:cost ratio is based on long out-of-date energy supply cost analyses that do not reflect higher gas costs, incorporation of carbon costs as directed by the California Public Utilities Commission, or non-energy benefits of energy efficiency investments.	We will review the degree of conservatism more closely. Some aspects of the SWEEP study were admittedly conservative, such as its exclusion of efficiency potential for certain household end uses; but other aspects may not be conservative. We will revisit our determinations and clarify.		
NRDC	6	3	6-9: The decision to limit the analysis to system benefits charge-based energy efficiency programs is too narrow. The "selling" utilities also have rate reform and building code technical support and enforcement assistance available to them, at a minimum. Utilities in the Pacific Northwest have jointly funded Market Transformation efforts through the Northwest Energy Efficiency Alliance (as have utilities in the Northeast through NEEP). Southern California Edison and the other large investor-owned utilities in California are funding a large portion of their energy efficiency programs with funds that otherwise would be used to procure generation.	We will revisit our decision to exclude certain categories of energy efficiency potential in our summary table. The primary purpose of our examination of the SWEEP study was to determine if sufficient energy efficiency potential exists to consider an innovative interstate DSM resource procurement. It was unclear to us how EE programs other than SBC-based utility programs would be a practical alternative for the contractual mechanism contemplated.	Several utilities have adopted "service standards" which are functionally equivalent to energy codes. This is an example of how a "utility" can achieve savings outside of the system benefits charge framework. They can then augment those with SBC-funded incentives to go "beyond code."	
NRDC	6	4	6-10: The decision to limit the analysis to "moderate" as opposed to "aggressive" programmatic efforts is extremely conservative.	Agreed. We seek to demonstrate that even under relatively conservative assumptions the DSM procurement contemplated is feasible. For the purposes of this project, we are less concerned with computing, deriving or even assuming a realistic maximum potential.	The final report should recognize that the entire potential identified in SWEEP could become a potential of programs that result from this process.	
NRDC	6	5	6-12: Despite the conservatisms discussed in the analysis, by the time Mohave could be back in service after retrofit, efficiency that could be cost-effectively acquired in Arizona and New Mexico could replace over 40% of the energy and capacity from Mohave. NRDC suspects that the capacity savings would be even greater, given the on-peak nature of energy efficiency savings. With a typical load factor of 50%, energy efficiency investments provide twice as much peaking relief as baseload resources with similar annual energy production. This should be acknowledged in the final report.	The final report will contain more detailed representations of the peaking benefits of DSM and its impact as a substitute for at least a significant fraction of Mohave.		
NRDC	6	6	6-13: It is unclear whether the "cost of saved energy" represented is measured on a Total Resource Cost ("TRC") basis or a Utility Cost basis. The report should use TRC for consistency with other supply-side resources.	A total resource cost basis is assumed. The final report will clarify all assumptions and clearly define terms used in the illustrative examples.		

NRDC	6	7	However, despite cost of energy saved ranging from $13/mWh to $37/mWh, the Draft assumes $40/mWh for energy savings. When comparing energy efficiency savings to generation savings, several adjustments need to be made. First, in addition to generation avoidance, there is reserves avoidance, transmission avoidance, and distribution and distribution loss avoidance on the system where the measure is installed. Thus, a utility such as Public Service of New Mexico, receiving 10 megawatts of conservation funded by SCE, could probably sell 12 megawatts of generating capacity to SCE and still maintain its pre-conservation reliability. This should be acknowledged in the final report.	Distribution loss savings will be reflected in the final examples used in the final report. We are reluctant to explicitly include other avoided costs in our illustrative example, as a purposeful conservatism used to demonstrate the potential viability without including these additional benefits. The final report will acknowledge the additional potential areas of net benefits.		
NRDC	6	8	6-18: The conceptual 5 x 16 shaping of conservation benefits appears to leave a substantial portion of the on-peak conservation benefits with the selling utility. This is a benefit to the seller, and should be reflected as such in the final report.	The final report will include considerably more detail on the on-peak conservation benefits and how they can be allocated to different parties of the DSM transaction.		
NRDC	6	9	6-26: The fact that conservation savings are available at Palo Verde not only reduces transmission capacity requirements and transmission costs compared with a resource near Moenkopi, but also transmission losses. This should be reflected in the final report.	The final report will acknowledge this.		
NRDC	7	1	No comments submitted as no promising resources identified.			
NRDC	8	1	The Draft Report demonstrates that carbon dioxide sequestration is feasible through the injection of CO2 in enhanced oil recovery ("EOR"), enhanced gas recovery, unminable coal seams, or deep saline aquifers. The most well-established and economical approach in the near term is the use of CO2 for EOR. The final report should include information on the market price for CO2 purchased for use in EOR in various fields. These data should reflect current market conditions as well as future estimates, as the value of CO2 for EOR is much higher at current oil prices than at the prevailing prices used in previous studies.	We will address the market conditions as best we can. However, there is little publicly available information on the price for CO2.		
NRDC	8	2	8-2: Even with a blow-down phase, moving generation-related CO2 to EOR provides global CO2 benefits, assuming that the alternative would be mined CO2. In the first case, one unit of CO2 is released to the atmosphere associated with BOTH power generation AND EOR. Absent such a move, TWO units of CO2 can be expected to be released, one from generation without capture, and one from mined CO2 shipped to EOR and blown down. This should be reflected in the final report.	We will include a statement to this affect in the next draft.		
NRDC	8	3	The gasification plant at Beulah, North Dakota, discussed here, is not reflected in the table of gasification facilities shown on page 2-5.	Table 2-1 on page 2-5 shows IGCC demonstration plants. The Beulah plant is not used to produce electric power. It creates syngas for the chemical industry.		
NRDC	8	4	8-10: With current oil prices at $60+/bbl, not $25/bbl, the economics of EOR must be significantly greater than when the underlying studies relied upon by the Draft were prepared. The increase in gas prices should be acknowledged in discussing the economics of EOR. If possible, the analysis should be recalculated to reflect the current market.	We cannot re-do the analysis in the original study as we do not have access to the authors' data and models. We can comment, however, on the change in the market prices. However, it is important to understand that the Bakersfield site produces an oil with more impurities than light sweet crude oil, on which the $60+/bbl is based; the Bakersfield site prices are likely to remain lower.	There are separate prices in the market for Kern "cracking" and "coking" petroleum production. The "cracking" product carries a higher price, as would be expected. The avoidance of crude transportation costs is an offset to the lower quality of Kern crude.	
NRDC	8	5	8-13: The prices for wellhead natural gas are forecast to exceed the levels provided here, which peak at $5.50 per mmbtu, based on NYMEX futures, through at least 2010. This should be reflected in the final report.	Again, we cannot re-do the analysis. We can comment, however, on the change in the market prices.		
NRDC	8	6	8-15: The final paragraph on this page is misleading and should be deleted. As discussed in the comment about p. 8-2, while it is certainly true that CO2 will be emitted from the combustion of any oil produced with CO2-EOR, this oil can be assumed to substitute for oil that would otherwise be produced without CO2 capture or with CO2 obtained from a natural CO2 reservoir. In either case there is a substantial net reduction in CO2 emissions due to carbon capture and sequestration from an IGCC power plant.	We will review this issue and reconsider it in the final report. However, in the absence of US GHG policy, it seems unlikely that IGCC CO2 could be considered a direct substitute for natural CO2, because natural CO2 will continue to remain significantly less expensive than that produced as a by-product from an IGCC plant.	The point here was apparently misunderstood. If the current market for CO2 for EOR results in the production of CO2, injection of CO2, and then blow-down of that CO2, the net effect is an increase in CO2 emitted to the atmosphere. If, alternatively, an IGCC provided CO2 to EOR, that CO2 were injected, and the wells then subjected to blow-down, exactly the same amount of CO2 would be emitted to the atmosphere as in the first case. The electricity production using the IGCC would occur with approximately zero net additional release of CO2 to the atmosphere compared with the non-IGCC case. The substitution has the same net environmental effect as would sequestration without EOR.	
NRDC	9	1	The analysis of tribal issues should be more robust and reflective of the opportunities identified elsewhere in the report for incentives, tax breaks, and other opportunities to encourage tribal economic development. NRDC is concerned that the Draft Report in this chapter unnecessarily introduces a bias against tribal pursuit of the various options discussed in the report.	We will provide discussion of the cited opportunities in this chapter in the final report.		

NRDC	9	2	The general tone of the Tribal Issues chapter is one of complexity and convolution, supported by declarative statements and very little data and information, despite the fact that promising opportunities are presented for IGCC, wind. and solar. Nor does the chapter present reasonable findings and conclusions on issues such as job impact analysis, estimation of tribal taxes, tribal acceptance, permitting, royalties and other payments to tribes. In so doing, the Draft Report creates a scenario where costs of alternatives are clear but benefits to the tribes are not calculated. Moreover, the pursuit of any given alternative is effectively discouraged due to its purported "complexity" and its many "difficulties" and "challenges."	We are attempting to quantify the extent to which the options would provide employment benefits and tax revenue to the tribes. We concluded (with apparent agreement of the stakeholders) that it is not feasible to quantify the royalties or other fees that might be obtained by the Navajo Nation or the Hopi Tribe from land, coal, and water rights. The scope of work did not provide for quantification of any other benefits. We are continuing to work on evaluating the specifics of the land ownership and the water rights that are applicable to the specific alternatives; and to the extent that we are able to obtain additional information with respect to those matters, we will assess the impacts of the information specifically. But insofar as the draft suggests that complexity attends alternatives, we think the draft is accurate: the patterns of land ownership, and therefore land control, and the manner in which water rights are regulated by the two tribal governments and the United States government, are not simple, and to suggest otherwise would be misleading.		
NRDC	9	3	First, the Draft Report fails to quantify the benefits of any given technology. In this way, the tribes do not have a basis from which to weigh each technology in terms of net impact on the reservation. As currently drafted, the Draft Report fails to calculate the tribal taxes and royalties that would apply to these technologies, as well as estimates of investment, operation and maintenance revenue, employment impacts, and secondary business activity benefits. These numbers are necessary to adequately measure the costs and benefits of each technology.	We agree that these numbers will be valuable for ultimate decision making on the options. We are attempting to quantify the extent to which the options would provide employment benefits and tax revenue to the tribes. We concluded (with apparent stakeholder agreement) that it is not feasible to quantify the royalties or other fees that might be obtained by the Navajo Nation or the Hopi Tribe from land, coal, and water rights. The scope of work did not provide for quantification of any other benefits.		
NRDC	9	4	Second, the Draft Report consistently overstates the "issues" for any given technology on tribal lands. In so doing, the Draft Report gives an impressionist's brushstroke to various nuances of the land use approvals presented by each technology, choosing instead to clump them together and discourage further analysis. Rather than deconstruct these "issues," the Draft Report draws conclusions based on information not included in the report. For example, a closer look at Table 6.1 reveals at least four straight-forward alternatives on tribal land: IGCC at Black Mesa, Solar 1 and 2, and Wind 1. These four alternatives are all on tribal lands held in trust by the U.S. for either one or both tribes, which would simply require U.S. and tribal approval followed by a straight-forward National Environmental Policy Act ("NEPA") process. If the Draft Report is referencing other issues not mentioned in the study, then these issues must be identified and discussed in detail for each technology.	Merely because it may be possible to site an alternative on lands wholly owned in trust by the United States for one or both of the affected tribes does not mean that the process of implementing the alternative is without complexity. For example, to the extent that the use of other lands is required, for transmission purposes or for other associated infrastructure, the approval processes that attend the use of those lands must be considered in evaluating the alternative. We are continuing to work on evaluating the specifics of the land ownership and the water rights that are pertinent to the specific alternatives, and to the extent that we are able to obtain additional information with respect to those matters we will assess the impacts of the information specifically. But insofar as the draft suggests that complexity attends alternatives, we think the draft is accurate. If there are particular conclusions whose bases should be better documented, we will able to consider any that are identified to us.		
NRDC	9	5	In addition, the Draft Report summarily concludes, "to the extent that more land is required for the business activities, the potential approval difficulties increases significantly." This claim finds no basis in the Draft Report. The Draft Report does not provide any information to determine whether the size of the leasehold makes project approval more difficult. Instead of outlining the reasons for this conclusion, this statement is proffered without supporting evidence or analysis of the characteristics of each of the proposed sites, including, but not limited to, available acreage at the proposed sites, current population – if any – at the proposed sites, and their current use.	This concern apparently flows from an interpretation different from that intended by the PD. The intention was not to communicate that the "size of the leasehold" made approval more difficult. Rather, the intention was to state that if increased land requirements led to a need for lands under different and additional types of ownership or trusteeship, this could trigger additional types of approval requirements and add to the complexity of approval. This will be clarified in the final report.		
NRDC	9	6	Third, the Draft Report notes that siting on or near tribal land, including IGCC at Black Mesa, Solar 1 and 2, and Wind 1, would impact "exceeding complex water rights issues." This argument is disingenuous. The Draft Report fails to address how a major contributing factor to the water rights issues on and around the reservations is the water requirements for preparation and transport of coal from Black Mesa to the Mohave Generating Station. In fact, the proposed life-of-mine extension for Black Mesa coal and the concomitant water requirements create a major water issue themselves, which is currently before the Office of Surface Mining, Reclamation and Enforcement.	Agreed in part. We will clarify that life extension or renewal of the existing Mohave Generating Station would also raise such issues.		
NRDC	9	7	There is little distinction between the short-run jobs created by resource construction (of an IGCC, wind, solar, or conservation) versus resource operation. Some of these options provide long-term employment for skilled labor in tribal areas, and others provide only temporary activity.	Employment impact analysis, when completed, will present its results in terms of job-year totals and jobs in each year. We believe this will make the distinction sought here.	It is crucial that the final report recognize that the operational jobs provided by alternatives can extend for the life of those measures, while the jobs provided by Mohave extend only to 2026.	
NRDC	9	8	There needs to be more interplay between this chapter and Chapter 10. For example, at 10-25, a 20% federal tax credit is noted for wages paid to tribal reservation residents. This could significantly affect the cost and cost-effectiveness of renewable resource development on tribal lands – perhaps by almost as much as the scheduled-to-expire production tax credit. Similarly, at 10-28, low-interest loan funds are identified as being available to tribes. These may improve the cost-effectiveness of tribal resources. As an example, while the development of Stirling Dish solar resources may, at first examination, make more economic sense in California (avoiding some transmission costs), the transmission advantage may be outweighed by these types of tax incentives. NRDC discusses this below under Chapter 10, Financial Issues.	Agreed. The final report will cross-reference such opportunities shown in Chapter 10.	As indicated above, a case study of a project, such as Grays Mountain Wind, showing potential incentives available for that project from various sources would be very useful to the stakeholders.	
NRDC	10	1	This is an outstanding assemblage of tax and other incentives available to support renewable energy development, innovative coal resources, and tribal energy. Perhaps the greatest value in the final report would be to assemble some hypothetical packages of incentives that might apply to the specific resources identified as promising by the Draft Report: a) IGCC, with or without CO2 capture b) Wind generation on tribal lands	We will consider the possibility of preparing such a matrix.		

			c) Stirling Dish generation on tribal lands d) Energy efficiency measure installation in Arizona and New Mexico employing tribal members Such a matrix would allow for approximation of the savings, below otherwise-applicable costs, that could be achieved because of the unique combination of technologies and tribal enterprise participation.			
NRDC	10	2	Without suggesting that this is an explicit prospect or an exclusive list, the following all seem potentially applicable to NTUA development of the Gray Mountain wind farm. If all were applicable, more than one-third of the project cost might be mitigated, making it more competitive in supplying replacement energy than non-tribal resources.	We will try to look at this in more detail.		
NRDC	10	3	a) EPACT Loan Guarantee, P. 10-13 b) EPACT Section 202 Tax Credit, P. 10-12 c) EPACT Section 2602 Grants, P. 10-19 d) EPACT Section 2603 Grants, P. 10-19 e) Taxpayer Relief Act Grants and Bonds, P. 10-23 f) Indian Employment Tax Credit, P. 10-25 g) Community Development Entity, P. 10-26	We will attempt to perform this analysis.	This package is an example of the combination of incentives that might be available to a tribal resource using a renewable energy source.	
NRDC	11	1	This is an extremely important part of this Draft Report, and it should not be relegated to the minor standing that it has been accorded in the Draft Report.	The item has its own report section. We therefore do not believe that it has been relegated to minor standing.		
NRDC	11	2	The most important characteristics of any alternative or complement resources are reliability, cost, and load shape. Resources that reliably provide power during peak hours and peak months are more valuable than baseload resources. This chapter provides key data to evaluate the resources on an economic basis. Absent full deployment of an hourly dispatch planning model, the data provided by this chapter is absolutely essential to compare individual resources and portfolios of available resources to the SCE system needs and to Mohave. No resource is flawlessly reliable. Even a dependable resource like Mohave has unscheduled outages. Ultimately, however, it can be measured in dollars – the value of resources that provide power at particular times of the day and year can be quantified.	The choice of "peaking" vs. "base load" resources will be made in the integrated resource plan process that is beyond the scope of this study. The consultants' report will provide input data for this process.	NRDC assumes that this means that all resources will now stand alone, and the fact that one or more do not provide energy of the same shape as Mohave will no longer be a criteria for ranking or scoring resources. All ranking and scoring will be done in the IRP process.	
NRDC	11	3	11-2: The Draft Report appears to rely on a period when gas prices were significantly lower than now forecast. For example, the evening prices of $10/mWh and afternoon prices of $35/mWh are now more like $70 and $100. Use of the 2002 load shape is just fine – the load shape has not changed much. But current and forecast prices must be used.	We used 2002 because a full set of load and price data was available for SCE for that year. For later years only the aggregate California data is available. It makes sense to use that to reflect higher natural gas costs and energy prices, although predictions are for some price declines over the coming years.	NRDC agrees that there is some backwardization in the natural gas markets (a situation in a commodity market is when longer-term futures prices are lower than shorter-term prices). However, even in the furthest out years, prices exceed what was used in the PD,	
NRDC	11	4	11-5: The statement that "…a resource with a better match to the load profile would be even more valuable" is unambiguously true. However, a resource with a clear on-peak load profile, even if NOT matched to the SCE system load profile, is even MORE valuable on a per-kWh basis. There are much deeper markets for shoulder-period and off-peak power in the West than for coincident peak power of the type that certain resources discussed in the Draft Report can clearly provide to SCE.	The choice of "peaking" vs. "base load" resources will be made in the integrated resource plan process that is beyond the scope of this study. The consultants' report will provide input data for this process. Units that provide base load power only do so because of a merit dispatch system. If the merit process values generation correctly, then lower-cost generation runs more. It covers load during peaking hours as well as non-peaking hours, therefore it obtains value for every peaking hour in the same measure as a peaking resource. It also obtains value during non-peak hours. Thus it is the concept of "value" that may be differing in the perception of the commenter. We understand that, during peaking hours, variable costs of certain resources, such as solar resources, may be lower than variable costs of fossil resources, such as coal resources. This will be reflected in the dispatch of these units.		
NRDC	11	5	11-6: The fact that the wind energy resource on and near tribal lands is high in summer and in late afternoon should be compared to wind resources in other regions – where the load profile may be MUCH less favorable. SCE has data for existing wind resources as to their diurnal and seasonal load shape. NRDC believes that the resources identified in the Draft Report are superior to most in the West.	We do not understand how this proposed task would relate to our scope of work or to decisions on the specific options under study.		
NRDC	11	6	11-7: The discussion of DSM load shape is relatively weak. NRDC suggests that the authors consult published sources of DSM load shape, including the extensive work on more than 1000 DSM measures by the Northwest Power and Conservation Council's Regional Technical Forum, available at: http://www.nwcouncil.org/energy/rtf/crd/recommendations/origappendixe.htm	The final report will contain more discussion of DSM load shape detail and the illustrative examples will include the assumptions we make about this load shape for the purpose of assessing DSM alternative benefits.		
NRDC	11	7	11-8: If SCE funded DSM programs in Arizona or New Mexico, it is likely that the load shape of the resulting savings would be similar to the utility overall load shape, as depicted on 11-1, 11-3, and 11-4, not like that of Mohave. If the energy delivered to SCE were of the same shape as Mohave (making it a "replacement" as narrowly defined), the load shape benefits would remain with the host utility. The economic value of this should be incorporated into the cost-effectiveness of the proposed program. The methodology discussed on 11-9, using hourly values, is an appropriate way to do this.	See the response to NRDC 11-6 above. We will address the allocation of the benefits associated with DSM load shapes in the final report.		

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<tr><td>NRDC</td><td>11</td><td>8</td><td>11-9: The approach to cost-effectiveness set forth here is a very appropriate short-cut, compared with the more complex use of a system dispatch planning model. Multiplying hourly output by hourly energy price, and indexing value to “1” would allow ranking of resources. The notion to assemble some resource portfolios is also excellent. It is not reasonable to think that a single resource would be used to replace Mohave, nor is it desirable to do so from a system reliability and fuel diversity perspective. The DSM savings profiles can be derived from the Northwest Power Planning Council RTF work, if not available elsewhere. Alternatively, valuing a full portfolio of DSM measures at the system average load profile for the host utility (e.g., PNM, not SCE) would be a reasonable shortcut.</td><td>It must be noted that the scope of this study is, in general, to provide inputs to an integrated resource plan. The resource plan, not a part of the current scope, will rank the resources and no “short-cuts” will be made. We do not propose to make any such ranking evaluations in this report. Furthermore, while the notion of studying a “portfolio” of resources may have merit, this is beyond the scope of this study.</td><td></td><td></td></tr>
<tr><td>NRDC</td><td>12</td><td>1</td><td>NRDC is generally very impressed with both the quality and quantity of analysis that has been devoted to transmission issues. Some questions about issues raised on specific pages are provided below. First, NRDC is concerned about the analysis of transmission availability and how it could influence resource development.</td><td>Agreed in part; the approach is conservative because the use of a contract path reservation construct implies such conservatism; but reserving over OASIS is the only currently-available mechanism to secure incremental transmission from a new resource (other than obtaining rights on a new line or purchasing rights from existing users of firm service). Using OASIS to reserve transmission may lead to a somewhat inefficient utilization of transmission, but it is somewhat economically-based. The PD has not drawn any conclusions concerning economic viability that are linked to current transmission availability.
Also, see responses below for comments NRDC-12-2 to NRDC-12-8.</td><td></td><td></td></tr>
<tr><td>NRDC</td><td>12</td><td>2</td><td>The approach used to determine transmission availability appears to be extremely conservative, and non-economic in nature. It is likely that the development of new resources in Arizona will make additional transmission facilities desirable to facilitate the flow of power and meet historical reliability criteria. However, it does not neccessarily follow that such investments are essential to the economic viability of potential generating projects.</td><td>The criteria employed are typical for transmission system planning. The approach is not conservative. This is a technical evaluation based on NERC and WSCC reliability criteria. These are upgrades required to interconnect a facility.</td><td></td><td></td></tr>
<tr><td>NRDC</td><td>12</td><td>3</td><td>First, the criteria apparently used looks at the four most congested hours per year on the transmission system. Given the methodology discussed in Section 11.4 for valuation of generation, it is entirely plausible that some of the proposed resources might be more valuable without transmission system augmentation than if the costs identified in Section 12 are incurred. For example, hypothetically, if failure to invest in the $544 million of identified transmission resources in Case 3 at page 12-26 meant that up to 1,000 megawatts of renewable generation were shut in for four hours per year, it would be possible to measure that loss of output against the market for those hours, and determine if the transmission upgrades were cost-effective. Given a 10% annual charge rate applied to this investment, the value of the power would need to be more than $54 million per year for those four hours before the upgrade would be cost-effective. This would appear to work out to over $13,000 per megawatt-hour for the shut-in generation, as shown below:
<table>
<tr><td>Cost of Transmission Upgrades</td><td>$544,200,000</td></tr>
<tr><td>Annual Charge Factor</td><td>10%</td></tr>
<tr><td>Annualized Capital Cost</td><td>$54,420,000</td></tr>
<tr><td>Megawatts of Generation Shut In:</td><td>1,000</td></tr>
<tr><td>Annual cost per megawatt</td><td>$54,420</td></tr>
<tr><td>Hours per year shut in (assumed as the underlying reliability criteria)</td><td>4</td></tr>
<tr><td>Cost Per Megawatt-hour of Transmission Upgrade</td><td>$13,605</td></tr>
<tr><td>Typical Needle-Peak Value Per Megawatt-hour In Southern California</td><td>$50 - $500</td></tr>
</table></td><td>Assigning the [significant] costs of certain Palo Verde – west 500 kV upgrades to Mohave alternatives is somewhat misleading; the costs for these types of upgrades are likely to be shared across many parties if the upgrade is actually undertaken.
Regarding the $544 million investment in Case 3, Sargent & Lundy agrees with the underlying view that such costs are high. However, we plan to re-run this case with the solar generation amount connected to the 500 kV system. Upgrade costs similar to those of Case 2 ($170 million) are expected.
The technical criteria employed are those customarily used in load flow studies. The interconnection study evaluates upgrades required to tie into the network. Transmission service options are not evaluated in the load flow study.</td><td></td><td></td></tr>
<tr><td>NRDC</td><td>12</td><td>4</td><td>Clearly one key issue is the number of hours per year that the transmission system fails to provide reliable service. If it is a contingency condition that creates a need for additional capacity, it may be cost-effective to develop this type of resource without firm transmission capacity, use what capacity is available on an as-available basis, and shut the generation in for a few hours per year. Other key issues involve losses on the transmission system during periods of congestion, loop flow, and other factors that are not as simple to understand or measure.</td><td>Agreed, in general. However, any conditions of “firm capacity” requirements imposed by SCE, or the CPUC must be clearly understood if SCE is to include a resource that has less than (e.g.) the transmission security that SCE’s Four Corners Generation Station output has. Also, in the same way that the CA ISO considers a connection to Four Corners as a “pseudo-tie”, Mohave alternatives could conceivably incorporate similar transmission arrangements. Further investigation is required to determine this. We will attempt to speak with the CA ISO operators on this issue.
Also, see response to comment NRDC-12-3.</td><td></td><td></td></tr>
<tr><td>NRDC</td><td>12</td><td>5</td><td>Another way of looking at this is from a system reliability perspective. Any generation added to a utility system at any hour reduces the loss of load probability (“LOLP”) for that system. Numerous studies have shown that even sporadic resources like wind, operated on an as-available basis, improve system reliability. It would be useful to measure the contribution to system reliability that these potential resources offer, both with and without transmission augmentation. It is possible that the $544 million in transmission upgrades identified for Case 3 would do less for system reliability than an equivalent amount invested in energy efficiency, wind generation, solar generation, or other alternatives. In order to measure the need for and value of proposed transmission augmentation, it is necessary to know what the cost is, what the reliability benefits are, and what contribution to reliability could be achieved for the same cost by investing in other alternatives. The relatively simple project-by-project, path-based analysis in Chapter 12 only provides insights, not actual data for this type of analysis.</td><td>Chapter 12 load flow studies are not “path-based” analyses, but rather the results of transmission network load flow calculations. The calculation of the reliability benefits of the transmission upgrades is beyond the scope of the current effort.</td><td>The point being made here is that even without any transmission upgrades, addition of generation that is available for some hours of the year (even unpredictable hours) increases system reliability. Assume, for an example, that a required transmission upgrade to provide “firm” service to a 400 mw wind farm costs as much as 100 mw of wind generation. It is useful, for example, to compare addition of 500 mw of wind generation with no transmission upgrades to addition of 400 mw of wind generation with</td><td></td></tr>
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					accompanying transmission upgrades. Both have the same capital cost. Both have similar operating costs. One or the other provides a greater contribution to system reliability. It is impossible to know which without a LOLP study. It may be that having an extra 100 mw of generation adds more to reliability than having an extra 400 MW of transmission.	
NRDC	12	6	OASIS – 12-7: It is our understanding that "contract path" measurement of transmission availability tends to understate the physical capacity that is available in part because the contract paths are based on single-contingency ratings, and many hours of the year, none of the contingencies are being experienced. In other regions (and in the gas industry) "best-efforts" transmission service is being offered, which provides firm service only when it can be provided without impairing any contract path commitments. Generally, it is available when generating units are down and/or transmission contingencies are not being experienced. It may be very attractive for wind or solar generation, where the 30% - 40% capacity factor may not justify development of firm transmission services. In the rare case when best-efforts service is unavailable, the units would be subject to curtailment. In those situations, given their low running costs, they might use financial mechanisms to displace a thermal resource to gain access, but the number of hours involved is probably quite small. The high degree of availability for hourly non-firm capacity shown at pages 12-12 to 12-14 suggests that this could enable the addition of these renewable resources to the SCE portfolio without the expense of transmission upgrades discussed at pages 12-23 through 12-30. Has the option of providing non-firm transmission service to as-available generating resources been examined?	The scope of work includes examination of shorter-term and/or non-firm transmission service. The cost of such an alternative is likely lower than the cost of securing firm service. The scope of work does not include determining which form of transmission service should/would be selected for any Mohave alternative.		
NRDC	12	7	Load Flow Studies – Page 12-26: The cost of augmenting transmission for the package of generating resources identified in 12.7.4.3 seems to address BOTH "normal" and "contingency" operating conditions. Can these be separated, with an estimate of the number of hours associated with "contingency" operating conditions? If the number of hours when contingency operating conditions AND high SCE loads would force curtailment of firm service to retail customers is very small, then demand-response measures may be less expensive than the $544 million in transmission upgrade costs. If this is the case, then the demand-response option to meet contingencies should logically be considered as an alternative to transmission construction. There is no examination of demand response options, because this study is focused on supply options to replace or complement Mohave, but if transmission obstacles exist for only a few hours per year, then adding demand response to a portfolio may be economical.	It may not be necessary to build additional transmission if an optimum portfolio of resources is chosen. This could be the case if there is an ability to rely on any other SCE-region peaking resource, not just demand response. This aspect should be considered as part of SCE's integrated resource planning, but is beyond the scope of the current effort. Also, see the response to comment NRDC-12-3.		
NRDC	12	8	Four Corners – P. 13-31: The ownership rights that SCE currently has for Four Corners were not considered as a possible source of transmission access for any of the Mohave alternatives. This reasoning does not appear to be explained.	The Four Corners transmission rights are required to transmit SCE's share of the power from the Four Corners resource.		
			Subject: Comments on MACS Preliminary Draft dated September 2005 **This e-mail provides stakeholder comment on behalf of the Hopi Tribe on the MACS Preliminary Draft ("PD") dated September 2005**			
Hopi	General	1	We recognize that the PD is incomplete in several material respects, and does not at this time propose conclusions. Our comments on the MACS are necessarily limited by these circumstances. However, at this time, we suggest that the following points be considered:	Sargent & Lundy will improve the conclusions presented in the final report taking into account stakeholder comments.		
Hopi	ES	1	The Executive Summary could be improved if the data on plant performance, capital costs and other factors were made more uniform among the alternatives studied. While different considerations are applicable to each technology examined, it would be useful to make the table data as comparable and uniform as possible to avoid confusion.	We plan to provide summary data for each alternative side-by-side in a table for more convenient comparison.		
Hopi	ES	2	The analysis of Energy Efficiency / DSM appears to be based upon the 2002 SWEEP study. We recommend that the MACS report use care to identify this source and to avoid language in the report suggesting that the MACS study is producing new "findings." (See, e.g., MACS Preliminary Report page ES-9: "... we find that by 2010 there is at least 2,394 GWh of energy per year and 408 MW of capacity available from these two states alone.")	We will revisit the language used. It was not our intent to introduce any new "raw" findings since we are not conducting a ground-up potential study. However, it is our intent to critically examine the study, and use a "refined" estimate if appropriate; e.g., a more conservative estimate to ensure no exaggeration of the actual technical potential. In particular, the absolute level of technical potential is not necessarily required to be precisely determined in order to address the fundamental "DSM resource procurement" option being considered.		
Hopi	6	1	We recommend that the MACS consultants address more clearly the existing legal and structural barriers to the Energy Efficiency / DSM proposal under examination.	The final report will more clearly address the regulatory and institutional barriers present. We are not aware of any particular legal barriers other than those that are considered as part of the regulatory-institutional construct (i.e., the way that State law empowers Commissions to address the ratepayer impact of regulated utilities' actions including power transfers across state boundaries).		
Hopi	6	2	We would like to better understand how the Energy Efficiency / DSM proposal generates revenues and jobs on or near the Hopi reservation. See, e.g., Chapter 6 of the PD (Energy Efficiency/Demand Side Management Technology) and Table xx at page 10-49.	We will address this to the extent feasible in the final report.		

Hopi	9	1	With respect to Chapter 9, Tribal Issues, we appreciate the work performed by the MACS consultants. We agree that the issue of acceptance of a particular energy project is a matter uniquely within the province and jurisdiction of the Native American tribe whose interests are affected, and involves numerous factors and considerations. Given the level of specificity of the draft PD, we agree that further study of this area by the MACS consultants would not add sufficient additional value to the MACS project.	Agreed, but we are open to further analysis if the stakeholders agree and are committed to supporting the work.		
Hopi	10	1	With respect to Chapter 10, Financial Issues, we recommend that the MACS consultants review their conclusions regarding recommended ownership structures of various energy technologies. In particular, given the level of specificity contained in the draft PD, it may be premature to conclude, for example, that a particular technology is, or is not, suited to tribal ownership. Such decisions are best made in conjunction with particular project and project financing proposals. See, e.g. MACS Preliminary Report, Table xx and page 10-49.	Agreed. The PD reflects what we believe to be reasonable *generic* conclusions that can be considered as starting points, subject to reconsideration when a specific project and its details are ready to examine. This point will be reflected in the next draft.		
Hopi	12	1	With respect to Chapter 12, Transmission Issues, we recommend that the MACS consultants consider more directly the impact of the data on transmission availability to the prospects of actual development of projects in the study area. Consideration should also be given to incorporating this information into the Executive Summary.	The consultants will not opine on the prospects for actual development of projects as part of this study. The prospects for actual development of projects will result from review of the output of the integrated resource plan process, which links development of projects to load demand forecasts and other variables.		
Hopi	Appendix I	1	The consultants should consider whether the natural gas price forecasts they have employed in the study remain valid. In particular, the consultants should consider whether the permanent impacts of hurricanes Katrina and Rita on domestic natural gas production are adequately addressed in existing gas price forecasts.	We can undertake an update of the natural gas price forecasts, but there is still the question of how long lasting the current hurricane impacts are.		
			NAVAJO NATION COMMENTS Re : Initial Comments of the Navajo Nation on the Preliminary Draft of the Study of Potential Mohave Alternative/Complementary Generation Resources			
Navajo	General	1	Because the PD is concededly incomplete, and because the Navajo Nation has had no opportunity to review the comments of other stakeholders or to review the PD following the study preparers' incorporation/resolution of stakeholder comments in the study document, the Navajo Nation respectfully requests that it be accorded an opportunity to comment on the Draft when it is more complete and before the document is finalized.	We expect to issue a second draft report taking into account stakeholder comments.		
Navajo	General	2	First, the central and most important criticism of the PD is that it fails to examine how any of the so-called "alternatives" would really operate in place of Mohave . As the study preparers should be aware, SCE ran simulations with and without Mohave to demonstrate the cost of losing it (the so-called "Mohave-In" and "Mohave-Out" scenarios) . This is precisely the type of comparison that needs to be run regarding potential "alternative" resources . Even that may not be sufficient because the simulations presented focus on annual dispatch and costs . On a daily basis, the intermittent nature of some of the "alternatives" will be more evident . As presently prepared, the PD is nothing more than a detailed shopping list of potential technologies. Beyond this central criticism, most of the costs and performance for the "alternatives" is based on bench testing and demonstration plants . A high level of uncertainty, skewed significantly upwards, must be applied to these values as a consequence . With respect to the conservation "alternative," this is really not an "alternative ." SCE does not have the ability (or the obligation) to insure that all consumers minimize their electricity consumption . As Paul Joskow of MIT has argued, telling utilities to discourage electricity consumption is like telling a butcher shop to sell vegetables . Because of these flaws, the PD fails to identify any viable "alternative" to Mohave.	This is the subject of integrated resource planning and is beyond the scope of this study. While these may be valid points in terms of how final decisions would need to be made, these tasks are beyond our scope of work. The consultants can perform such analyses if desired by stakeholders and if they were committed to providing the necessary information, we would also need additional information from SCE in order to prepare a proposal for doing so. Re DSM: The Consultants disagree with this comment. The particular DSM concept evaluated in this study is a novel one, as are some of the other alternatives being considered, and will require considerable development. However, the proposal is not for “all consumers [to] minimize their consumption,” but for SCE to acquire cost effective efficiency resources. The only novelty here is that the resources lie in another utility’s service territory. There is a long and successful history of utilities, including SCE, implementing cost effective DSM.	In essence, the electric power market in the west is fungible. If SCE (or anyone else) implements DSM programs in New Mexico, the generation now serving that load would be available to the market (including SCE). The DSM option being examined simply formalizes the transactions in advance – in exchange for contributing to the cost of the DSM, SCE receives the right to purchase the displaced generation at a defined price. Yes, the institutional arrangements are non-typical, but they are not unprecedented, and they are not particularly complex (particularly compared with multi-utility agreements for joint ownership and joint operation of thermal plants like Mohave). The DSM options are not intermittent; they have well-defined, predictable, and highly reliable load shapes. Because they avoid the need for generation, associated losses, and associated reserves, they provide much greater system capacity benefits than an equivalent amount of generation.	
Navajo	General	3	Moreover, in considering whether certain potential generation resources are or may be "alternatives" or "complements" to the continuing operation of the Mohave Generating Station ("Mohave") post-2005 — the period when Mohave must operate consistently with the requirements of a federal court Consent Decree if it is to operate — the PD fails adequately to define the concepts of "alternative," "replacement," and "complement" in the context of D .04-12-016. That failure begins with the PD's failure to note that Mohave is currently providing "baseload" power to its California customers and the vast majority of the identified "alternatives" are peaking power options . The PD's failure to make this distinction results in a series of inaccurate "apples to oranges" comparisons throughout the PD.	We propose to identify each resource as an “option.” Their employment as “alternatives or replacements” or “compliments” depends on the decision on whether to continue operations at the existing Mohave plant. We identify whether the options can provide base load power or are only peaking power plants by identifying, where applicable, the generation profile of each option. As an example, Chapter 3, CSP Technologies, clearly identifies the base load profile of the Mohave Plant and the limitations of CSP to provide base load power.		

Navajo	General	4	Moreover, as will be explained below, the vagueness and imprecision with which the PD uses those key terms fosters serious misunderstanding of the issues confronting the stakeholders and the CPUC, and of the very purpose of the Mohave Alternatives/Complements Study ("the MACS Study") . The PD should be modified to clarify the meaning of the terms "alternative," "replacement," and "complement," and to provide frequent reminders throughout the revised study document of the relevant definitions and distinctions . Without such clarification, the study will run afoul of the purposes and principles of D .04-12-016.	See response to Comment Navajo-General-6.		
Navajo	General	5	In D .04-12-016, the Commission found that the continued future operation of Mohave as a coal-burning plant "is a matter of economic life or death" for the Navajo Nation and Hopi Tribe and other affected persons." (D.04-12-016, Finding of Fact No. 25.) With that in mind, the Commission ordered SCE, as a primary matter, to continue negotiations with the goals of securing coal and water supply agreements and thus continuing Mohave's coal-fired generation operations . "This decision authorizes [SCE] to make necessary and appropriate expenditures on [Mohave] for critical path investments required by the 1999 Consent Decree to allow Mohave to continue operations post year-end 2005 ." (Id., p . 2 .) The Commission then ordered SCE to study the energy options or alternatives "to work in concert with Mohave's continued operation" or, secondarily, to replace Mohave's output and Mohave's economic benefits to the Navajo Nation and Hopi Tribe if and only if"Mohave cannot continue as a coal-fired plant." (Id.)	See response to Comment Navajo-General-6.		
Navajo	General	6	As a matter of Commission policy, then, SCE is to do all it can to resolve coal and water supply issues and keep Mohave operating as a coal-fired facility . While the MACS Study is intended to examine options that can complement Mohave, consideration of energy options to replace Mohave, when Mohave is capable of continuing to operate, violates the spirit and the letter of D.04-12-016.	D.04-12-016 Finding of Fact No. 19 [p. 67 of the Decision] states "Edison should investigate alternative resources to first allow for a meaningful comparison of Mohave's costs with other alternatives, including the WEC solar and the NRDC IGCC proposals, and also to replace the output from Mohave if the Commission ultimately determines that keeping Mohave open as a coal-burning plant is not in the public interest, or compliment the generation from Mohave if it returns to service." This does not subordinate the replacement options to the compliment options.	The "public interest" is an economic concept. The integrated resource planning model is the only logical way to determine what portfolio of resources provides the best set of resources for the public interest.	
Navajo	General	7	Even if it were determined for any reason that SCE should not go ahead with the post-2005 operation of Mohave, it would be inconsistent with D .04-12-016, and grossly imprudent, to permit SCE to decommission the Mohave plant instead of requiring SCE to sell its interest in Mohave to enable the plant to continue to operate through another owner/operator (although without SCE customers receiving 56% of Mohave's low-cost electric generation output).	This statement, while perhaps true, is not material to the study scope.	This issue would appear to provide Peabody and the Tribes with a competitive market advantage – by refusing to negotiate acceptable coal and water agreements, it could force the Mohave partners to sell the plant to Peabody and the Tribes at a below-fair-market value. The prohibition imposed on the study consultants to have no role in the future of Mohave should also apply to study stakeholders and commentors.	
Navajo	General	8	In sum, the only scenario in which the resources considered in the MACS Study could be "alternatives" to or "replacements" for Mohave would be if a permanent shutdown of the plant were required because the stakeholders currently addressing water and coal issues in pending confidential negotiations were unable to reach agreement resolving those issues – a result that is not in the economic interest of any stakeholder.	This statement, while perhaps true, is not material to the study scope.		
Navajo	General	9	The MACS Study should make crystal clear that in light of the findings of D .04-12-016, the resources considered in the MACS Study are, as a practical matter, unlikely to be "alternatives" or "replacements" for Mohave but may be "complements" to Mohave . Moreover, those proposed resources that would utilize, among other things, the site, the water supply ' and the transmission capacity applicable to Mohave are not realistic "alternatives" and should be dropped from the study, or the study should clarify that such resources are not realistic proposals.	It is not clear that certain technology options, such as IGCC, using the same water and fuel sources as the existing plant would necessarily be "unrealistic." The integrated resource plan process may show this to be true but that conclusion is the subject of that process and that determination is not within the scope of the current effort.	NRDC agrees that resources that use the Mohave site or the Mohave water supply cannot logically co-exist with Mohave. This makes them strictly alternatives, but not complements. It does not affect whether the resources are realistic proposals. If they are technologically feasible and economically desirable, they belong in the IRP process.	
Navajo	General	10	In addition, the Commission's order to consider energy alternatives — whether as a complement to Mohave's continued coal-fired operations or as a replacement for it in the event Mohave must permanently shut down – explicitly required that the study consider only those options "that will provide the fullest possible benefit to the Hopi and Navajo ." (Id., p . 53 .) While it is unclear that any of the options considered in the Study will provide significant "benefit to the Hopi and Navajo," the study preparers cannot ignore the Commission's clear instructions on this matter . Accordingly, the study preparers should consider and quantify based on detailed analysis how and the extent to which each of the proposed resources will provide benefit to the Navajo Nation and Hopi Tribe. No such analysis is contained in the current PD.	We are attempting to quantify the extent to which the options would provide employment benefits and tax revenue to the tribes. We concluded (apparently with the agreement of the stakeholders) that it is not feasible to quantify the royalties or other fees that might be obtained by the Navajo Nation or the Hopi Tribe from land, coal, and water rights. The scope of work did not provide for quantification of any other benefits.	NRDC believes that the Study has concentrated on resources that would provide considerable economic benefit to the tribes. A large number of alternative resources in the state of California, in the Pacific Northwest, and in Baja California will need to be considered in SCE's IRP process. These other resources do not have the same potential to benefit the tribes, and are therefore outside the scope of this study as we understand it. Examples of this might be construction of an IGCC unit using petroleum coke at the site of the Kern River oilfields, with direct utilization of the CO2 for EOR. Such a resource might be beneficial to SCE, economic, environmentally acceptable, and easier to construct, but	

					would not have the benefits to the tribes that is the focus of this study.	
Navajo	General	11	At the same time, the MACS Study must balance options that provide the greatest benefit to the Navajo Nation and Hopi Tribe against the "interests of Edison's ratepayers," 1 The current Mohave use of Colorado River water as its cooling water is available pursuant to a contract with U .S. B.O.R. that contains a condition that requires the burning of Black Mesa Coal from the Navajo Nation and the Hopi Reservations . Any alternative that assumes such water is available without use of such coal is not a valid alternative .including the need for SCE to secure low-cost and reliable energy sources for its customers . (Id., p. 53 .) Surely, the key ratepayer considerations for the MACS Study will be the long-term cost of energy, the ability of energy sources to shield ratepayers from the natural gas and electricity market volatility, and the reliability of an energy source . On the subject of cost of its energy alternatives, some have described the economics of a Stirling solar dish option as "quite good" without providing even a dollar range, and the record in Application ("A .") 02-05-046 (in which D.04-12-016 was issued) demonstrated an enormous disparity between the low cost of an upgraded Mohave and an unproven, comparably-sized Stirling solar dish . Moreover, the study must make clear that "clean fossil-fuel generation" — facilities fueled by natural gas — are hostage to volatile natural gas prices. Almost five years after the 2000-2001 California Energy Crisis, natural gas prices in the West and nationwide have yet to stabilize over the long term, and natural gas today is selling at over $10/MMBtu . In contrast, record evidence in A .02-05-046 demonstrates that the all-in cost of energy from Mohave is likely to be less than $46/MWh . The economics of Mohave are clearly far superior to the alleged "quite good" economics of any other resource options considered in the MACS Study.	This study will not make comparisons of Mohave and the retained alternatives. That comparison is part of an integrated resource planning process which is outside the scope of this study.	The IGCC option at Laughlin would appear to meet the criteria specified by the Navajo. An NGCC probably would appear to not meet this condition, unless it operated on syngas manufactured from Black Mesa coal. In any event, the study appears to conclude that dry cooling is preferable at all locations for newly constructed resources.	
Navajo	General	12	Nor is there any merit to the notion urged by NRDC that the MACS Study should consider certain energy options — such as energy efficiency, renewables, or "clean fossil-fueled generation" — in a combined form as a portfolio of options to replace the energy output of the Mohave. (See Letter from Jody London (representing NRDC) to Paul Klapka (of SCE) dated September 14, 2005 .)2 NRDC appears to find fault with Mohave as a baseload resource, but without good reason . For example, NRDC claims that the wind generation alternative at Moenkopi can be a source of peak power and would therefore be "much better than a baseload power plant" such as Mohave. NRDC does not, however, explain how it determined that peak power sources are more valuable than baseload power plants, particularly in periods like the present and the foreseeable future in which natural gas prices are at unprecedented high levels.	A “portfolio” would arise as the result of an integrated resource planning process outside the scope of this study.		
Navajo	General	13	In terms of providing consistent, reliable sources of energy, baseload power sources supply the great majority of customers' demand for energy . If, on the other hand, SCE does in fact require additional peak power, one cannot conclude from this that SCE does not require its existing baseload power from Mohave . It would be highly imprudent and unduly limit SCE's ability to choose from options if it were to instruct Sargent & Lundy to bundle peak power sources with baseload resources that would replace any portion of Mohave's output, as well as being in violation of the Commission's orders in D .04-12-016.2	It is not clear why this would be in violation of that Order, but that is an issue for the stakeholders. As for the substance, based on our experience in utility planning, it is customary to evaluate alternative resource options as part of a balanced portfolio that takes into account the availability and costs of the various options and how they fit with the existing resources and expected load of the utility. Our current assignment is to provide SCE with data on the various options that would allow it to perform IRP analyses of various combinations of the options, not just any particular “bundle.” Such an analysis is usually done in combination with existing committed resources and the various other options available to the company. Also, see the response to comment Navajo-General-12		
Navajo	General	14	To consider multiple resources in different combinations, as suggested by NRDC, would involve the consideration of multiple new and different "alternatives" combined together — something well beyond the scope of the study as originally defined. Moreover, while it may be theoretically possible that some combination of investments could be made to replace Mohave, each such combination would have to be subjected to the same cost comparison as a single studied "alternative ."	If such analysis were needed, we agree that it is beyond the scope of work. Such work could be performed with agreement and cooperation from stakeholders as well as additional funding. Also, see the response to comment Navajo-General-12		
Navajo	General	15	One important point that the Sargent & Lundy should incorporate into the MACS Study is the recent proposal by Senator James Inhofe (R-Okla .), chairman of the Senate environment committee, to temporarily waive the United States Environmental Protection Agency's ("EPA's") air pollution limits in order to meet the nation's energy needs in the aftermath of Hurricane Katrina and the anticipated worsening energy constraints in the aftermath of Hurricane Rita. NRDC's emphasis on sources that meet seasonal and time of day peak period ignores other factors that can increase costs far above peak power . Moreover, NRDC's emphasis here fails to take into account uncertainties such as natural disasters that can quickly send energy costs upward — uncertainties and increased costs for which ratepayers will have to pay . In the face of both supply and price volatility and uncertainty, Mohave's long history of providing cheap, reliable energy underscores the fact that Mohave is an extremely valuable asset to SCE and its customers.	It is possible to review this proposal and determine whether it is sufficiently specific to be used as part of the analysis. However, estimating the probability of a similar event occurring, and the corresponding emissions allowance values, would probably be a large task. Furthermore, as it is a proposal for a “temporary waiver,” it is unlikely to have long term effects on the options being studied. Therefore, temporary changes and waivers to environmental regulatory limits are not considered in this study.		

Navajo	General	16	The Navajo Nation urges SCE and the study preparers to comply with the letter and spirit of the Commission's clear directives in D .04-12-016 to continue to pursue the continued operation of Mohave as a coal-fired facility, consider energy alternatives complementing Mohave, and consider energy alternatives to replacing Mohave if and only if it is clear that Mohave must be permanently shut down. SCE should therefore reject, as premature, the NRDC request that the energy options it proposes be considered on a portfolio basis.	It is not clear what this comment would have us do that differs from our current scope of work. The continued operation of the Mohave plant is not the subject of speculation or opinion of the study preparers.		
Navajo	General	17	1. The MACS Study could be significantly improved if it contained an "apples and apples" comparison of Mohave and the six posited "alternative" resource options. Since Mohave is a 1,580 MW plant, then there should be a comparable 1,580 MW option for each of the six other resources evaluated by the study . If some options cannot meet that level of output, then the Study should explain why not and should explain whether that failure disqualifies the option as an alternative . For instance, for solar technology the Study includes a 425,000 KW option, but not a 1,580 MW option. The problems (or benefits) of enlarging each of the options to 1,580 MW should be described . The Study should also include a Table that directly compares $/KWh (all-in cost including fuel cost) for each options based on that option's meeting the entire 1,580 MW demand . For Mohave cost, the Study should use as a proxy the $46/MWh cost cap proposed by the Navajo Nation in the CPUC evidentiary hearing conducted in A .02-05-046.	The study only considers the 885 MW portion of the Mohave plant. The cost of scale on page 2-12 addresses this issue in general terms. The IECM data does not allow for plants of greater than about 1350 MW. As can be seen in the trend line, the cost of scale becomes fairly linear at the limit of the data presented. The levelized cost comparison is the result of an integrated resource planning model that is not within the scope of the current study.	There is no reason to believe that the current size of Mohave is economically optimal, nor that SCE's 56% share of Mohave is optimal. The IRP process is the logical place to optimize a resource portfolio. NRDC does not agree that the levelized cost comparison is a result of the IRP. Because substantially all of the resources (except NGCC, which we consider non-viable) have variable running costs that are lower than the system lambda for SCE during off-peak periods, essentially all of these resources would operate to the limits of their availability. Therefore it is relatively straightforward to calculate levelized costs for each resource independent of the dispatch model of an IRP.	
Navajo	General	18	45. Additional comments. Certain Tables should be developed that treat each of the alternative/complements equally, being sure to look at the needed power presently developed by Mohave for SCE of 885 MW and comparing that output with the alternatives considered and the costs associated with each.	Cost comparisons will be made on a per unit basis.	A unit basis is appropriate.	
Navajo	ES	1	8. The first paragraph of the Executive Summary incorrectly states the ownership interests of the Mohave co-owners . The Navajo Nation understands that Salt River Project has a 20% interest, and the Los Angeles Department of Water and Power has a 10% interest. (PD, p. ES-1.)	We will correct errors in ownership percentages stated as required.		
Navajo	ES	2	The nature of the informational requests made to the Navajo Nation by the study preparers have been extremely broad and included some materials that the Nation views as proprietary and/or confidential . Moreover those requesting information seemed to assume that they had little or no duty to conduct their own search of various public information sources . The Nation has provided some information to date and continues to be willing to provide information it deems relevant to this inquiry . Materials such as those noted above will provided when copying is completed .	We look forward to receiving those materials. We understood at the beginning that the original information requests were broad. We have offered to attempt to narrow them and have done so in some regards. We have attempted to respect the fact that some of the information requested was confidential or proprietary and have offered to attempt to further narrow the requests through brief discussions with relevant staff. We have made searches for publicly available information and are using some such data; generally, we are seeking additional information that we believe may be available to the Navajo Nation and the Hopi Tribe. If any information we seek is known to be available from specific public sources, we would be glad to try to obtain it from such sources.	It is unfortunate that some stakeholders have not been willing to cooperate with the consultant team. NRDC has attempted to provide all information available to us that would assist the project team.	
Navajo	ES	3	9. The Executive Summary is probably the most important part of the study and should concisely identify all the resource options considered in the study, and provide Tables that summarize all the options considered in the study . Such tables should include Mohave information in the first column with the various options studied to the right.	We will provide concise tables in the executive summary. Inclusion of data for the Mohave plant is beyond the scope of the current effort.		
Navajo	ES	4	10. The study should clarify what EPC Fees are. (See p. ES-2, Table ES-2 .)	EPC fee is substantially profit to the EPC contractor in return for the guarantees on schedule and performance that are made.		
Navajo	ES	5	11. On p. ES-3, where is the water coming from for the IGCC water consumption and other systems identified later in the text?	We assume that if built at the existing site cooling water comes from the Colorado River allocation and coal slurry water comes from the "C-acquifer." At the Black Mesa site, dry cooling would be employed and slurry water would come from the "C-acquifer."	The cost of these water supplies needs to be updated to be consistent with the information provided at the October 21 meeting.	
Navajo	ES	6	12. Under solar generation, the term "annual generation" (p . ES-3) is noted — for comparison, what are the numbers for Mohave? The study should consider the Mohave energy going to California which is 66% of output, when the LADWP share is added to the SCE share.	Chapter 3, CSP Technologies, shows the Mohave annual generation. This chapter discusses California Renewable Portfolio Standards (RPS) where retail sellers of electricity are required to increase their procurement of eligible renewable energy resources such that 20% of their retail sales (on a MWh basis) are procured from eligible renewable energy resources by 2017. The report indicates an 885 MW plant at 72% capacity factor (equivalent to Mohave Generating Plant capacity factor) produces approximately 5,600,000 MWh of electricity per year. If all the generation is procured by California, 1,120,000 MWh will theoretically have to come from renewable energy resources by the year 2017. The 1,120,000 MWh represents 180 MW of power at 72% capacity factor.	The 20% requirement is a percentage of retail sales, not a percentage of any individual generating resource. SCE has retail sales of approximately 97 mllion megawatt-hours, and 20% of this would be approximately 20 mllion megawatt-hours. The size of Mohave has no bearing on the amount of renewable generation that SCE is obligated to obtain. That is dictated by the Company's load, and by its pre-existing compliant renewable resources. In the IRP process, the optimal mix of renewable resources can be ascertained, and the economic viability of Mohave then examined in light of that result.	
Navajo	ES	7	13. At p. ES-4, under the solar table CAPX and operating costs should be identified.	We will identify these as necessary.		
Navajo	ES	8	14. Within Table ES-6, clarify whether the MW identification noted is gross or net.	MW output is net.		

Navajo	ES	9	15. At p . ES-6, Table ES-8 identifies input, output, capacities, etc . at various ambient temperatures. What is the net-net estimate for these items?			
Navajo	ES	10	16. At p . ES-9, the study addresses energy efficiency/DSM . The plant output for the three Mohave co-owners other than SCE is 44% of plant output . Where is this loss going to be made up?	Any items pertaining to co-owners' shares are beyond the scope of the current effort.		
Navajo	ES	11	17. At p. ES-10, while the Navajo Nation is pleased to see the suggestions regarding the use of renewable resources as Mohave complements, as mentioned, the NFPI was shut down in 1995 . More importantly, the growth rate of renewable resources in the area of the Navajo and Hopi reservations is too slow . As a case in point, the Surface Mining Control and Reclamation Act requires miners to re-vegetate mined lands. In the west, that law requires them to wait 10 years to prove establishment of that vegetation, while in the east miners only need to wait 5 years. Moisture, or the lack of it, is the biggest factor.	While we indentified the maximum potential of other renewables as part of this study, it is, in fact, our belief that such a project is not a reasonable alternative. We will clarify this conclusion in the next draft of the report.	NRDC concurs that biomass resources on tribal lands are not viable alternatives or complements. However, we note that a 20 MW biomass plant has been approved for construction in northern Arizona, which will use fire-damaged forest products.	
Navajo	ES	12	18. At p . ES-11, carbon sequestration is discussed with respect to IGCC and NGCC technologies. First, we understand that carbon sequestration is not expected to be commercial until 2020, and thus ask why it is being addressed in the study. Second, if carbon sequestration is expected to be so effective, why can't Mohave be retrofitted to utilize such technology? Third, the uses for CO2 are identified in the PD, but not very well. Will there actually be a market for CO2 when it becomes a commercial process — or will there be a flood of the stuff? For example, how can it be assumed that enhanced oil recovery in Kern County will economically support CO2 injection and a CO2 pipeline from Mohave, when two enormous natural gas pipelines to Kern County already support enhanced oil recovery from steam injection obtained from cogeneration facilities.	Re "not expected to be commercial until 2020": We believe that this is a misunderstanding. The PD states that 90% carbon capture depends on turbines capable of burning pure hydrogen and that such turbines are not expected to be commercial until 2020. However, capture of a portion of the CO2 is technically feasible now. Certain types of potential CO2 sequestration, such as CO2-EOR, have been commercialized for many decades. Re retrofitting: The decision to retrofit Mohave or any substitute power plant to capture carbon dioxide is expected to be largely a decision based on the economics of such technology, but its evaluation was not part of the scope of this study. The costs to retrofit the Existing Mohave Station would be excessive and would require considerable auxiliary power to operate. Carbon sequestration was mandated in the scope of the study. S&L believes that maximum removal of CO2 cannot be implemented with limited risk until 2020. Lower levels of CO2 removal are possible sooner. Re markets for CO2: There currently does exist a market for CO2 gas in the Permian Basin, as mentioned in the PD. The extent to which that market can absorb additional CO2 gas should carbon capture occur on a widespread scale is not known. Certainly, preliminary studies such as the California study discussed in the PD indicate that there is a significant potential market for CO2 gas. Whether that market is flooded or not will depend on the supply of CO2 gas to the region which in turn depends on variables such as the availability of transport (i.e. pipelines), the extent to which generators employ capture technology and the real and opportunity costs of carbon capture. While worth considering, these are highly speculative and we cannot provide an answer to this question with any level of certainty. Re Kern County: The PD does not conclude that EOR in Kern County would economically support CO2 injection and transport from Mohave. Indeed, the information presented should not be construed as sufficient basis to support such a statement. The PD simply states that the ability of Mohave to access the proposed Kinder Morgan pipeline is currently unknown.		
Navajo	ES	13	19. At p. ES-17, employment impacts to the mining and generating sector will be felt. We see no multiplier of jobs and income to the areas being affected by using these different generating methods.	These multipliers are intended to be quantified as part of the employment impact study task, which is still underway.	Any multipliers should apply equally to IGCC construction jobs, IGCC operator jobs, wind and solar construction jobs, wind and solar operation and maintenance jobs, and to energy efficiency implementation jobs. Many non-Mohave options are likely to be more labor-intensive than Mohave, and have higher local multipliers..	
Navajo	1	1	20. At p . 1-2, what is the margin of error for the IECM model, i.e ., how far off is the model from actual information – 5%, 10% or 15%, or more?	For screening studies of this type, cost is typically -20+30%. A similar assumption can be used for the IECM model. Greater levels of accuracy require extensive engineering and proposals for major equipment from vendors.		
Navajo	1	2	21. At p. 1-3, in discussing the solar technology, what is the need to discuss the Power Tower, when none are still operating any more? Conversely, Para 1 .3.2 suggests that the Parabolic Trough and the Dish Engine are the choice technologies – why not discuss them more?	We have identified the various possible technologies. We attempt to impartially analyze each to come up with conclusions regarding technical feasibility. We therefore cannot simply reject or give less attention to certain technology options. We believe are discussions of each technology are appropriate.		
Navajo	2	1	6. The PD provides no explanation where the IGCC plant at Mohave would obtain its 7,093 acre-feet of water.	The source would have to be the same as existing sources; if allotments from those existing sources were already used for other purposes the plant would not be feasible. We assumed that all water for providing slurry feed would be from the C-Aquifer. All other water needs would come from the Colorado River.	As indicated above and in the PD, the actual amount of cooling water required would be much smaller, assuming dry cooling. If located at Black Mesa, the amount required would be dramatically lower.	
Navajo	2	2	22. Integrated Gasification Combined Cycle Technology (IGCC). At p. 2-4, below Figure 2-3, the preparers state : "The use of IGCC systems has limited market penetration to date ." This is an important statement . Although the technology seems to be good few have been built and continue to operate today . Is this technology too expensive?	This is a qualitative statement. The relative cost of IGCC is typically about 20% more than from a PC boiler. However, the attributes of a plant that is being built today that could have a 50 year life span may justify the added costs. This is an owner's decision.		
Navajo	2	3	23. At p. 2-5, Table 2-1, the text above the table indicates that only four (4) IGCC plants have been built in the USA . The Table shows five (5) . Which is it?	Five IGCC plants build. Pinion Pine was never operated successfully. Others were operated but shut down for economics at the end of the demo period.		
Navajo	2	4	24. At p. 2-9, what is the justification for escalating cost 3%?	Inflation rates over the long-term average approximately 3%.		
Navajo	2	5	25. At p. 2-13, how does the ash fusion temperature affect an IGCC unit?	For gasification processes that produce molten slag, the gasifier must operate at a temperature sufficient to melt the ash. This may require additives to "flux" the ash. For gasifiers that produce a "dry" ash they must operate below the ash fusion temperature to avoid slagging conditions.		
Navajo	2	6	26. At p. 2-27, where is Appendix Y? Information was only given for appendices A-L	This is a typographical error (place holder during writing). It should be Appendix A.		
Navajo	2	7	27. At p. 2-29, where did the $70,000 labor cost come from, and does it include benefits, etc.?	This is an average value that S&L has used in a number of recent studies to cover aggregate labor costs for a complete facility covering all site labor including benefits. It is easier to adjust an average value than to construct a detailed job-by-job level budget.		
Navajo	2	8	28. At Table 2-15, are the staffing figures in man-months?	Yes, as indicated these are in man-months.		

Navajo	3	1	29. Solar Technology. At p. 3-2, the PD should swap around Power Tower and dish/engine.	This change will be made.		
Navajo	3	2	30. At p. 3-4, the PD should swap around Power Tower and dish/engine.	This change will be made.		
Navajo	3	3	31. At p. 3-9, the PD should swap around Power Tower and dish/engine .	This change will be made.		
Navajo	3	4	32. At p. 3-13, although it is not practical to store 885 kW for 15 to 16 hours, Mohave runs 24-7 at 1,580 MW at a certain efficiency. The plant delivers power continuously unless it breaks or the system breaks . Just because the sun doesn't shine at night (in Arizona) is not an adequate basis for favoring solar technology over coal technology . The two systems do not deliver the same product . The study must compare apple to apples, not apples to oranges.	Solar technology is not necessarily favored over coal technology nor does Chapter 3 state that. The basic intent of the study was to determine if concentrating solar power (CSP) technology could feasibly replace or compliment the Mohave generation. The report clearly identifies the baseload profile of the Mohave Plant and the limitations of CSP to provide baseload power.		
Navajo	3	5	33. At p. 3-16, where is all this water coming from and how is it being paid for, and to whom?	The determination of the location of water sources other than the "C-acquifer," "N-acquifer," and Colorado River is beyond the scope of this study. Determination of the legal availability of water from these sources is the subject of negotiation and is beyond the scope of this study.		
Navajo	4	1	34. Wind Technology . It should be clarified, once again, that developing the technology would engender a potential complement technology to Mohave . The study should address who would be the owner of this technology either on or off the reservation(s). If off, how do the Tribes benefit from the technology? If on, is there a benefit? Personnel assigned to this type of operation (a maximum of 14) are significantly less than the 230-350 presently working at the mine and power station. How, is this job loss offset — or is it?	This is a decision the Navajo and NTUA will need to make. What structure do they want to use to develop wind? Bring in private capital or do it themselves, or partnership structure? Wind will not provide the same level of permenant employment as the 230 currently employed at Mohave. It will provide tax and lease revenue to the Nation, and it will provide a lot of construction employment.		
Navajo	4	2	5. The PD describes the NTUA Gray Mountain Wind Site, but does not clarify whether that site is considered a replacement for Mohave, or a complement for Mohave . If NTUA is anticipating this site in addition to Mohave, there may be an opportunity cost to the Nation if it is used instead to replace lost capacity at Mohave rather than market the energy elsewhere or use it on the Navajo Nation Reservation.	Decisions about "replacements" or "compliments" depend on the decision regarding closure or continued operation of the existing Mohave plant. That decision is beyond the scope of this effort. We provide expected output profiles of the various technology options and compare these the existing plant, pointing out whether the options can, in fact, mimic the output profile of the existing plant. Decisions about going forward with any of the various options will take this into account in an integrated resource planning effort, which is outside the scope of the current effort.		
Navajo	5	1	35. Natural-Gas Combined Cycle Technology (NGCC) . The study should be reformatted and this technology should be either ahead or right behind the IGCC technology — there are too many similarities between the two processes.	We appreciate that IGCC and NGCC can be thought of as similar, since they are both combined-cycle technologies. We do not feel, however, that the chapters need necessarily be together. The aspects of the IGCC technology that require discussion are, of course, associated with the gasification system. This is sufficiently complex that the form of discussion of the chapters is significantly different.		
Navajo	5	2	36. The land needed for the NGCC plant is minimal (30 to 46 acres) depending on whether or not the plant has CO2 sequestration and whether the plant uses mechanical cooling as opposed to air cooling . As mentioned before, a considerable amount of water is needed for these plants — where will it come from? Construction for the site is dependent on the schedule for permitting, etc. Where is the fuel supply coming from and how does it affect costs?	We assume that water at the existing site will be available from the same sources as currently used. We understand that water rights are tied to the use of coal from the Black Mesa mine. Nevertheless, it is technically possible to construct an NGCC plant on the Mohave site. Assessment of the possibility to transfer the water rights to a new NGCC plant is not directly in the scope of our effort, however, we will point out that this issue is a significant potential barrier to the development of such a product at that site. Fuel will come from existing natural gas trunk pipelines either located west or south of the site. Costs will depend on the cost of natural gas.		
Navajo	6	1	37. Energy Efficiency/Demand Side Management Technology (EE/DSM) — Though creative, the question arises : How practical will it be for California to implement this proposal?. How likely is it that out-of-state utilities would be willing to sell their excess power to another power company, unless there is a lot of money put on the table ? That said, SCE customers will want to know why they aren't getting a break on their power bill . Sure, it's great for a customer of an out-of-state utility to get a rebate for buying an energy efficient washing machine/refrigerator — but that's a one time shot . How will the out-of-state utility keep its customers happy? If fuel prices go up, how will the out-of-state utility justify that increase?	The final report will include clearer and expanded DSM-alternative illustrative examples that will address the economic issues noted here. Practicality, risk, and the allocation of any/all net economic benefits of a DSM alternative - across SCE and utility partner ratepayers and shareholders - will be addressed.		
Navajo	7	1	38. Other Renewable Energy Technologies. This technology is not an "alternative ." Geothermal is wonderful if the water is hot enough and the only possible place is in the New Mexico portion of the Navajo Nation, at the Bisti area (a federally designated wilderness area), which might be difficult to develop . As for biomass, that is not a good idea for use in the desert . The study preparers suggest that if the forest products group in Navajo, NM was still operating, there may be an opportunity . We don't believe so. The PD also mentioned the co-fired biomass/coal feedstock technology, but how much heat loss is involved?	We concur with the Navajo assessment of the biomass and geothermal potential in the area. Since no data exist concerning the volume of wood waste from forest products plant, we concede that it may very well be true that no significant potential may have existed. With regard to co-fired biomass technology, the greater moisture content of the biomass does lead to greater heat loss to the power plant stack. However, if the biomass feedstock is sufficiently cheap, this concern can be alleviated. Also, if forest levels remain the same through replanting, then over time, the next greenhouse gas emissions of the biomass fired is zero.		
Navajo	8	1	39. CO2 Sequestration . Unfortunately, the recovery and disposal of CO2 is not an available option. The PD notes that where CO2 is used for enhanced oil recovery, the outcrops of the reservoir must be at great distances from the input point . It further notes that there is a "blow down" effect when CO2 gas is no longer needed, releasing the CO2 to the atmosphere, but at a later date . It appears that the marketing of CO2 will be difficult.	Currently, there is not a specific market for CO2 from an IGCC or NGCC unit. However, that does not mean that one could not develop in the future. (particularly under some sort of GHG policy.)		
Navajo	9	1	40. Tribal Issues. The chapter is superficial. The Study should include a Table in this section (and moved to the Executive Summary) that would explain that the jobs will not be gained by some of these "alternatives ."	The tribal issues identified in the scope of work included acceptance, permitting, employment impacts, tax revenues, and income from royalties, fees and the like for land, water, and coal. We are working on the employment impacts and tax revenues and have reported (with apparent agreement from the stakeholders) that acceptance and permitting issues, as well as estimating income from royalties, fees, and the like were not feasible due to the confidential nature of past data and current negotiations. If there is an alternative way to address those issues that would be acceptable to the stakeholders, we are open to revisiting them.		
Navajo	9	2	3. The PD makes no mention of the Navajo Nation Water Code and the Water Code Fee Structure, despite the fact that early on the Navajo Nation's representatives explained the central position the Navajo Nation Code had in this inquiry . The drafters were specifically referred to the Navajo Nation Code.	We are cognizant of both the Navajo Nation Water Code and the Hopi Tribal Water Code; during the preparation of the draft we purchased the complete Navajo Nation Code; and, shortly before the draft was circulated, the Hopi Tribe furnished us with a copy of the Hopi Tribal Water Code. Both Codes make it clear that any decisions affecting the water rights of either tribe will be governed by the pertinent tribal authorities. However, with respect to the Navajo Water Code fee structure, the Navajo Code says only that "reasonable" fees may be assessed (22 NNC sect. 1307); we hope to obtain further information with respect to its present or anticipated fee structure.		
Navajo	9	3	4. The PD makes several comments about needing additional information from the Tribes to facilitate its economic evaluation. However, it is not clear what information is needed . 3 There have been IMPLAN studies of the Three Canyon Project, a water project, and Navajo-Gallup Water Supply Project . The Kyl Study (U.S. B.O.R.H .D.R. Western Navajo and Hopi Water Supply Study, Need Alternatives and Impacts (May 2003) also included much of this information.	We have provided lists of types of information that would be helpful and have offered to discuss those needs and what information would be available with tribal government staff or others that might have that information. We have requested copies of economic impact studies, such as the IMPLAN studies mentioned, because they might provide some of the necessary information. If they are made available, those studies may provide some of the information we seek, and we will be glad to make use of that data. If they are available publicly, we will seek to obtain them, but would appreciate more complete citations, including identification of the authors.		
Navajo	10	1	41. Financial Issues . A lot of valuable information complied here . It appears this should be in the division of economic development master plan.	We believe this to be a comment internal to the Navajo and is not relevant to our report.		

Navajo	10	2	2. The PD frequently states that IGCC technology is not conducive to a tribal enterprise. However, it contains no argument or explanation about why a tribal enterprise is impossible. For example, the Navajo Nation has recently received an offer from AEC to investigate an IGCC facility that would be a tribal enterprise. While the Navajo Nation will not opine on that specific proposal, the Study should tone down and rethink, or better explain, its anti-tribal enterprise position .	The PD does not state that a tribal enterprise is impossible, but points out certain reasons why a third-party enterprise organization might be preferable. However, we will make this distinction more clearly and note that a tribal enterprise is possible and that the specifics of any proposal should be evaluated in the tribe's actual decision.		
Navajo	10	3	7. Contrary to the mandate of D .04-12-016, the PD provides no economic analysis from a Tribal perspective Instead, it provides its economic analysis only from the SCE ratepayer perspective. This inadequacy in the PD may lead to faulty decision-making . While two options may have similar cost from the SCE ratepayer perspective, they could have vastly different economic impacts on the Tribes. It would be very helpful if the final MACS Study included an analysis of the economic impacts of each of the considered options from the perspective of the Tribes.	For the economic impacts of each of the options on the Tribes, please see response to comment Navajo 9-1, above.		
Navajo	11	1	42. Generation and Demand Profiles. This section of the Study seeks to address the letter of NRDC discussed above, which seeks the combination into a portfolio of multiple resources to replace Mohave. For the reasons stated above (General Comments), this section should be deleted from the Study.	This task is required by our original scope of work, and is not in response to the NRDC letter cited.		
Navajo	12	1	43. Transmission Issues . This is an important part of the PD in that it identifies the existing circuit, its existing load and potential additional capacity available.	We have attempted to be as specific as possible regarding circuits and loading in our load flow studies.		
Navajo	Appendices	1	44. Appendices A through J . Just the back up information from the research developed.	We will use the appendices to report supporting data and provide certain important analyses and reports important to the study effort.		
			SIERRA CLUB COMMENTS FROM ROB SMITH, ROBERT TOHE, AND ANDY BESSLER			
Sierra Club	General	1	The Sierra Club supports this alternatives study to the MGS and urges Sargent and Lundy to explore the possibility of combining an aggregate collection of renewable energy alternatives to replace the total energy collection of MGS. Such a combination is found in the Potential Mohave Alternative/Complementary Generation Resources at 12.7.1 under the Interconnection Feasibility Methodology portion	Collections or "portfolios" of technology options may be appropriate. However, selection of the elements of any "portfolio" will be the subject of an integrated resource planning effort beyond the scope of this effort. We have provided certain combinations in Section 12 in order to assess the impact of multiple projects on transmission requirements. We will augment this discussion with the impact of single projects at Gray Mountain (450 MW) and IGCC at Black Mesa.		
Sierra Club	General	2	The Sierra Club supports Case 3 and Case 4 in which a combination of power plants would be built using solar Sterling Dish technology and wind turbines to replace nearly 1000 MW of electricity for CA ratepayers. However, further study needs to also include with these combinations, the MW replacement from conservation measures to reduce the total amount of power to replace the power Mohave produced.	Analyzing portfolios of options is outside of the scope of work.		
Sierra Club	General	3	In June 2005, Governor Schwarzenegger announced his groundbreaking initiative to reduce California's greenhouse gas (GHG) emissions to 1990 levels by 2020. Because of this, on October 6, 2005, the CPUC passed their " Policy Statement on Greenhouse Gas Performance Standards." By compiling [sic] with this statement on reducing greenhouse gas, the Mohave Alternatives Study should prioritize the case studies to weigh more heavily on wind and solar sterling [sic] dish technology rather than coal-fired plant replacements.	Our analysis estimates the opportunity cost of CO2 emissions by projecting CO2/carbon allowance prices under probable federal policy scenarios. The alternatives will be presented with the total costs and revenues associated with each, including carbon policy compliance costs. Carbon cost data based on national policy are fairly rigorous and more-or-less readily available, whereas the policy development in California involves considerable uncertainty (the policy statement was posted very recently—Oct. 6, 2005—and directs Staff to investigate numerous aspects of the standard). However, we will address this initiative qualitatively and, if possible, quantitatively.		
Sierra Club	General	4	The Sierra Club supports alternatives that promote wind and solar energy development on tribal lands that would, at the same time, meet the electrical needs of California ratepayers and help rebuild the tribal economies of the Navajo and Hopi Tribes.	This report is meant simply to provide data concerning solar and wind projects. Whether this data supports or impedes development of such projects will be determined by others.		
Sierra Club	General	5	In addition, the Sierra Club urges Sargent & Lundy to articulate the possible scenario of funding wind and solar energy projects on Navajo and Hopi lands through transfers of sulfur dioxide allowances from Mohave owners to the tribes. The challenges of tribal laws supporting energy development for alternatives could be overcome with financial support from investment from Mohave owners based upon a cash inflow to tribal governments and small business investment companies operated by tribal governments. The cash flow could be directed to economic planning efforts at the Hopi village and Navajo chapter level and as investment to the tribes to develop the alternatives listed in Case 3 and/or 4. This type of investment would not impact California ratepayers and would respect tribal sovereignty by allowing the tribes to direct clean energy development on tribal lands.	While we have not specifically researched this issue, it is our general understanding that any revenue from the disposal of such allowances or cost savings from eliminating the need to purchase them would flow through to SCE's retail ratepayers under traditional ratemaking. If the situation is different for SCE or MGS, we would appreciate clarification of that. Otherwise, we are not aware of a scenario under which transfer of those allowances to the tribes would be permitted by California regulators. Conversely, if the allowances and revenue from their disposal is the property of SCE and does not flow through to rate payers, SCE would need to make a corporate decision about their disposal.		
Sierra Club	9	6	Unfortunately, the analysis of tribal issues found in Chapter 9 fail [sic] to adequately address tribal opportunities for renewable energy development and should be more specific about the opportunities identified elsewhere in the report for incentives, tax breaks, and other opportunities to encourage tribal economic development. Like NRDC, Sierra Club is concerned that the Draft Report in this chapter unnecessarily introduces a bias against tribal renewable energy development.	We will provide a discussion of the cited opportunities in this chapter in the final report.		
			SCE COMMENTS			
SCE	General	1	1. In the body of the report it says S&L did this and S&L did that Synapse did this and Synapse did that It is recommended that the report not be personalized, the wording should be generic. It's OK to say in one place that work was divided between the two companies and then define the scope for each company, but then it should not say who did what thereafter. Use a neutral word such as "it" to replace S&L or Synapse.	We will eliminate references to S&L and Synapse except as specified and replace such references with general descriptors such as "the consultants," or will employ the passive voice.		
SCE	General	2	2. There are a number of spelling and grammatical errors in the report. It is assumed that they will be corrected for the next issue.	We will of course strive to eliminate such errors in the next draft of the report.		
SCE	General	3	10. As a general comment, any place in the report that general information exists that could be focused in on the specific projects and locations under discussion, it would be helpful.	We will address this in the process of preparing the second draft of the report.		
SCE	General	4	For some of the technologies you show various units of use, such as gpm or annual gallons or acre-feet. Acre-feet is the number that most stakeholders are going to be interested in. You should show gpm and annual acre-feet for each technology. The capacity factor that the annual consumption is based upon should be noted.	We understand that acre-ft are the units most familiar to interested users and will ensure that gpm and acre-ft/yr are shown for all water usage.		
SCE	ES	1	1. Page ES-1, 1st paragraph: LADWP now only owns 10% of Mohave and SRP now owns 20% of Mohave (LADWP sold half of their original ownership in Mohave to SRP a few years ago).	We will clarify the ownership of the plant in the next draft of the report.		
SCE	ES	2	2. Page ES-2, Table ES-2: What year dollars are shown (this comment applies to all dollar references in the report)? You should state this fact once in the beginning of the report if possible and appropriate.	We will employ year 2006 dollars.		
SCE	ES	3	3. Page ES-2, Table ES-2: What about O&M costs? All of the other economic tables for the other technologies show O&M costs also. O&M costs should be included in this table also. When you show the O&M cost, you should also state what fuel cost was assumed for coal, natural gas, etc.	We will ensure that O&M costs are stated for all options. Fuel costs are the subject of a separate effort within the scope of the study. We will use the fuel price projections for coal and natural gas to develop the fuel cost in $/MMBTU terms for each option.		

<table>
<tr><td>SCE</td><td>ES</td><td>4</td><td>4. Page ES-3, Table ES-4: The report is inconsistent between the various technologies. The report should be made consistent. For example, in this table you show Annual Capacity Factors and Annual Generation. These two items are not shown for the IGCC. It might be useful to include a summary table similar to the one shown below including all of the items for each technology and indicate what might not be applicable to any specific technology.

<table>
<tr><th>Item</th><th>IGCC</th><th>SOLAR</th><th>WIND</th><th>CCGT</th></tr>
<tr><td>Unit Size, MW</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Net Output, MW</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Capacity Factor, %</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Annual Generation, MWhrs/yr</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Heat Rate, Btu/kW-hr</td><td></td><td>N/A</td><td>N/A</td><td></td></tr>
<tr><td>Capital Cost, $ or $/kW</td><td></td><td></td><td></td><td></td></tr>
<tr><td>O&M Cost, $/kW-yr or $/kWhr</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Fuel Cost, $/ton or $/MMBtu</td><td></td><td>N/A</td><td>N/A</td><td></td></tr>
<tr><td>Land Use, Acres</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Water Use, gpm & Acre-Feet/yr</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Total Staffing</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Transmission Requirements</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Any other item you</td><td></td><td></td><td></td><td></td></tr>
</table>

Transmission Requirements: This item may require two entries to describe transmission requirements from the new generation to the existing transmission system(s) and any potential upgrades, immediate or in the future to the existing transmission system(s).</td><td>We will present the coordinated table with the data as requested in this comment. We will present fixed and variable O&M costs as $/kW-yr and $/MWh, respectively.

Synapse and S&L will coordinate the drafting of the final transmission section and will address the overlap of 1) transmission requirements arising out of the load flow analysis, and 2) the availability of transmission arising from the OASIS and studies' review tasks.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>5</td><td>5. Page ES-3, Table ES-4: Water Requirement-see comment No. 4 [SCE-General-4] (Water Use) above.</td><td>See response to comment SCE-ES-4.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>6</td><td>6. Page ES-4, Table ES-4: You show a Total Staffing number of 26 for the Dish/Stirling Engine. Is this sufficient to operate and maintain 17,000 units especially when you show 62 per unit and 82 total for the solar trough technology?</td><td>This number has been updated based on input from Stirling Energy. The revised staffing is: 118
Administrative = 4
Technical Services = 2
Operations = 12
Maintenance = 100</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>7</td><td>7. Page ES-4, Table ES-5: See comment No. 6 (Annual Generation) above.</td><td>See response to comment SCE-ES-4.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>8</td><td>8. Page ES-4, Table ES-6: See comment No. 6 (O&M Cost) above.</td><td>See response to comment SCE-ES-4.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>9</td><td>9. Page ES-5: It is suggested that it is more appropriate that the technical explanations shown deleted below be included in the body of the report rather than in the Executive Summary.
"Combined cycle technology has been used to generate power for a number of years. ~~Combined cycle technology in the power industry is primarily a combination of the Brayton and Rankine cycles. The combustion turbine operates on the Brayton cycle and the bottoming cycle, which is made up of the heat recovery, steam generator, steam turbine, and related balance of plant systems, operates on the Rankine cycle. "~~
~~"For a combined cycle power plant, the combination of multiple power cycles is performed to improve the overall efficiency of the total power plant. In general, a simple cycle combustion turbine (i.e. Brayton cycle) has an efficiency in the range of 19% to 38% on a higher heating value basis. The efficiency range is quite broad due to the firing temperature of the combustion turbine, the pressure ratio, and the blade and component design of the machine. The Rankine cycle power plant efficiency is typically in the range of 32% to 39% on a higher heating value basis. The Rankine cycle efficiency is generally a function of the cycle configuration, the steam conditions, the equipment design, and the cooling source. The combination of these two power cycles, representing the combined cycle power plant, generally provides efficiencies in the range of 48% to 52% on a higher heating value basis."~~</td><td>We concur and will succinctly summarize the technology options in the Executive Summary and provide more detail as required in the body of the report.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>10</td><td>10. Page ES-6, Tables ES-7 and ES-8:
A. Why did you choose to show performance at 67 °F rather than the ISO standard of 60 °F? Wouldn't it be more appropriate to use the ISO condition?
B. Using the 125 °F design condition is appropriate for what the maximum power reduction would be, but it is probably not appropriate for a summertime design temperature. You should leave the 125 °F results in the table, but it is also suggested that you use the ASHRAE 5% design summer dry-bulb temperature of 108 °F for that area (Needles, CA). The 108 °F temperature would provide a more "realistic" output for the summertime since the 125 °F temperature might only occur for one or two hours per day and not every day during the summer months. The wet-bulb temperature that corresponds to the 108 °F temperature is 77.9 °F which is based on previous cooling tower sizing applications for Mohave.</td><td>We determined that 67 °F is the annual average temperature at the site.

We will run the case of the ASHRAE 5% design dry-bulb temperature using the data provided here (108 °F dry bulb, 77.9 °F wet bulb).</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>11</td><td>11. Page ES-8, Table ES-10: What was the assumed fuel cost?</td><td>We will provide the 2006 fuel cost here as provided by Synapse.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>12</td><td>12. Page ES-8, Table ES-12: Water Requirement-see comment No. 4 (Water Use) above.</td><td>We will provide the data in acre-ft as requested.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>13</td><td>13. Page ES-8, last paragraph: The first sentence is too personal for this type of report. It is the use of the word "we" that makes it too personal. It is suggested that the sentence (and everywhere else in the report where the text is similar) use a more neutral approach as suggested below:
~~As part~~ Part of the Study analysis, ~~we were tasked~~ included a task to undertake a review of energy efficiency/DSM resources available in western US states outside of California.
This same type of wording change should be used to replace the company names, S&L and Synapse, as noted in comment No. 1 above and all other personal terms such as "us," "our," etc..</td><td>We will correct this in the final report.</td><td></td><td></td></tr>
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<tr><td></td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>14</td><td>14. When reviewing the Executive Summary, the following technology outputs have been noted:
<table><tr><th>Item</th><th>Mohave</th><th>IGCC</th><th>Solar</th><th>Wind</th><th>CCGT</th></tr><tr><td>Unit Size, MW</td><td>885</td><td>630/595</td><td>300/425</td><td>61-150</td><td>500/1,000</td></tr></table>
Yet, nowhere in the Executive Summary does it explain why the unit sizes chosen are so disparate, especially when technologies such as the Dish/Stirling solar and wind could be made to match almost any output closely. This disparate output should be explained in the Executive Summary.</td><td>We will summarize the rationale for each unit size here in the Executive Summary in the next draft of the report.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>15</td><td>15. Page ES-11, Subsection ES.4.1 Financial Incentives: This section includes a lot of text, but no “meat and potatoes.” For all of the incentives listed the question is asked “So, how much?” In other words, what is the range of percent for these incentives that could be applied to either capital and/or O&M to reduce costs? Some numbers or potential examples here would be very helpful.</td><td>We will provide some examples in the next draft.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>16</td><td>16. Page ES-13, Subsection ES.4.4 Fuel Prices: Same comment as No. 17 above, a lot of text, but no numbers. You need to quote actual fuel costs here in dollars and cents and the basis for the numbers presented.</td><td>We will provide summary numbers in the ES of the next draft.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>17</td><td>17. Page ES-14, 1st paragraph: You state “Coal prices, generally, on the other hand, are likely to increase gradually (in real dollars) from present time until 2025, but at a modest rate compared to that of natural gas.” It is agreed that this is probably true, but does not have any real bearing on Mohave or this study. For “normal” coal plants, they can receive coal from multiple sources which is not true for Mohave. Also, “normal” coal contracts are for shorter terms than would be for Mohave. It’s expected that the new coal contract will be similar to the existing coal contract in both duration and price and that the price will be fixed for the contract term with some provisions for price increases. Thus, the Mohave coal price will be “more fixed” until it expires in 2026 and will not be subject to market forces as are the contracts for other coal plants.</td><td>Agree that the specific coal supply contractual arrangements for any plant will take precedence over general market factors. However market prices do influence contract prices. Other factors such as fuel price increases for the mining equipment is also likely to be passed through in contract prices.
Mohave (Black Mesa) coal may have a price fixed for some period. Explanatory language will be added pointing out that this projection does not apply to Black Mesa, but to open market coal and mines that can ship to open markets.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>18</td><td>18. Page ES-17: The following text should be deleted and rewritten when the data becomes available.
“The Hopi Tribe has informed us that it does not at present have a tax code; and, under the Hopi Tribe’s Constitution, a referendum vote of the Tribe’s members would be necessary to change that situation. ~~We are working to schedule opportunities to review with relevant tribal government personnel the manner in which such taxes are or may be applied and determined and any anticipated changes or trends.~~
~~After collection and verification of this basic information on the tribal taxes that would apply to the technologies that may be considered for tribal land (IGCC at Black Mesa, Solar 1 and 2, and the four wind sites), we will use that information, along with the investment and O&M estimates for the technologies to estimate the tax payments that would be due under identified provisions.~~”</td><td>Agreed.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>19</td><td>19. Page ES-18: Ditto the comments above regarding rewriting when data is available;
“~~The purpose of our employment impact analysis is to convert estimates of the initial, direct purchase of goods and services by the relevant technology options into total employment impacts in the local region, taking into account all the secondary purchases and activity. This conversion will be done with a custom economic model for the counties that include the Navajo Nation and Hopi Tribe reservations, a total of six counties. To obtain the best possible accuracy, we will also need information and advice from the economic development entities within each tribe and information regarding the operation of tribal employment preference laws, as well apprenticeship or other job development programs.~~
~~The custom economic model for this task has been obtained and the basic county economic data is available. Sargent and Lundy has provided some but not all of the data on direct employment and goods and services for construction and O&M. Discussions are under way with the Navajo Nation and the Hopi Tribe to obtain and understand (1) historic economic and demographic data, (2) tribal employment preference programs and their impacts, and (3) other relevant programs, especially apprenticeship and job training programs. Our ability to provide timely employment impact results will depend on receipt of the additional data collection.”~~</td><td>Agreed.</td><td></td><td></td></tr>
<tr><td>SCE</td><td>ES</td><td>20</td><td>20. Page ES-19, ES.6 Load and Generation Profiles: After the first paragraph, a graph/chart with would be helpful to visualize what is being said. The text should then be modified to help explain the graph/chart and vice versa.</td><td>We will consider how this could be done.</td><td></td><td></td></tr>
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SCE	ES	21	21. Page ES-20: "Our analysis demonstrates that shorter-term[A], or non-firm service, is available from most source points examined, but not necessarily during all periods. Thus, alternative or complementary sources located in the Study Area connecting up to the grid in the near-term might need to rely on shorter term transmission[B] availability. It is important to keep in mind, however, that the value of OASIS information is limited because of its time frame; it is not predictive beyond the near-term time periods, at most a few years out.[C] Sargent & Lundy also performed load flow studies of various generation alternatives. Please see Section 12.8 for details. Costs shown in section 12.8 for required transmission upgrades may be reduced if transmission upgrades detailed elsewhere in the report are performed by others.[D] In addition it is important to consider that new transmission line proposals or works in progress[E] add significant capacity to into-CA (and likely intra-Arizona) transaction paths. To the extent these lines are built, it is possible that most alternatives or complements could secure access to import into SCE territory." A. The definition of "shorter-term " should be provided. B. The definition of "shorter-term" should be provided unless it is the same as noted above. Also, some explanation needs to be provided in this summary regarding "long-term" including specifics. C. What about long term? Some explanation needs to be provided in this summary regarding "long-term" including a definition and specifics. D. Some data, costs or specific values, if possible, should be added in the overall table for the various technologies above (see comment 6 above). The reference to this table (or data values) should also be made here. E. It might be good to provide some examples here to illustrate your point.	Definitions and clarifications will be included in the final report.		
SCE	2	1	22. Page 2-8, Under the limitations for the model, you have noted a bullet item regarding "No SCR for enhanced NOx reduction …." and also have an item under the Combustion Turbine Model Limitations "- Does not consider SCR". Are these two items a duplication of the same thing? Please clarify in the report.	We will clarify this in the next draft report.		
SCE	4	1	3. Wind projects A. Do the listed projects already have PPA's? B. Is the power currently available to be purchased by CA or not? C. Were the projects just looked at to get a range of costs for other projects that could be constructed to potentially supply power to CA? The current write-up begs this question, please clarify.	Sunshine is the only project which is advanced enough to have a PPA. Foresight is negotiating with APS but has not executed a PPA as of yet. None of the other projects has a PPA at this time. Yes, all of the power from these wind projects could be sold into the CA market given mutually agreeable transmission arrangements. These projects were chosen using the following criteria • On Hopi or Navajo lands or near them • Category 3 wind resource or better These sites are specific sites that have the required wind resources, not sites that were looked at simply as surrogates for obtaining estimates of the range of costs that would be incurred in the construction of a wind power plant.		
SCE	7	1	23. Page7-16, Agricultural residues: We assume the first bullet is also indicating wheat straw rather than "what straw".	Yes, that is correct.		
SCE	7	2	24. Page 7-23, 7.2.3.3 Utah: The first sentence on this page should indicate Utah, not "New Mexico".	We will make this correction.		
SCE	9	1	6. Tribal Issues: It would be highly desirable if some assessment or ranking of likely tribal benefits among the various projects could be included in the report. If no specific dollar amounts are available, perhaps a high, med, low income ranking based on different categories of potential direct & indirect income (e.g., coal royalties, lease income, tax income, employment income, indirect income, etc.) could be developed for each type of resource to be able to directly compare them in one table.	Agreed. However, quantification is not likely to be feasible except for tax revenue and job impacts. *See* response to Navajo 9-1.		
SCE	12	1	4. Transmission: When the report states that that transmission is not available during all periods, it would be helpful to specifically identify those periods and amount of transmission that is actually available to wheel power into CA, to clearly understand the results of the study.	The final report will include additional appendix material which will list the periods in which transmission is not available, or is available at lower levels. These tables will support the set of summary ATC tables in the PD.		
SCE	12	2	5. Transmission: In the next issue, it would be helpful if conclusions could be grouped into three scenarios: A. Those projects/locations that could wheel power into CA now, based on existing transmission; B. Those projects/locations that could wheel power into CA if reasonably certain new transmission project re constructed, along with a time frame of when that might occur. C. Those projects/locations that could wheel power into CA if all proposed transmission is built, along with some information on the status and challenges facing the less likely routes so a reader would be able to assess the ultimate likelihood of their success. For example, there is currently insufficient funding to construct the Navajo Transmission Project even through Phase 1.	The results in the current report provide this detail. We cannot make judgments as to what overloads will be eliminated due to system upgrades without actually rerunning the studies. For part B, a review of the possible transmission projects identified revealed two that are "reasonably certain" to be completed. These are the Palo-Verde Devers #2 (2009) and East Colorado River Path 49 Short Term Upgrades (phase angle regulation + VAR compensation) (2005-2006) (approx. 4,000 MW transfer increase total). These projects can be added into the model and the cases re-run. We expect to treat the part B cases as derivatives of the part A cases and will provide summary conclusions about the differences made to the part A results by the "reasonably certain" project in our discussion in the report. In order to provide some detail related to part C, we will present a list of potential transmission projects and provide information regarding the status and likelihood of completion of such projects. We will not run any load flow studies based on the likelihood of these projects. If all or most of the transmission projects are completed, it is reasonable to expect that the generation projects will be able to interconnect.		
SCE	Appendix I	1	7. Emissions Valuation: The emissions valuation discussion is currently quite general. It would be helpful if it were more specific to the projects and locations being analyzed. For example, when discussing non-attainment in NV, most of the non-attainment areas listed do not include the MGS site. Knowing what actually applies at the MGS site would be helpful. Further there are two sites under consideration for combustion sources, the MGS site and the mine site. However, no analysis of the mine site was included. Is it in attainment for all pollutants? If so, that would be helpful to mention.	Discussion of emissions regulations that apply to the IGCC alternative located at the Black Mesa Mine site will be included in the final report. The final report will also include more location-specific information.		

SCE	Appendix I	2	8. Emissions Valuation: It should be noted that power generation sources are not under the jurisdiction of Clark County, but are under the jurisdiction of the Nevada State Department of Environmental Protection (NDEP). When discussing future NV only trading regulations, talking to the NDEP for additional insight would be helpful since it is believed that there are only 10 (approximately) potential point sources available to include in any type of trading program and most are significantly controlled making a state-only market infeasible due to liquidity issues. When discussing H_g, it might be helpful to compare MGS post-control and new IGCC/CCGT emissions to the levels likely to be included in a trading program, since they may be below the threshold of currently contemplated programs.	For the final report, we will be talking to the NDEP and the AZ Dept. of Environmental Quality and will provide any insights they provide. Valuation of emissions of a post-control MGS is beyond the scope of this project. It is not clear what is meant by "the levels likely to be included in a trading program", however we do document the parameters of the Clean Air Mercury Rule.		
SCE	Appendix I	3	9. Emissions Valuation: Similar to the transmission comment above, it would be helpful to clearly identify which emission credit programs currently exist that are applicable to each of the listed technologies and sites vs. mixing that discussion with potential future regulations. It is believed that only the Acid Rain SO2 program would apply to combustion sources at either the MGS or mine site. To the extent that future regulations could be adopted, a date range of when that might occur would be helpful to include.	Agreed		
			RE: COMMENTS BY THE GRAND CANYON TRUST ON THE PRELIMINARY DRAFT MOHAVE ALTERNATIVES STUDY BY: ROGER CLARK AIR & ENERGY PROGRAM DIRECTOR GRAND CANYON TRUST (928) 774-7488			
Grand Canyon Trust	General	1	We have read and fully endorse comments to the Preliminary Draft submitted by the Natural Resources Defense Council.	Our responses to NRDC's comments are provided elsewhere in this document.		
Grand Canyon Trust	9	1	The Mohave Alternatives Study should describe existing issues of inequity that have resulted from historic patterns of energy development on tribal lands. We recommend that the development and analysis of alternative energy scenarios evaluate their ability to create equitable and sustainable benefits with and for native people.	This task is beyond the scope of work provided for in this project.		
Grand Canyon Trust	9	2	For example, energy development on tribal lands has fueled decades of rapid suburban growth in prospering cities throughout the West. However, fewer than half of the homes of people who live on rural tribal lands where energy is produced have electricity and running water. Unemployment chronically exceeds forty percent within the region's Indian reservations. The health of native and non-native residents is damaged by air and water pollution caused by years of mining and converting oil, uranium, coal, and natural gas into profits that are exported to distant centers of commerce. While Navajos and Hopis have received some royalties and employment from mineral extraction on their lands, most of the benefits have gone to outside utilities, investors, and ratepayers in the form of cheap energy.	See response to comment Grand Canyon Trust-9-1.		
Grand Canyon Trust	9	3	The economic drain caused by the exportation of energy profits is exacerbated by the lack of native-owned businesses and equity in capital investments on tribal lands. For example, the Navajo Nation is both the region's and the United States' largest reservation (in both population and area). However the per capita income for the Navajo Nation is less than $8,000 per year, while the estimated total personal income amounts to more than $1.2 billion annually. Of that $1.2 billion, the Navajo people spend less than 30 percent on their reservation. The resulting net loss or economic leakage from the Navajo Nation is more than $800 million per year	See response to comment Grand Canyon Trust-9-1.		
Grand Canyon Trust	9	4	Energy development in the region has too often come at the expense of the tribes. The Mohave plant has generated billions of dollars in electricity and shareholder profits for more than three decades. Those gains, however, have been derived from externalized expenses paid for by indigenous people and the environment. The cost of electricity from Mohave has been kept artificially low by, among other things, dumping millions of tons of pollution into the atmosphere in violation of the Clean Air Act, purchasing coal from tribes at prices well below market rates, and mining groundwater for a coal slurry line that has depleted springs and wells on the Hopi and Navajo reservations. As a former tribal chairman concluded, "they have taken our coal and water and given us polluted air in return."	See response to comment Grand Canyon Trust-9-1.		
Grand Canyon Trust	10	1	The Mohave Alternatives Study should explore possible applications of revenues derived from sulfur dioxide allowances when Mohave shuts down. For example, these "windfall" revenues could provide investment funding for tribes to develop alternatives such as wind. The amount available could be equal to the annual amount that the owners of Mohave will receive from the sale of approximately 50,000 tons of sulfur allowances that they will receive when it shuts down on December 31, 2005 (a value of at least $40 million annually at current prices of more than $800 per ton).	While we have not specifically researched this issue, it is our general understanding that any revenue from the disposal of such allowances or cost savings from eliminating the need to purchase them would flow through to SCE's retail ratepayers under traditional ratemaking. We are not aware of a scenario under which transfer of those allowances to the tribes would be permitted by California regulators.		
Grand Canyon Trust	10	2	The Mohave Alternatives Study should evaluate opportunities for underwriting investments in alternative energy generation through long-term procurement agreements with owners of Mohave and other utilities in the region. These opportunities may include purchases preferences for minority or economically depressed sources as well as for purchasing power from sources that meet California's newly adopted performance standards for reducing greenhouse gas emissions.	We will explore this issue and discuss it in the final report.		
			TURN COMMENTS ON PRELIMINARY DRAFT STUDY OF POTENTIAL MOHAVE ALTERNATIVE/COMPLEMENTARY GENERATION RESOURCES			
TURN	General	1	TURN is generally pleased with the quality and scope of the work that has gone into the Mohave Alternatives study to date. The individual technologies are properly investigated with respect to gross costs, operation and maintenance costs, water and land use requirements, labor to build and operate, transmission upgrades necessary, ownership considerations and tax implications. However, the authors have not presented the results of any significant analysis that would pull all of these considerations together to provide policy makers and other stakeholders with an opportunity to readily compare the bundles of options available as an alternative to the refurbished Mohave plant. TURN believes that without this next level of analysis, the study will have limited use in this proceeding.	This is beyond the scope of this study. The study's results were meant to be used as inputs into SCE's IRP.		
TURN	General	2	Detailed comments by TURN on the draft study will be offered when a more complete analysis of various Mohave replacement scenarios has been completed. We recognize that creating such scenarios will require significant work and recommend additional time, if necessary, for the authors to complete the analysis in a form usable by stakeholders. Absent such additional work, any decision to proceed either with Mohave refurbishment or alternatives would not be based on sufficient information. Further, the study of the C-Aquifer is also incomplete at this time making haste on this study unnecessary and ill-considered.	We expect to have all of the required analyses completed in the next draft report.		
TURN	General	3	TURN has serious concerns about one major assumption used by the study authors. The effort to consider alternatives which exactly mimic the daily and seasonal supply of power from Mohave is not useful. A baseload power supply, such as provided by Mohave, may not be the best form replacement power for the SCE system. It is well known that SCE projects excess off-peak resources in its portfolio during the coming years and has identified a need for peaking, not baseload, generation to fill unmet needs. Failing to incorporate this reality into the MACS report will only skew the analysis and provide a false portrait of the true cost of alternatives. For example, adding thermal storage to potential solar systems to mimic the Mohave supply curve does not add ratepayer value but will adversely skew the costs of these technologies to make them appear less attractive.	Based on our experience in utility planning, it is customary to evaluate alternative resource options as part of a balanced portfolio that takes into account the availability and costs of the various options and how they fit with the existing resources and expected load of the utility. Our current assignment is to provide SCE with data on the various options that would allow it to perform IRP analyses of various combinations of the options, not just any particular "bundle." Such an analysis is usually done in combination with existing committed resources and the various other options available to the company. The basic intent of Chapter 3 was to determine if concentrating solar power (CSP) technology could feasibly replace or complement the Mohave generation. To this end the load profile of the Mohave Plant was used to		

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<tr><td></td><td></td><td></td><td></td><td>determine how much generation would have to be replaced or complemented.
Chapter 3 shows CSP technology is not a logical alternative to totally replace the electrical generation of the Mohave Generating Station. One point stated in the report is that CSP is not a logic Mohave generation replacement since thermal storage or a hybrid configuration would be necessary to match the existing Mohave Generating Plant load profile. However, CSP technology is shown to be a potential alternative to complement the electrical generation of the Mohave Generating Station, both as Dispatchable Power Systems and Distributed Power Systems.
The capital cost estimate for the Parabolic Trough 100 MW Plant provides a breakout cost for storage – the storage cost can be deducted to obtain the capital cost for a 100 MW Parabolic Trough Plant without storage.</td><td></td><td></td></tr>
<tr><td>TURN</td><td>General</td><td>4</td><td>In order to ensure that this document is useful for policy makers and stakeholders, TURN strongly recommends producing another version of the draft report showing a range of replacement generation scenarios for Mohave developed using the professional judgment of the study authors. These scenarios would include various mixes of alternatives to meet the actual replacement power needs of the SCE system (not merely a facsimile of the Mohave profile). The scenarios should be based largely on the data already presented by this draft study and must incorporate all costs of each technology at a given site including those for site acquisition, water supplies and power transmission. Tax implications, such as production tax credits and special funding available due to recent federal legislation, should be incorporated in order to realistically assess the actual costs of delivered power from each scenario.
These scenarios should be constructed based on this data and then optimized for two key variables – total ratepayer cost and total level of economic benefits to the Navajo and Hopi Tribes. In particular, the study authors should identify scenarios which provide at least the same level of economic benefits to the Tribes as is received from the jobs and royalties associated with the Black Mesa mine. The goal of this exercise, in TURN's view, should be to ensure that the replacement of Mohave by a package of alternatives results in no net revenue loss while providing cost-effective power to serve California ratepayers.</td><td>This is beyond our scope of work.</td><td></td><td></td></tr>
<tr><td>TURN</td><td>2</td><td>1</td><td>Heat Rates for IGCC
The heat rates reported for the IGCC plant appear quite high (low overall efficiency) using the DOE model. An effort should be made to generate comments from IGCC technology vendors on the model results. TURN recognizes that the IGCC equipment vendors have not been forthcoming with useful data in this study process but believes it may be to their advantage to do so, even on a limited basis, at this time. Using high heat rates will potentially skew alternative comparisons and is not "conservative" as stated on page 2-15.</td><td>S&L believes that the high heat rates is conservative and avoids being overly optimistic about efficiency. We have noted areas where the efficiency may increase by 2 to 4% depending on degree of integration not covered by IECM and by using dry feed technologies. S&L has contacted the vendors repeatedly, with no success.</td><td></td><td></td></tr>
<tr><td>TURN</td><td>2</td><td>2</td><td>Possible IGCC sites
On page 2-14 three alternative projects are listed, one at the Mohave Generating Station site and two at the Black Mesa site. The difference in the Black Mesa projects was slurry versus dry delivery of coal. In Table 2-6 "Water Demand for IGCC at Mohave GS and At Black Mesa Mine" summaries of water use for all three alternatives are presented but it is unclear how the total for the dry delivery (Shell technology) is calculated.</td><td>The dry feed systems don't include water as a slurry feed with the coal. Typically the technologies feed ~ 65% solids or add 35% water to the coal.</td><td></td><td></td></tr>
<tr><td>TURN</td><td>2</td><td>3</td><td>The study authors must grapply with the following question -- is there enough water quality data at this point to assume that the C-Aquifer water will be suitable for the IGCC technology boiler?</td><td>The study assumes minimal water conditioning for the well water delivered to slurry the coal. If there are harmful (corrosive, etc.) compounds in the water that must be removed first, this would add some cost and increase content due to treatment techniques.</td><td></td><td></td></tr>
<tr><td>TURN</td><td>2</td><td>4</td><td>Additionally, the use of Colorado River water for cooling purposes cannot be relied upon past 2025. Given this reality, any power plant sited at the Mohave Generating Station site should be assumed closed after that date or have dry cooling installed either initially or at some time in the future before that date. This limitation needs to be factored into the annual cost considerations for power from this site.</td><td>We have provided costs for either contingency to SoCal and they can plan as appropriate in their production model.</td><td></td><td></td></tr>
<tr><td>TURN</td><td>2</td><td>5</td><td>On Table 2-10 (page 2-24) it is unclear how the figures for the "Total Expected Costs" are tallied. In particular, why does the "90% CO2 Removal" column have substantially larger costs for the dry cooling option versus the wet cooling one?</td><td>Costs are represented on a normalized $/kW basis. Since CO2 removal systems produce less energy from the same "turbine model" equipment, the relative cost per unit energy is magnified by higher actual cost and fewer kW to amortize the cost against.</td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td>Solar</td><td></td><td></td><td></td></tr>
<tr><td>TURN</td><td>3</td><td>1</td><td>The variable O&M figures for the Parabolic Trough, Power Tower, and Stirling Engine appear quite high ($0.03/kWh - Table 3-2). What is the source for these figures?</td><td>As with the capital costs, the O&M costs are speculative since the last commercial-scale CSP plant was built in 1990 (the SEGS IX parabolic-trough plant) and the current dish/engine (Stirling) and concentrating photovoltaics plants are small demonstration plants. The cost estimates presented are based primarily on NREL data and publicly available CSP technical information and represent the upper range of projected O&M costs. Parabolic Trough O&M costs include SEGS O&M historical data.</td><td></td><td></td></tr>
<tr><td>TURN</td><td>3</td><td>2</td><td>On page 3-26 an O&M cost of $0.011/kWh is shown for the Stirling Engine which is inconsistent with the $0.03/kWh figure given in Table 3-2.</td><td>The $0.03/kWh is the correct one.</td><td></td><td></td></tr>
<tr><td>TURN</td><td>3</td><td>3</td><td>The water usage for the Parabolic trough and Power Tower are very high with virtually all use for cooling. In the text you describe a dry cooling alternative at modest additional cost (4-8% of capital cost) which would seem a far more likely choice given the locations for these plants. Table 3-5 should reflect these lower usages.</td><td><table>
<tr><th></th><th>Parabolic Trough</th><th>Power Tower</th><th>Dish/engine (Stirling)</th><th>Concentrating Photovoltaics</th></tr>
<tr><td>Cooling Tower Makeup, (gal/yr)</td><td>0
(based on air-cooled system)</td><td>0
(based on air-cooled system)</td><td>0</td><td>0</td></tr>
<tr><td>Rankine Cycle Makeup, (gal/yr)</td><td>90,000,000</td><td>90,000,000</td><td>0</td><td>0</td></tr>
<tr><td>Mirror Washing, (gal/yr)</td><td>11,000,000</td><td>11,000,000</td><td>6,000,000</td><td>6,000,000*</td></tr>
<tr><td>Total (gal/yr)</td><td>101,000,000</td><td>101,000,000</td><td>6,000,000</td><td>6,000,000</td></tr>
<tr><td>Total (acre-ft/yr)</td><td>310</td><td>310</td><td>18.4</td><td>18.4</td></tr>
</table>
This information will be included in the next draft report.</td><td></td><td></td></tr>
<tr><td>TURN</td><td>3</td><td>4</td><td>Finally, the study authors should verify cost data on dish stirling pricing by reviewing the recently-executed PPA between Stirling Energy and Southern California Edison. SCE should make this PPA available to the study authors for this purpose.</td><td>Stirling Energy was requested to provide cost information, however they indicated this information is confidential. SCE was requested to provide the executed PPA and they also indicated that the information is confidential.</td><td></td><td></td></tr>
<tr><td>TURN</td><td>Appendix H</td><td>1</td><td>Forecasted Natural Gas Prices
TURN questions the forecast of declining natural prices (in real terms) "over the next several years". Ignoring the current problems in the Gulf, in the last year the US has doubled the number of rigs drilling for natural gas and the production response has been nil. Canada and Mexico are seeing increases in demand and LNG is not anticipated to impact supplies until at least 2009. With these price pressures, what mechanisms did the authors believe would cause natural gas price declines?</td><td>The decline in NG prices is directly based on the most recent pattern of Henry Hub natural gas futures through 2010. Thus it reflects market consensus expectations. We will investigate whether recent future prices have changed significantly.</td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td>PEABODY ENERGY</td><td></td><td></td><td></td></tr>
<tr><td>Peabody</td><td>2</td><td>1</td><td>On p. 2-22, the table in the draft report indicates that, for a 500 MW GCC plant operating at 100% capacity, the emissions of CO2, in lbs/MMBTU, without CO2 capture would be 200; with CO2 removal but without shift conversion would be 142; and 90% CO2 would be 17. Are these figures the same whether the plant is located at Black Mesa or Mohave? And what is the equivalent figure for CO2 emissions for a 500 MW NGCC plant without CO2 removal?</td><td>It can be assumed that the CO_2 emissions at Black Mesa are the same as at Mohave.

We will provide CO_2 emissions for the NGCC plant for comparison. Emissions data for all plants will be summarized in the Executive Summary in a manner amenable to comment SCE-ES-4 regarding consistency</td><td></td><td></td></tr>
</table>

				of summary data reporting.		
Peabody	2	2	Also, on p. 2-22, the draft report states that it is not likely that it will be technically viable to remove a high degree of CO2 from the syngas until 2020. Does this statement match up with the 90% CO2 removal in the chart?	The CO2 removal data in the chart is what is possible from the gasification technology. The issue on technical viability resides in the ability to procure a combustion turbine that will burn hydrogen-only fuel with confidence.		
			"JOHNSON JOHNNY L" <JLJOHNSO@SRPNET.COM> SRP COMMENTS RE: MACS PRELIMINARY DRAFT REPORT			
SRP	ES	1	In the first paragraph, SRP's and LADWP's percentage interest are reversed;	We will make this correction.		
SRP	ES	2	in the second paragraph, should you note that the study only investigated these technologies as potential alternatives to replace or complement SCE's share of Mohave, not the entire plant?	The scope provided to the consultants directed us to consider only the SCE share of the plant.		

Org	Section	Index	Comment	Response
SCE	ES	1	Page I. The formatting of the Contents for the Executive Summary is inconsistent with the actual Section and the paging needs to be corrected.	Formatting will be corrected.
SCE	ES	2	Page ES-20. Starting with page ES-20, the Section numbering needs to be revised.	Formatting will be corrected.
SCE	ES	3	Page ES-4. It is suggested that a table be inserted immediately prior to Section ES.1.2 summarizing the project sizes discussed in Section ES.1.1.	Table to be inserted as requested.
SCE	ES	4	Page ES-5, Table ES-1. Please include a line showing the total staffing required for this alternative.	Total staffing to be inserted
SCE	ES	5	Page ES-6, Table ES-3. Please include a line showing land use for this alternative. It is also suggested for illustrative purposes that, in additio to showing the acreage, you convert the acreage into square miles and to state how big the site would be. For example, later in the report you show a land use of 34,000 acres for one of the wind sites. In addition to showing the 34,000 acre number if you showed that this was equivalen to 53.1 square miles and 7.3 miles on each side, readers would have a more visual picture of the size of the area required for a wind farm.	Land use illustrative data will be inserted. It should be noted that only about 11,000 acres is included in Phase 1 of Gray Mountain, and that only if all 3 phases actually get built would it occupy 34,000 acres. should also be noted at 450 MW's it would be one of the larger wind sites in the world.
SCE	ES	6	Page ES-7, Table ES-4. See comment [SCE-ES-5] above. Show 4.1 square miles and 2 miles per side for the parabolic-trough and 3.3 square miles and 1.8 miles per side for the dish/Stirling engine	Land use illustrative data will be inserted.
SCE	ES	7	Page ES-7, Table ES-4. The total staffing at 118 shown for the Dish/Stirling engine does not match the staffing from page 3-27 at 26.	Data will reconciled. 118 value is correct based on information from SES.
SCE	ES	8	Page ES-8, Table ES-7. The staffing figures seem low. Does this include just routine maintenance/repair, and if so is the study making consistent assumptions among the different options about using outside contractors rather than FTE for routine maintenance/repair?	Most Wind Projects execute long term parts and services agreements with OEM's when purchasing win turbines. Most of the O&M expense is included in these LTSA's and only a few people including the OEM's dedicated staff at the project are required for modern wind farm O&M
SCE	ES	9	Page ES-8, Table ES-7. This is the only table in which you show the average and peak construction jobs for any alternative. It is suggested tha either you delete this information from this table or provide the same information for each of the other alternativ	We will delete the construction job data here to make the presentation in the Executive Summary consistent with the other technology alternative
SCE	ES	10	Page ES-8, Table ES-8. See comment [SCE-ES-5] above.	Land use illustrative data to be inserted.
SCE	ES	11	Page ES-9, Table ES-9. It is suggested that you expand this table to also show the performance at 20 ºF, 108 ºF and 125 ºF and that you footnote each temperature to explain: • 20 ºF would be the minimum site design temperature • 67 ºF is the average annual site temperature • 108 ºF would be the site design temperature • 125 ºF would be the maximum site design temperature	We will expand this table to include the data provided in the body of the report for the temperatures mentioned for both configurations of the plant (cooling tower, air-cooled condenser) and provide the requested footnote.
SCE	ES	12	Page ES-12, last paragraph. The analysis indicates that energy efficiency in Arizona and New Mexico could replace over 40% of the energy and capacity from the Mohave Plant. Has the likely potential that SRP which owns 20% of the Mohave Plant and supplies power in Arizona would probably utilize much of the potential energy efficiency to make up for their loss of energy and capacity from Mohave?	The potential for SRP, or other utilities, to achieve additional energy efficiency beyond the 40% cited is already reflected in the conservatism used to define the "readily achievable potential" listed in table 6.4 and referenced on page ES-12. The "readily achievable" potential excludes a significant amount of additional efficiency which could be tapped by internal SRP (or other utilities') programs if they so chos
SCE	ES	13	Page ES-30, bullet on Alternative Locations of Options. Even with the DSM alternative, wouldn't some of the existing PV generation have to bumped off line in order to handle the additional flow of energy? There may need to be some qualitative discussion on this distinction of power coming from the PV area.	The bullet on page ES-30 will be expanded to further explain that transmission from PV hub resource (e.g., to implement the DSM option) could lead to increased congestion charges "into CA", such as currently noted in the transmission chapter at page 12-4, in particular footnote 5 on that page. The analysis was not detailed enough to be able to make any definitive statements about PV generation that might have to be "bumped' or the interactions between into-CA path capacity, PV hub generation levels, and the absence of Mohave generation.
SCE	ES	14	Page ES-32, Table ES-20. Nothing has been mentioned about the schedule requirements for the various alternatives/complements. This table would be a good place to add a line and summarize the schedule (lead time) requirements for the various option:	Schedule data will be included.
SCE	ES	15	Page ES-32, last paragraph. You state "…DSM, while this option has a high initial cost, it has virtually no operating costs…" In the analysis starting on page 6-16, an assumption is made to set the cost of DSM at \$70/MWh. If this is the basis of considering this to be "…a viable option for replacing/complementing Mohave…" why isn't this shown in Table ES-20 as a Total Operating Cost? You need to have some stronger ba for considering this to be a viable option considering all of the negatives of out of State, never been done, cost basis, other competing Mohave Owners, etc.	The noted sentence will be deleted from the final report, and edits will be made to the DSM aspects o table ES-20 and the related text. Updated DSM information for Table ES-20 and subsequent DSM-related text was developed just prior to issuance of the November 22nd draft and did not make it into the version sent to stakeholders. The final report will address this. We note here that the DSM option is unlike the other alternatives listed and is difficult to characterize in a way that allows for apples-to-apples comparison. The final report text and table information will reflect this.
SCE	ES	16	Page ES-35, first paragraph. In this paragraph, you state that "…a pipeline from the existing Mohave site to Bakersfield, California…." This phrase implies that the pipeline would go directly from Mohave to Bakersfield which is probably not the case. Siting the pipeline would proba be easier if it were to go due south from the plant approx. 25 miles and intercept Interstate 40 and follow along I-40 towards Barstow in order t avoid impacting the Mohave National Preserve which is due west of Mohave. You may want to rephrase your statement. Would the longer route also increase the pipeline capital cost	The route chosen for the pipeline is as described in SCE's comment. The capital cost shown is for that route. Sargent & Lundy will provide a longer description of the pipeline route similar to that provided b SCE.
SCE	2	1	Page 2-3, Figure 2-3. The title of the slide should read "IGCC Schematic of Generic IGCC Power Plant".	Title will be corrected.
SCE	2	2	Page 2-15, first paragraph in Section 2.2.4. You state that "It is assumed that all pumping and transportation costs are included in the price of the water." This is an incorrect assumption. Edison estimates that the C-Aquifer well field, two pump stations and 109-mile pipeline capital c will be approx. \$200 million and that the annual O&M costs will be approx. \$14 million per year (in 2005 dollars) exclusive of any APS or NTUA costs to provide power to the pipeline and well field	We assumed that the capital cost and power costs mentioned would have to be recovered in the price of water.
SCE	2	3	Page 2-42, Table 2-23. Although the Maintenance Staff and Maintenance Labor Costs are probably reasonable estimates, but done differently, the data shown in Table 2-23 makes them look inconsistent. Note that the Maintenance Staff varies from 20, 40, to 40 for the three CO2 remo scenarios, however, the Maintenance Labor Costs vary from \$4.56, \$6.54, to \$9.36. Would you please double check this data.	The Maintenance staff for the case of CO2 removal without shift conversion should a value of 30. This was a typographical error.
SCE	4	1	Page 4-10, Section 4.1.5. See comment 3 above. For this section it is suggested that you also include the square miles and miles per side for each alternative in each place where you provide the required acreage	Illustrative data will be provided as requested.
SCE	6	1	Page 6-10, second paragraph. The two electric utilities in the state of Nevada have merged and are one utility at this time.	This will be reflected in the final report.
SCE	6	2	Page 6-11, third paragraph. See comment 10 above. Based on the fact that SRP owns 20% of the Mohave Plant's output and provides power t the State of Arizona, shouldn't this be taken into account as to the estimates of energy and capacity available within the State of Arizona? It would seem logical that they would want to replace any lost capacity and energy (if economically viable by this means) before contemplating any type of power purchase arrangement with Edison.	The potential for SRP, or other utilities, to achieve additional energy efficiency beyond the 40% cited is already reflected in the conservatism used to define the "readily achievable potential" listed in table 6.4 and referenced on page ES-12. The "readily achievable" potential excludes a significant amount of additional efficiency which could be tapped by internal SRP (or other utilities') programs if they so chos

SCE	7	1	Page 7-12, third paragraph. There is a reference to the "Bitsi" area. Is the correct spelling "Bisti?	We will provide the correct spelling.
Mills	10	1	I believe Table 10-19 overstates the financial impact of a loan guarantee. The table assumes that the loan guarantee allows the debt/equity structure to change to 90% debt/10% equity. However, the debt/equity structure is governed primarily by the debt service coverage ratio in a wind farm project. A project with only 10% equity will most likely require a much higher revenue stream to meet the debt constraints than a project with a more even debt/equity ratio. I've attached a paper that explains this in more detail. See Table 3 for the impacts of a loan guarantee on wind projects. I'll be happy to clarify if this raises more questions. Thanks for the opportunity to comment.	We agree that the issue raised needs to be considered and we will do so.
SES	3	1	We have reviewed the material provided on the solar analyses (specifically Ch. 3). We have not seen the appendix material on solar, so I'm not sure how some of the numbers are derived. We also provided Synapse some additional information regarding employment and O&M costs that do not seem to be reflected in the Ch.3 write-up	The solar appendix is a placeholder and will not be present in the final report.
SES	3	2	On p 3-4 and again on p 3-9 and 3-24, reference is made to the PPA for 500-850 MW for SCE. In early September, we signed a similar PPA with San Diego Gas & Electric for 300-900 MW. Timing for this project is similar to that of SCE	We will mention both PPAs.
SES	3	3	There is an internal conflict in O&M figures for dish Stirling systems -- on p 3-14, for example, O&M costs are cited at $3/kW-yr plus $0.03/kWh. In Table 3-13, O&M costs are shown as $0.011/kWh total. I'm not sure how either of these figures was derived, but we believe our O&M costs will be closer to the $0.011/kWh figure (possibly closer to $0.015/kWh). This number includes the fact that we will need more than the 26 folks shown for staffing the plant. We calculate needing about 60 full-time mirror washers (probably all in addition to the 26 people listed)	The $3/kW-yr fixed, $0.03/kWh variable is Sargent & Lundy's estimate. Personnel levels in the report reflect the staffing levels indicated by SES.
SES	3	4	Finally, on page 3-18, you refer to the AZ RPS. (It's actually called EPS in AZ, for Environmental Portfolio Standard.) You should check, but I believe the AZ Corp. Commission has just recently approved a new, higher EPS -- growing to 5% by 2015 and 15% by 202	We will correct the terminology and check for newly revised EPS parameters.
NRDC	ES	1	As requested by Sargent & Lundy, the contractor preparing the draft "Study of Potential Mohave Alternative/Complementary Generation Resources," ("Draft Report") the Natural Resources Defense Council ("NRDC") provides these comments on the Draft Report. NRDC continues to be encouraged by the analysis and findings in the report. In particular, the tables in Chapter 10 that evaluate the package of incentives, tax relief, and other financing options for the various technologies are helpf	The Consultants appreciates NRDC's recognition of our efforts.
NRDC	ES	2	Operations and Maintenance ("O&M") Costs for Solar Dish. In follow-up comments on the response matrix, NRDC questioned the different O&M costs used for dish solar technology. At one point the report uses $.011/kwh, while at another point it uses $.03/kwh. Stirling Energy Systems has confirmed that the $.03/kwh figure is higher than the company is projecting. This final report should reflect the lower O&M cost solar dish technology	See comment SES-3-3.
NRDC	ES	3	Presentation of Data in Summary Tables. The summary tables are helpful, but should contain an all-in $/MWh cost so that each technology can be compared on an apples-to-apples basis. The report says this is beyond the scope and would require other inputs like a discount rate. NRDC suggests that the contractors could perform a sensitivity analysis if they do not want to pick a discount rate.	The comparison, as has been stated, will be made as part of the integrated resource plan process. While one could perform some calculation based on some assumptions for discount rate and generation over some assumed time period, and perform sensitivity analyses varying the assumed discount rate, the proper place to make the comparison is in the integrated resource plan process.
NRDC	ES	4	Greenhouse Gas Requirements. The discussion of emissions valuation cites the California Public Utilities Commission's ("CPUC") decision on the "GHG adder" (D.04-04-024, Conclusion of Law 7) but does not have the final requirement for utility modeling of the value - which is $8/ton CO2 in 2004 escalated at 5% per year (based on the CPUC's adopted avoided costs). Even Appendix I is missing this link. This should be corrected. Also, it is unclear whether in fact the contractors are factoring the cost into a comparison of the resources - both because they do not indicate what value is being used and because there is not a full $/MWh cost for each resource and it is unclear if this is included in the variable operating cost	Footnote 104 on p. 33 of Appendix I addresses the E3 CO2 price escalation. On p. ES-24, we will insert "escalated by 5% annually" after $8 in the last sentence of the 2nd bullet point. Emissions values have n been included in the variable operating costs of the different technology options. These values, however, should be included as inputs to SCE's IRP model.
NRDC	ES	5	Inclusion of Energy Efficiency Information in Summary Table. The energy efficiency information in table ES-20 is missing. This should be corrected in the final report.	Updated DSM information for Table ES-20 and subsequent DSM-related text was developed just prior to issuance of the November 22nd draft and did not make it into the version sent to stakeholders. The final report will address this. We note here that the DSM option is unlike the other alternatives listed and is difficult to characterize in a way that allows for apples-to-apples comparison. The final report text and table information will reflect this.
NRDC	ES	6	Explanation of transmission analysis. The transmission discussion in the Executive Summary should be more explicit about whether the analysis is contract path or flow-based approach. It may be a matter of specifying on p. ES-27 that transmission is flow-based up to California border, and contract path within California	An additional sentence on page ES-27 will be included in the final report, summarizing the "flow-based" vs. "contract path" characteristics of the different pieces of transmission analysis.
NRDC	ES	7	Opportunity Cost of Water. The Draft Report does not outline the opportunity costs of water used to transport coal to the Mohave plant and the financial benefits accruable to the tribe due to the reduction thereof. By replacing Mohave's generation output and liberating significant water resources previously used for coal transport, the various technology options provide a potential stream of annual revenue in the tens of millions of dollars. The various technology options use substantially less than the 1.4 billion gallons annually currently used for coal transporting activities. The Draft Report should reflect these substantial potential earning	Estimating opportunity costs relating to water and land consumption is beyond our scope of work. However, in the final draft, we will note the existence of such costs.
NRDC	9	1	Tribal Issues. NRDC appreciates the steps that have been between the first and second drafts of the report to address the concerns NRDC raised on the first draft. NRDC believes that the final report could be strengthened in this area in several ways. First, the Draft Report fails to quantify the benefits of any given technology for the Hopi Tribe. In this way, the Hopi do not have a basis from which to weigh each technology option in terms of net impact on the reservation. As currently drafted, the Draft Report fails to calculate the tribal taxes and royalties that would apply to the various technology options with respect to the Hopi Tribe, as well as entertain estimates of investment, operation and maintenance revenue and secondary business activity benefits. This information is critical to portray the costs and benefits of each technology for the Hopi. If this cannot be done because certain data or information was not provided to the contractors, that should be so indicated in the final report.	the November 22 draft notes that there are no Hopi taxes in effect at this time. With regard to royalties for both tribes, the November 22 draft explains why royalty estimates were dropped as part of this project. We do not understand the reference to "estimates of investment" and of "operation and maintenace revenue," but note that the November 22 draft includes estimates of both investment and O&M outlays for the technology options. The extent to which either investment or O&M outlays would translate into direct revenues for either tribe (aside from tax revenue which is addressed) is either a royalty issue (which has been dropped from the study) or a secondary economic impact issue. Secondary economic impact analysis is underway, but has been delayed due to technical difficulties being experienced by the model vendor. This portion of the work will be available shortly for stakeholder review.
NRDC	9	2	Second, although the current draft goes a long way towards eliminating the consistently overstated "issues" in the previous draft, the latest Draft Report should further differentiate the "issues" from the "processes." Potential issues include site approval on checkerboard lands or fractional allotments. In those instances, development is complicated by required approval of potentially numerous interested parties. On the other hand, environmental review under the National Environmental Policy Act is a process intended to inform the decision maker of the environmental effects of any given activity, potential mitigation measures, and alternatives. It is an opportunity to present environmental, cultural, economic social impacts of the various technology options that might otherwise be ignored. The smaller the footprint of a given technology option in terms of adverse effects, the less cumbersome the process becomes, and vice versa.	In the final draft, we will make the distinction between issues and processes.

NRDC	9	3	Third, NRDC is unable to comment on employment impacts due to the exclusion of this topic from the Draft Report.	Secondary economic impact analysis is underway, but has been delayed due to technical difficulties bei experienced by the model vendor. This portion of the work will be available shortly for stakeholder review.
Hopi	ES	1	Further Refinement of Study Conclusions is Recommended. Reference is made to the Study Plan at Section 1.2 of the draft report. In particular, Decision 04-12-016 required as follows: "Both the IGCC and renewable energy projects should include consideration of any enhancements to transmission system that may be necessary to bring power into California. The final plan should be sufficiently detailed, including cost components, proposed counterparties and generation on-line dates, to allow this Commission to affirm a specific resource plan during Edison's next long-term planning process. Ownership arrangements involving the Hopi and Navajo should be given consideration in the feasibility stud The current draft should do more to address these core requirements. Some particular areas of concern are as follows:	See responses to subparts 1a-1d directly below
Hopi	ES	1a	First, the report should contain a frank and direct assessment and evaluation of the impact of transmission constraints on the ability to build and finance alternative or complementary projects, and on the critical question of the timing of both any anticipated transmission upgrades and the timing of new powerplant investments. In particular, the study seems to avoid directly addressing the impact of the lack of longer-term transmission service on the feasibility of the examined projects, including the impact of transmission constraints on the ability to attract investment capital. The report also does not address fully when additional long term transmission capacity is reasonably likely to be available within the study area. Thus, the report concludes, at ES-30, that "Existing conditions appear to limit the availability of long-term (i.e., one or more years) firm service from Arizona supply sources, without new transmission upgrades. Shorter-term service of more limited duration is	The report addresses the impact of transmission constraints on potential alternatives or complements to Mohave, but it is beyond the scope of work to address investment community risk given the transmission issues. The report also addresses the cost of transmission upgrades required to connect alternatives or complements to the grid and includes cost estimates for some of the major upgrades that might be required to allow for longer-term firm transmmission. An exhaustive analysis of all regional transmissi construction costs necessary to ensure any of the complements or alternatives firm long-term access is beyond the scope of work.
Hopi	ES	1b	Second, the report's handling of grant and tax incentives should be integrated into estimated project costs to better reflect the anticipated net cost of developing the generation alternatives. Particularly in the area of IGCC development, where capital costs are higher but significant grant and tax incentive offsets are available, the summary financial data does not appear to present a scenario that contains cost adjustments for tax and grant assistance that is reasonably likely to be obtained. Conversely, if the availability of such tax and grant assistance is highly speculative, then the report's conclusions should expressly take that risk into account in reaching conclusions about the realistic possibility that any alternative o complementary projected identified in the MACS study is a realistic Mohave alternative or complementary project.	Information on tax incentives and grants to offset capital costs is available in the text of the report and in the executive summary. It is very difficult to ascertain with any certainty whether or not a particular incentive will be available to a particular project. As stated in the report, some incentives are competitiv and thus one would have to have an idea of all other competing projects in order to ascertain the likelihood that a specific incentive might be available. Such an analysis is beyond the scope of work of the project.
Hopi	ES	1c	Third, I do not believe the MACS report should rely on wind projects already under development as alternatives or compliments to Mohave. To the extent the wind projects examined in the MACS report were in development already, the report fails to identify alternatives or complements to Mohave consistent with the spirit of the CPUC directive. Stated differently, projects that were already in development were in development regardless of Mohave operations. It would be an improper result to classify existing projects under development -- which were proceeding without regard to Mohave's status -- as replacements or "complements" to Mohave. Categorizing existing wind projects already under development as complements or alternatives to Mohave substitutes those projects for Mohave in a pernicious way that provides no net benefit to the Hopi or the Navajo in terms of revenue or employment, and in many ways offers no additional generation capacity to California ratepayers	None of the projects cited has a completed power purchase agreement. Therefore it is still possible for SCE to obtain one and use the associated capacity and energy as an alternative or complement to the existing plant.
Hopi	ES	1d	Fourth, the report should frankly and directly acknowledge that the Demand Side Management/Energy Efficiency Technology examination does not meet the specific criteria set out by the CPUC for further consideration as a compliment or alternative to Mohave. The reasons why this conclusion must be reached include, but are not limited to, the following: (1) the legal and structural impediments that remain to implementation of the DSM/EE proposal render it an unrealistic near-term alternative or complement to Mohave; (2) there is no structure for creating meaning monetary or employment benefits from a DSM/EE transfer between California and other states that would benefit the Hopi Tribe and Navajo Nation; and (3) the DSM/EE analysis does not address the source of energy acquired through a DSM/EE transaction, which would likely be conventional coal fired power generation, and the issue of whether such an acquisition would be consistent with California policy.	Institutional constraints may be comparatively quick to resolve if the parties are in agreement. Re (2): Our labor impact analysis (to be completed shortly) will outline ideas for how possible employment benefits to the Tribes could come about, and the tax analysis identifies certain parallel revenues for the Navajo. No Hopi taxes are estimated, as no such taxes exist. Re (3): The source of energy is notionally the DSM savings itself; actual generated energy shipped to C is energy that would otherwise have been generated without the DSM, thus it is not incremental but, rather, decremental. Hence, it is no necessarily true that it would be treated as new coal fired generation under the proposed California policy.
		1d	At ES-21, for example, the MACS draft asserts that DSM/EE technologies have "a high potential to create future jobs for the tribes, both on and off reservation territories." This claim, however, is not supported by the study analysis. There is no basis presented in the study for the proposition that DSM/EE employment or economic benefits would benefit the tribes directly instead of the economy in general. Nor does the analysis evaluate the importance of creation of jobs on or near the Hopi tribal reservatic	Our labor impact analysis (to be completed shortly) will outline ideas for how possible employment benefits to the Tribes could come about.
		1d	While pursuit of the DSM/EE strategy identified in the MACS report deserves further consideration by the PUC, this option clearly does not satisfy the criteria of Decision 04-12-016 as an alternative or complement to Mohave.	The report provides an explanation of the mechanism by which the innovative DSM/EE strateg contained therein could be implemented. That strategy's legal standing in California is beyond our scope of work.
Hopi	ES	4	Levelized Cost Issues. At ES-33, the draft MACS reports claims to ignore the calculation of the levelized cost of energy, because the analysis of certain costs over the life time of the project "is beyond the scope of this study and is rightfully performed as part of the integrated resource planning process." The report further states, "[n]either the levelized cost of energy calculation nor the discounted cash flow analysis is within the scope of this study." Yet, at 1.3.2 (Solar Technology), the following statement appears: "Based on the review, potential power plant configurations were developed that are considered to be feasible based on the maturity of the technology, technical risks and expected reliability, capital costs, O&M costs, levelized energy costs, and dispatch constraints." See Draft MACS Report at 1.3.2, p. 1-3. These positions appear	We refer in section 1.3.2 to levelized energy costs that exist as public information estimated by others.
Hopi	ES	5	There appears to be a typographical error on page ES-5 in either Table ES-1 or ES-2, relating to Net Output under the No CO2 removal Scenario. Table ES-1 refers to 548.4, whereas ES-4 refers to 548.9	Table ES-1 has a typographical error: the value should be 548.9.
Hopi	2	1	IGCC. I recommend the report clearly state what IGCC technology is feasible for development today. (Compare the statement at 2-24: "... although it is technically possible to remove a high degree of CO2 from the syngas, it is not likely that such a plant will be technically viable until the 2020 time frame. This is due to the need to develop a hydrogen-fueled combustion turbine that can reliably generate power and be guaranteed by the turbine vendors.") The report acknowledges that certain technical issues remain regarding turbine component design that mu be addressed before pure hydrogen syngas can be reliably burned in power turbines. It was suggested at the last meeting of the stakeholders tha the MACS report identify what is technologically achievable at an IGCC plant that could be economically and realistically designed and built today, and to focus on the economics and technology relevant to that option. The report remains unclear in this area. In particular, ES.1.2 shou expressly state which of the three cases identified is commercially achievable today. In this regard, it is my understanding that the 90% CO2 removal case is not realistically achievable today. If so, this conclusion should be stated clearly. At present, the discussion is potentially confu	The timetable for introduction technology making this option possible is subject to various factors, including federal and state subsidies, vendor research and development, and other financial and research issues. Vendors may have informed other stakeholders that they are confident that this option will be technically feasible. However, these vendors will all admit that the question of when is the salient question. Sargent & Lundy cannot make any definitive comment regarding when the technology that makes this option possible, that is, the hydrogen-burning combustion turbine, will be commercially available. The US DOE has set a target date for completion of the demonstration unit of 2012. Providing time for testing and evaluation of this demonstration unit, we do not believe that commercial availability of the turbine will occur in less than, at least, the next ten to twelve years.

Hopi	2	2	The draft does not include the Dakota Gasification plant in Table 2-2. Why?	The Great Plains Synfuels Plant is the same as the Dakota Gasification plant (orignial name)
Hopi	2	3	Conceptual Project Construction Schedule. The discussion at Section 2.9, at page 2-40, appears to begin with a description of the amount of time required to complete an IGCC facility from the decision to begin. However, the time estimate provided appears to exclude any estimate of the time required to receive permitting and all approvals necessary to begin construction. This same problem appears to exist with respect to the other technology options considered. To comply with the PUC's directive, the MACS Study should include an analysis of the time required to receive permitting and all approvals necessary to begin construction.	Sargent & Lundy's construction schedule estimates assume lengths of time for permitting that we have have observed in other projects. We however, do not have the expertise or competence to address the numerous issues that may arise in the process of permitting a project in the specific localities that are the subject of this study. Given the uncertain nature of the objections to any plant's construction, we do not believe an analysis of the possible length of time required for permitting would provide any useful data. We understand that it is possible that the permitting process could last for several years.
Hopi	6	1	Carbon Sequestration Analysis. The study does not appear to address whether there is actual demand for CO2 in EOR activities in California. While the report concludes that, technically, the possibility exists to ship CO2 from a Mohave alternative or complement powerplant to Califor for use in EOR operations, the study consultants do not appear to have examined whether there is actual demand in the marketplace for such a product. Anecdotal information that I have received suggests that, at the present time, there is not a market for CO2 transported from Arizona for use in EOR operations in Californi	It is true that there is no existing market for CO2 for EOR in California. The technical potential doe exist for extensive CO2-EOR, but the lack of supply to the oilfields is at least part of the reason that CO EOR has not been undertaken to any large degree. Whether power plants outside of California can economically sell their CO2 in California will be largely determined by the potential for cheaper CO2 from California oil refineries. This dynamic will be clarified in the final report.

Appendix F

Fuel Prices

1. APPENDIX F – FUEL PRICES

We were asked to investigate historic and future prices for electrical generation fuels in the Southwest. Costs for all fuels, except coal, have increased significantly over the last several years. Natural gas, once near half the price of oil, has moved dramatically upward, yet remains cheaper than oil. Coal prices, by comparison, have increased at less than the rate of inflation.

In terms of future fuel prices, we believe that natural gas prices (in real dollars) are likely to decline somewhat over the next several years (through 2010), but gradually rise thereafter, reaching our current peaks only after 2025. The forecasted decline for the period 2006-2010 in natural gas prices is based on the rate of decline of prices for that period existing currently in the NYMEX Henry Hub futures market. Coal prices, generally, on the other hand, are likely to increase gradually (in real dollars) from present time until 2025, but at a modest rate compared to that of natural gas.

Table F-1 — Electric Generation Fuel Price Forecast for AZ & NV

	2006	2007	2008	2009	2010	2015	2020	2025
Natural Gas	9.30	7.98	7.02	6.36	5.85	6.45	7.12	7.86
Coal	1.24	1.26	1.28	1.31	1.34	1.48	1.63	1.80
Prices are in year 2006 dollars per million-Btu.								

1.1 TASK AND METHODOLOGY

This task involved investigating historic and future prices for electrical generation fuels in the Southwest.

Work on this task proceeded by:

- Collecting historic prices for coal[1], natural gas and other fuels in the Southwest
- Reviewing forecasts and projections of fuel prices
- Developing possible fuel price forecasts

[1] Coal prices for purposes of this task do not include prices for the Black Mesa Mine coal presently used by the Mohave Generating Station.

1.2 HISTORIC PRICES

Costs for all fuels except coal have shown significant increases over the last several years. The table below summarizes costs for Arizona and Nevada since 1998. This data was based on EIA fuel costs for generation. Oil (petroleum liquids) is the most expensive fuel and has doubled in price over this period. Natural gas, once near half the price of oil, has moved dramatically upward but still is cheaper than oil. Coal prices, by comparison, have increased at less than the rate of inflation

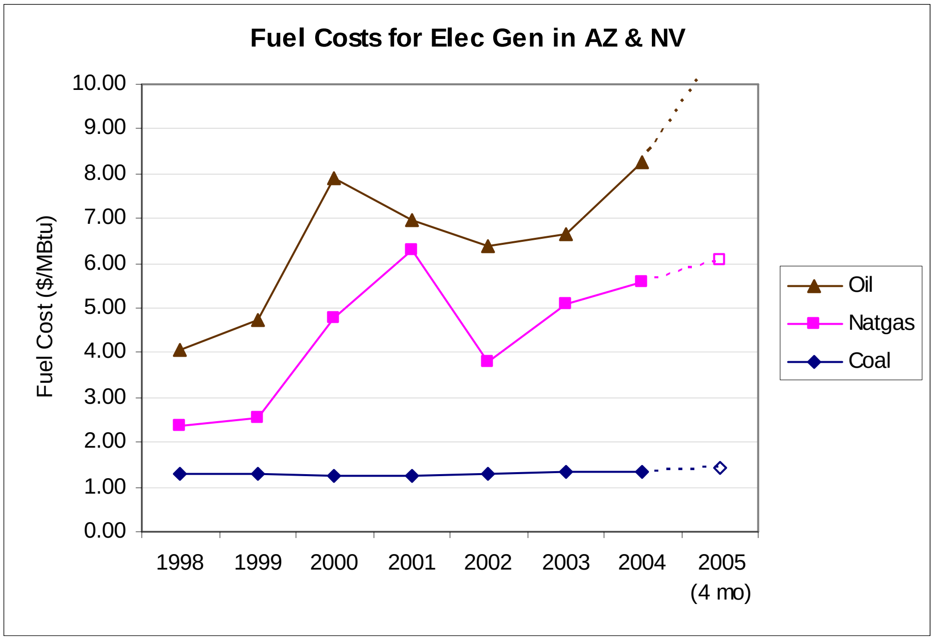
Table F-2 — Average Cost of Fuels Delivered for Electricity Generation in Arizona & Nevada

Cost (nominal $/Million Btu)		Year						
Fuel	State	1998	1999	2000	2001	2002	2003	2004
Coal	AZ	1.33	1.33	1.24	1.25	1.25	1.26	1.29
	NV	1.30	1.29	1.26	1.26	1.34	1.39	1.35
Coal Total		1.31	1.31	1.25	1.26	1.29	1.32	1.32
NG	AZ	2.39	2.64	4.78	4.60	3.20	5.04	5.71
	NV	2.30	2.42	4.75	8.03	4.38	5.11	5.48
NG Total		2.35	2.53	4.76	6.31	3.79	5.08	5.60
Oil [2]	AZ	4.29	4.98	8.60	8.11	6.73	7.92	9.30
	NV	3.80	4.53	7.22	5.85	6.00	5.42	7.22
Oil Total		4.04	4.75	7.91	6.98	6.37	6.67	8.26

The figure below graphically represents this data and includes prices for the first four months of 2005. Here, again, there has been a steep rise in oil prices and a more modest one for natural gas prices.

[2] Petroleum liquids include distillate fuel oil, residual fuel oil, jet fuel, kerosene, and waste oil.

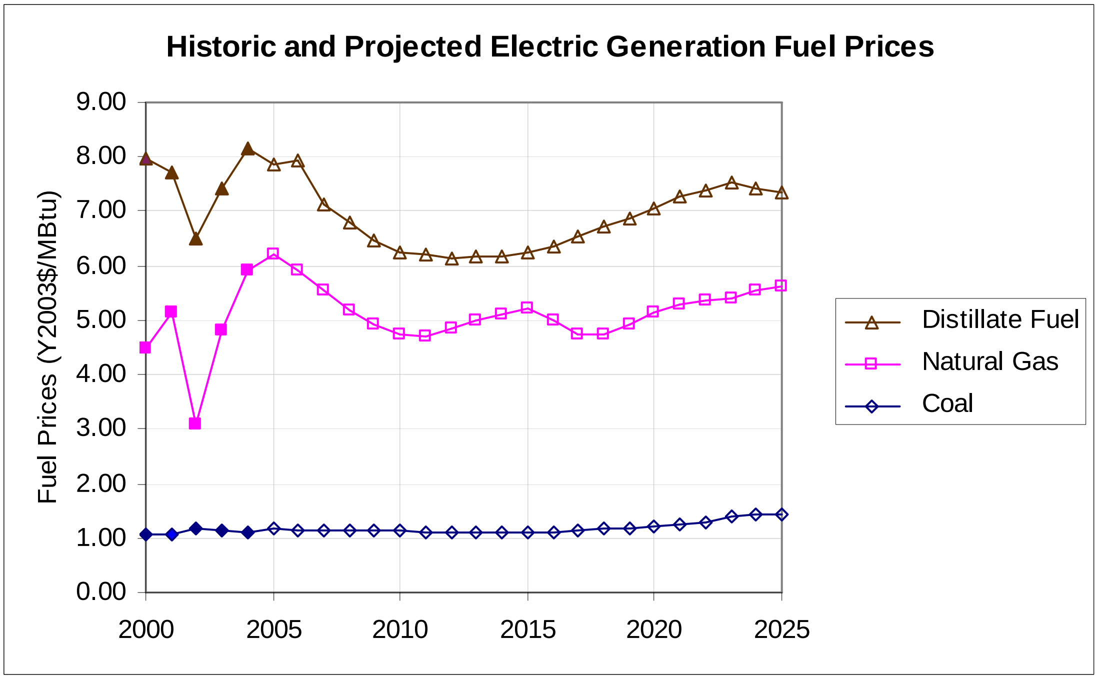
Figure F-1 — Historic Fuel Costs for Electric Generation in Arizona and Nevada



1.3 FUTURE PRICES

A starting point for considering future energy prices is the latest version of the Annual Energy Outlook (AEO) produced by the EIA. The most recent version, released in the spring of 2005 is AEO 2005, which was developed in the later part of 2004. The figure below shows the actual prices (in solid markers) through 2004 and the forecast (hollow markers) up through 2025.

Figure F-2 — Historic Prices and AEO 2005 Fuel Price Forecasts for the Region [3]



One basic feature of this forecast is the projected decline of oil and natural gas prices in real terms from their present values to moderately lower ones by 2010 and modest increases thereafter.

The following figure from EIA's Short Term Energy Outlook (STEO) of November 8, 2005 shows that current natural gas spot prices are above the equivalent of $12/Million Btu and predicts a steep decline to slightly above $8/Million Btu in the Summer of 2006, but followed by a subsequent increase.

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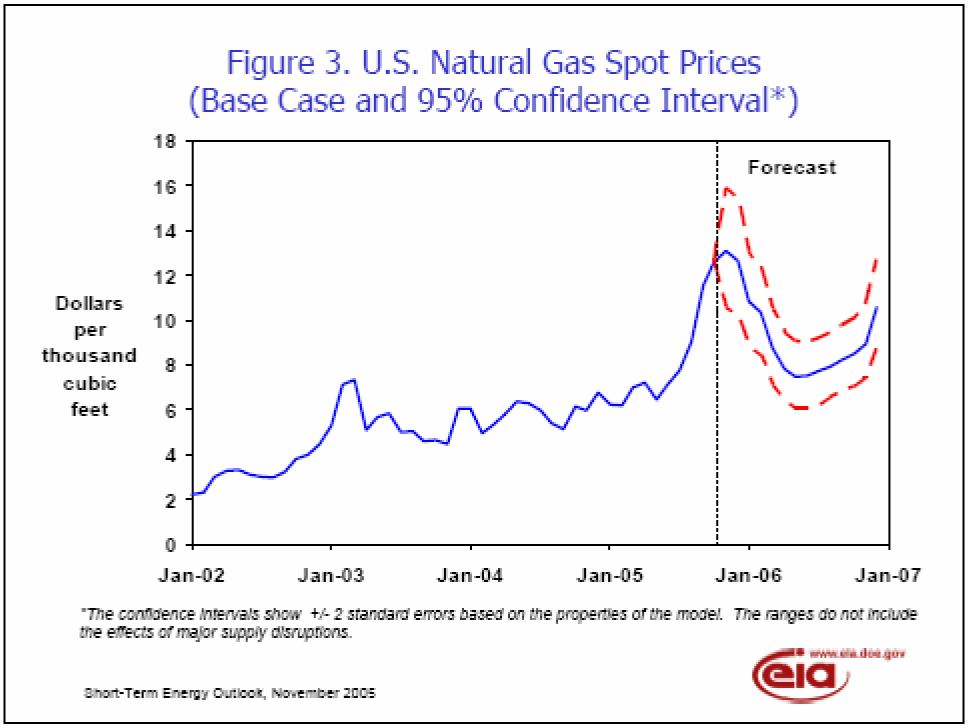
[3] AOE 2005, Table 71. Electric Power Projections for Electricity Market Module Western Electricity Coordinating Council / Rocky Mountain Power Area and Arizona-New Mexico-Southern Nevada Power Area

Figure F-3 — EIA STEO Natural Gas Price Forecast



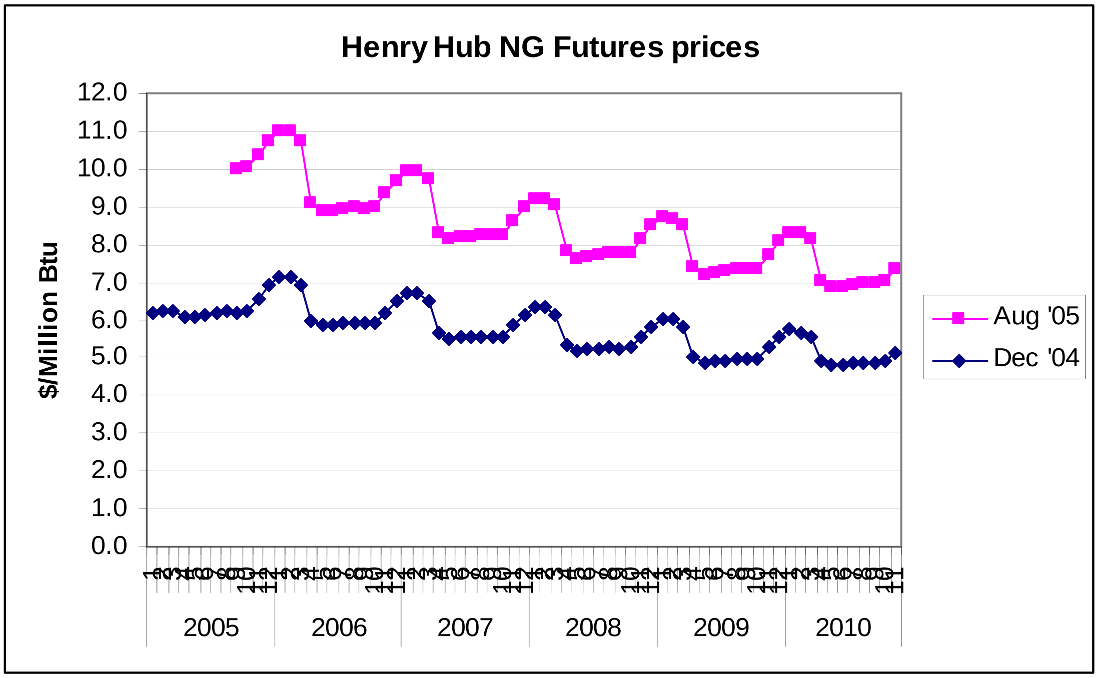
A further comparison can be performed using natural gas citygate prices from the STEO (Short-Term Energy Outlook) for the Mountain region. In 2004 they were $5.63/thousand CF, in 2005 based on partial year data they are calculated to be $7.06, and for 2006 they are forecasted to be $8.19 [4]. Converting to a Btu basis,[5] those prices are respectively $5.49, $6.88 and $7.88 per million Btu. The 2004 citygate price of $5.49 is very close to the $5.60 cost of natural gas in AZ & NV for electric generation given in Table 1. Thus, changes in citygate natural gas prices will likely be very closely matched by the prices paid by electric generators.

Further indications of the long-term increase in natural gas prices can be obtained from the NYMEX natural gas futures for Henry Hub. The graph below shows those prices for late 2004 when the AEO was being produced and much more recent prices from August 2005. Prices for 2006 are now about $3 higher and even for 2010 they are still higher by about $2 per million Btu

[4] "EIA Short Term Energy Outlook", Table 8c. U.S. Regional Natural Gas Prices: Medium Recovery Case, September 2005.

[5] Average heat content for natural gas consumption is 1,026 Btu/CF, from EIA AEO Documentation Appendix H.

Figure F-4 — Natural Gas Futures Price Change from Dec 2004 to Aug 2005.



Given this recent price data, it seems that the AEO 2005 natural gas forecast should be adjusted upward to reflect these more recent markets. While it seems that some decline in the real price of natural gas is likely over the next few years, it also seems that that over the long-term, with depletion of natural gas resources and greater world competition for this fuel, prices will experience a gradual rise.[6]

While coal prices are not likely to increase to as great an extent, there are factors, such as the use of other fuels to mine and transport coal and overall increased demand, that will most likely cause a modest increase in real prices. A countervailing factor is that CO2 emission costs will reduce the relative cost of coal and thus may reduce the demand for and price of coal. However, our revised coal forecast is slightly above that of the AEO.

[6] The specific methodology used for the intermediate term natural gas price forecast was to take the November 2005 STEO price and to apply a proportional adjustments based on the August & October NYMEX natural gas futures through 2010.

Figure F-5 — Revised Fuel Price Forecast for AZ & NV

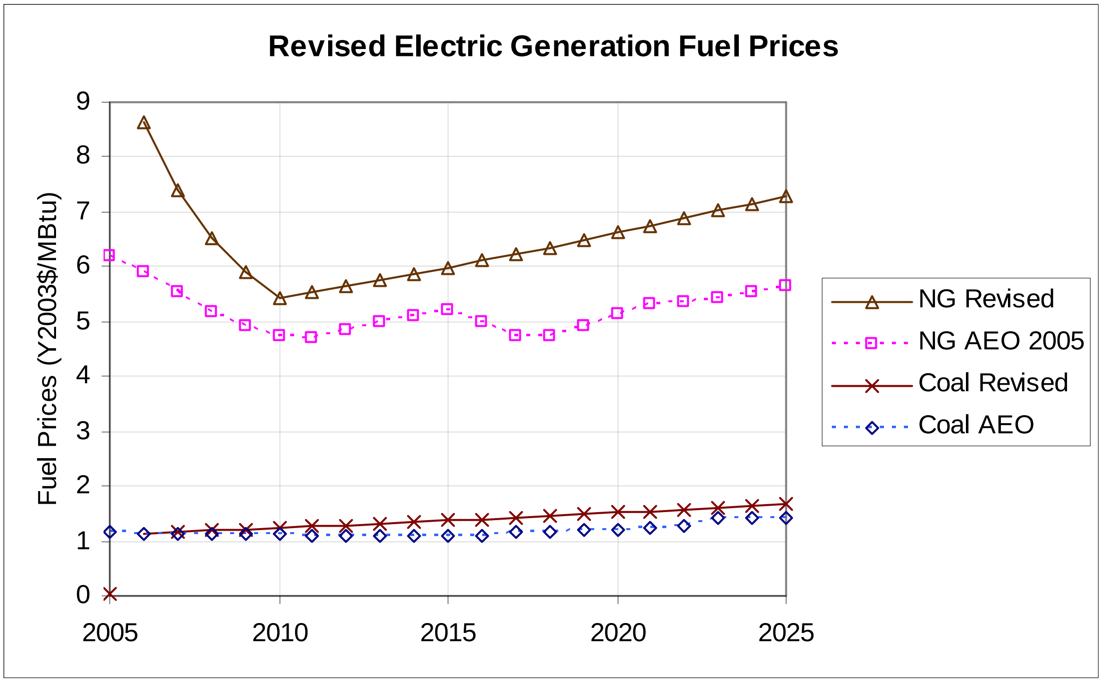


Table F-3 — Electric Generation Fuel Price Forecast for AZ & NV

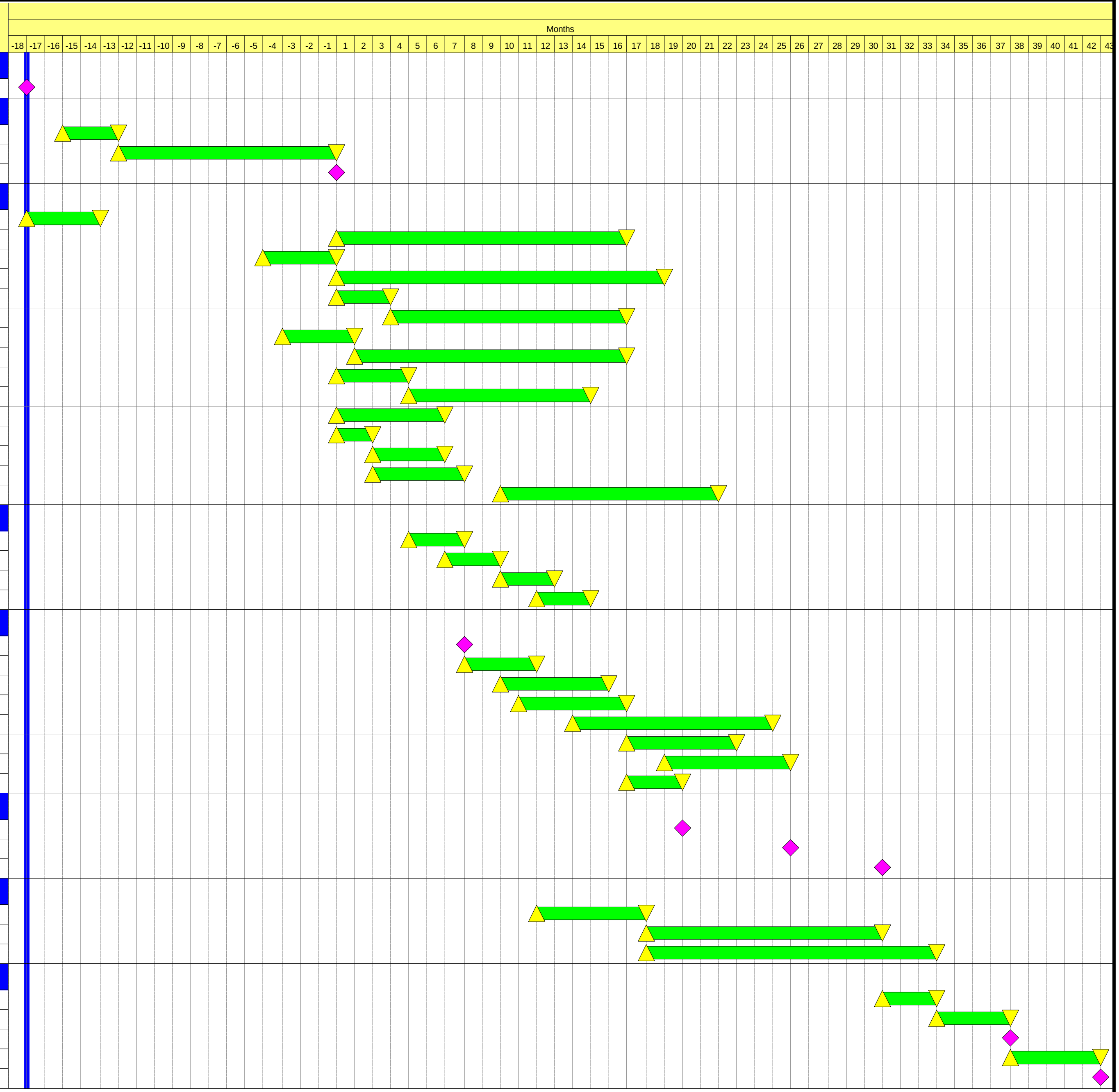
	2006	2007	2008	2009	2010	2015	2020	2025
Natural Gas	9.30	7.98	7.02	6.36	5.85	6.45	7.12	7.86
Coal	1.24	1.26	1.28	1.31	1.34	1.48	1.63	1.80
Prices are in year 2006 dollars per million-Btu.								

To summarize, future natural gas and coal prices are likely to be above the AEO 2005 forecast. In view of the price sequence of Henry Hub natural gas futures prices, natural gas prices are likely to decline somewhat over the next several years, but then rise again. Coal prices are also likely to increase but at a modest rate.

Appendix G

Supplementary IGCC Information

Activity ID	Activity Description
AUTHORIZATION	
A0005	NOTICE TO PROCEED
PERMITTING	
A0025	PREPARE PERMIT APPLICATION
A0030	AGENCY REVIEW APPLICATION
A0035	OBTAIN CONSTRUCTION PERMIT
ENGINEERING / PROCUREMENT	
A0045	PROCURE COMBUSTION TURBINES
A0047	FABRICATE / DELIVER COMBUSTION TURBINE
A0050	PROCURE STEAM TURBINE
A0051	FABRICATE / DELIVER STEAM TURBINE
A0052	PROCURE STEP-UP TRANSFORMER
A0053	FABRICATE / DELIVER STEP-UP TRANSFORMER
A0055	PROCURE GASIFICATION SYSTEM
A0057	FABRICATE / DELIVER GASIFICATION SYSTEM
A0060	PROCURE GRINDING / MILL EQUIPMENT
A0063	FABRICATE / DELIVER GRINDING / MILL EQUIP
A0067	P&ID DEVELOPMENT
A0068	FINALIZE GAs / START DETAILED DESIGN
A0072	SITEWORK DESIGN
A0074	POWER BLOCK FOUNDATION DESIGN
A0076	WIRING DESIGN
CONSTRUCTION CONTRACTS	
A0096	SITEWORK
A0106	SUBSTRUCTURE
A0116	MECHANICAL
A0126	ELECTRICAL
COMBINED CYCLE PLANT CONSTRUCTION	
A0080	START CONSTRUCTION
A0086	SITEWORK
A0087	UNDERGROUND DUCTRUNS & UTILITIES
A0090	MAJOR FOUNDATIONS
A0115	HRSGs
A0125	CTs
A0127	STEAM TURBINE
A0135	STEP-UP TRANSFORMER
CC/CT PLANT STARTUP ON NATURAL GAS	
A0145	ENERGIZE AUXILIARY POWER
A0150	FIRST FIRE CT
A0155	COMMERCIAL OPERATION
GASIFICATION PLANT CONSTRUCTION	
A0160	FOUNDATIONS
A0162	GRINDING / MILL SYSTEM
A0165	GASIFICATION SYSTEM
GASIFICATION PLANT STARTUP	
A0175	CHECK-OUT GRINDING / MILL EQUIPMENT
A0180	CHECK-OUT GASIFICATION PLANT
A0185	FIRE COMBINED CYCLE PLANT ON SYN GAS
A0190	TUNE PERIOD
A0195	COMMERCIAL OPERATION



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IGB5

PROJECT SCHEDULE
INTEGRATED GASIFICATION COMBINED CYCLE
2x2x1- 500 MW

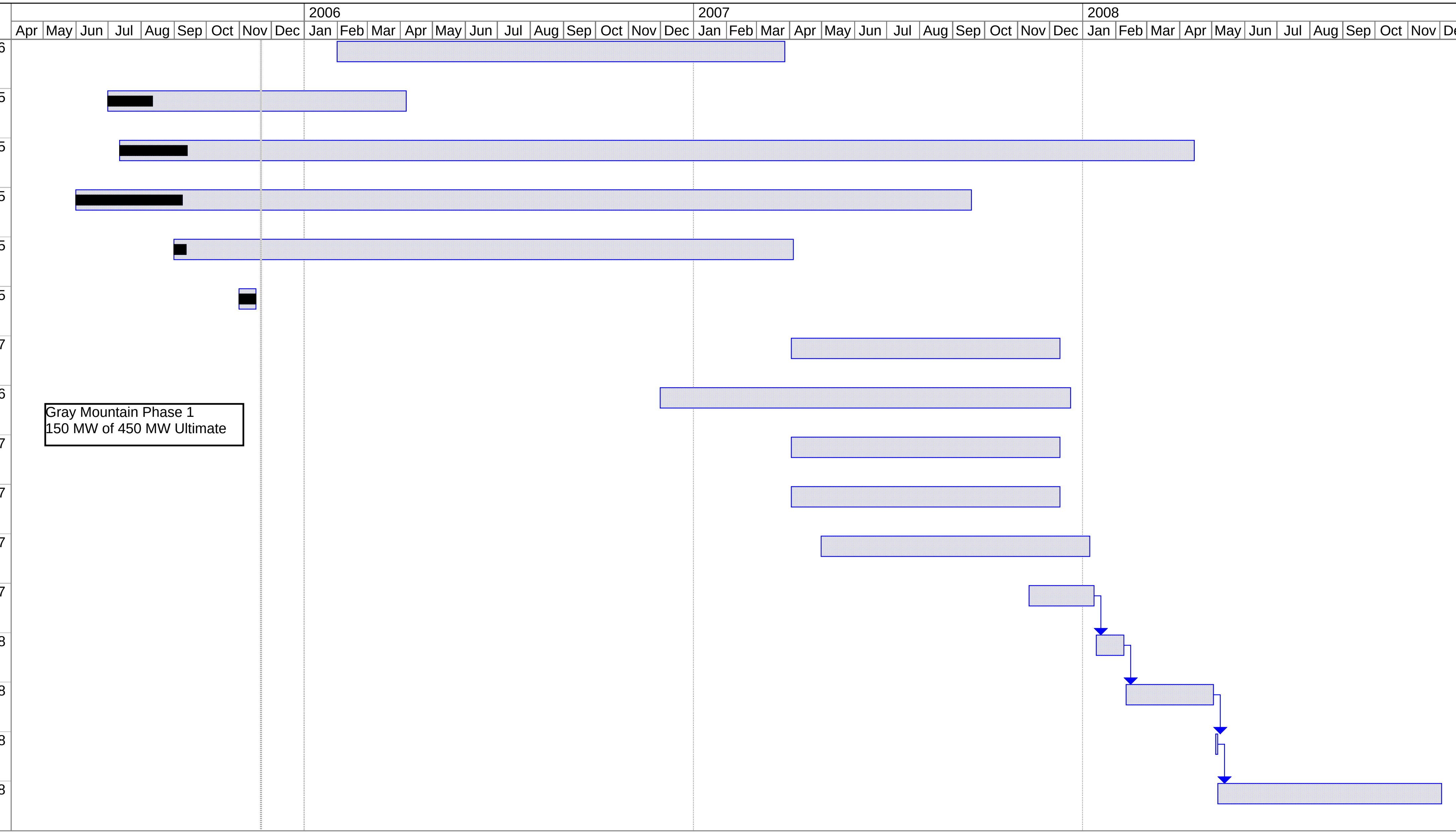
Sheet 1 of 1

Sargent & Lundy LLC

Appendix H

Supplementary Wind Information

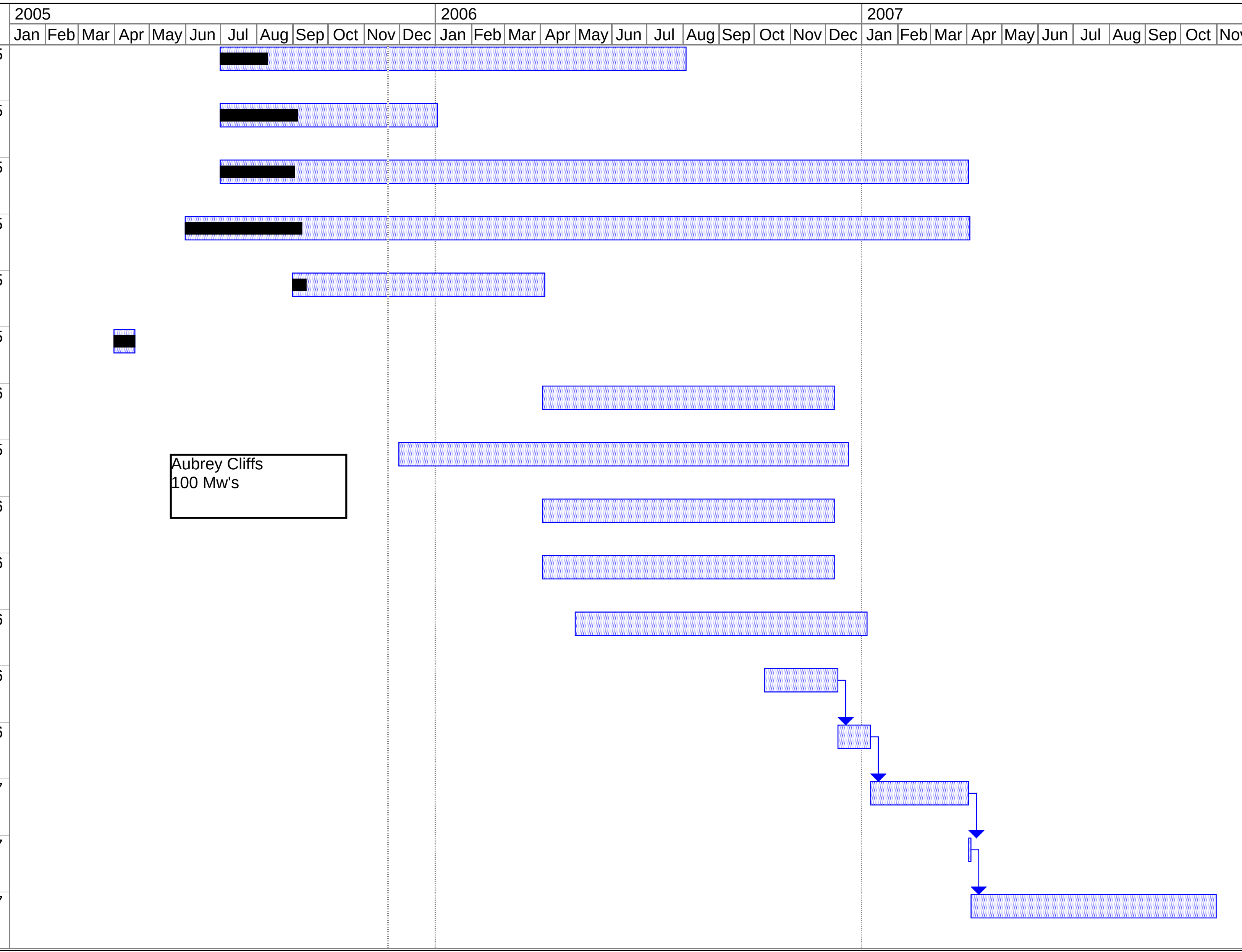
ID	Task Name	Duration	Start
1	Project Site Easements & Leases	300 days	Wed 2/1/06
2	Erect Met towers	200 days	Fri 7/1/05
3	Wind Measurement -Gray Mountain	720 days	Tue 7/12/05
4	Environmental Due Diligence	600 days	Wed 6/1/05
5	Obtain Site Permits	415 days	Thu 9/1/05
6	Build Project Model	12 days	Tue 11/1/05
7	Negotiate PPA	180 days	Tue 4/3/07
8	Negotiate Interconnection	275 days	Fri 12/1/06
9	Negotiate Turbine Purchase	180 days	Tue 4/3/07
10	Negotiate LTSA/O&M contract	180 days	Tue 4/3/07
11	Negotiate EPC contract	180 days	Tue 5/1/07
12	RFP for Banks	45 days	Mon 11/12/07
13	Select Lead Bank	20 days	Mon 1/14/08
14	Bank Diligence, Opinions, Consents	60 days	Mon 2/11/08
15	Financial Closing	2 days	Mon 5/5/08
16	Notice to Proceed-Construction	150 days	Wed 5/7/08



Project: GrayMountain
Date: Mon 11/21/05

Task	Milestone	Rolled Up Task	Rolled Up Progress	External Tasks	Group By Summary
Progress	Summary	Rolled Up Milestone	Split	Project Summary	

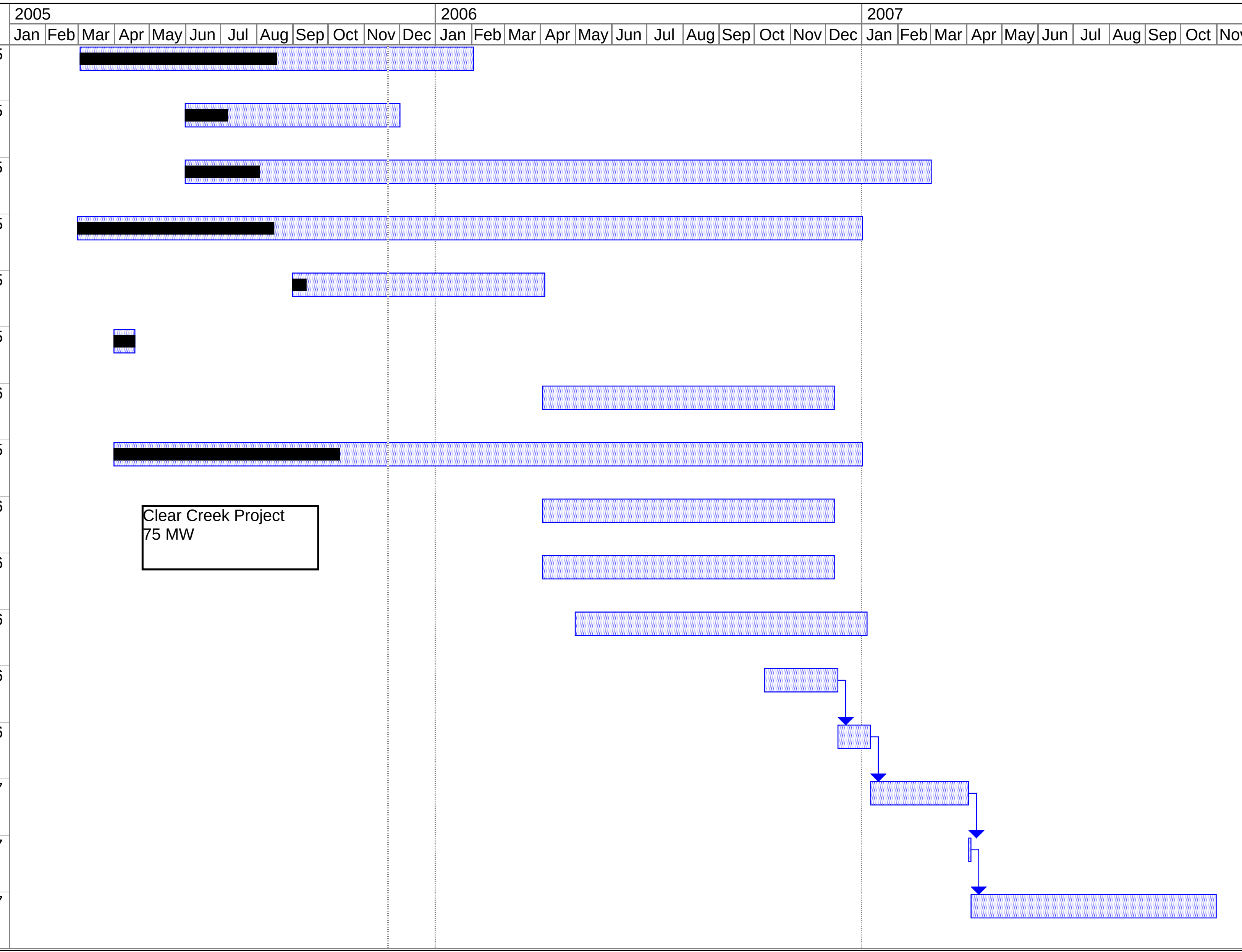
ID	Task Name	Duration	Start
1	Project Site Easements & Leases	285 days	Fri 7/1/05
2	Erect Met towers	132 days	Fri 7/1/05
3	Wind Measurement -Aubrey Cliffs	457 days	Fri 7/1/05
4	Environmental Due Diligence	480 days	Wed 6/1/05
5	Obtain Site Permits	154 days	Thu 9/1/05
6	Build Project Model	12 days	Fri 4/1/05
7	Negotiate PPA	180 days	Mon 4/3/06
8	Negotiate Interconnection w/Extension	275 days	Thu 12/1/05
9	Negotiate Turbine Purchase	180 days	Mon 4/3/06
10	Negotiate LTSA/O&M contract	180 days	Mon 4/3/06
11	Negotiate EPC contract	180 days	Mon 5/1/06
12	RFP for Banks	45 days	Tue 10/10/06
13	Select Lead Bank	20 days	Tue 12/12/06
14	Bank Diligence, Opinions, Consents	60 days	Tue 1/9/07
15	Financial Closing	2 days	Tue 4/3/07
16	Notice to Proceed-Construction	150 days	Thu 4/5/07



Project: AubreyCliffs
Date: Mon 11/21/05

Task	Summary	Rolled Up Progress	Project Summary
Progress	Rolled Up Task	Split	Group By Summary
Milestone	Rolled Up Milestone	External Tasks	

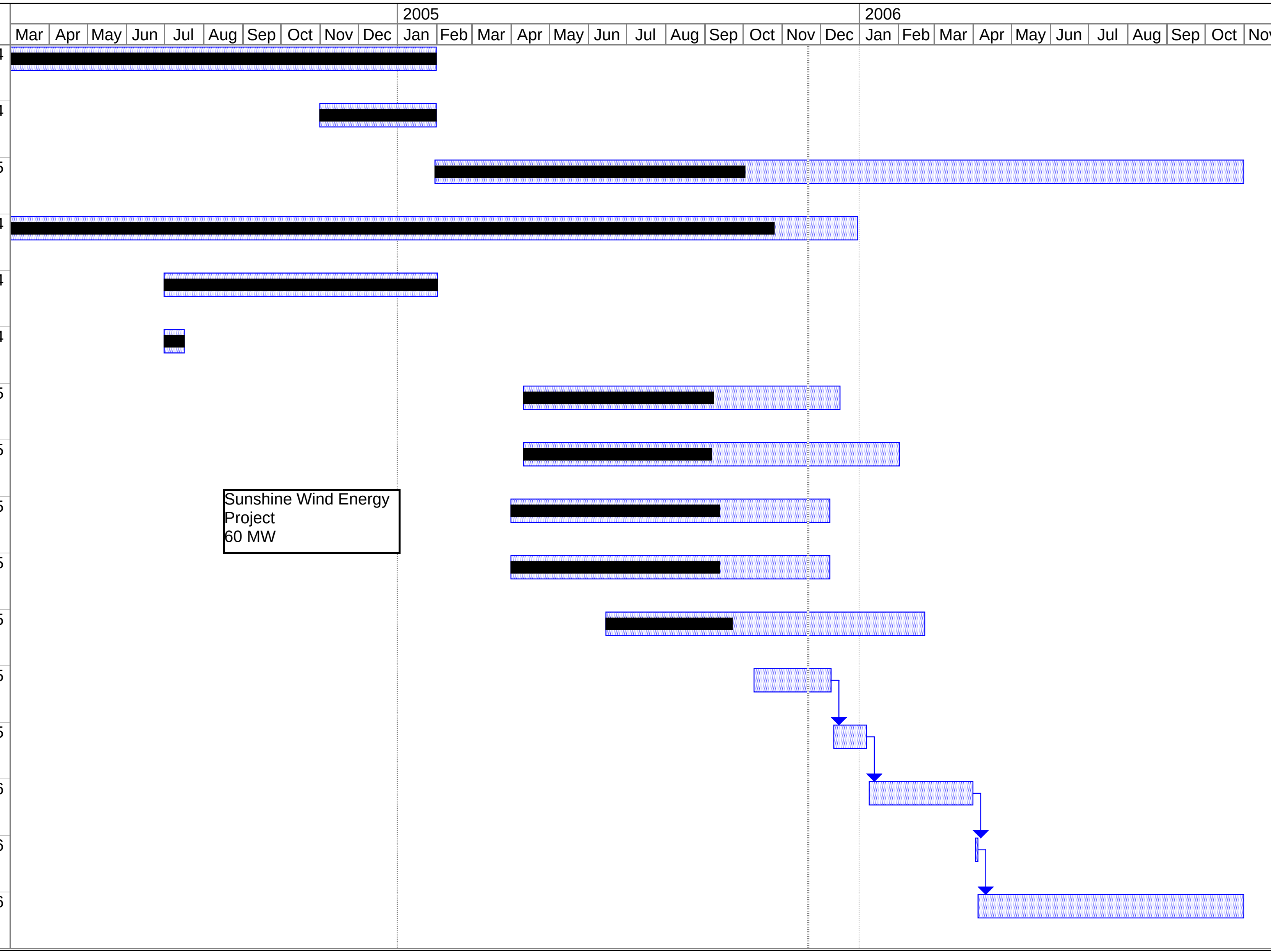
ID		Task Name	Duration	Start
1		Project Site Easements & Leases	241 days	Thu 3/3/05
2		Erect Met towers	132 days	Wed 6/1/05
3		Wind Measurement -Clear Creek	457 days	Wed 6/1/05
4		Environmental Due Diligence	480 days	Tue 3/1/05
5		Obtain Site Permits	154 days	Thu 9/1/05
6		Build Project Model	12 days	Fri 4/1/05
7		Negotiate PPA	180 days	Mon 4/3/06
8		Negotiate Interconnection w/Extension	457 days	Fri 4/1/05
9		Negotiate Turbine Purchase	180 days	Mon 4/3/06
10		Negotiate LTSA/O&M contract	180 days	Mon 4/3/06
11		Negotiate EPC contract	180 days	Mon 5/1/06
12		RFP for Banks	45 days	Tue 10/10/06
13		Select Lead Bank	20 days	Tue 12/12/06
14		Bank Diligence, Opinions, Consents	60 days	Tue 1/9/07
15		Financial Closing	2 days	Tue 4/3/07
16		Notice to Proceed-Construction	150 days	Thu 4/5/07



Project: ClearCreek
Date: Mon 11/21/05

Task		Summary		Rolled Up Progress		Project Summary	
Progress		Rolled Up Task		Split		Group By Summary	
Milestone		Rolled Up Milestone		External Tasks			

ID	Task Name	Duration	Start
1	Project Site Easements & Leases	241 days	Mon 3/1/04
2	Erect Met towers	66 days	Mon 11/1/04
3	Wind Measurement -Sunshine	457 days	Mon 1/31/05
4	Environmental Due Diligence	480 days	Mon 3/1/04
5	Obtain Site Permits	154 days	Thu 7/1/04
6	Build Project Model	12 days	Thu 7/1/04
7	Negotiate PPA	180 days	Mon 4/11/05
8	Negotiate Interconnection	213 days	Mon 4/11/05
9	Negotiate Turbine Purchase	180 days	Fri 4/1/05
10	Negotiate LTSA/O&M contract	180 days	Fri 4/1/05
11	Negotiate EPC contract	180 days	Wed 6/15/05
12	RFP for Banks	45 days	Mon 10/10/05
13	Select Lead Bank	20 days	Mon 12/12/05
14	Bank Diligence, Opinions, Consents	60 days	Mon 1/9/06
15	Financial Closing	2 days	Mon 4/3/06
16	Notice to Proceed-Construction	150 days	Wed 4/5/06



Project: Sunshine
Date: Mon 11/21/05

Task | Summary | Rolled Up Progress | Project Summary
Progress | Rolled Up Task | Split | Group By Summary
Milestone | Rolled Up Milestone | External Tasks

Appendix I

Geothermal Resources Maps

Figure I-1 — Potential Areas for Geothermal Plants

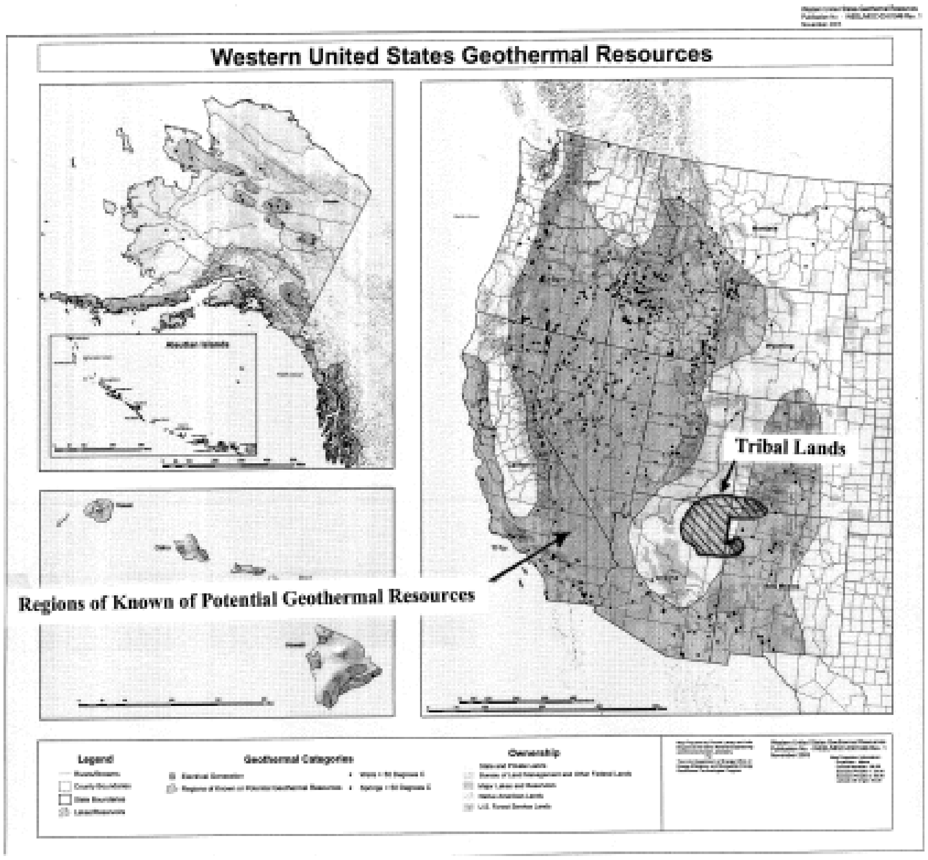


Figure I-2 — Location of Geothermal Wells in Arizona

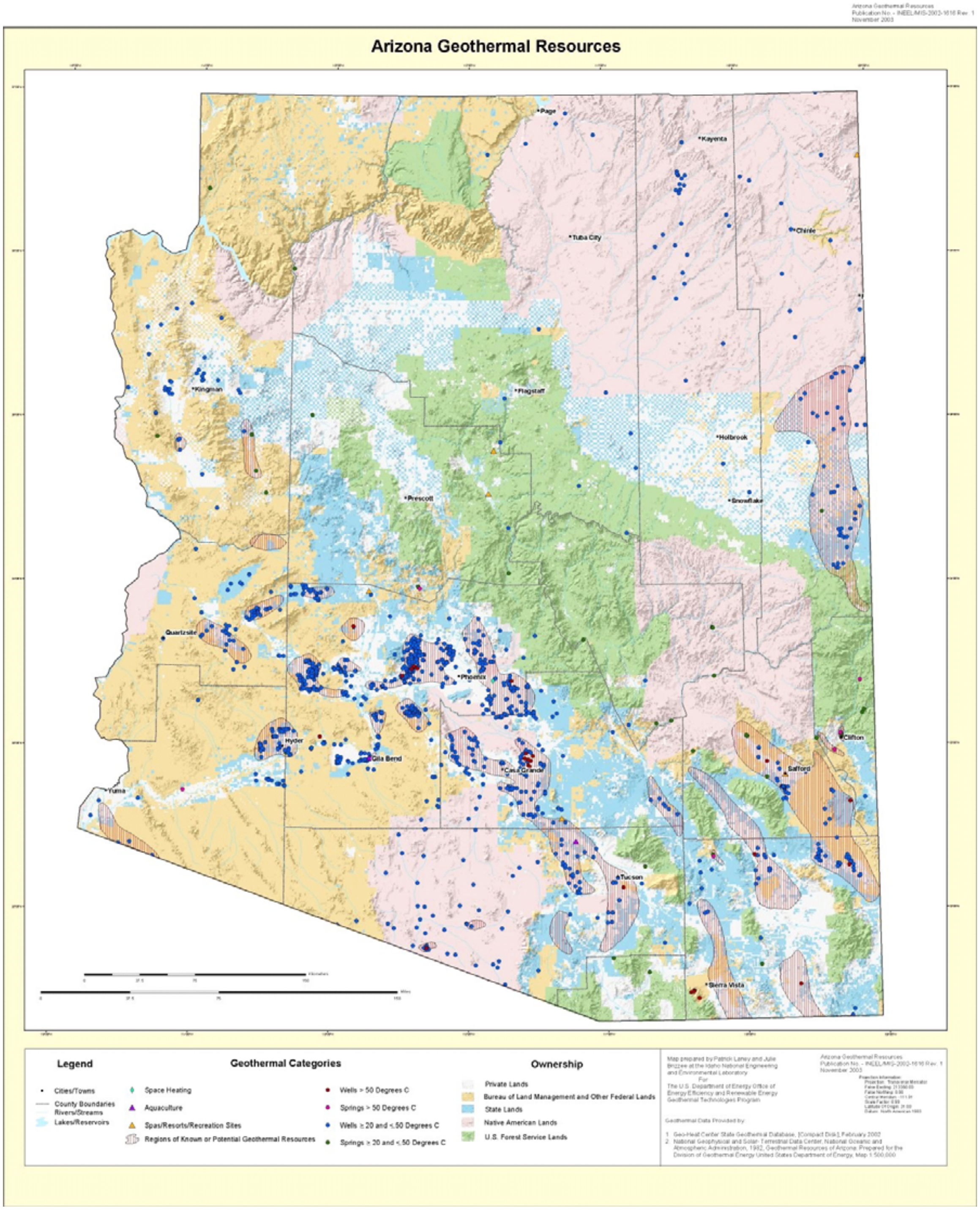


Figure I-3 — Location of Geothermal Wells in New Mexico

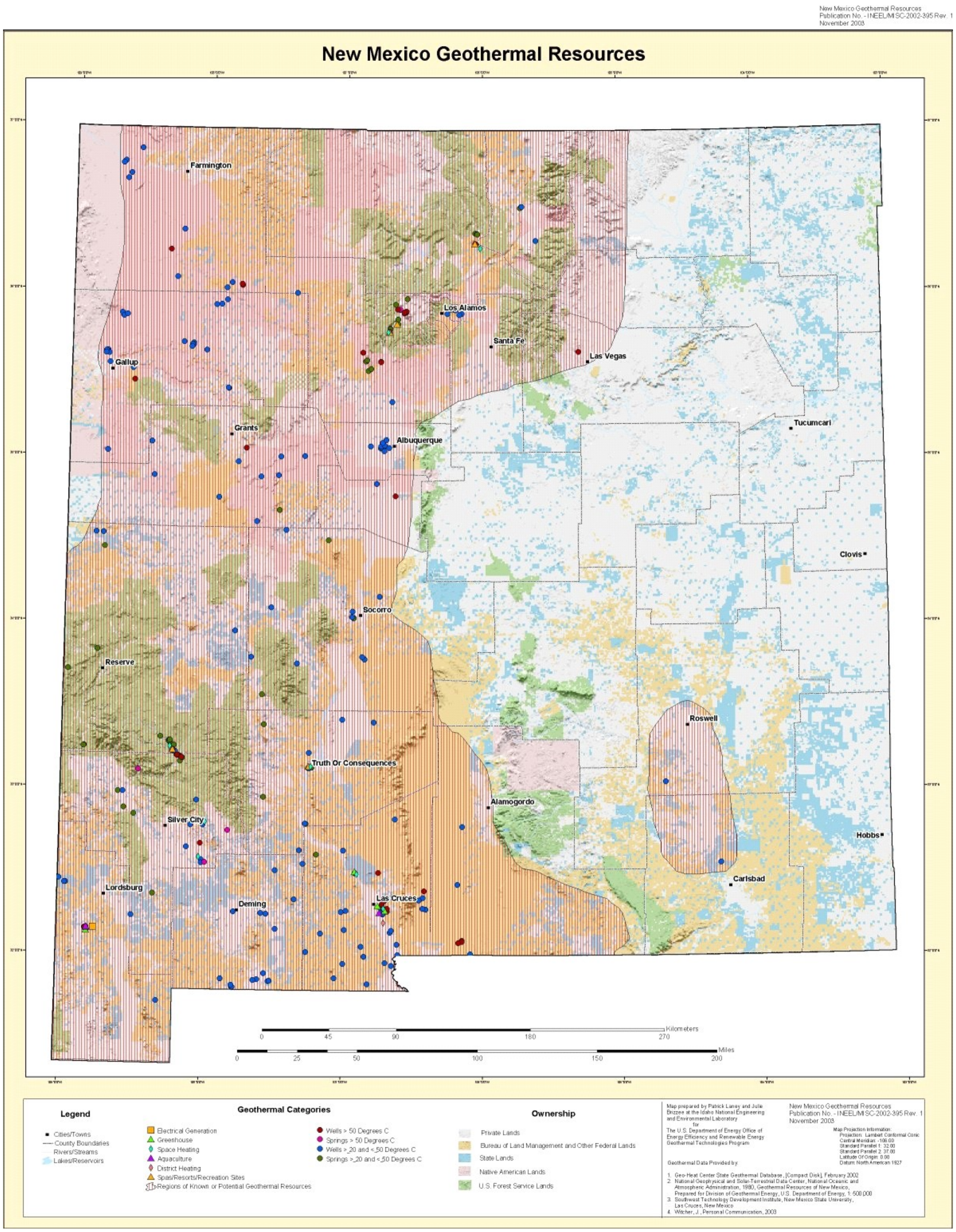


Figure I-4 — Location of Geothermal Wells in Colorado

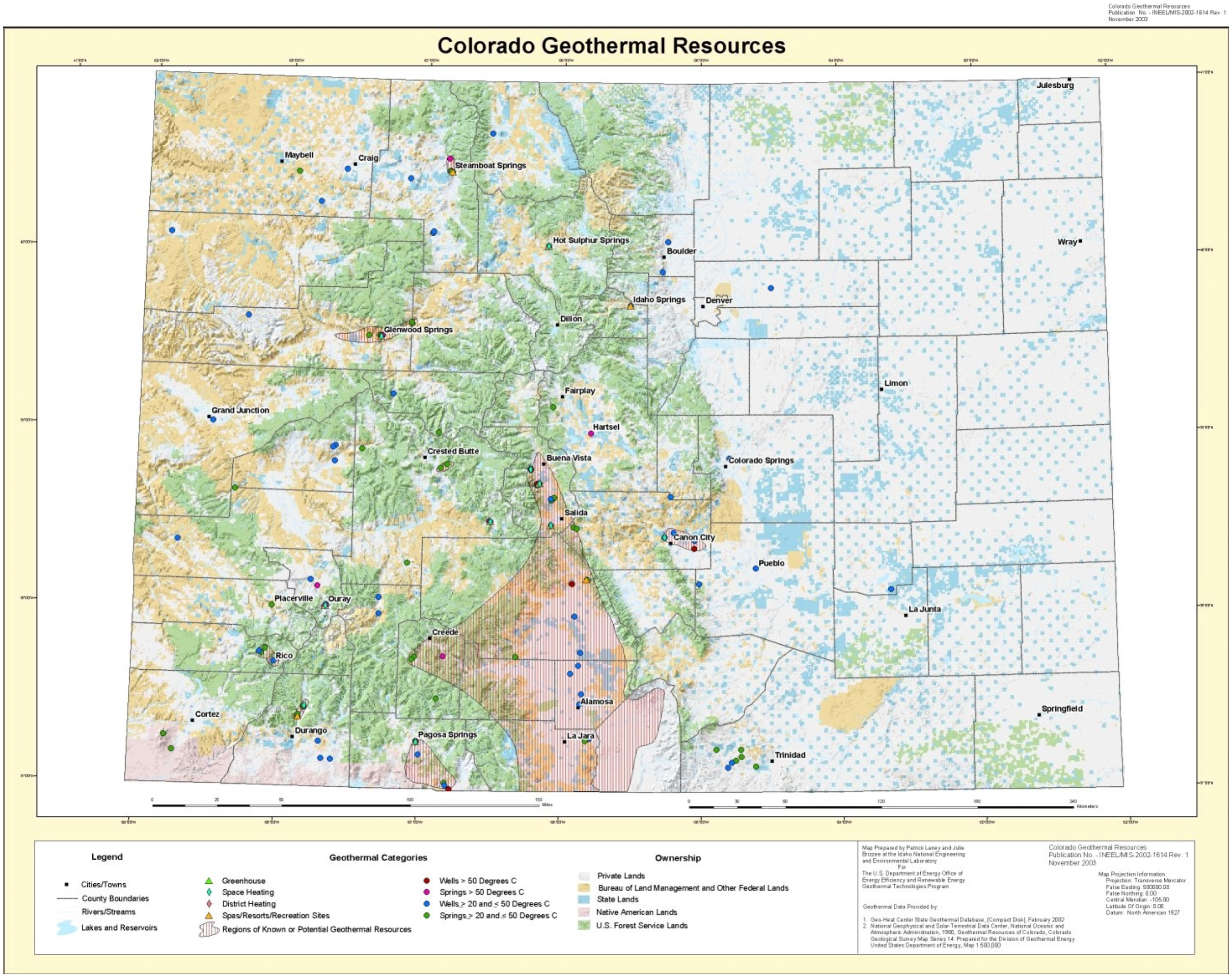
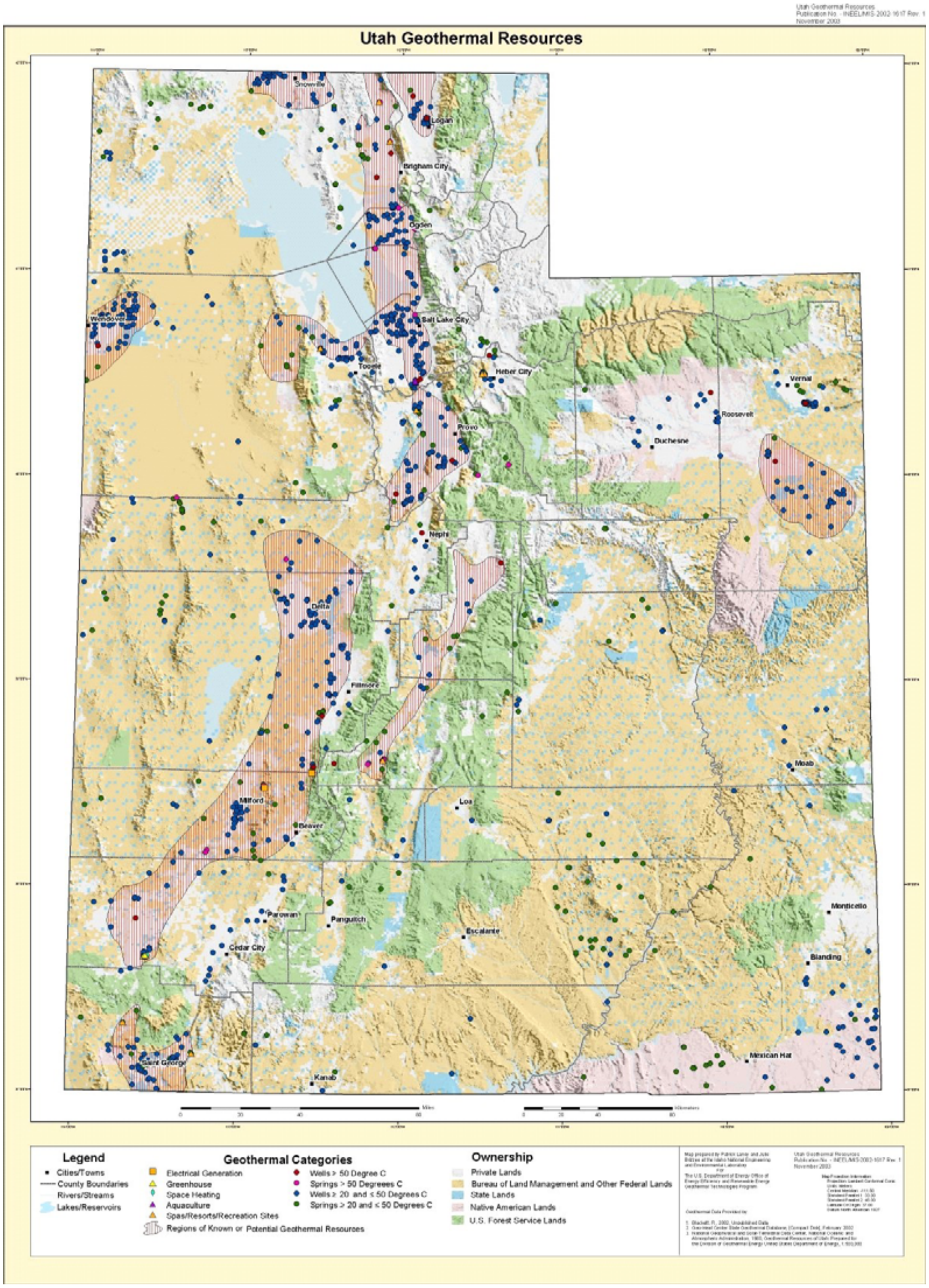


Figure I-5 — Location of Geothermal Wells in Utah



Appendix J

Biomass Resources Maps

Figure J-1 — Four-State Region Biomass Resource Map

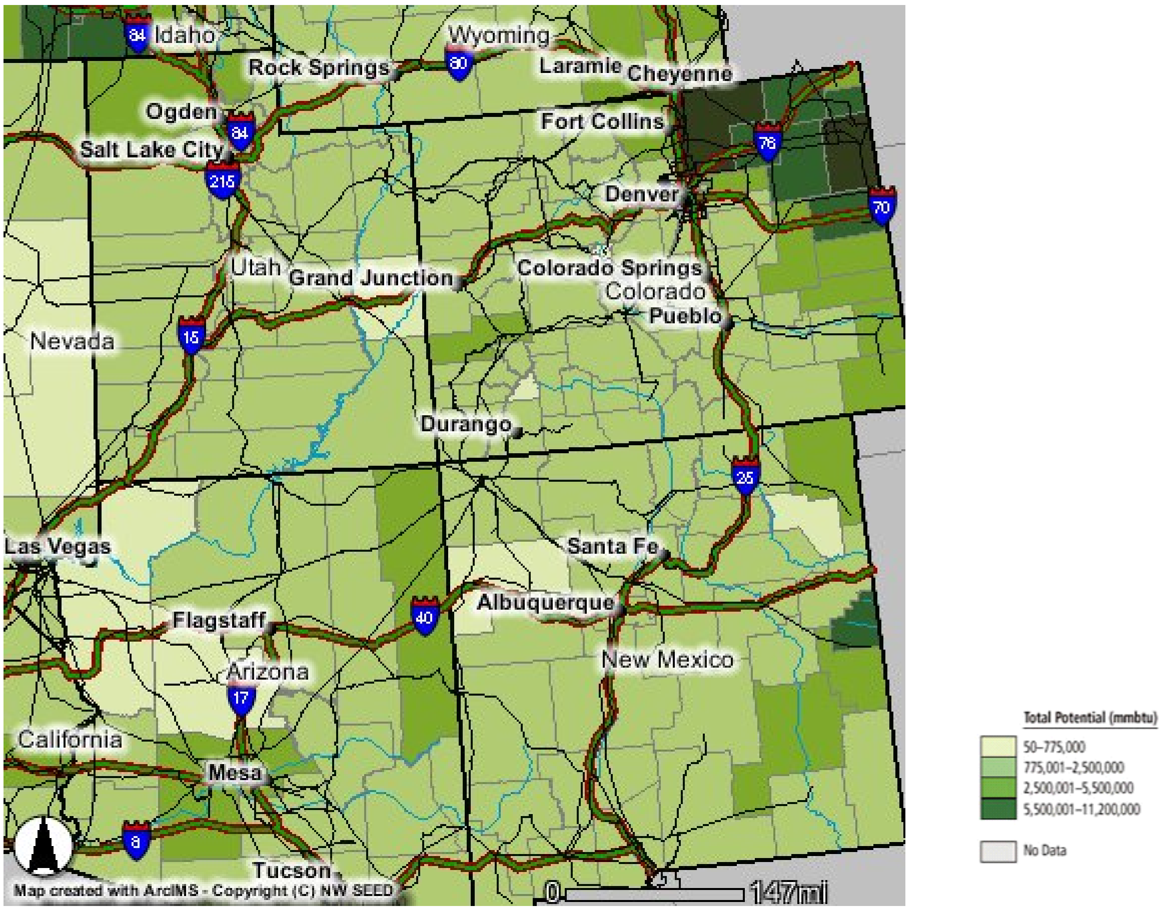


Figure J-2 — Arizona Biomass Resource Map

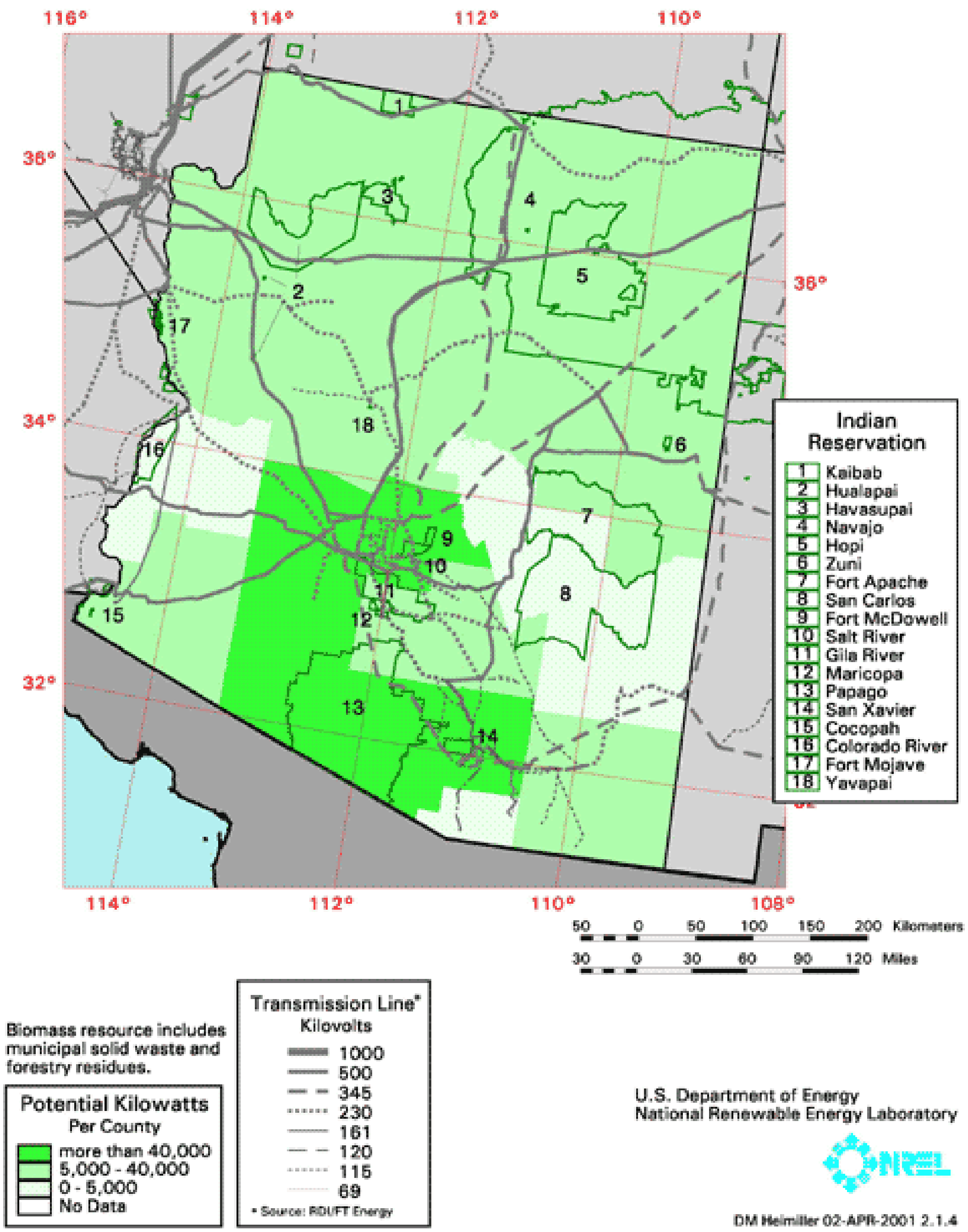


Figure J-3 — New Mexico Biomass Resource Map

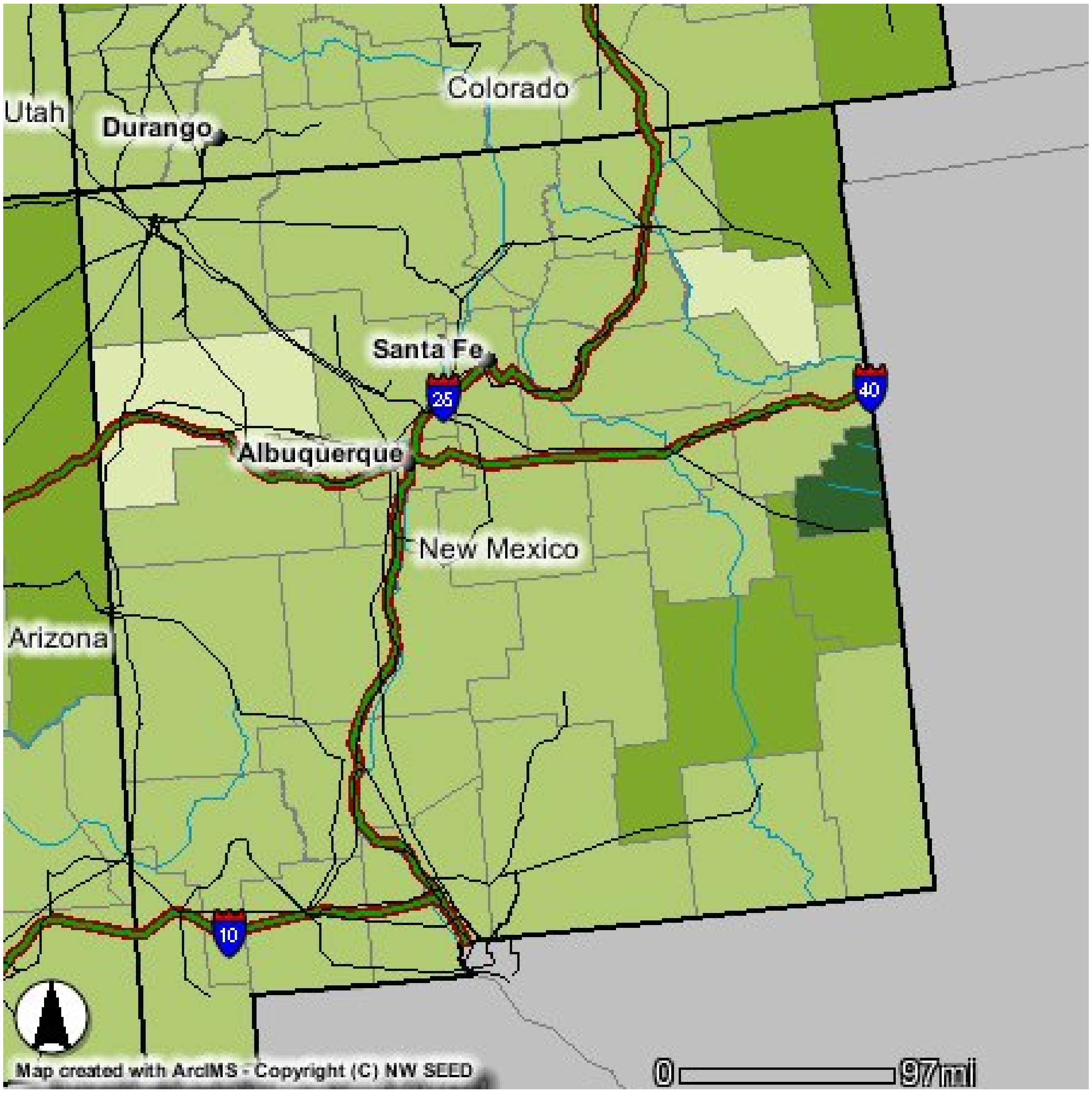
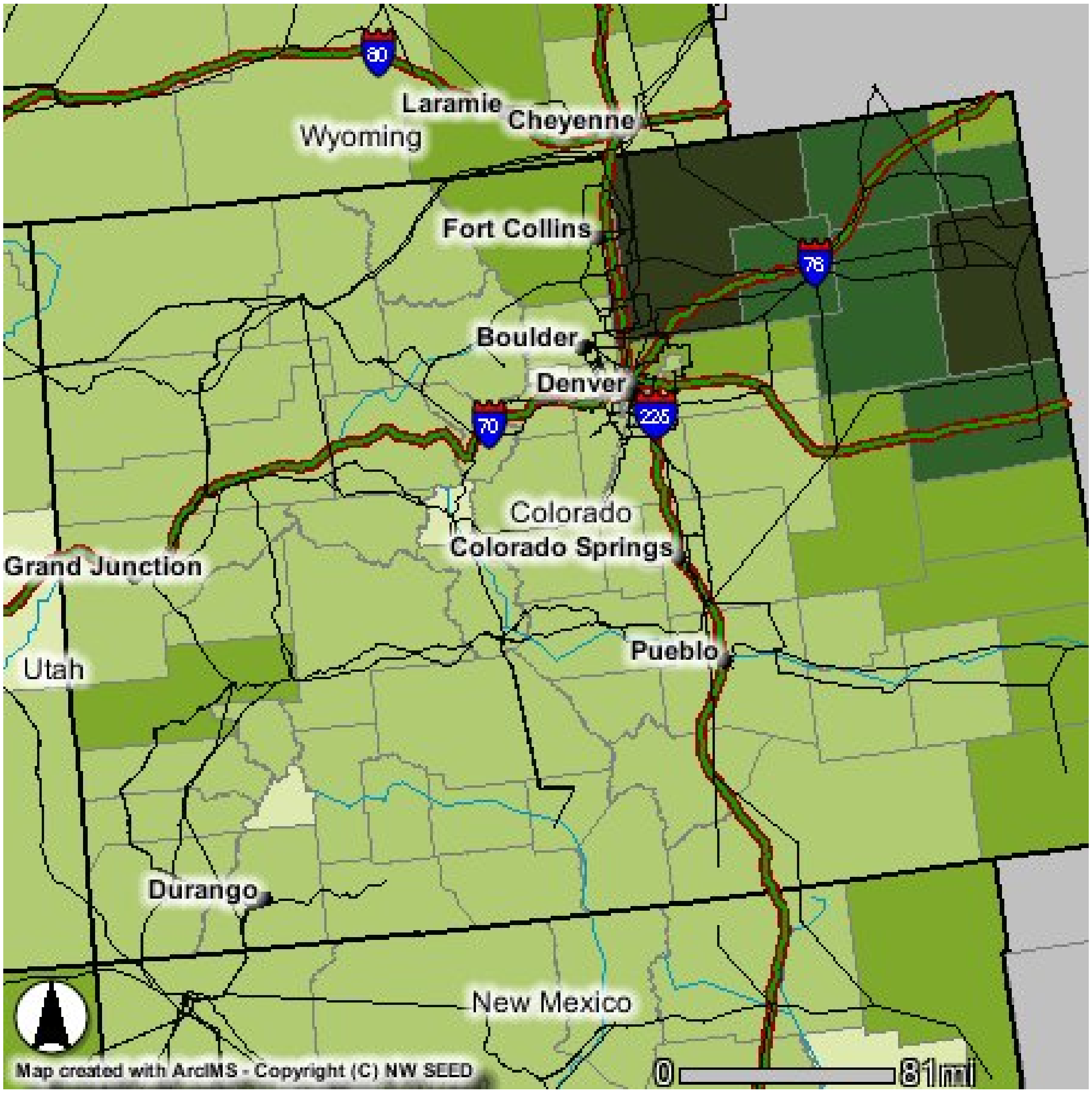


Figure J-4 — Utah Biomass Resource Map

Figure J-5 — Colorado Biomass Resource Map



Appendix J material

Appendix K

Transmission Data

Path: Four Corners to Palo Verde, via 230 or 345 kV

Yearly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		YEARLY	
Start Date	PATH_NAME	FIRM	
9/19/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	0	
1/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	0	
1/1/2007	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	
1/1/2008	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	

Monthly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		MONTHLY	
Start Date	PATH_NAME	FIRM	NON-FIRM
9/16/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	0	0
9/17/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	0	0
9/18/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	0	0
9/19/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	0	
9/20/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	0	0
11/1/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
12/1/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
1/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
2/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
3/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	0	0
4/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
5/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
6/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
7/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
8/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
9/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	53	53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	53	53
10/1/2006	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	53	53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	53	53

Path: Four Corners to Palo Verde, via 230 or 345 kV

Weekly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		WEEKLY	
Start Date	PATH_NAME	FIRM	NON-FIRM
9/20/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	0	0
10/3/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/10/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/17/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/24/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104

Path: Four Corners to Palo Verde, via 230 or 345 kV

Daily

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		DAILY	
Start Date	PATH_NAME	FIRM	NON-FIRM
9/16/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	0	0
9/17/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	117	117
9/20/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	0	0
9/21/2005	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	0	0
10/2/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/3/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/4/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/5/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/6/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/7/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/8/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/9/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/10/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/11/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/12/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/13/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/14/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104
10/15/2005	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	0	0
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/	94	94
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SH	104	104

Path: Four Corners to Palo Verde, via 230 or 345 kV

Hourly

TS_TYPE	POINT_TO_POINT
Start Date	(Multiple Items)

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		HOURLY	
Start Hour	PATH_NAME	FIRM	NON-FIRM
4	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	171	171
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	322	
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
5	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	171	171
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	422	
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
6	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	171	171
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/		422
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
7	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	171	171
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	422	
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
8	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	171	171
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/		322
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
9	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
10	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	247	252
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
11	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/		247
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
12	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/		247
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
13	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	117	117
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/		117
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
14	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	117	117
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	422	422
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
15	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	167	167
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	422	
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
16	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	167	167
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	117	422
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
17	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	167	167
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	117	117
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
18	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	167	167

Path: Four Corners to Palo Verde, via 230 or 345 kV

18	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	167	
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
19	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	167	167
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	167	
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
20	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	167	167
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
21	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	167	167
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/	167	167
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
22	W/AZPS/AZPS-AZPS/FOURCORNE230-PALOVERDE500/	171	171
	W/AZPS/AZPS-AZPS/FOURCORNE345-PALOVERDE500/		167
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44
23	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/		53
	W/TEPC/AZPS-SRP/FOURCORNE345-PALOVERDE500/SHR		44

Path: Fourcorners to Mead

Yearly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		YEARLY	
PATH_NAME	Start Date	FIRM	
W/AZPS/AZPS-AZPS/FOURCORNE345-MEAD500/	1/1/2006	0	

Monthly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		MONTHLY	
PATH_NAME	Start Date	FIRM	NON-FIRM
W/AZPS/AZPS-AZPS/FOURCORNE345-MEAD500/	10/1/2005	0	0
	11/1/2005	0	0
	12/1/2005	0	0
	1/1/2006	0	0
	2/1/2006	0	0
	3/1/2006	0	0
	4/1/2006	0	0
	5/1/2006	0	0
	6/1/2006	0	0
	7/1/2006	0	0
	8/1/2006	0	0
	9/1/2006	0	0
	10/1/2006	0	0

Weekly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		WEEKLY	
PATH_NAME	Start Date	FIRM	NON-FIRM
W/AZPS/AZPS-AZPS/FOURCORNE345-MEAD500/	9/19/2005	1	0
	9/26/2005	0	0
	10/3/2005	0	0
	10/10/2005	0	0
	10/17/2005	0	0
	10/24/2005	0	0
	10/31/2005	0	0

Path: Fourcorners to Mead

Daily

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		DAILY	
PATH_NAME	Start Date	FIRM	NON-FIRM
W/AZPS/AZPS-AZPS/FOURCORNE345-MEAD500/	9/17/2005	1	1
	9/18/2005	1	0
	9/19/2005	1	0
	9/20/2005	1	0
	9/21/2005	1	58
	9/22/2005	1	11
	9/23/2005	1	36
	9/24/2005	1	36
	9/25/2005	1	1
	9/26/2005	1	1
	9/27/2005	1	1
	9/28/2005	1	1
	9/29/2005	1	1
	9/30/2005	0	0
	10/1/2005	0	0
	10/2/2005	0	0
	10/3/2005	0	0
	10/4/2005	0	0
	10/5/2005	0	0
	10/6/2005	0	0
	10/7/2005	0	0
	10/8/2005	0	0
	10/9/2005	0	0
	10/10/2005	0	0
	10/11/2005	0	0
	10/12/2005	0	0
	10/13/2005	0	0
	10/14/2005	0	0
	10/15/2005	0	0
	10/16/2005	0	0
	10/17/2005	0	0
	10/18/2005	0	0
	10/19/2005	0	0
	10/20/2005	0	0
	10/21/2005	0	0
	10/22/2005	0	0
	10/23/2005	0	0

Path: Fourcorners to Mead

Hourly

TS_TYPE	POINT_TO_POINT
Start Date	9/16/2005

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		HOURLY	
PATH_NAME	Start Hour	FIRM	NON-FIRM
W/AZPS/AZPS-AZPS/FOURCORNE345-MEAD500/	12	1	211
	13	1	161
	14	1	161
	15	1	211
	16	1	211
	17	1	211
	18	1	211
	19	1	211
	20	1	211
	21	1	211
	22	1	211
	23	1	211

Path: Navajo 500 to Palo Verde

Yearly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		YEARLY	
Start Date	PATH_NAME	FIRM	
10/1/2005	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
11/1/2005	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
12/1/2005	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
1/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	
2/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
3/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
4/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
5/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
6/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
7/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
8/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
9/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
10/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
11/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
12/1/2006	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
1/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	
2/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
3/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
4/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
5/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
6/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
7/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
8/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
9/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
10/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
11/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
12/1/2007	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
1/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	
2/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
3/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
4/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
5/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
6/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
7/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
8/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
9/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
10/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
11/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
12/1/2008	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
1/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
2/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
3/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
4/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
5/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
6/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
7/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
8/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
9/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
10/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	

Path: Navajo 500 to Palo Verde

11/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
12/1/2009	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
1/1/2010	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	

Monthly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		MONTHLY	
Start Date	PATH_NAME	FIRM	NON-FIRM
10/1/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	0
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
11/1/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
12/1/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
1/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	403	403
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
2/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	403	403
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
3/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	403	403
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
4/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	378	378
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
5/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	378	378
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
6/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	378	378
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
7/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	378	378
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
8/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	378	378
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
9/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	378	378
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	

Path: Navajo 500 to Palo Verde

9/1/2006	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/1/2006	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	44	44
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	378	378
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
11/1/2006	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0

Weekly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		WEEKLY	
Start Date	PATH_NAME	FIRM	NON-FIRM
9/19/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	209
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/26/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
10/3/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/10/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/17/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/24/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/31/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125

Daily

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		DAILY	
Start Date	PATH_NAME	FIRM	NON-FIRM
9/17/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
9/18/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220

Path: Navajo 500 to Palo Verde

9/18/2005	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	45
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
9/19/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
9/20/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/21/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	70
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	43
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/22/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	70
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	43
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	64	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/23/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	41
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/24/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	76
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/25/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	209
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	76
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/26/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	209
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	76
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/27/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	209
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	76
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/28/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	209
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	76
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/29/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	209
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	76
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
9/30/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	6	6
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	25	25
10/1/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/2/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/3/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9

Path: Navajo 500 to Palo Verde

10/3/2005	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/4/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/5/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/6/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/7/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/8/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/9/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/10/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	9	9
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/11/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/12/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/13/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/14/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/15/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/16/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/17/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/18/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0

Path: Navajo 500 to Palo Verde

10/18/2005	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/19/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/20/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/21/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/22/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125
10/23/2005	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	0	0
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	0	0
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	0	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/	125	125

Path: Navajo 500 to Palo Verde

Hourly

TS_TYPE	POINT_TO_POINT
Start Date	9/18/2005

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		HOURLY	
Start Hour	PATH_NAME	FIRM	NON-FIRM
0	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	108	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
1	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	209	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
2	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	120
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	258	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
3	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	70
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	260	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
4	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	245
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	45
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	260	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
5	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	231
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	70
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	260	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
6	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	230
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	95
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	260	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
7	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	231
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	70
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	260	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
8	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	269	280
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	70
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	260	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
9	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	269	530
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	70
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	244	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
10	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	269	280
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	67
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	226	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
11	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	269	280
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	67
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	230	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
12	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	269	280
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	167
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	246	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125

Path: Navajo 500 to Palo Verde

13	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	269	280
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	170
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	243	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
14	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	269	280
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	193	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
15	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
16	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
17	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
18	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
19	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
20	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
21	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	40	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
22	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	93	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125
23	W/AZPS/AZPS-AZPS/NAVAJO500-PALOVERDE500/	209	220
	W/LDWP/NAV TO PV/NAVAJO TO PALOVERDE/	76	220
	W/SRP/AZPS-SRP/NAVAJO500-PALOVERDE500/059	136	
	W/TEPC/AZPS-SRP/NAVAJO500-PALOVERDE500/		125

Path: Cholla 500 to Palo Verde

Yearly

No Offerings

Monthly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		MONTHLY	
PATH_NAME	Start Date	FIRM	NON-FIRM
W/AZPS/AZPS-SRP/CHOLLA500-PALOVERDE500/	10/1/2005	0	0
	11/1/2005	69	69
	12/1/2005	69	69
	1/1/2006	115	115
	2/1/2006	115	115
	3/1/2006	115	115
	4/1/2006	115	115
	5/1/2006	115	115
	6/1/2006	115	115
	7/1/2006	115	115
	8/1/2006	115	115
	9/1/2006	115	115
	10/1/2006	115	115

Weekly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		WEEKLY	
PATH_NAME	Start Date	FIRM	NON-FIRM
W/AZPS/AZPS-SRP/CHOLLA500-PALOVERDE500/	9/19/2005	115	34
	9/26/2005	0	0
	10/3/2005	0	0
	10/10/2005	0	0
	10/17/2005	69	69
	10/24/2005	69	69

Path: Cholla 500 to Palo Verde

Daily

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT TS_CLASS	
		DAILY	
PATH_NAME	Start Date	FIRM	NON-FIRM
W/AZPS/AZPS-SRP/CHOLLA500-PALOVERDE500/	9/17/2005	115	397
	9/18/2005	15	15
	9/19/2005	115	34
	9/20/2005	115	115
	9/21/2005	115	115
	9/22/2005	115	115
	9/23/2005	115	115
	9/24/2005	115	115
	9/25/2005	115	115
	9/26/2005	115	115
	9/27/2005	115	115
	9/28/2005	115	115
	9/29/2005	115	115
	9/30/2005	115	115
	10/1/2005	0	0
	10/2/2005	0	0
	10/3/2005	0	0
	10/4/2005	0	0
	10/5/2005	0	0
	10/6/2005	0	0
	10/7/2005	0	0
	10/8/2005	0	0
	10/9/2005	0	0
	10/10/2005	0	0
	10/11/2005	0	0
	10/12/2005	0	0
	10/13/2005	0	0
	10/14/2005	0	0
	10/15/2005	69	69
	10/16/2005	69	69

Hourly

TS_TYPE	POINT_TO_POINT
Start Date	9/16/2005

Max of CAPACITY		SERVICE_INCREMENT TS_CLASS	
		HOURLY	
PATH_NAME	Start Hour	FIRM	NON-FIRM
W/AZPS/AZPS-SRP/CHOLLA500-PALOVERDE500/	12	115	467
	13	115	464
	14	115	462
	15	115	461
	16	115	396
	17	115	403
	18	115	386
	19	115	360
	20	115	309
	21	115	327
	22	115	444
	23	115	424

Moenkopi to Palo Verde, 500 kV

Yearly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		YEARLY	
Start Date	PATH_NAME	FIRM	
10/1/2005	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
11/1/2005	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
12/1/2005	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
1/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	
2/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
3/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
4/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
5/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
6/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
7/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
8/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
9/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
10/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
11/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
12/1/2006	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
1/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	
2/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
3/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
4/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
5/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
6/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
7/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
8/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
9/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
10/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
11/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
12/1/2007	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
1/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	
2/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
3/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
4/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
5/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
6/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
7/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
8/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
9/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
10/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
11/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
12/1/2008	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
1/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
2/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
3/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
4/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
5/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
6/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
7/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
8/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
9/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
10/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	

Moenkopi to Palo Verde, 500 kV

11/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
12/1/2009	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
1/1/2010	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	

Monthly

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		MONTHLY	
Start Date	PATH_NAME	FIRM	NON-FIRM
10/1/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	0
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
11/1/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
12/1/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
1/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	472	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
2/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	472	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
3/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	472	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
4/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	472	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
5/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	472	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
6/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	472	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
7/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	472	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
8/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	472	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	472	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/1/2006	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	44	44
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	0	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125

Weekly

TS_TYPE	POINT_TO_POINT

Moenkopi to Palo Verde, 500 kV

Max of CAPACITY		SERVICE_INCREMENT TS_CLASS	
		WEEKLY	
Start Date	PATH_NAME	FIRM	NON-FIRM
9/19/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/26/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/3/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/10/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/17/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/24/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125

Daily

TS_TYPE	POINT_TO_POINT

Max of CAPACITY		SERVICE_INCREMENT TS_CLASS	
		DAILY	
Start Date	PATH_NAME	FIRM	NON-FIRM
9/17/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/18/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/19/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/20/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/21/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/22/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/23/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/24/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/25/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/26/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	

Moenkopi to Palo Verde, 500 kV

9/26/2005	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/27/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/28/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/29/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
9/30/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/1/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/2/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/3/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/4/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/5/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/6/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/7/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/8/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/9/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/10/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/11/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/12/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/13/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/14/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125
10/15/2005	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	9	9
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	8	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/	125	125

Moenkopi to Palo Verde, 500 kV

Hourly

TS_TYPE	POINT_TO_POINT
Start Date	9/16/2005

Max of CAPACITY		SERVICE_INCREMENT	TS_CLASS
		HOURLY	
Start Hour	PATH_NAME	FIRM	NON-FIRM
4	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
5	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
6	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
7	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
8	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	329	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
9	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	0	0
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	177	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
10	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	0	0
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	177	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
11	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	0	0
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	177	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
12	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	0	0
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	177	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
13	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	0	0
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	177	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
14	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	0	0
	W/SRP/AZPS-SRP/MOENKOPI500-PALOVERDE500/055	177	
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
15	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
16	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
17	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
18	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
19	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
20	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
21	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
22	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125
23	W/AZPS/AZPS-AZPS/MOENKOPI500-PALOVERDE500/	209	209
	W/TEPC/AZPS-SRP/MOENKOPI500-PALOVERDE500/		125

Contingency List
Case 1: Black Mesa IGCC

Conting #	Contingency
1	L_10011AMBROSIA-10041BISTIC1
2	L_10025B-A-10369WESTMESAC1
3	L_10025B-A-10292SAN_JUANC&1-MS
4	L_10041BISTI-10248PILLARC1
5	L_10052BURNHAM-10111GALLEGOSC1
6	L_10052BURNHAM-10248PILLARC1
7	L_10232OJO-10292SAN_JUANC1
8	T_10232OJO-12050OJOC1
9	L_10232OJO-12082TAOSC1
10	L_10248PILLAR-14211FOURCORNC1
11	T_10292SAN_JUAN-10289SAN_JUANC1
12	T_10291SAN_JUAN-10290SAN_JUANC1
13	T_10292SAN_JUAN-10290SAN_JUANC1
14	T_10292SAN_JUAN-10291SAN_JUANC1
15	T_10292SAN_JUAN-10318SJUAN_G1C1
16	T_10292SAN_JUAN-10319SJUAN_G2C1
17	T_10292SAN_JUAN-10320SJUAN_G3C1
18	T_10292SAN_JUAN-10321SJUAN_G4C1
19	L_10292SAN_JUAN-16102MCKINLEYC&1-MS
20	L_10292SAN_JUAN-16102MCKINLEYC&2-MS
21	L_10292SAN_JUAN-14101FOURCORNC1
22	T_79060SANJNPS-10292SAN_JUANC1
23	L_10292SAN_JUAN-79064SHIPROCKC1
24	L_10294SANDIA-10369WESTMESAC1
25	T_10369WESTMESA-10370WESTMS_1C1
26	T_10369WESTMESA-10371WESTMS_2C1
27	L_10369WESTMESA-11014ARR___PSC1
28	L_10369WESTMESA-14101FOURCORNC&1-MS
29	T_16102MCKINLEY-10382YAHTAHEYC1
30	L_12038HERNANDZ-12050OJOC1
31	T_12081TAOS-12082TAOSC1
32	L_14000CHOLLA-14004SAGUAROC&1-MS
33	T_14000CHOLLA-14100CHOLLAC1
34	T_14000CHOLLA-14100CHOLLAC2
35	T_14000CHOLLA-14901CHOLLA2C1
36	T_14000CHOLLA-14902CHOLLA3C1
37	T_14000CHOLLA-14903CHOLLA4C1
38	L_14000CHOLLA-15001CORONADOC1
39	L_14001FOURCORN-14002MOENKOPIC&1-MS
40	T_14001FOURCORN-14101FOURCORNC1
41	T_14001FOURCORN-14915FCNGN5CCC1
42	L_14002MOENKOPI-14006YAVAPAIC&1-MS
43	L_14002MOENKOPI-26044MARKETPLC&1-MS
44	L_14002MOENKOPI-24042ELDORDOC&1-MS
45	L_14002MOENKOPI-14003NAVAJOC&1-MS
46	L_14002MOENKOPI-79095SHIPROCKC&1-MS
47	L_14003NAVAJO-14005WESTWINGC&1-MS
48	L_14003NAVAJO-26123CRYSTALC&1-MS
49	T_14003NAVAJO-15981NAVAJO1C1
50	T_14003NAVAJO-15982NAVAJO2C1
51	T_14003NAVAJO-15983NAVAJO3C1
52	L_14005WESTWING-14006YAVAPAIC&1-MS
53	T_14006YAVAPAI-14234YAVAPAIC1
54	T_14006YAVAPAI-14234YAVAPAIC2
55	L_14100CHOLLA-14103PRECHCYNC1
56	L_14100CHOLLA-14102PNPKAPSC&1-MS
57	L_14100CHOLLA-14101FOURCORNC&1-MS
58	L_14100CHOLLA-14101FOURCORNC&2-MS
59	T_14100CHOLLA-14204CHOLLAC1
60	T_14100CHOLLA-14204CHOLLAC2
61	T_14101FOURCORN-14211FOURCORNC1
62	T_14101FOURCORN-14211FOURCORNC2
63	T_14101FOURCORN-14914FCNGN4CCC1
64	L_14101FOURCORN-66235PINTOPSC1
65	L_14101FOURCORN-79064SHIPROCKC1
66	L_14102PNPKAPS-14103PRECHCYNC&1-MS
67	L_14204CHOLLA-14215LEUPPC1
68	T_14204CHOLLA-14900CHOLLAC1
69	T_14211FOURCORN-14911FCNGEN1C1
70	T_14211FOURCORN-14912FCNGEN2C1

Conting #	Contingency
71	T_14211FOURCORN-14913FCNGEN3C1
72	L_14211FOURCORN-79063SHIPROCKC1
73	L_14222PRESCOTT-14234YAVAPAIC1
74	L_14230VERDE-14234YAVAPAIC1
75	L_16102MCKINLEY-16104SPRINGRC1
76	L_16102MCKINLEY-16104SPRINGRC2
77	L_19038MEAD-26044MARKETPLC1
78	L_24042ELDORDO-24097MOHAVEC1
79	L_24042ELDORDO-24086LUGOC&1-MS
80	T_24042ELDORDO-24196ELDOR1IC1
81	T_24042ELDORDO-24221ELDOR2IC2
82	L_24042ELDORDO-26048MCCULLGHC1
83	L_26003ADELANTO-26044MARKETPLC&1-MS
84	L_26044MARKETPL-26048MCCULLGHC1
85	L_26044MARKETPL-26120MKTPSVCC1
86	L_65005ABAJO-66230PINTOC1
87	L_65260CAMPWIL-65805HUNTNGTNC1
88	L_65510EMERY-65805HUNTNGTNC1
89	T_65805HUNTNGTN-65795HUNTNG1C1
90	T_65805HUNTNGTN-65795HUNTNG1C2
91	T_65805HUNTNGTN-65800HUNTNG2C1
92	T_65805HUNTNGTN-65800HUNTNG2C2
93	T_65805HUNTNGTN-65810HUNTNGTNC1
94	T_65805HUNTNGTN-65810HUNTNGTNC2
95	L_65805HUNTNGTN-66225PINTOC1
96	L_65805HUNTNGTN-66400SPANFRKC1
97	L_65990MOAB-66230PINTOC1
98	T_66225PINTO-66226PINTMP2C2
99	T_66225PINTO-66227PINTMP3C3
100	T_66225PINTO-66230PINTOC1
101	T_66225PINTO-66230PINTOC2
102	T_66225PINTO-66235PINTOPSC1
103	T_66230PINTO-66226PINTMP2C2
104	T_66230PINTO-66227PINTMP3C3
105	L_79043KAYENTA-79063SHIPROCKC&1-MS
106	L_79045LOSTCANY-79061SHIPPSC1
107	L_79049MONTROSE-79072HESPERUSC1
108	L_79060SANJNPS-79072HESPERUSC1
109	T_79061SHIPPS-79063SHIPROCKC1
110	T_79063SHIPROCK-79062SHIPROCKC1
111	L_79062SHIPROCK-79101FRUITAPC1
112	L_79062SHIPROCK-79112MESAFMC1
113	T_79064SHIPROCK-79063SHIPROCKC1
114	T_79095SHIPROCK-79064SHIPROCKC1
115	T_79095SHIPROCK-79064SHIPROCKC2
116	T_79072HESPERUS-79071HESPERUSC1

Contingency List

Case 2: Gray Mountain

Conting #	Contingency
1	L_10232OJO-10292SAN_JUANC1
2	L_10248PILLAR-14211FOURCORNC1
3	T_10292SAN_JUAN-10289SAN_JUANC1
4	T_10292SAN_JUAN-10290SAN_JUANC1
5	T_10292SAN_JUAN-10291SAN_JUANC1
6	T_10292SAN_JUAN-10318SJUAN_G1C1
7	T_10292SAN_JUAN-10319SJUAN_G2C1
8	T_10292SAN_JUAN-10320SJUAN_G3C1
9	T_10292SAN_JUAN-10321SJUAN_G4C1
10	L_10292SAN_JUAN-16102MCKINLEYC&1-MS
11	L_10292SAN_JUAN-16102MCKINLEYC&2-MS
12	L_10025B-A-10292SAN_JUANC&1-MS
13	L_10292SAN_JUAN-14101FOURCORNC1
14	T_79060SANJNPS-10292SAN_JUANC1
15	L_10292SAN_JUAN-79064SHIPROCKC1
16	L_14001FOURCORN-14002MOENKOPIC&1-MS
17	T_14001FOURCORN-14101FOURCORNC1
18	T_14001FOURCORN-14915FCNGN5CCC1
19	L_14002MOENKOPI-14006YAVAPAIC&1-MS
20	L_14002MOENKOPI-26044MARKETPLC&1-MS
21	L_14002MOENKOPI-24042ELDORDOC&1-MS
22	L_14002MOENKOPI-14003NAVAJOC&1-MS
23	L_14002MOENKOPI-79095SHIPROCKC&1-MS
24	L_14003NAVAJO-14005WESTWINGC&1-MS
25	L_14003NAVAJO-26123CRYSTALC&1-MS
26	T_14003NAVAJO-15981NAVAJO1C1
27	T_14003NAVAJO-15982NAVAJO2C1
28	T_14003NAVAJO-15983NAVAJO3C1
29	L_14005WESTWING-14006YAVAPAIC&1-MS
30	T_14005WESTWING-14231WESTWINGC1
31	T_14005WESTWING-14231WESTWINGC2
32	T_14005WESTWING-14231WESTWINGC3
33	L_14005WESTWING-15021PALOVRDEC1
34	L_14005WESTWING-15021PALOVRDEC2
35	L_14005WESTWING-15033PERKINPSC1
36	T_14005WESTWING-16309WW.3WPC1
37	T_14006YAVAPAI-14234YAVAPAIC1
38	T_14006YAVAPAI-14234YAVAPAIC2
39	L_14100CHOLLA-14101FOURCORNC&1-MS
40	L_14100CHOLLA-14101FOURCORNC&2-MS
41	L_10369WESTMESA-14101FOURCORNC&1-MS
42	T_14101FOURCORN-14211FOURCORNC1
43	T_14101FOURCORN-14211FOURCORNC2
44	T_14101FOURCORN-14914FCNGN4CCC1
45	L_14101FOURCORN-66235PINTOPSC1
46	L_14101FOURCORN-79064SHIPROCKC1
47	L_14205COCONINO-14215LEUPPC1
48	L_14205COCONINO-14230VERDEC1
49	L_14207DEERVALY-14231WESTWINGC1
50	L_14210ELSOL-14231WESTWINGC1
51	T_14211FOURCORN-14911FCNGEN1C1
52	T_14211FOURCORN-14912FCNGEN2C1
53	T_14211FOURCORN-14913FCNGEN3C1
54	L_14211FOURCORN-79063SHIPROCKC1
55	L_14213HAPPYVLY-14231WESTWINGC1
56	L_14213HAPPYVLY-19062PINPKC1
57	L_14221PNPKAPS-19062PINPKC1
58	L_14222PRESCOTT-14223ROUNDVLYC1
59	L_14222PRESCOTT-14234YAVAPAIC1
60	T_14222PRESCOTT-14355PRESCOTTC1
61	L_14222PRESCOTT-19062PINPKC1
62	L_14223ROUNDVLY-19314PEACOCKC1
63	L_14228SURPRISE-14231WESTWINGC1
64	L_14230VERDE-14234YAVAPAIC1
65	L_14231WESTWING-15201AGUAFRIAC1
66	L_14231WESTWING-15201AGUAFRIAC2
67	L_14231WESTWING-19052LIBERTYC1
68	L_14231WESTWING-19208N.WADDELC1
69	L_14351BAGDAD-14355PRESCOTTC1
70	T_15021PALOVRDE-14931PALOVRD1C1
71	T_15021PALOVRDE-14932PALOVRD2C1
72	T_15021PALOVRDE-14933PALOVRD3C1
73	T_15021PALOVRDE-14934PVNGSCT1C1
74	T_15021PALOVRDE-14935PVNGSCT2C1
75	L_15011KYRENE-15021PALOVRDEC1
76	L_15021PALOVRDE-22536N.GILAC&1-MS
77	L_15021PALOVRDE-24801DEVERSC&1-MS
78	L_15021PALOVRDE-15061ESTRELLAC1
79	L_15031PERKPS1-15033PERKINPSC1
80	L_15032PERKPS2-15033PERKINPSC1
81	L_15211PINPKSRP-19062PINPKC1
82	L_15211PINPKSRP-19062PINPKC2
83	L_15212ROGERS-19062PINPKC1
84	L_15212ROGERS-19062PINPKC2
85	T_16107WESTWING-16309WW.3WPC1
86	L_18004ARDEN-26046MCCULLGHC2
87	L_18005BASIC-19011MEADNC1
88	L_18015DECATUR-19011MEADNC1
89	L_18016EASTSIDE-19011MEADNC1
90	L_18017TOLSON-26046MCCULLGHC1
91	L_18018FAULKNER-26046MCCULLGHC1
92	L_18021NEWPORT-19011MEADNC1
93	T_24097MOHAVE-18166LAUGHLINC1
94	T_24097MOHAVE-18166LAUGHLINC2
95	L_18600EQUEST-19011MEADNC2
96	L_18620MERCHANT-24041ELDORDOC1
97	L_18620MERCHANT-26046MCCULLGHC2
98	L_19011MEADN-19012MEADSC1
99	L_19011MEADN-19018BCTAPC1
100	L_19011MEADN-19022DAVISC1
101	T_19037MEAD-19011MEADNC1
102	T_19038MEAD-19011MEADNC1
103	L_19012MEADS-24041ELDORDOC1
104	L_19012MEADS-24041ELDORDOC2
105	L_19012MEADS-26046MCCULLGHC1
106	L_19012MEADS-26046MCCULLGHC2
107	L_19022DAVIS-26046MCCULLGHC1
108	L_15034PERKINS-19038MEADC&1-MS
109	L_19038MEAD-26044MARKETPLC1
110	T_79053PINPKBRB-19062PINPKC1
111	T_79053PINPKBRB-19062PINPKC2
112	T_79053PINPKBRB-19062PINPKC3
113	T_24041ELDORDO-24043ELDORDOC1
114	T_24041ELDORDO-24196ELDOR1IC1
115	L_24041ELDORDO-24219PISGAHC2
116	T_24041ELDORDO-24221ELDOR2IC2
117	L_24041ELDORDO-24627CIMAC1
118	L_24042ELDORDO-24097MOHAVEC1
119	L_24042ELDORDO-24086LUGOC&1-MS
120	T_24042ELDORDO-24196ELDOR1IC1
121	T_24042ELDORDO-24221ELDOR2IC2
122	L_24042ELDORDO-26048MCCULLGHC1
123	T_24097MOHAVE-24095MOHAV1CCC1
124	T_24097MOHAVE-24096MOHAV2CCC1
125	L_24086LUGO-24097MOHAVEC&1-MS
126	L_26003ADELANTO-26044MARKETPLC&1-MS
127	L_26044MARKETPL-26048MCCULLGHC1
128	L_26044MARKETPL-26120MKTPSVCC1
129	T_26048MCCULLGH-26046MCCULLGHC1
130	T_26048MCCULLGH-26046MCCULLGHC2
131	T_26048MCCULLGH-26046MCCULLGHC3
132	L_26048MCCULLGH-26105VICTORVLC&1-MS
133	L_26048MCCULLGH-26105VICTORVLC&2-MS
134	L_26048MCCULLGH-26123CRYSTALC&1-MS
135	T_66225PINTO-66235PINTOPSC1
136	L_79043KAYENTA-79063SHIPROCKC&1-MS
137	T_79061SHIPPS-79063SHIPROCKC1
138	T_79063SHIPROCK-79062SHIPROCKC1
139	T_79064SHIPROCK-79063SHIPROCKC1
140	T_79095SHIPROCK-79064SHIPROCKC1
141	T_79095SHIPROCK-79064SHIPROCKC2

Contingency List
Case 3: Solar Site 2

Conting #	Contingency
1	L_10041BISTI230-10248PILLAR230C1
2	L_10052BURNHAM230-10248PILLAR230C1
3	L_10232OJO345-10292SAN_JUAN345C1
4	T_10232OJO345-12050OJO115C1
5	L_10232OJO345-12082TAOS345C1
6	L_10248PILLAR230-14211FOURCORN230C1
7	T_10292SAN_JUAN345-10289SAN_JUAN69C1
8	T_10291SAN_JUAN230-10290SAN_JUAN12.5C1
9	T_10292SAN_JUAN345-10290SAN_JUAN12.5C1
10	T_10292SAN_JUAN345-10291SAN_JUAN230C1
11	T_10292SAN_JUAN345-10318SJUAN_G122C1
12	T_10292SAN_JUAN345-10319SJUAN_G224C1
13	T_10292SAN_JUAN345-10320SJUAN_G322C1
14	T_10292SAN_JUAN345-10321SJUAN_G422C1
15	L_10292SAN_JUAN345-16102MCKINLEY345C&1-MS
16	L_10292SAN_JUAN345-16102MCKINLEY345C&2-MS
17	L_10025B-A345-10292SAN_JUAN345C&1-MS
18	L_10292SAN_JUAN345-14101FOURCORN345C1
19	T_79060SANJNPS345-10292SAN_JUAN345C1
20	L_10292SAN_JUAN345-79064SHIPROCK345C1
21	L_10369WESTMESA345-14101FOURCORN345C&1-MS
22	T_14000CHOLLA500-14100CHOLLA345C1
23	T_14000CHOLLA500-14100CHOLLA345C2
24	L_14001FOURCORN500-14002MOENKOPI500C&1-MS
25	T_14001FOURCORN500-14101FOURCORN345C1
26	T_14001FOURCORN500-14915FCNGN5CC22C1
27	L_14002MOENKOPI500-14006YAVAPAI500C&1-MS
28	L_14002MOENKOPI500-26044MARKETPL500C&1-MS
29	L_14002MOENKOPI500-24042ELDORDO500C&1-MS
30	L_14002MOENKOPI500-14003NAVAJO500C&1-MS
31	L_14002MOENKOPI500-79095SHIPROCK500C&1-MS
32	L_14003NAVAJO500-14005WESTWING500C&1-MS
33	L_14003NAVAJO500-26123CRYSTAL500C&1-MS
34	T_14003NAVAJO500-15981NAVAJO126C1
35	T_14003NAVAJO500-15982NAVAJO226C1
36	T_14003NAVAJO500-15983NAVAJO326C1
37	L_14005WESTWING500-14006YAVAPAI500C&1-MS
38	T_14005WESTWING500-14231WESTWING230C1
39	T_14005WESTWING500-14231WESTWING230C2
40	T_14005WESTWING500-14231WESTWING230C3
41	L_14005WESTWING500-15021PALOVRDE500C1
42	L_14005WESTWING500-15021PALOVRDE500C2
43	L_14005WESTWING500-15033PERKINPS500C1
44	T_14005WESTWING500-16309WW.3WP100C1
45	T_14006YAVAPAI500-14234YAVAPAI230C1
46	T_14006YAVAPAI500-14234YAVAPAI230C2
47	L_14100CHOLLA345-14103PRECHCYN345C1
48	L_14100CHOLLA345-14102PNPKAPS345C&1-MS
49	L_14100CHOLLA345-14101FOURCORN345C&1-MS
50	L_14100CHOLLA345-14101FOURCORN345C&2-MS
51	T_14100CHOLLA345-14204CHOLLA230C1
52	T_14100CHOLLA345-14204CHOLLA230C2
53	T_14101FOURCORN345-14211FOURCORN230C1
54	T_14101FOURCORN345-14211FOURCORN230C2
55	T_14101FOURCORN345-14914FCNGN4CC22C1
56	L_14101FOURCORN345-66235PINTOPS345C1
57	L_14101FOURCORN345-79064SHIPROCK345C1
58	L_14205COCONINO230-14230VERDE230C1
59	T_14211FOURCORN230-14911FCNGEN120C1
60	T_14211FOURCORN230-14912FCNGEN220C1
61	T_14211FOURCORN230-14913FCNGEN320C1
62	L_14211FOURCORN230-79063SHIPROCK230C1
63	L_14222PRESCOTT230-14223ROUNDVLY230C1
64	L_14222PRESCOTT230-14234YAVAPAI230C1
65	T_14222PRESCOTT230-14355PRESCOTT115C1
66	L_14222PRESCOTT230-19062PINPK230C1
67	L_14230VERDE230-14234YAVAPAI230C1
68	T_24097MOHAVE500-18166LAUGHLIN69C1
69	T_24097MOHAVE500-18166LAUGHLIN69C2
70	T_19038MEAD500-19011MEADN230C1

Conting #	Contingency
71	L_15034PERKINS500-19038MEAD500C&1-MS
72	L_19038MEAD500-26044MARKETPL500C1
73	T_24041ELDORDO230-24196ELDOR1I13.8C1
74	T_24041ELDORDO230-24221ELDOR2I13.8C2
75	L_24042ELDORDO500-24097MOHAVE500C1
76	L_24042ELDORDO500-24086LUGO500C&1-MS
77	T_24042ELDORDO500-24196ELDOR1I13.8C1
78	T_24042ELDORDO500-24221ELDOR2I13.8C2
79	L_24042ELDORDO500-26048MCCULLGH500C1
80	T_24097MOHAVE500-24095MOHAV1CC22C1
81	T_24097MOHAVE500-24096MOHAV2CC22C1
82	L_24086LUGO500-24097MOHAVE500C&1-MS
83	L_26003ADELANTO500-26044MARKETPL500C&1-MS
84	L_26044MARKETPL500-26048MCCULLGH500C1
85	L_26044MARKETPL500-26120MKTPSVC500C1
86	T_26048MCCULLGH500-26046MCCULLGH230C1
87	T_26048MCCULLGH500-26046MCCULLGH230C2
88	T_26048MCCULLGH500-26046MCCULLGH230C3
89	L_26048MCCULLGH500-26105VICTORVL500C&1-MS
90	L_26048MCCULLGH500-26105VICTORVL500C&2-MS
91	L_26048MCCULLGH500-26123CRYSTAL500C&1-MS
92	L_65805HUNTNGTN345-66225PINTO345C1
93	T_66225PINTO345-66226PINTMP2100C2
94	T_66225PINTO345-66227PINTMP3100C3
95	T_66225PINTO345-66230PINTO138C1
96	T_66225PINTO345-66230PINTO138C2
97	T_66225PINTO345-66235PINTOPS345C1
98	L_79043KAYENTA230-79063SHIPROCK230C&1-MS
99	L_79060SANJNPS345-79072HESPERUS345C1
100	T_79061SHIPPS230-79063SHIPROCK230C1
101	T_79063SHIPROCK230-79062SHIPROCK115C1
102	T_79064SHIPROCK345-79063SHIPROCK230C1
103	T_79095SHIPROCK500-79064SHIPROCK345C1
104	T_79095SHIPROCK500-79064SHIPROCK345C2

Contingency List

Case 4: Aubrey Cliffs

Conting #	Contingency
1	L_14002MOENKOPI500-14006YAVAPAI500C&1-MS
2	L_14005WESTWING500-14006YAVAPAI500C&1-MS
3	T_14005WESTWING500-14231WESTWING230C1
4	T_14005WESTWING500-14231WESTWING230C2
5	T_14005WESTWING500-14231WESTWING230C3
6	T_14006YAVAPAI500-14234YAVAPAI230C1
7	T_14006YAVAPAI500-14234YAVAPAI230C2
8	L_14100CHOLLA345-14102PNPKAPS345C&1-MS
9	L_14102PNPKAPS345-14103PRECHCYN345C&1-MS
10	T_14102PNPKAPS345-14221PNPKAPS230C1
11	T_14102PNPKAPS345-14221PNPKAPS230C2
12	T_14102PNPKAPS345-14221PNPKAPS230C3
13	L_14202CACTUS230-14219OCOTILLO230C1
14	L_14202CACTUS230-14221PNPKAPS230C1
15	L_14205COCONINO230-14215LEUPP230C1
16	L_14205COCONINO230-14230VERDE230C1
17	L_14207DEERVALY230-14231WESTWING230C1
18	L_14207DEERVALY230-15202ALEXANDR230C1
19	L_14207DEERVALY230-15211PINPKSRP230C1
20	L_14208DOWNING230-14219OCOTILLO230C1
21	L_14208DOWNING230-14221PNPKAPS230C1
22	L_14210ELSOL230-14231WESTWING230C1
23	L_14213HAPPYVLY230-14231WESTWING230C1
24	L_14213HAPPYVLY230-19062PINPK230C1
25	L_14217LONEPEAK230-14220PARADISE230C1
26	L_14217LONEPEAK230-14221PNPKAPS230C1
27	L_14217LONEPEAK230-14227SUNYSLOP230C1
28	L_14220PARADISE230-14221PNPKAPS230C1
29	L_14221PNPKAPS230-15211PINPKSRP230C1
30	L_14221PNPKAPS230-15211PINPKSRP230C2
31	L_14221PNPKAPS230-19062PINPK230C1
32	L_14222PRESCOTT230-14223ROUNDVLY230C1
33	L_14222PRESCOTT230-14234YAVAPAI230C1
34	T_14222PRESCOTT230-14355PRESCOTT115C1
35	L_14222PRESCOTT230-19062PINPK230C1
36	L_14223ROUNDVLY230-19314PEACOCK230C1
37	L_14228SURPRISE230-14231WESTWING230C1
38	L_14230VERDE230-14234YAVAPAI230C1
39	L_14231WESTWING230-15201AGUAFRIA230C1
40	L_14231WESTWING230-15201AGUAFRIA230C2
41	L_14231WESTWING230-19052LIBERTY230C1
42	L_14231WESTWING230-19208N.WADDEL230C1
43	L_14351BAGDAD115-14355PRESCOTT115C1
44	L_15204BRANDOW230-15207KYRENE230C1
45	L_15204BRANDOW230-15209PAPAGOBT230C1
46	L_15204BRANDOW230-15211PINPKSRP230C1
47	L_15204BRANDOW230-15211PINPKSRP230C2
48	L_15204BRANDOW230-15217WARD230C1
49	L_15204BRANDOW230-15217WARD230C2
50	T_15204BRANDOW230-15609BRANDOW69C1
51	T_15204BRANDOW230-15609BRANDOW69C2
52	T_15204BRANDOW230-15609BRANDOW69C3
53	T_15204BRANDOW230-15609BRANDOW69C4
54	L_15206GOLDFELD230-15216THUNDRST230C1
55	L_15206GOLDFELD230-15216THUNDRST230C2
56	L_15207KYRENE230-15209PAPAGOBT230C1
57	L_15209PAPAGOBT230-15211PINPKSRP230C1
58	T_15209PAPAGOBT230-15612PAPAGOBT69C1
59	T_15209PAPAGOBT230-15612PAPAGOBT69C2
60	T_15209PAPAGOBT230-15612PAPAGOBT69C3
61	T_15209PAPAGOBT230-15612PAPAGOBT69C4
62	L_15211PINPKSRP230-19062PINPK230C1
63	L_15211PINPKSRP230-19062PINPK230C2
64	L_15212ROGERS230-15216THUNDRST230C1
65	T_15212ROGERS230-15613ROGERS69C1
66	T_15212ROGERS230-15613ROGERS69C2
67	T_15212ROGERS230-15613ROGERS69C3
68	T_15212ROGERS230-15613ROGERS69C4
69	L_15212ROGERS230-19062PINPK230C1
70	L_15212ROGERS230-19062PINPK230C2

Conting #
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Contingency List

Case 5: Clear Creek and Sunshine

Conting #	Contingency
1	L_10292SAN_JUAN-14101FOURCORNC1
2	L_14000CHOLLA-14004SAGUAROC&1-MS
3	T_14000CHOLLA-14100CHOLLAC1
4	T_14000CHOLLA-14100CHOLLAC2
5	T_14000CHOLLA-14901CHOLLA2C1
6	T_14000CHOLLA-14902CHOLLA3C1
7	T_14000CHOLLA-14903CHOLLA4C1
8	L_14000CHOLLA-15001CORONADOC1
9	T_14001FOURCORN-14101FOURCORNC1
10	L_14001FOURCORN-14002MOENKOPIC&1-MS
11	L_14002MOENKOPI-14006YAVAPAIC&1-MS
12	L_14002MOENKOPI-26044MARKETPLC&1-MS
13	L_14002MOENKOPI-24042ELDORDOC&1-MS
14	L_14002MOENKOPI-14003NAVAJOC&1-MS
15	L_14002MOENKOPI-79095SHIPROCKC&1-MS
16	L_14003NAVAJO-14005WESTWINGC&1-MS
17	L_14005WESTWING-14006YAVAPAIC&1-MS
18	T_14005WESTWING-14231WESTWINGC1
19	T_14005WESTWING-14231WESTWINGC2
20	T_14005WESTWING-14231WESTWINGC3
21	L_14005WESTWING-15021PALOVRDEC1
22	L_14005WESTWING-15021PALOVRDEC2
23	L_14005WESTWING-15033PERKINPSC1
24	T_14005WESTWING-16309WW.3WPC1
25	T_14006YAVAPAI-14234YAVAPAIC1
26	T_14006YAVAPAI-14234YAVAPAIC2
27	L_14100CHOLLA-14103PRECHCYNC1
28	L_14100CHOLLA-14102PNPKAPSC&1-MS
29	L_14100CHOLLA-14101FOURCORNC&1-MS
30	L_14100CHOLLA-14101FOURCORNC&2-MS
31	T_14100CHOLLA-14204CHOLLAC1
32	T_14100CHOLLA-14204CHOLLAC2
33	L_10369WESTMESA-14101FOURCORNC&1-MS
34	T_14101FOURCORN-14211FOURCORNC1
35	T_14101FOURCORN-14211FOURCORNC2
36	T_14101FOURCORN-14914FCNGN4CCC1
37	L_14101FOURCORN-66235PINTOPSC1
38	L_14101FOURCORN-79064SHIPROCKC1
39	L_14102PNPKAPS-14103PRECHCYNC&1-MS
40	T_14102PNPKAPS-14221PNPKAPSC1
41	T_14102PNPKAPS-14221PNPKAPSC2
42	T_14102PNPKAPS-14221PNPKAPSC3
43	L_14202CACTUS-14221PNPKAPSC1
44	L_14204CHOLLA-14215LEUPPC1
45	T_14204CHOLLA-14900CHOLLAC1
46	L_14205COCONINO-14215LEUPPC1
47	L_14205COCONINO-14230VERDEC1
48	L_14207DEERVALY-15211PINPKSRPC1
49	L_14208DOWNING-14221PNPKAPSC1
50	L_14213HAPPYVLY-14231WESTWINGC1
51	L_14213HAPPYVLY-19062PINPKC1
52	L_14217LONEPEAK-14221PNPKAPSC1
53	L_14220PARADISE-14221PNPKAPSC1
54	L_14221PNPKAPS-15211PINPKSRPC1
55	L_14221PNPKAPS-15211PINPKSRPC2
56	L_14221PNPKAPS-19062PINPKC1
57	L_14222PRESCOTT-14223ROUNDVLYC1
58	L_14222PRESCOTT-14234YAVAPAIC1
59	T_14222PRESCOTT-14355PRESCOTTC1
60	L_14222PRESCOTT-19062PINPKC1
61	L_14223ROUNDVLY-19314PEACOCKC1
62	L_14230VERDE-14234YAVAPAIC1
63	L_14351BAGDAD-14355PRESCOTTC1
64	L_15001CORONADO-15041SILVERKGC1
65	T_15001CORONADO-15971CORONAD1C1
66	T_15001CORONADO-15972CORONAD2C1
67	T_15001CORONADO-16100CORONADOC1
68	L_15204BRANDOW-15211PINPKSRPC1
69	L_15204BRANDOW-15211PINPKSRPC2
70	L_15209PAPAGOBT-15211PINPKSRPC1
71	L_15211PINPKSRP-19062PINPKC1
72	L_15211PINPKSRP-19062PINPKC2
73	L_15212ROGERS-15216THUNDRSTC1
74	T_15212ROGERS-15613ROGERSC1
75	T_15212ROGERS-15613ROGERSC2
76	T_15212ROGERS-15613ROGERSC3
77	T_15212ROGERS-15613ROGERSC4
78	L_15212ROGERS-19062PINPKC1
79	L_15212ROGERS-19062PINPKC2
80	L_15212ROGERS-19215SPOOKHILC1
81	T_79053PINPKBRB-19062PINPKC1
82	T_79053PINPKBRB-19062PINPKC2
83	T_79053PINPKBRB-19062PINPKC3
84	L_19072HILLTOP-19314PEACOCKC1
85	L_19310GRIFFITH-19314PEACOCKC1
86	T_19315PEACOCK-19314PEACOCKC1
87	L_79024FLAGSTAF-79053PINPKBRBC1
88	L_79024FLAGSTAF-79053PINPKBRBC2
89	L_10232OJO-10292SAN_JUANC1
90	L_10248PILLAR-14211FOURCORNC1
91	T_10292SAN_JUAN-10289SAN_JUANC1
92	T_10292SAN_JUAN-10290SAN_JUANC1
93	T_10292SAN_JUAN-10291SAN_JUANC1
94	T_10292SAN_JUAN-10318SJUAN_G1C1
95	T_10292SAN_JUAN-10319SJUAN_G2C1
96	T_10292SAN_JUAN-10320SJUAN_G3C1
97	T_10292SAN_JUAN-10321SJUAN_G4C1
98	L_10292SAN_JUAN-16102MCKINLEYC&1-MS
99	L_10292SAN_JUAN-16102MCKINLEYC&2-MS
100	L_10025B-A-10292SAN_JUANC&1-MS
101	T_79060SANJNPS-10292SAN_JUANC1
102	L_10292SAN_JUAN-79064SHIPROCKC1
103	T_14001FOURCORN-14915FCNGN5CCC1
104	T_14211FOURCORN-14911FCNGEN1C1
105	T_14211FOURCORN-14912FCNGEN2C1
106	T_14211FOURCORN-14913FCNGEN3C1
107	L_14211FOURCORN-79063SHIPROCKC1
108	L_15011KYRENE-15041SILVERKGC1
109	T_15041SILVERKG-15042SILVERKGC1
110	L_15041SILVERKG-15051BROWNINGC1
111	L_16100CORONADO-16104SPRINGRC1
112	T_66225PINTO-66235PINTOPSC1
113	T_79064SHIPROCK-79063SHIPROCKC1
114	T_79095SHIPROCK-79064SHIPROCKC1
115	T_79095SHIPROCK-79064SHIPROCKC2

Contingency List

Case 6: Black Mesa and Solar Site 1

Conting #	Contingency
1	L_10011AMBROSIA-10041BISTIC1
2	L_10025B-A-10369WESTMESAC1
3	L_10025B-A-10292SAN_JUANC&1-MS
4	L_10041BISTI-10248PILLARC1
5	L_10052BURNHAM-10111GALLEGOSC1
6	L_10052BURNHAM-10248PILLARC1
7	L_10232OJO-10292SAN_JUANC1
8	T_10232OJO-12050OJOC1
9	L_10232OJO-12082TAOSC1
10	L_10248PILLAR-14211FOURCORNC1
11	T_10292SAN_JUAN-10289SAN_JUANC1
12	T_10291SAN_JUAN-10290SAN_JUANC1
13	T_10292SAN_JUAN-10290SAN_JUANC1
14	T_10292SAN_JUAN-10291SAN_JUANC1
15	T_10292SAN_JUAN-10318SJUAN_G1C1
16	T_10292SAN_JUAN-10319SJUAN_G2C1
17	T_10292SAN_JUAN-10320SJUAN_G3C1
18	T_10292SAN_JUAN-10321SJUAN_G4C1
19	L_10292SAN_JUAN-16102MCKINLEYC&1-MS
20	L_10292SAN_JUAN-16102MCKINLEYC&2-MS
21	L_10292SAN_JUAN-14101FOURCORNC1
22	T_79060SANJNPS-10292SAN_JUANC1
23	L_10292SAN_JUAN-79064SHIPROCKC1
24	L_10294SANDIA-10369WESTMESAC1
25	T_10369WESTMESA-10370WESTMS_1C1
26	T_10369WESTMESA-10371WESTMS_2C1
27	L_10369WESTMESA-11014ARR___PSC1
28	L_10369WESTMESA-14101FOURCORNC&1-MS
29	T_16102MCKINLEY-10382YAHTAHEYC1
30	L_12038HERNANDZ-12050OJOC1
31	T_12081TAOS-12082TAOSC1
32	L_14000CHOLLA-14004SAGUAROC&1-MS
33	T_14000CHOLLA-14100CHOLLAC1
34	T_14000CHOLLA-14100CHOLLAC2
35	T_14000CHOLLA-14901CHOLLA2C1
36	T_14000CHOLLA-14902CHOLLA3C1
37	T_14000CHOLLA-14903CHOLLA4C1
38	L_14000CHOLLA-15001CORONADOC1
39	L_14001FOURCORN-14002MOENKOPIC&1-MS
40	T_14001FOURCORN-14101FOURCORNC1
41	T_14001FOURCORN-14915FCNGN5CCC1
42	L_14002MOENKOPI-14006YAVAPAIC&1-MS
43	L_14002MOENKOPI-26044MARKETPLC&1-MS
44	L_14002MOENKOPI-24042ELDORDOC&1-MS
45	L_14002MOENKOPI-14003NAVAJOC&1-MS
46	L_14002MOENKOPI-79095SHIPROCKC&1-MS
47	L_14003NAVAJO-14005WESTWINGC&1-MS
48	L_14003NAVAJO-26123CRYSTALC&1-MS
49	T_14003NAVAJO-15981NAVAJO1C1
50	T_14003NAVAJO-15982NAVAJO2C1
51	T_14003NAVAJO-15983NAVAJO3C1
52	L_14005WESTWING-14006YAVAPAIC&1-MS
53	T_14006YAVAPAI-14234YAVAPAIC1
54	T_14006YAVAPAI-14234YAVAPAIC2
55	L_14100CHOLLA-14103PRECHCYNC1
56	L_14100CHOLLA-14102PNPKAPSC&1-MS
57	L_14100CHOLLA-14101FOURCORNC&1-MS
58	L_14100CHOLLA-14101FOURCORNC&2-MS
59	T_14100CHOLLA-14204CHOLLAC1
60	T_14100CHOLLA-14204CHOLLAC2
61	T_14101FOURCORN-14211FOURCORNC1
62	T_14101FOURCORN-14211FOURCORNC2
63	T_14101FOURCORN-14914FCNGN4CCC1
64	L_14101FOURCORN-66235PINTOPSC1
65	L_14101FOURCORN-79064SHIPROCKC1
66	L_14102PNPKAPS-14103PRECHCYNC&1-MS
67	L_14204CHOLLA-14215LEUPPC1
68	T_14204CHOLLA-14900CHOLLAC1
69	T_14211FOURCORN-14911FCNGEN1C1
70	T_14211FOURCORN-14912FCNGEN2C1
71	T_14211FOURCORN-14913FCNGEN3C1
72	L_14211FOURCORN-79063SHIPROCKC1
73	L_14222PRESCOTT-14234YAVAPAIC1
74	L_14230VERDE-14234YAVAPAIC1
75	L_16102MCKINLEY-16104SPRINGRC1
76	L_16102MCKINLEY-16104SPRINGRC2
77	L_19038MEAD-26044MARKETPLC1
78	L_24042ELDORDO-24097MOHAVEC1
79	L_24042ELDORDO-24086LUGOC&1-MS
80	T_24042ELDORDO-24196ELDOR1IC1
81	T_24042ELDORDO-24221ELDOR2IC2
82	L_24042ELDORDO-26048MCCULLGHC1
83	L_26003ADELANTO-26044MARKETPLC&1-MS
84	L_26044MARKETPL-26048MCCULLGHC1
85	L_26044MARKETPL-26120MKTPSVCC1
86	L_65005ABAJO-66230PINTOC1
87	L_65260CAMPWIL-65805HUNTNGTNC1
88	L_65510EMERY-65805HUNTNGTNC1
89	T_65805HUNTNGTN-65795HUNTNG1C1
90	T_65805HUNTNGTN-65795HUNTNG1C2
91	T_65805HUNTNGTN-65800HUNTNG2C1
92	T_65805HUNTNGTN-65800HUNTNG2C2
93	T_65805HUNTNGTN-65810HUNTNGTNC1
94	T_65805HUNTNGTN-65810HUNTNGTNC2
95	L_65805HUNTNGTN-66225PINTOC1
96	L_65805HUNTNGTN-66400SPANFRKC1
97	L_65990MOAB-66230PINTOC1
98	T_66225PINTO-66226PINTMP2C2
99	T_66225PINTO-66227PINTMP3C3
100	T_66225PINTO-66230PINTOC1
101	T_66225PINTO-66230PINTOC2
102	T_66225PINTO-66235PINTOPSC1
103	T_66230PINTO-66226PINTMP2C2
104	T_66230PINTO-66227PINTMP3C3
105	L_79043KAYENTA-79063SHIPROCKC&1-MS
106	L_79045LOSTCANY-79061SHIPPSC1
107	L_79049MONTROSE-79072HESPERUSC1
108	L_79060SANJNPS-79072HESPERUSC1
109	T_79061SHIPPS-79063SHIPROCKC1
110	T_79063SHIPROCK-79062SHIPROCKC1
111	L_79062SHIPROCK-79101FRUITAPC1
112	L_79062SHIPROCK-79112MESAFMC1
113	T_79064SHIPROCK-79063SHIPROCKC1
114	T_79095SHIPROCK-79064SHIPROCKC1
115	T_79095SHIPROCK-79064SHIPROCKC2
116	T_79072HESPERUS-79071HESPERUSC1
117	L_66355SIGURDPS-79031GLENCANYC1
118	T_79021CURECANT-79020CURECANTC1
119	L_79021CURECANT-79045LOSTCANYC1
120	L_79021CURECANT-79054PONCHABRC1
121	L_79021CURECANT-79070NORTHFRKC1
122	L_79021CURECANT-79163MORROWPTC1
123	T_79028GLENPS-79031GLENCANYC1
124	L_79028GLENPS-79093NAVAJOC1
125	T_79032GLENCANY-79031GLENCANYC1
126	T_79032GLENCANY-79031GLENCANYC2
127	T_79150GLENC1-2-79031GLENCANYC1
128	T_79153GLENC7-8-79031GLENCANYC1
129	L_79043KAYENTA-79096LNGHOUSEC&1-MS
130	T_79045LOSTCANY-79044LOSTCANYC1
131	L_79044LOSTCANY-79074E.CORTEZC1
132	L_79044LOSTCANY-79075EMPIRETSC1
133	L_79044LOSTCANY-79111MANCOSTPC1
134	L_79044LOSTCANY-79122TOWAOCC1
135	L_79093NAVAJO-79096LNGHOUSEC1
136	L_79097ANIMAS-79112MESAFMC1
137	L_79097ANIMAS-79116SULLIVANC1
138	L_79100FOOTHILS-79106HOODMESAC1
139	L_79101FRUITAP-79102FRUITLNDC1
140	L_79101FRUITAP-79106HOODMESAC1
141	L_79105GLADETAP-79106HOODMESAC1
142	L_79106HOODMESA-79116SULLIVANC1

Contingency List

Case 7: Black Mesa and Gray Mountain and Aubrey Cliffs

Conting #	Contingency
1	L_10041BISTI-10248PILLARC1
2	L_10052BURNHAM-10248PILLARC1
3	L_10232OJO-10292SAN_JUANC1
4	T_10232OJO-12050OJOC1
5	L_10232OJO-12082TAOSC1
6	L_10248PILLAR-14211FOURCORNC1
7	T_10292SAN_JUAN-10289SAN_JUANC1
8	T_10291SAN_JUAN-10290SAN_JUANC1
9	T_10292SAN_JUAN-10290SAN_JUANC1
10	T_10292SAN_JUAN-10291SAN_JUANC1
11	T_10292SAN_JUAN-10318SJUAN_G1C1
12	T_10292SAN_JUAN-10319SJUAN_G2C1
13	T_10292SAN_JUAN-10320SJUAN_G3C1
14	T_10292SAN_JUAN-10321SJUAN_G4C1
15	L_10292SAN_JUAN-16102MCKINLEYC&1-MS
16	L_10292SAN_JUAN-16102MCKINLEYC&2-MS
17	L_10025B-A-10292SAN_JUANC&1-MS
18	L_10292SAN_JUAN-14101FOURCORNC1
19	T_79060SANJNPS-10292SAN_JUANC1
20	L_10292SAN_JUAN-79064SHIPROCKC1
21	L_10369WESTMESA-14101FOURCORNC&1-MS
22	T_14000CHOLLA-14100CHOLLAC1
23	T_14000CHOLLA-14100CHOLLAC2
24	L_14001FOURCORN-14002MOENKOPIC&1-MS
25	T_14001FOURCORN-14101FOURCORNC1
26	T_14001FOURCORN-14915FCNGN5CCC1
27	L_14002MOENKOPI-14006YAVAPAIC&1-MS
28	L_14002MOENKOPI-26044MARKETPLC&1-MS
29	L_14002MOENKOPI-24042ELDORDOC&1-MS
30	L_14002MOENKOPI-14003NAVAJOC&1-MS
31	L_14002MOENKOPI-79095SHIPROCKC&1-MS
32	L_14005WESTWING-14006YAVAPAIC&1-MS
33	T_14006YAVAPAI-14234YAVAPAIC1
34	T_14006YAVAPAI-14234YAVAPAIC2
35	L_14100CHOLLA-14103PRECHCYNC1
36	L_14100CHOLLA-14102PNPKAPSC&1-MS
37	L_14100CHOLLA-14101FOURCORNC&1-MS
38	L_14100CHOLLA-14101FOURCORNC&2-MS
39	T_14100CHOLLA-14204CHOLLAC1
40	T_14100CHOLLA-14204CHOLLAC2
41	T_14101FOURCORN-14211FOURCORNC1
42	T_14101FOURCORN-14211FOURCORNC2
43	T_14101FOURCORN-14914FCNGN4CCC1
44	L_14101FOURCORN-66235PINTOPSC1
45	L_14101FOURCORN-79064SHIPROCKC1
46	T_14211FOURCORN-14911FCNGEN1C1
47	T_14211FOURCORN-14912FCNGEN2C1
48	T_14211FOURCORN-14913FCNGEN3C1
49	L_14211FOURCORN-79063SHIPROCKC1
50	L_65805HUNTNGTN-66225PINTOC1
51	T_66225PINTO-66226PINTMP2C2
52	T_66225PINTO-66227PINTMP3C3
53	T_66225PINTO-66230PINTOC1
54	T_66225PINTO-66230PINTOC2
55	T_66225PINTO-66235PINTOPSC1
56	L_79043KAYENTA-79063SHIPROCKC&1-MS
57	L_79060SANJNPS-79072HESPERUSC1
58	T_79061SHIPPS-79063SHIPROCKC1
59	T_79063SHIPROCK-79062SHIPROCKC1
60	T_79064SHIPROCK-79063SHIPROCKC1
61	T_79095SHIPROCK-79064SHIPROCKC1
62	T_79095SHIPROCK-79064SHIPROCKC2
63	L_14003NAVAJO-14005WESTWINGC&1-MS
64	L_14003NAVAJO-26123CRYSTALC&1-MS
65	T_14003NAVAJO-15981NAVAJO1C1
66	T_14003NAVAJO-15982NAVAJO2C1
67	T_14003NAVAJO-15983NAVAJO3C1
68	T_14005WESTWING-14231WESTWINGC1
69	T_14005WESTWING-14231WESTWINGC2
70	T_14005WESTWING-14231WESTWINGC3
71	L_14005WESTWING-15021PALOVRDEC1
72	L_14005WESTWING-15021PALOVRDEC2
73	L_14005WESTWING-15033PERKINPSC1
74	T_14005WESTWING-16309WW.3WPC1
75	L_14205COCONINO-14230VERDEC1
76	L_14222PRESCOTT-14223ROUNDVLYC1
77	L_14222PRESCOTT-14234YAVAPAIC1
78	T_14222PRESCOTT-14355PRESCOTTC1
79	L_14222PRESCOTT-19062PINPKC1
80	L_14230VERDE-14234YAVAPAIC1
81	T_24097MOHAVE-18166LAUGHLINC1
82	T_24097MOHAVE-18166LAUGHLINC2
83	T_19038MEAD-19011MEADNC1
84	L_15034PERKINS-19038MEADC&1-MS
85	L_19038MEAD-26044MARKETPLC1
86	T_24041ELDORDO-24196ELDOR1IC1
87	T_24041ELDORDO-24221ELDOR2IC2
88	L_24042ELDORDO-24097MOHAVEC1
89	L_24042ELDORDO-24086LUGOC&1-MS
90	T_24042ELDORDO-24196ELDOR1IC1
91	T_24042ELDORDO-24221ELDOR2IC2
92	L_24042ELDORDO-26048MCCULLGHC1
93	T_24097MOHAVE-24095MOHAV1CCC1
94	T_24097MOHAVE-24096MOHAV2CCC1
95	L_24086LUGO-24097MOHAVEC&1-MS
96	L_26003ADELANTO-26044MARKETPLC&1-MS
97	L_26044MARKETPL-26048MCCULLGHC1
98	L_26044MARKETPL-26120MKTPSVCC1
99	T_26048MCCULLGH-26046MCCULLGHC1
100	T_26048MCCULLGH-26046MCCULLGHC2
101	T_26048MCCULLGH-26046MCCULLGHC3
102	L_26048MCCULLGH-26105VICTORVLC&1-MS
103	L_26048MCCULLGH-26105VICTORVLC&2-MS
104	L_26048MCCULLGH-26123CRYSTALC&1-MS
105	L_14102PNPKAPS-14103PRECHCYNC&1-MS
106	T_14102PNPKAPS-14221PNPKAPSC1
107	T_14102PNPKAPS-14221PNPKAPSC2
108	T_14102PNPKAPS-14221PNPKAPSC3
109	L_14202CACTUS-14219OCOTILLOC1
110	L_14202CACTUS-14221PNPKAPSC1
111	L_14205COCONINO-14215LEUPPC1
112	L_14207DEERVALY-14231WESTWINGC1
113	L_14207DEERVALY-15202ALEXANDRC1
114	L_14207DEERVALY-15211PINPKSRPC1
115	L_14208DOWNING-14219OCOTILLOC1
116	L_14208DOWNING-14221PNPKAPSC1
117	L_14210ELSOL-14231WESTWINGC1
118	L_14213HAPPYVLY-14231WESTWINGC1
119	L_14213HAPPYVLY-19062PINPKC1
120	L_14217LONEPEAK-14220PARADISEC1
121	L_14217LONEPEAK-14221PNPKAPSC1
122	L_14217LONEPEAK-14227SUNYSLOPC1
123	L_14220PARADISE-14221PNPKAPSC1
124	L_14221PNPKAPS-15211PINPKSRPC1
125	L_14221PNPKAPS-15211PINPKSRPC2
126	L_14221PNPKAPS-19062PINPKC1
127	L_14223ROUNDVLY-19314PEACOCKC1
128	L_14228SURPRISE-14231WESTWINGC1
129	L_14231WESTWING-15201AGUAFRIAC1
130	L_14231WESTWING-15201AGUAFRIAC2
131	L_14231WESTWING-19052LIBERTYC1
132	L_14231WESTWING-19208N.WADDELC1
133	L_14351BAGDAD-14355PRESCOTTC1
134	L_15204BRANDOW-15207KYRENEC1
135	L_15204BRANDOW-15209PAPAGOBTC1
136	L_15204BRANDOW-15211PINPKSRPC1
137	L_15204BRANDOW-15211PINPKSRPC2
138	L_15204BRANDOW-15217WARDC1
139	L_15204BRANDOW-15217WARDC2
140	T_15204BRANDOW-15609BRANDOWC1
141	T_15204BRANDOW-15609BRANDOWC2
142	T_15204BRANDOW-15609BRANDOWC3
143	T_15204BRANDOW-15609BRANDOWC4
144	L_15206GOLDFELD-15216THUNDRSTC1
145	L_15206GOLDFELD-15216THUNDRSTC2
146	L_15207KYRENE-15209PAPAGOBTC1
147	L_15209PAPAGOBT-15211PINPKSRPC1
148	T_15209PAPAGOBT-15612PAPAGOBTC1
149	T_15209PAPAGOBT-15612PAPAGOBTC2
150	T_15209PAPAGOBT-15612PAPAGOBTC3
151	T_15209PAPAGOBT-15612PAPAGOBTC4
152	L_15211PINPKSRP-19062PINPKC1
153	L_15211PINPKSRP-19062PINPKC2
154	L_15212ROGERS-15216THUNDRSTC1
155	T_15212ROGERS-15613ROGERSC1
156	T_15212ROGERS-15613ROGERSC2
157	T_15212ROGERS-15613ROGERSC3
158	T_15212ROGERS-15613ROGERSC4
159	L_15212ROGERS-19062PINPKC1
160	L_15212ROGERS-19062PINPKC2
161	L_15212ROGERS-19215SPOOKHILC1
162	L_15213SANTAN-15216THUNDRSTC1
163	T_15216THUNDRST-15614THUNDRSTC1
164	T_15216THUNDRST-15614THUNDRSTC2
165	T_15216THUNDRST-15614THUNDRSTC3
166	T_15216THUNDRST-15614THUNDRSTC4
167	T_15216THUNDRST-15614THUNDRSTC5
168	L_17019RIVIERA-19022DAVISC1
169	T_19001DAVISG1-19022DAVISC1
170	T_19002DAVISG2-19022DAVISC1
171	T_19003DAVISG3-19022DAVISC1
172	T_19004DAVISG4-19022DAVISC1
173	T_19005DAVISG5-19022DAVISC1
174	L_19011MEADN-19022DAVISC1
175	T_19037MEAD-19011MEADNC1
176	L_19019BLKMESA-19022DAVISC1
177	L_19022DAVIS-19042PARKERC1
178	L_19022DAVIS-19056MCCONICOC1
179	L_19022DAVIS-19073N.HAVASUC1
180	L_19022DAVIS-19320TOPOCKC1
181	L_19022DAVIS-19320TOPOCKC2
182	L_19022DAVIS-26046MCCULLGHC1
183	L_19037MEAD-19053LIBERTYC&1-MS
184	L_19037MEAD-19315PEACOCKC&1-MS
185	L_19045COOLIDGE-19215SPOOKHILC1
186	T_19053LIBERTY-19054LIBTYPHSC1
187	L_19053LIBERTY-19315PEACOCKC&1-MS
188	L_19056MCCONICO-19072HILLTOPC1
189	L_19056MCCONICO-19310GRIFFITHC1
190	T_79053PINPKBRB-19062PINPKC1
191	T_79053PINPKBRB-19062PINPKC2
192	T_79053PINPKBRB-19062PINPKC3
193	L_19072HILLTOP-19314PEACOCKC1
194	T_19310GRIFFITH-19311GRIFFTH1C1
195	T_19310GRIFFITH-19312GRIFFTH2C2
196	T_19310GRIFFITH-19313GRIFFTH3C3
197	L_19310GRIFFITH-19314PEACOCKC1
198	T_19315PEACOCK-19314PEACOCKC1
199	L_79024FLAGSTAF-79032GLENCANYC1
200	L_79024FLAGSTAF-79032GLENCANYC2
201	L_79024FLAGSTAF-79053PINPKBRBC1
202	L_79024FLAGSTAF-79053PINPKBRBC2

Contingency List

Case 8: Solar Site 1 and Gray Mountain and Aubrey Cliffs

Conting #	Contingency
1	L_14002MOENKOPI-14006YAVAPAIC&1-MS
2	L_14005WESTWING-14006YAVAPAIC&1-MS
3	T_14005WESTWING-14231WESTWINGC1
4	T_14005WESTWING-14231WESTWINGC2
5	T_14005WESTWING-14231WESTWINGC3
6	T_14006YAVAPAI-14234YAVAPAIC1
7	T_14006YAVAPAI-14234YAVAPAIC2
8	L_14100CHOLLA-14102PNPKAPSC&1-MS
9	L_14102PNPKAPS-14103PRECHCYNC&1-MS
10	T_14102PNPKAPS-14221PNPKAPSC1
11	T_14102PNPKAPS-14221PNPKAPSC2
12	T_14102PNPKAPS-14221PNPKAPSC3
13	L_14202CACTUS-14219OCOTILLOC1
14	L_14202CACTUS-14221PNPKAPSC1
15	L_14205COCONINO-14215LEUPPC1
16	L_14205COCONINO-14230VERDEC1
17	L_14207DEERVALY-14231WESTWINGC1
18	L_14207DEERVALY-15202ALEXANDRC1
19	L_14207DEERVALY-15211PINPKSRPC1
20	L_14208DOWNING-14219OCOTILLOC1
21	L_14208DOWNING-14221PNPKAPSC1
22	L_14210ELSOL-14231WESTWINGC1
23	L_14213HAPPYVLY-14231WESTWINGC1
24	L_14213HAPPYVLY-19062PINPKC1
25	L_14217LONEPEAK-14220PARADISEC1
26	L_14217LONEPEAK-14221PNPKAPSC1
27	L_14217LONEPEAK-14227SUNYSLOPC1
28	L_14220PARADISE-14221PNPKAPSC1
29	L_14221PNPKAPS-15211PINPKSRPC1
30	L_14221PNPKAPS-15211PINPKSRPC2
31	L_14221PNPKAPS-19062PINPKC1
32	L_14222PRESCOTT-14223ROUNDVLYC1
33	L_14222PRESCOTT-14234YAVAPAIC1
34	T_14222PRESCOTT-14355PRESCOTTC1
35	L_14222PRESCOTT-19062PINPKC1
36	L_14223ROUNDVLY-19314PEACOCKC1
37	L_14228SURPRISE-14231WESTWINGC1
38	L_14230VERDE-14234YAVAPAIC1
39	L_14231WESTWING-15201AGUAFRIAC1
40	L_14231WESTWING-15201AGUAFRIAC2
41	L_14231WESTWING-19052LIBERTYC1
42	L_14231WESTWING-19208N.WADDELC1
43	L_14351BAGDAD-14355PRESCOTTC1
44	L_15204BRANDOW-15207KYRENEC1
45	L_15204BRANDOW-15209PAPAGOBTC1
46	L_15204BRANDOW-15211PINPKSRPC1
47	L_15204BRANDOW-15211PINPKSRPC2
48	L_15204BRANDOW-15217WARDC1
49	L_15204BRANDOW-15217WARDC2
50	T_15204BRANDOW-15609BRANDOWC1
51	T_15204BRANDOW-15609BRANDOWC2
52	T_15204BRANDOW-15609BRANDOWC3
53	T_15204BRANDOW-15609BRANDOWC4
54	L_15206GOLDFELD-15216THUNDRSTC1
55	L_15206GOLDFELD-15216THUNDRSTC2
56	L_15207KYRENE-15209PAPAGOBTC1
57	L_15209PAPAGOBT-15211PINPKSRPC1
58	T_15209PAPAGOBT-15612PAPAGOBTC1
59	T_15209PAPAGOBT-15612PAPAGOBTC2
60	T_15209PAPAGOBT-15612PAPAGOBTC3
61	T_15209PAPAGOBT-15612PAPAGOBTC4
62	L_15211PINPKSRP-19062PINPKC1
63	L_15211PINPKSRP-19062PINPKC2
64	L_15212ROGERS-15216THUNDRSTC1
65	T_15212ROGERS-15613ROGERSC1
66	T_15212ROGERS-15613ROGERSC2
67	T_15212ROGERS-15613ROGERSC3
68	T_15212ROGERS-15613ROGERSC4
69	L_15212ROGERS-19062PINPKC1
70	L_15212ROGERS-19062PINPKC2

Conting #	Contingency
71	L_15212ROGERS-19215SPOOKHILC1
72	L_15213SANTAN-15216THUNDRSTC1
73	T_15216THUNDRST-15614THUNDRSTC1
74	T_15216THUNDRST-15614THUNDRSTC2
75	T_15216THUNDRST-15614THUNDRSTC3
76	T_15216THUNDRST-15614THUNDRSTC4
77	T_15216THUNDRST-15614THUNDRSTC5
78	L_17019RIVIERA-19022DAVISC1
79	T_19001DAVISG1-19022DAVISC1
80	T_19002DAVISG2-19022DAVISC1
81	T_19003DAVISG3-19022DAVISC1
82	T_19004DAVISG4-19022DAVISC1
83	T_19005DAVISG5-19022DAVISC1
84	L_19011MEADN-19022DAVISC1
85	T_19037MEAD-19011MEADNC1
86	L_19019BLKMESA-19022DAVISC1
87	L_19022DAVIS-19042PARKERC1
88	L_19022DAVIS-19056MCCONICOC1
89	L_19022DAVIS-19073N.HAVASUC1
90	L_19022DAVIS-19320TOPOCKC1
91	L_19022DAVIS-19320TOPOCKC2
92	L_19022DAVIS-26046MCCULLGHC1
93	L_19037MEAD-19053LIBERTYC&1-MS
94	L_19037MEAD-19315PEACOCKC&1-MS
95	L_19045COOLIDGE-19215SPOOKHILC1
96	T_19053LIBERTY-19054LIBTYPHSC1
97	L_19053LIBERTY-19315PEACOCKC&1-MS
98	L_19056MCCONICO-19072HILLTOPC1
99	L_19056MCCONICO-19310GRIFFITHC1
100	T_79053PINPKBRB-19062PINPKC1
101	T_79053PINPKBRB-19062PINPKC2
102	T_79053PINPKBRB-19062PINPKC3
103	L_19072HILLTOP-19314PEACOCKC1
104	T_19310GRIFFITH-19311GRIFFTH1C1
105	T_19310GRIFFITH-19312GRIFFTH2C2
106	T_19310GRIFFITH-19313GRIFFTH3C3
107	L_19310GRIFFITH-19314PEACOCKC1
108	T_19315PEACOCK-19314PEACOCKC1
109	L_79024FLAGSTAF-79032GLENCANYC1
110	L_79024FLAGSTAF-79032GLENCANYC2
111	L_79024FLAGSTAF-79053PINPKBRBC1
112	L_79024FLAGSTAF-79053PINPKBRBC2
113	L_10292SAN_JUAN-14101FOURCORNC1
114	L_10292SAN_JUAN-79064SHIPROCKC1
115	L_14001FOURCORN-14002MOENKOPIC&1-MS
116	T_14001FOURCORN-14101FOURCORNC1
117	T_14001FOURCORN-14915FCNGN5CCC1
118	L_14002MOENKOPI-26044MARKETPLC&1-MS
119	L_14002MOENKOPI-24042ELDORDOC&1-MS
120	L_14002MOENKOPI-14003NAVAJOC&1-MS
121	L_14002MOENKOPI-79095SHIPROCKC&1-MS
122	L_14003NAVAJO-14005WESTWINGC&1-MS
123	L_14003NAVAJO-26123CRYSTALC&1-MS
124	T_14003NAVAJO-15981NAVAJO1C1
125	T_14003NAVAJO-15982NAVAJO2C1
126	T_14003NAVAJO-15983NAVAJO3C1
127	L_14005WESTWING-15021PALOVRDEC1
128	L_14005WESTWING-15021PALOVRDEC2
129	L_14005WESTWING-15033PERKINPSC1
130	T_14005WESTWING-16309WW.3WPC1
131	L_14100CHOLLA-14101FOURCORNC&1-MS
132	L_14100CHOLLA-14101FOURCORNC&2-MS
133	L_10369WESTMESA-14101FOURCORNC&1-MS
134	T_14101FOURCORN-14211FOURCORNC1
135	T_14101FOURCORN-14211FOURCORNC2
136	T_14101FOURCORN-14914FCNGN4CCC1
137	L_14101FOURCORN-66235PINTOPSC1
138	L_14101FOURCORN-79064SHIPROCKC1
139	T_24097MOHAVE-18166LAUGHLINC1
140	T_24097MOHAVE-18166LAUGHLINC2

Conting #	Contingency
141	T_19038MEAD-19011MEADNC1
142	L_15034PERKINS-19038MEADC&1-MS
143	L_19038MEAD-26044MARKETPLC1
144	T_24041ELDORDO-24196ELDOR1IC1
145	T_24041ELDORDO-24221ELDOR2IC2
146	L_24042ELDORDO-24097MOHAVEC1
147	L_24042ELDORDO-24086LUGOC&1-MS
148	T_24042ELDORDO-24196ELDOR1IC1
149	T_24042ELDORDO-24221ELDOR2IC2
150	L_24042ELDORDO-26048MCCULLGHC1
151	T_24097MOHAVE-24095MOHAV1CCC1
152	T_24097MOHAVE-24096MOHAV2CCC1
153	L_24086LUGO-24097MOHAVEC&1-MS
154	L_26003ADELANTO-26044MARKETPLC&1-MS
155	L_26044MARKETPL-26048MCCULLGHC1
156	L_26044MARKETPL-26120MKTPSVCC1
157	T_26048MCCULLGH-26046MCCULLGHC1
158	T_26048MCCULLGH-26046MCCULLGHC2
159	T_26048MCCULLGH-26046MCCULLGHC3
160	L_26048MCCULLGH-26105VICTORVLC&1-MS
161	L_26048MCCULLGH-26105VICTORVLC&2-MS
162	L_26048MCCULLGH-26123CRYSTALC&1-MS
163	T_79064SHIPROCK-79063SHIPROCKC1
164	T_79095SHIPROCK-79064SHIPROCKC1
165	T_79095SHIPROCK-79064SHIPROCKC2
166	L_10232OJO-10292SAN_JUANC1
167	L_10248PILLAR-14211FOURCORNC1
168	T_10292SAN_JUAN-10289SAN_JUANC1
169	T_10292SAN_JUAN-10290SAN_JUANC1
170	T_10292SAN_JUAN-10291SAN_JUANC1
171	T_10292SAN_JUAN-10318SJUAN_G1C1
172	T_10292SAN_JUAN-10319SJUAN_G2C1
173	T_10292SAN_JUAN-10320SJUAN_G3C1
174	T_10292SAN_JUAN-10321SJUAN_G4C1
175	L_10292SAN_JUAN-16102MCKINLEYC&1-MS
176	L_10292SAN_JUAN-16102MCKINLEYC&2-MS
177	L_10025B-A-10292SAN_JUANC&1-MS
178	T_79060SANJNPS-10292SAN_JUANC1
179	T_14211FOURCORN-14911FCNGEN1C1
180	T_14211FOURCORN-14912FCNGEN2C1
181	T_14211FOURCORN-14913FCNGEN3C1
182	L_14211FOURCORN-79063SHIPROCKC1
183	T_66225PINTO-66235PINTOPSC1

Contingency List
Case 9: Solar Sites 1 and 2

Conting #	Contingency
1	L_10011AMBROSIA-10041BISTIC1
2	L_10041BISTI-10248PILLARC1
3	L_10052BURNHAM-10111GALLEGOSC1
4	L_10052BURNHAM-10248PILLARC1
5	L_10232OJO-10292SAN_JUANC1
6	T_10232OJO-12050OJOC1
7	L_10232OJO-12082TAOSC1
8	L_10248PILLAR-14211FOURCORNC1
9	T_10292SAN_JUAN-10289SAN_JUANC1
10	T_10291SAN_JUAN-10290SAN_JUANC1
11	T_10292SAN_JUAN-10290SAN_JUANC1
12	T_10292SAN_JUAN-10291SAN_JUANC1
13	T_10292SAN_JUAN-10318SJUAN_G1C1
14	T_10292SAN_JUAN-10319SJUAN_G2C1
15	T_10292SAN_JUAN-10320SJUAN_G3C1
16	T_10292SAN_JUAN-10321SJUAN_G4C1
17	L_10292SAN_JUAN-16102MCKINLEYC&1-MS
18	L_10292SAN_JUAN-16102MCKINLEYC&2-MS
19	L_10025B-A-10292SAN_JUANC&1-MS
20	L_10292SAN_JUAN-14101FOURCORNC1
21	T_79060SANJNPS-10292SAN_JUANC1
22	L_10292SAN_JUAN-79064SHIPROCKC1
23	L_14001FOURCORN-14002MOENKOPIC&1-MS
24	T_14001FOURCORN-14101FOURCORNC1
25	T_14001FOURCORN-14915FCNGN5CCC1
26	L_14100CHOLLA-14101FOURCORNC&1-MS
27	L_14100CHOLLA-14101FOURCORNC&2-MS
28	L_10369WESTMESA-14101FOURCORNC&1-MS
29	T_14101FOURCORN-14211FOURCORNC1
30	T_14101FOURCORN-14211FOURCORNC2
31	T_14101FOURCORN-14914FCNGN4CCC1
32	L_14101FOURCORN-66235PINTOPSC1
33	L_14101FOURCORN-79064SHIPROCKC1
34	T_14211FOURCORN-14911FCNGEN1C1
35	T_14211FOURCORN-14912FCNGEN2C1
36	T_14211FOURCORN-14913FCNGEN3C1
37	L_14211FOURCORN-79063SHIPROCKC1
38	T_66225PINTO-66235PINTOPSC1
39	L_66355SIGURDPS-79031GLENCANYC1
40	T_79021CURECANT-79020CURECANTC1
41	L_79021CURECANT-79045LOSTCANYC1
42	L_79021CURECANT-79054PONCHABRC1
43	L_79021CURECANT-79070NORTHFRKC1
44	L_79021CURECANT-79163MORROWPTC1
45	T_79028GLENPS-79031GLENCANYC1
46	L_79028GLENPS-79093NAVAJOC1
47	T_79032GLENCANY-79031GLENCANYC1
48	T_79032GLENCANY-79031GLENCANYC2
49	T_79150GLENC1-2-79031GLENCANYC1
50	T_79153GLENC7-8-79031GLENCANYC1
51	L_79043KAYENTA-79063SHIPROCKC&1-MS
52	L_79043KAYENTA-79096LNGHOUSEC&1-MS
53	T_79045LOSTCANY-79044LOSTCANYC1
54	L_79044LOSTCANY-79074E.CORTEZC1
55	L_79044LOSTCANY-79075EMPIRETSC1
56	L_79044LOSTCANY-79111MANCOSTPC1
57	L_79044LOSTCANY-79122TOWAOCC1
58	L_79045LOSTCANY-79061SHIPPSC1
59	L_79060SANJNPS-79072HESPERUSC1
60	T_79061SHIPPS-79063SHIPROCKC1
61	T_79063SHIPROCK-79062SHIPROCKC1
62	L_79062SHIPROCK-79101FRUITAPC1
63	L_79062SHIPROCK-79112MESAFMC1
64	T_79064SHIPROCK-79063SHIPROCKC1
65	T_79095SHIPROCK-79064SHIPROCKC1
66	T_79095SHIPROCK-79064SHIPROCKC2
67	L_79093NAVAJO-79096LNGHOUSEC1
68	L_14002MOENKOPI-79095SHIPROCKC&1-MS
69	L_79097ANIMAS-79112MESAFMC1
70	L_79097ANIMAS-79116SULLIVANC1

Conting #	Contingency
71	L_79100FOOTHILS-79106HOODMESAC1
72	L_79101FRUITAP-79102FRUITLNDC1
73	L_79101FRUITAP-79106HOODMESAC1
74	L_79105GLADETAP-79106HOODMESAC1
75	L_79106HOODMESA-79116SULLIVANC1
76	T_14000CHOLLA-14100CHOLLAC1
77	T_14000CHOLLA-14100CHOLLAC2
78	L_14002MOENKOPI-14006YAVAPAIC&1-MS
79	L_14002MOENKOPI-26044MARKETPLC&1-MS
80	L_14002MOENKOPI-24042ELDORDOC&1-MS
81	L_14002MOENKOPI-14003NAVAJOC&1-MS
82	L_14003NAVAJO-14005WESTWINGC&1-MS
83	L_14003NAVAJO-26123CRYSTALC&1-MS
84	T_14003NAVAJO-15981NAVAJO1C1
85	T_14003NAVAJO-15982NAVAJO2C1
86	T_14003NAVAJO-15983NAVAJO3C1
87	L_14005WESTWING-14006YAVAPAIC&1-MS
88	T_14005WESTWING-14231WESTWINGC1
89	T_14005WESTWING-14231WESTWINGC2
90	T_14005WESTWING-14231WESTWINGC3
91	L_14005WESTWING-15021PALOVRDEC1
92	L_14005WESTWING-15021PALOVRDEC2
93	L_14005WESTWING-15033PERKINPSC1
94	T_14005WESTWING-16309WW.3WPC1
95	T_14006YAVAPAI-14234YAVAPAIC1
96	T_14006YAVAPAI-14234YAVAPAIC2
97	L_14100CHOLLA-14103PRECHCYNC1
98	L_14100CHOLLA-14102PNPKAPSC&1-MS
99	T_14100CHOLLA-14204CHOLLAC1
100	T_14100CHOLLA-14204CHOLLAC2
101	L_14205COCONINO-14230VERDEC1
102	L_14222PRESCOTT-14223ROUNDVLYC1
103	L_14222PRESCOTT-14234YAVAPAIC1
104	T_14222PRESCOTT-14355PRESCOTTC1
105	L_14222PRESCOTT-19062PINPKC1
106	L_14230VERDE-14234YAVAPAIC1
107	T_24097MOHAVE-18166LAUGHLINC1
108	T_24097MOHAVE-18166LAUGHLINC2
109	T_19038MEAD-19011MEADNC1
110	L_15034PERKINS-19038MEADC&1-MS
111	L_19038MEAD-26044MARKETPLC1
112	T_24041ELDORDO-24196ELDOR1IC1
113	T_24041ELDORDO-24221ELDOR2IC2
114	L_24042ELDORDO-24097MOHAVEC1
115	L_24042ELDORDO-24086LUGOC&1-MS
116	T_24042ELDORDO-24196ELDOR1IC1
117	T_24042ELDORDO-24221ELDOR2IC2
118	L_24042ELDORDO-26048MCCULLGHC1
119	T_24097MOHAVE-24095MOHAV1CCC1
120	T_24097MOHAVE-24096MOHAV2CCC1
121	L_24086LUGO-24097MOHAVEC&1-MS
122	L_26003ADELANTO-26044MARKETPLC&1-MS
123	L_26044MARKETPL-26048MCCULLGHC1
124	L_26044MARKETPL-26120MKTPSVCC1
125	T_26048MCCULLGH-26046MCCULLGHC1
126	T_26048MCCULLGH-26046MCCULLGHC2
127	T_26048MCCULLGH-26046MCCULLGHC3
128	L_26048MCCULLGH-26105VICTORVLC&1-MS
129	L_26048MCCULLGH-26105VICTORVLC&2-MS
130	L_26048MCCULLGH-26123CRYSTALC&1-MS
131	L_65805HUNTNGTN-66225PINTOC1
132	T_66225PINTO-66226PINTMP2C2
133	T_66225PINTO-66227PINTMP3C3
134	T_66225PINTO-66230PINTOC1
135	T_66225PINTO-66230PINTOC2

Contingency List

Case 10: Gray Mountain and Aubrey Cliffs and Clear Creek and Sunshine

Conting #	Contingency
1	L_10292SAN_JUAN-14101FOURCORNC1
2	L_10292SAN_JUAN-79064SHIPROCKC1
3	L_14001FOURCORN-14002MOENKOPIC&1-MS
4	T_14001FOURCORN-14101FOURCORNC1
5	T_14001FOURCORN-14915FCNGN5CCC1
6	L_14002MOENKOPI-14006YAVAPAIC&1-MS
7	L_14002MOENKOPI-26044MARKETPLC&1-MS
8	L_14002MOENKOPI-24042ELDORDOC&1-MS
9	L_14002MOENKOPI-14003NAVAJOC&1-MS
10	L_14002MOENKOPI-79095SHIPROCKC&1-MS
11	L_14003NAVAJO-14005WESTWINGC&1-MS
12	L_14003NAVAJO-26123CRYSTALC&1-MS
13	T_14003NAVAJO-15981NAVAJO1C1
14	T_14003NAVAJO-15982NAVAJO2C1
15	T_14003NAVAJO-15983NAVAJO3C1
16	L_14005WESTWING-14006YAVAPAIC&1-MS
17	T_14005WESTWING-14231WESTWINGC1
18	T_14005WESTWING-14231WESTWINGC2
19	T_14005WESTWING-14231WESTWINGC3
20	L_14005WESTWING-15021PALOVRDEC1
21	L_14005WESTWING-15021PALOVRDEC2
22	L_14005WESTWING-15033PERKINPSC1
23	T_14005WESTWING-16309WW.3WPC1
24	T_14006YAVAPAI-14234YAVAPAIC1
25	T_14006YAVAPAI-14234YAVAPAIC2
26	L_14100CHOLLA-14101FOURCORNC&1-MS
27	L_14100CHOLLA-14101FOURCORNC&2-MS
28	L_10369WESTMESA-14101FOURCORNC&1-MS
29	T_14101FOURCORN-14211FOURCORNC1
30	T_14101FOURCORN-14211FOURCORNC2
31	T_14101FOURCORN-14914FCNGN4CCC1
32	L_14101FOURCORN-66235PINTOPSC1
33	L_14101FOURCORN-79064SHIPROCKC1
34	L_14205COCONINO-14230VERDEC1
35	L_14222PRESCOTT-14223ROUNDVLYC1
36	L_14222PRESCOTT-14234YAVAPAIC1
37	T_14222PRESCOTT-14355PRESCOTTC1
38	L_14222PRESCOTT-19062PINPKC1
39	L_14230VERDE-14234YAVAPAIC1
40	T_24097MOHAVE-18166LAUGHLINC1
41	T_24097MOHAVE-18166LAUGHLINC2
42	T_19038MEAD-19011MEADNC1
43	L_15034PERKINS-19038MEADC&1-MS
44	L_19038MEAD-26044MARKETPLC1
45	T_24041ELDORDO-24196ELDOR1IC1
46	T_24041ELDORDO-24221ELDOR2IC2
47	L_24042ELDORDO-24097MOHAVEC1
48	L_24042ELDORDO-24086LUGOC&1-MS
49	T_24042ELDORDO-24196ELDOR1IC1
50	T_24042ELDORDO-24221ELDOR2IC2
51	L_24042ELDORDO-26048MCCULLGHC1
52	T_24097MOHAVE-24095MOHAV1CCC1
53	T_24097MOHAVE-24096MOHAV2CCC1
54	L_24086LUGO-24097MOHAVEC&1-MS
55	L_26003ADELANTO-26044MARKETPLC&1-MS
56	L_26044MARKETPL-26048MCCULLGHC1
57	L_26044MARKETPL-26120MKTPSVCC1
58	T_26048MCCULLGH-26046MCCULLGHC1
59	T_26048MCCULLGH-26046MCCULLGHC2
60	T_26048MCCULLGH-26046MCCULLGHC3
61	L_26048MCCULLGH-26105VICTORVLC&1-MS
62	L_26048MCCULLGH-26105VICTORVLC&2-MS
63	L_26048MCCULLGH-26123CRYSTALC&1-MS
64	T_79064SHIPROCK-79063SHIPROCKC1
65	T_79095SHIPROCK-79064SHIPROCKC1
66	T_79095SHIPROCK-79064SHIPROCKC2
67	L_14100CHOLLA-14102PNPKAPSC&1-MS
68	L_14102PNPKAPS-14103PRECHCYNC&1-MS
69	T_14102PNPKAPS-14221PNPKAPSC1
70	T_14102PNPKAPS-14221PNPKAPSC2

Conting #	Contingency
71	T_14102PNPKAPS-14221PNPKAPSC3
72	L_14202CACTUS-14219OCOTILLOC1
73	L_14202CACTUS-14221PNPKAPSC1
74	L_14205COCONINO-14215LEUPPC1
75	L_14207DEERVALY-14231WESTWINGC1
76	L_14207DEERVALY-15202ALEXANDRC1
77	L_14207DEERVALY-15211PINPKSRPC1
78	L_14208DOWNING-14219OCOTILLOC1
79	L_14208DOWNING-14221PNPKAPSC1
80	L_14210ELSOL-14231WESTWINGC1
81	L_14213HAPPYVLY-14231WESTWINGC1
82	L_14213HAPPYVLY-19062PINPKC1
83	L_14217LONEPEAK-14220PARADISEC1
84	L_14217LONEPEAK-14221PNPKAPSC1
85	L_14217LONEPEAK-14227SUNYSLOPC1
86	L_14220PARADISE-14221PNPKAPSC1
87	L_14221PNPKAPS-15211PINPKSRPC1
88	L_14221PNPKAPS-15211PINPKSRPC2
89	L_14221PNPKAPS-19062PINPKC1
90	L_14223ROUNDVLY-19314PEACOCKC1
91	L_14228SURPRISE-14231WESTWINGC1
92	L_14231WESTWING-15201AGUAFRIAC1
93	L_14231WESTWING-15201AGUAFRIAC2
94	L_14231WESTWING-19052LIBERTYC1
95	L_14231WESTWING-19208N.WADDELC1
96	L_14351BAGDAD-14355PRESCOTTC1
97	L_15204BRANDOW-15207KYRENEC1
98	L_15204BRANDOW-15209PAPAGOBTC1
99	L_15204BRANDOW-15211PINPKSRPC1
100	L_15204BRANDOW-15211PINPKSRPC2
101	L_15204BRANDOW-15217WARDC1
102	L_15204BRANDOW-15217WARDC2
103	T_15204BRANDOW-15609BRANDOWC1
104	T_15204BRANDOW-15609BRANDOWC2
105	T_15204BRANDOW-15609BRANDOWC3
106	T_15204BRANDOW-15609BRANDOWC4
107	L_15206GOLDFELD-15216THUNDRSTC1
108	L_15206GOLDFELD-15216THUNDRSTC2
109	L_15207KYRENE-15209PAPAGOBTC1
110	L_15209PAPAGOBT-15211PINPKSRPC1
111	T_15209PAPAGOBT-15612PAPAGOBTC1
112	T_15209PAPAGOBT-15612PAPAGOBTC2
113	T_15209PAPAGOBT-15612PAPAGOBTC3
114	T_15209PAPAGOBT-15612PAPAGOBTC4
115	L_15211PINPKSRP-19062PINPKC1
116	L_15211PINPKSRP-19062PINPKC2
117	L_15212ROGERS-15216THUNDRSTC1
118	T_15212ROGERS-15613ROGERSC1
119	T_15212ROGERS-15613ROGERSC2
120	T_15212ROGERS-15613ROGERSC3
121	T_15212ROGERS-15613ROGERSC4
122	L_15212ROGERS-19062PINPKC1
123	L_15212ROGERS-19062PINPKC2
124	L_15212ROGERS-19215SPOOKHILC1
125	L_15213SANTAN-15216THUNDRSTC1
126	T_15216THUNDRST-15614THUNDRSTC1
127	T_15216THUNDRST-15614THUNDRSTC2
128	T_15216THUNDRST-15614THUNDRSTC3
129	T_15216THUNDRST-15614THUNDRSTC4
130	T_15216THUNDRST-15614THUNDRSTC5
131	L_17019RIVIERA-19022DAVISC1
132	T_19001DAVISG1-19022DAVISC1
133	T_19002DAVISG2-19022DAVISC1
134	T_19003DAVISG3-19022DAVISC1
135	T_19004DAVISG4-19022DAVISC1
136	T_19005DAVISG5-19022DAVISC1
137	L_19011MEADN-19022DAVISC1
138	T_19037MEAD-19011MEADNC1
139	L_19019BLKMESA-19022DAVISC1
140	L_19022DAVIS-19042PARKERC1

Conting #	Contingency
141	L_19022DAVIS-19056MCCONICOC1
142	L_19022DAVIS-19073N.HAVASUC1
143	L_19022DAVIS-19320TOPOCKC1
144	L_19022DAVIS-19320TOPOCKC2
145	L_19022DAVIS-26046MCCULLGHC1
146	L_19037MEAD-19053LIBERTYC&1-MS
147	L_19037MEAD-19315PEACOCKC&1-MS
148	L_19045COOLIDGE-19215SPOOKHILC1
149	T_19053LIBERTY-19054LIBTYPHSC1
150	L_19053LIBERTY-19315PEACOCKC&1-MS
151	L_19056MCCONICO-19072HILLTOPC1
152	L_19056MCCONICO-19310GRIFFITHC1
153	T_79053PINPKBRB-19062PINPKC1
154	T_79053PINPKBRB-19062PINPKC2
155	T_79053PINPKBRB-19062PINPKC3
156	L_19072HILLTOP-19314PEACOCKC1
157	T_19310GRIFFITH-19311GRIFFTH1C1
158	T_19310GRIFFITH-19312GRIFFTH2C2
159	T_19310GRIFFITH-19313GRIFFTH3C3
160	L_19310GRIFFITH-19314PEACOCKC1
161	T_19315PEACOCK-19314PEACOCKC1
162	L_79024FLAGSTAF-79032GLENCANYC1
163	L_79024FLAGSTAF-79032GLENCANYC2
164	L_79024FLAGSTAF-79053PINPKBRBC1
165	L_79024FLAGSTAF-79053PINPKBRBC2
166	L_14000CHOLLA-14004SAGUAROC&1-MS
167	T_14000CHOLLA-14100CHOLLAC1
168	T_14000CHOLLA-14100CHOLLAC2
169	T_14000CHOLLA-14901CHOLLA2C1
170	T_14000CHOLLA-14902CHOLLA3C1
171	T_14000CHOLLA-14903CHOLLA4C1
172	L_14000CHOLLA-15001CORONADOC1
173	L_14100CHOLLA-14103PRECHCYNC1
174	T_14100CHOLLA-14204CHOLLAC1
175	T_14100CHOLLA-14204CHOLLAC2
176	L_14204CHOLLA-14215LEUPPC1
177	T_14204CHOLLA-14900CHOLLAC1
178	L_15001CORONADO-15041SILVERKGC1
179	T_15001CORONADO-15971CORONAD1C1
180	T_15001CORONADO-15972CORONAD2C1
181	T_15001CORONADO-16100CORONADOC1

Arizona Transmission Analysis

Case 5: Clear Creek and Sunshine

	Overloaded Transmission Facility			Thermal Loading (% of Rating)			
Contingency	Nom. Voltage (kV)	Type	Description	2010 Base Case	500 MW Added	Rating	Distribution Factor (%)
None	**500**	**Line**	**PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1**	**94.5**	**100.3**	**1404 Amps**	**14.10**
None	**230**	**Line**	**KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1**	**91.1**	**105.1**	**858 Amps**	**9.09**
None	**230**	**Line**	**KAYENTA (79043) -> KAYENT&1 (79051) CKT 1**	**89.7**	**101.3**	**827 Amps**	**7.58**
None	500	Transformer	MEAD (19038) -> MEAD N (19011) CKT 1	159.7	161.4	433 MVA	1.56
None	115	Transformer	SAG.EAST (14356) -> SAG. CT1 (14944) CKT 1	191.4	194.0	70 MVA	0.36
None	115	Line	MIRAGE (24807) -> TAMARISK (24821) CKT 1	99.9	100.5	1089 Amps	0.27
None	230	Line	PECOS (18024) -> SUNRISE (18667) CKT 1	132.4	132.5	1599 Amps	0.17
None	115	Transformer	WILLARD (12088) -> WILLARD (12087) CKT 1	121.2	128.9	9 MVA	0.14
None	138	Line	ANDREWS (18031) -> CAREY (18650) CKT 1	106.8	107.1	837 Amps	0.12
None	115	Transformer	ALAMOGPG (12003) -> ALAMOGPG (12002) CKT 1	133.1	144.7	5 MVA	0.10
L_10232OJO-10292SAN_JUANC1	115	Line	WESTMS_T (10374) -> IRVING (10143) CKT 1 at IRVING	99.7	100.0	670 Amps	0.10
L_14002MOENKOPI-14006YAVAPAIC&1-MS	**230**	**Line**	**NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO**	**94.7**	**105.9**	**753 Amps**	**6.72**
L_14003NAVAJO-14005WESTWINGC&1-MS	**230**	**Line**	**NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO**	**90.1**	**101.1**	**753 Amps**	**6.64**
L_14005WESTWING-14006YAVAPAIC&1-MS	**230**	**Line**	**NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO**	**90.7**	**101.9**	**753 Amps**	**6.73**
L_14100CHOLLA-14101FOURCORNC&1-MS	**230**	**Line**	**NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO**	**94.7**	**107.1**	**753 Amps**	**7.43**
L_14100CHOLLA-14101FOURCORNC&2-MS	**230**	**Line**	**NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO**	**94.7**	**107.1**	**753 Amps**	**7.43**
L_14100CHOLLA-14102PNPKAPSC&1-MS	**230**	**Line**	**NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO**	**94.7**	**106.4**	**753 Amps**	**7.03**
L_14100CHOLLA-14103PRECHCYNC1	**230**	**Line**	**NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO**	**95.3**	**107.0**	**753 Amps**	**7.03**
L_14102PNPKAPS-14103PRECHCYNC&1-MS	**230**	**Line**	**NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO**	**93.7**	**105.4**	**753 Amps**	**7.01**
L_14204CHOLLA-14215LEUPPC1	230	Line	YAVAPAI (14234) -> VERDE (14230) CKT 1 at YAVAPAI	120.5	120.7	530 Amps	0.10
T_14001FOURCORN-14915FCNGN5CCC1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	98.4	100.0	100 MVA	0.33
T_14101FOURCORN-14914FCNGN4CCC1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	98.7	100.4	100 MVA	0.34

Transmission Facilities Requiring Mitigation	Voltage Level	Control Area
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	500	ARIZONA
KAYENTA (79043) -> KAYENT&1 (79051) CKT 1	230	WAPALC
KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1	230	WAPALC
NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO	230	WAPALC

Note: Thermal loading percentages in above tables are based on amp ratings for transmission lines. Pie charts in Appendix K3 reflect equivalent MVA ratings.

Arizona Transmission Analysis

Case 5: Clear Creek and Sunshine

	Overloaded Transmission Facility			Thermal Loading (% of Rating)			
Contingency	Nom. Voltage (kV)	Type	Description	2010 Base Case	450 MW Added	Rating	Distribution Factor (%)
None	115	Transformer	SAG.EAST (14356) -> SAG. CT1 (14944) CKT 1	191.4	193.9	70 MVA	0.38
None	115	Line	MIRAGE (24807) -> TAMARISK (24821) CKT 1	99.9	100.5	1089 Amps	0.29
None	115	Transformer	WILLARD (12088) -> WILLARD (12087) CKT 1	121.2	128.9	9 MVA	0.16
None	138	Line	ANDREWS (18031) -> CAREY (18650) CKT 1	106.8	107.0	837 Amps	0.12
None	115	Transformer	ALAMOGPG (12003) -> ALAMOGPG (12002) CKT 1	133.1	144.7	5 MVA	0.11
L_14002MOENKOPI-14006YAVAPAIC&1-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	106.4	107.0	816 Amps	0.44
L_14002MOENKOPI-14006YAVAPAIC&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	102.7	103.3	816 Amps	0.43
L_14002MOENKOPI-14006YAVAPAIC&1-MS	230	Line	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	101.2	101.7	650 Amps	0.25
L_14005WESTWING-14006YAVAPAIC&1-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	102.7	103.2	816 Amps	0.35
L_15021PALOVRDE-22536N.GILAC&1-MS	230	Line	CAMINO (24019) -> IRON MTN (25405) CKT 1 at IRON MTN	102.7	104.6	764 Amps	1.26
L_15021PALOVRDE-22536N.GILAC&1-MS	230	Transformer	PARKER (19042) -> PARKER (19041) CKT 1 at PARKER	148.2	151.8	126 MVA	1.02
L_15021PALOVRDE-22536N.GILAC&1-MS	230	Transformer	PARKER (19042) -> PARKER (19041) CKT 2 at PARKER	148.2	151.8	126 MVA	1.02
L_15021PALOVRDE-22536N.GILAC&1-MS	161	Transformer	GILA (19050) -> GILA (19049) CKT 1 at GILA	126.6	128.9	120 MVA	0.64
L_15021PALOVRDE-24801DEVERSC&1-MS	230	Line	CAMINO (24019) -> IRON MTN (25405) CKT 1 at IRON MTN	101.5	103.3	764 Amps	1.18
L_15021PALOVRDE-24801DEVERSC&1-MS	230	Transformer	PARKER (19042) -> PARKER (19041) CKT 1 at PARKER	100.4	102.3	126 MVA	0.53
L_15021PALOVRDE-24801DEVERSC&1-MS	230	Transformer	PARKER (19042) -> PARKER (19041) CKT 2 at PARKER	100.4	102.3	126 MVA	0.53
L_19022DAVIS-26046MCCULLGHC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	99.9	100.0	1100 Amps	0.18
T_14001FOURCORN-14915FCNGN5CCC1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	98.4	100.6	100 MVA	0.50
T_14101FOURCORN-14914FCNGN4CCC1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	98.7	101.0	100 MVA	0.52
T_15021PALOVRDE-14931PALOVRD1C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	99.9	102.2	100 MVA	0.51
T_15021PALOVRDE-14932PALOVRD2C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	100.1	102.4	100 MVA	0.51
T_15021PALOVRDE-14933PALOVRD3C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	99.9	102.2	100 MVA	0.51

Transmission Facilities Requiring Mitigation	Voltage Level	Control Area
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Note: Thermal loading percentages in above tables are based on amp ratings for transmission lines. Pie charts in Appendix K3 reflect equivalent MVA ratings.

Arizona Transmission Analysis

Case 5: Clear Creek and Sunshine

	Overloaded Transmission Facility			Thermal Loading (% of Rating)			
Contingency	Nom. Voltage (kV)	Type	Description	2010 Base Case	425 MW Added	Rating	Distribution Factor (%)
None	115	Line	MIRAGE (24807) -> TAMARISK (24821) CKT 1	100.0	100.4	1089 Amps	0.21
L_10025B-A345-10292SAN_JUAN345C&1-MS	345	Transformer	OJO (10232) -> OJO (12050) CKT 1 at OJO	99.4	100.7	180 MVA	0.55
L_10025B-A345-10292SAN_JUAN345C&1-MS	115	Line	GRANTS_T (12035) -> LAGUNA (12044) CKT 1 at GRANTS_T	104.7	105.6	261 Amps	0.11
L_10232OJO345-10292SAN_JUAN345C1	115	Line	WESTMS_T (10374) -> IRVING (10143) CKT 1 at IRVING	99.7	100.0	670 Amps	0.12
L_10369WESTMESA345-14101FOURCORN345C&1-MS	115	Line	LAGUNA (12044) -> WESTMS_P (12086) CKT 1 at LAGUNA	110.6	113.0	261 Amps	0.30
L_10369WESTMESA345-14101FOURCORN345C&1-MS	115	Line	GRANTS_T (12035) -> LAGUNA (12044) CKT 1 at GRANTS_T	119.0	120.0	261 Amps	0.12
L_14001FOURCORN500-14002MOENKOPI500C&1-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	121.6	123.5	816 Amps	1.45
L_14002MOENKOPI500-14006YAVAPAI500C&1-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	102.7	106.4	816 Amps	2.83
L_14002MOENKOPI500-14006YAVAPAI500C&1-MS	230	Line	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	99.9	101.8	650 Amps	1.14
L_14002MOENKOPI500-14006YAVAPAI500C&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	101.2	102.6	816 Amps	1.07
L_14003NAVAJO500-14005WESTWING500C&1-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	98.4	101.2	816 Amps	2.11
L_14005WESTWING500-14006YAVAPAI500C&1-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	99.0	102.5	816 Amps	2.70
L_14100CHOLLA345-14101FOURCORN345C&1-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	102.7	105.2	816 Amps	1.92
L_14100CHOLLA345-14101FOURCORN345C&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	101.2	101.4	816 Amps	0.17
L_14100CHOLLA345-14101FOURCORN345C&2-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	102.7	105.2	816 Amps	1.92
L_14100CHOLLA345-14101FOURCORN345C&2-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	101.2	101.4	816 Amps	0.17
L_14100CHOLLA345-14102PNPKAPS345C&1-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	102.7	105.2	816 Amps	1.94
L_14100CHOLLA345-14102PNPKAPS345C&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	101.2	101.4	816 Amps	0.19
L_14100CHOLLA345-14103PRECHCYN345C1	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	103.3	105.8	816 Amps	1.95
L_14100CHOLLA345-14103PRECHCYN345C1	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	101.8	102.0	816 Amps	0.20
T_14001FOURCORN500-14915FCNGN5CC22C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	94.1	100.8	100 MVA	1.56
T_14101FOURCORN345-14914FCNGN4CC22C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	94.4	101.2	100 MVA	1.59

Transmission Facilities Requiring Mitigation	Voltage Level	Control Area
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Note: Thermal loading percentages in above tables are based on amp ratings for transmission lines. Pie charts in Appendix K3 reflect equivalent MVA ratings.

Arizona Transmission Analysis

Case 5: Clear Creek and Sunshine

	Overloaded Transmission Facility			Thermal Loading (% of Rating)			
Contingency	**Nom. Voltage (kV)**	**Type**	**Description**	**2010 Base Case**	**100 MW Added**	**Rating**	**Distribution Factor (%)**
None	500	Transformer	MEAD (19038) -> MEAD N (19011) CKT 1	162.5	163.1	433 MVA	2.50
None	230	Transformer	ELDORDO (24041) -> ELDOR 2I (24221) CKT 2	105.9	106.4	500 MVA	2.50
None	230	Transformer	ELDORDO (24041) -> ELDOR 1I (24196) CKT 1	106.9	107.3	500 MVA	2.40
None	115	Line	MIRAGE (24807) -> TAMARISK (24821) CKT 1	100.0	100.1	1089 Amps	0.26
L_14002MOENKOPI500-14006YAVAPAI500C&1-M	**230**	**Line**	**ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at PRESCOTT**	**99.9**	**111.9**	**650 Amps**	**31.20**
L_14100CHOLLA345-14102PNPKAPS345C&1-MS	230	Line	PINPK (19062) -> PNPKAPS (14221) CKT 1 at PINPK	107.1	107.3	1757 Amps	1.80
L_14102PNPKAPS345-14103PRECHCYN345C&1-MS	230	Line	PINPK (19062) -> PNPKAPS (14221) CKT 1 at PINPK	104.8	105.1	1757 Amps	1.81
L_14205COCONINO230-14215LEUPP230C1	230	Line	YAVAPAI (14234) -> VERDE (14230) CKT 1 at YAVAPAI	120.4	120.5	530 Amps	0.19
L_19011MEADN230-19022DAVIS230C1	**230**	**Line**	**TOPOCK (19320) -> BLK MESA (19019) CKT 1 at TOPOCK**	**99.2**	**100.4**	**1100 Amps**	**5.42**
L_19022DAVIS230-26046MCCULLGH230C1	**230**	**Line**	**TOPOCK (19320) -> BLK MESA (19019) CKT 1 at TOPOCK**	**99.6**	**100.9**	**1100 Amps**	**5.67**
L_19053LIBERTY345-19315PEACOCK345C&1-MS	**230**	**Line**	**ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at PRESCOTT**	**101.1**	**114.6**	**650 Amps**	**34.90**
L_19053LIBERTY345-19315PEACOCK345C&1-MS	**230**	**Line**	**TOPOCK (19320) -> BLK MESA (19019) CKT 1 at TOPOCK**	**101.1**	**102.5**	**1100 Amps**	**5.98**
T_19053LIBERTY345-19054LIBTYPHS230C1	**230**	**Line**	**ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at PRESCOTT**	**100.8**	**114.3**	**650 Amps**	**34.89**
T_19053LIBERTY345-19054LIBTYPHS230C1	**230**	**Line**	**TOPOCK (19320) -> BLK MESA (19019) CKT 1 at TOPOCK**	**101.0**	**102.4**	**1100 Amps**	**6.07**
T_19315PEACOCK345-19314PEACOCK230C1	**230**	**Line**	**ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at PRESCOTT**	**117.3**	**135.2**	**650 Amps**	**46.46**
T_19315PEACOCK345-19314PEACOCK230C1	**230**	**Line**	**TOPOCK (19320) -> BLK MESA (19019) CKT 1 at TOPOCK**	**101.3**	**103.4**	**1100 Amps**	**9.45**

Transmission Facilities Requiring Mitigation	**Voltage Level**	**Control Area**
ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at PRESCOTT	230	ARIZONA
TOPOCK (19320) -> BLK MESA (19019) CKT 1 at TOPOCK	230	WAPALC

Note: Thermal loading percentages in above tables are based on amp ratings for transmission lines. Pie charts in Appendix K3 reflect equivalent MVA ratings.

Arizona Transmission Analysis

Case 5: Clear Creek and Sunshine

Contingency	Nom. Voltage (kV)	Type	Description	2010 Base Case	450 MW Added	Rating	Distribution Factor (%)
	Overloaded Transmission Facility			Thermal Loading (% of Rating)			
None	138	Line	PECOS (18088) -> SHADOW (18100) CKT 1	117.9	155.9	837 Amps	56.29
None	230	Transformer	ELDORDO (24041) -> ELDOR 1I (24196) CKT 1	105.9	106.2	500 MVA	1.19
None	115	Line	MIRAGE (24807) -> TAMARISK (24821) CKT 1	100.0	100.1	1089 Amps	0.22
None	115	Line	WESTMS_1 (10370) -> WESTMS_T (10374) CKT 1	100.6	100.7	670 Amps	0.10
L_10025B-A-10292SAN_JUANC&1-MS	115	Line	WESTMS_T (10374) -> IRVING (10143) CKT 1 at WESTMS_T	123.6	123.7	670 Amps	0.11

Transmission Facilities Requiring Mitigation	Voltage Level	Control Area
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Note: Thermal loading percentages in above tables are based on amp ratings for transmission lines. Pie charts in Appendix K3 reflect equivalent MVA ratings.

Arizona Transmission Analysis

Case 5: Clear Creek and Sunshine

	Overloaded Transmission Facility			Thermal Loading (% of Rating)			
Contingency	**Nom. Voltage (kV)**	**Type**	**Description**	**2010 Base Case**	**925 MW Added**	**Rating**	**Distribution Factor (%)**
None	230	Line	PECOS (18024) -> SUNRISE (18667) CKT 1	132.4	132.6	1599 Amps	0.13
None	500	Transformer	ELDORDO (24042) -> ELDOR 1I (24196) CKT 1	103.2	103.6	500 MVA	0.22
None	500	Transformer	ELDORDO (24042) -> ELDOR 2I (24221) CKT 2	102.2	102.6	500 MVA	0.22
None	115	Line	MIRAGE (24807) -> TAMARISK (24821) CKT 1	100.0	101.0	1089 Amps	0.25
None	230	Transformer	ELDORDO (24041) -> ELDOR 2I (24221) CKT 2	105.9	106.6	500 MVA	0.37
None	230	Transformer	ELDORDO (24041) -> ELDOR 1I (24196) CKT 1	106.9	107.5	500 MVA	0.37
None	500	Transformer	MEAD (19038) -> MEAD N (19011) CKT 1	162.5	164.6	433 MVA	0.95
None	**500**	**Line**	**PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1**	**95.1**	**102.1**	**1400 Amps**	**9.14**
None	**500**	**Line**	**PALOVR&2 (15023) -> N.GILA (22536) CKT 1**	**95.1**	**102.1**	**1400 Amps**	**9.14**
None	**500**	**Line**	**PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1**	**95.9**	**102.9**	**1400 Amps**	**9.26**
None	**230**	**Transformer**	**GLEN PS (79028) -> GLENCANY (79031) CKT 1**	**69.6**	**145.6**	**350 MVA**	**28.76**
None	**230**	**Line**	**KAYENTA (79043) -> KAYENT&A (79055) CKT 1**	**67.9**	**136.7**	**1000 Amps**	**29.66**
None	**230**	**Line**	**NAVAJO (79093) -> LNGHOUSE (79096) CKT 1**	**62.1**	**131.2**	**1000 Amps**	**29.73**
None	**230**	**Line**	**KAYENT&A (79055) -> LNGHOUSE (79096) CKT 1**	**67.9**	**137.0**	**1000 Amps**	**29.76**
None	**230**	**Line**	**GLEN PS (79028) -> NAVAJO (79093) CKT 1**	**82.2**	**174.2**	**753 Amps**	**29.84**
L_10025B-A-10292SAN_JUANC&1-MS	345	Transformer	OJO (10232) -> OJO (12050) CKT 1 at OJO	99.4	101.1	180 MVA	0.33
L_10232OJO-10292SAN_JUANC1	115	Line	WESTMS_T (10374) -> IRVING (10143) CKT 1 at IRVING	99.7	100.7	670 Amps	0.15
L_10369WESTMESA-14101FOURCORNC&1-MS	115	Line	GRANTS_T (12035) -> LAGUNA (12044) CKT 1 at GRANTS_T	119.0	120.7	261 Amps	0.10
L_10369WESTMESA-14101FOURCORNC&1-MS	115	Line	LAGUNA (12044) -> WESTMS_P (12086) CKT 1 at LAGUNA	110.6	113.7	261 Amps	0.18
L_14100CHOLLA-14102PNPKAPSC&1-MS	230	Line	PINPK (19062) -> PNPKAPS (14221) CKT 1 at PNPKAPS	107.1	111.6	1757 Amps	3.43
L_14100CHOLLA-14103PRECHCYNC1	230	Line	PINPK (19062) -> PNPKAPS (14221) CKT 1 at PNPKAPS	107.6	112.3	1757 Amps	3.54
L_14102PNPKAPS-14103PRECHCYNC&1-MS	230	Line	PINPK (19062) -> PNPKAPS (14221) CKT 1 at PNPKAPS	104.8	109.3	1757 Amps	3.40
L_79028GLENPS-79093NAVAJOC1	**230**	**Line**	**KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1**	**26.2**	**113.7**	**816 Amps**	**30.74**
L_79028GLENPS-79093NAVAJOC1	**230**	**Line**	**KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA**	**20.1**	**116.9**	**816 Amps**	**34.02**
L_79043KAYENTA-79096LNGHOUSEC&1-MS	**230**	**Line**	**KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1**	**18.5**	**120.3**	**816 Amps**	**35.77**
L_79043KAYENTA-79096LNGHOUSEC&1-MS	**230**	**Line**	**KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA**	**10.9**	**123.5**	**816 Amps**	**39.56**
L_79093NAVAJO-79096LNGHOUSEC1	**230**	**Line**	**KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1**	**22.9**	**113.7**	**816 Amps**	**31.90**
L_79093NAVAJO-79096LNGHOUSEC1	**230**	**Line**	**KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA**	**17.3**	**116.9**	**816 Amps**	**35.00**
T_10292SAN_JUAN-10318SJUAN_G1C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	96.1	100.5	100 MVA	0.48
T_10292SAN_JUAN-10319SJUAN_G2C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	96.1	100.5	100 MVA	0.48
T_10292SAN_JUAN-10320SJUAN_G3C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	97.2	101.6	100 MVA	0.47
T_10292SAN_JUAN-10321SJUAN_G4C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	97.2	101.6	100 MVA	0.48
T_14000CHOLLA-14903CHOLLA4C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	96.2	100.6	100 MVA	0.48
T_14001FOURCORN-14101FOURCORNC1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	94.8	100.2	100 MVA	0.59
T_14001FOURCORN-14915FCNGN5CCC1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	98.4	102.7	100 MVA	0.46
T_14003NAVAJO-15981NAVAJO1C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	97.0	101.4	100 MVA	0.47
T_14003NAVAJO-15982NAVAJO2C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	97.0	101.4	100 MVA	0.47
T_14003NAVAJO-15983NAVAJO3C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	97.0	101.4	100 MVA	0.47
T_14101FOURCORN-14914FCNGN4CCC1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	94.4	103.1	100 MVA	0.94
T_65805HUNTNGTN-65795HUNTNG1C1	345	Transformer	HUNTN G1 (65795) -> HUNTNGTN (65805) CKT 2 at HUNTNGTN	141.4	142.1	252 MVA	0.21
T_65805HUNTNGTN-65795HUNTNG1C2	345	Transformer	HUNTN G1 (65795) -> HUNTNGTN (65805) CKT 1 at HUNTNGTN	141.4	142.2	252 MVA	0.21
T_79028GLENPS-79031GLENCANYC1	**230**	**Line**	**KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1**	**28.3**	**113.7**	**816 Amps**	**30.00**
T_79028GLENPS-79031GLENCANYC1	**230**	**Line**	**KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA**	**22.0**	**116.9**	**816 Amps**	**33.35**
T_79032GLENCANY-79031GLENCANYC1	**345**	**Transformer**	**GLENCANY (79031) -> GLENCANY (79032) CKT 2 at GLENCANY**	**81.6**	**114.2**	**400 MVA**	**14.10**
T_79032GLENCANY-79031GLENCANYC2	**345**	**Transformer**	**GLENCANY (79031) -> GLENCANY (79032) CKT 1 at GLENCANY**	**81.6**	**114.2**	**400 MVA**	**14.10**

Transmission Facilities Requiring Mitigation	Voltage Level	Control Area
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	500	ARIZONA
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	500	ARIZONA
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	500	SANDIEGO
KAYENTA (79043) -> KAYENT&A (79055) CKT 1	230	WAPALC
KAYENT&A (79055) -> LNGHOUSE (79096) CKT 1	230	WAPALC
NAVAJO (79093) -> LNGHOUSE (79096) CKT 1	230	WAPALC
KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA	230	WAPALC
KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1	230	WAPALC
GLEN PS (79028) -> NAVAJO (79093) CKT 1	230	WAPALC
GLENCANY (79031) -> GLENCANY (79032) CKT 1 at GLENCANY	230/345	WAPALC
GLENCANY (79031) -> GLENCANY (79032) CKT 2 at GLENCANY	230/345	WAPALC
GLEN PS (79028) -> GLENCANY (79031) CKT 1	230/230	WAPALC

Note: Thermal loading percentages in above tables are based on amp ratings for transmission lines. Pie charts in Appendix K3 reflect equivalent MVA ratings.

Arizona Transmission Analysis

Case 5: Clear Creek and Sunshine

Contingency	Overloaded Transmission Facility			Thermal Loading (% of Rating)		Rating	Distribution Factor (%)
	Nom. Voltage (kV)	Type	Description	2010 Base Case	1050 MW Added		
None	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1	94.3	100.1	100 MVA	0.55
None	115	Line	MIRAGE (24807) -> TAMARISK (24821) CKT 1	100.0	101.1	1089 Amps	0.25
None	500	Transformer	MEAD (19038) -> MEAD N (19011) CKT 1	162.5	164.0	433 MVA	0.60
None	230	Line	KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1	94.8	101.8	816 Amps	2.15
None	**500**	**Line**	**PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1**	**95.1**	**102.1**	**1400 Amps**	**8.04**
None	**500**	**Line**	**PALOVR&2 (15023) -> N.GILA (22536) CKT 1**	**95.1**	**102.1**	**1400 Amps**	**8.04**
None	**500**	**Line**	**PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1**	**95.9**	**102.9**	**1400 Amps**	**8.13**
L_10025B-A-10292SAN_JUANC&1-MS	345	Transformer	OJO (10232) -> OJO (12050) CKT 1 at OJO	99.4	100.9	180 MVA	0.25
L_10232OJO-10292SAN_JUANC1	115	Line	WESTMS_T (10374) -> IRVING (10143) CKT 1 at IRVING	99.6	100.8	670 Amps	0.16
L_10292SAN_JUAN-16102MCKINLEYC&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	92.9	101.2	816 Amps	2.58
L_10292SAN_JUAN-16102MCKINLEYC&2-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	92.9	101.2	816 Amps	2.58
L_10369WESTMESA-14101FOURCORNC&1-MS	115	Line	LAGUNA (12044) -> WESTMS_P (12086) CKT 1 at LAGUNA	110.6	113.6	261 Amps	0.15
L_14002MOENKOPI-14006YAVAPAIC&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	101.2	110.5	816 Amps	2.87
L_14002MOENKOPI-14006YAVAPAIC&1-MS	230	Line	NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO	94.3	103.1	753 Amps	2.53
L_14002MOENKOPI-14006YAVAPAIC&1-MS	230	Line	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	99.9	111.8	650 Amps	2.95
L_14002MOENKOPI-24042ELDORDOC&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	90.7	100.3	816 Amps	2.96
L_14003NAVAJO-14005WESTWINGC&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	97.0	105.5	816 Amps	2.64
L_14005WESTWING-14006YAVAPAIC&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	97.5	106.9	816 Amps	2.91
L_14100CHOLLA-14101FOURCORNC&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	101.2	110.1	816 Amps	2.75
L_14100CHOLLA-14101FOURCORNC&1-MS	230	Line	NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO	94.3	102.7	753 Amps	2.40
L_14100CHOLLA-14101FOURCORNC&2-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	101.2	110.1	816 Amps	2.75
L_14100CHOLLA-14101FOURCORNC&2-MS	230	Line	NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO	94.3	102.7	753 Amps	2.40
L_14100CHOLLA-14102PNPKAPSC&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	101.2	109.7	816 Amps	2.64
L_14100CHOLLA-14102PNPKAPSC&1-MS	230	Line	NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO	94.3	102.4	753 Amps	2.30
L_14100CHOLLA-14103PRECHCYNC1	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	101.8	110.3	816 Amps	2.64
L_14100CHOLLA-14103PRECHCYNC1	230	Line	NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO	94.9	103.0	753 Amps	2.30
L_14101FOURCORN-66235PINTOPSC1	**230**	**Line**	**KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1**	**91.0**	**101.0**	**816 Amps**	**3.12**
L_14102PNPKAPS-14103PRECHCYNC&1-MS	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	100.3	108.8	816 Amps	2.64
L_14102PNPKAPS-14103PRECHCYNC&1-MS	230	Line	NAVAJO (79093) -> GLEN PS (79028) CKT 1 at NAVAJO	93.3	101.4	753 Amps	2.30
L_14205COCONINO-14215LEUPPC1	230	Line	KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	92.0	100.3	816 Amps	2.55
L_19011MEADN-19022DAVISC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	99.4	100.7	1100 Amps	0.54
L_19022DAVIS-26046MCCULLGHC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	99.8	101.2	1100 Amps	0.58
L_19053LIBERTY-19315PEACOCKC&1-MS	230	Line	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	101.1	111.4	650 Amps	2.54
L_19053LIBERTY-19315PEACOCKC&1-MS	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	101.4	102.5	1100 Amps	0.44
T_15209PAPAGOBT-15612PAPAGOBTC2	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 3 at PAPAGOBT	106.7	108.4	210 MVA	0.33
T_15209PAPAGOBT-15612PAPAGOBTC2	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 4 at PAPAGOBT	107.1	108.7	202 MVA	0.32
T_15209PAPAGOBT-15612PAPAGOBTC3	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 2 at PAPAGOBT	105.9	107.7	203 MVA	0.34
T_15209PAPAGOBT-15612PAPAGOBTC3	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 4 at PAPAGOBT	111.6	113.4	202 MVA	0.35
T_15209PAPAGOBT-15612PAPAGOBTC4	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 2 at PAPAGOBT	104.1	105.7	203 MVA	0.32
T_15209PAPAGOBT-15612PAPAGOBTC4	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 3 at PAPAGOBT	109.2	111.0	210 MVA	0.35
T_15212ROGERS-15613ROGERSC2	230	Transformer	ROGERS (15212) -> ROGERS (15613) CKT 4 at ROGERS	101.1	102.0	309 MVA	0.26
T_15212ROGERS-15613ROGERSC4	230	Transformer	ROGERS (15212) -> ROGERS (15613) CKT 2 at ROGERS	101.1	102.0	309 MVA	0.26
T_19053LIBERTY-19054LIBTYPHSC1	230	Line	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	100.8	111.2	650 Amps	2.55
T_19053LIBERTY-19054LIBTYPHSC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	101.3	102.3	1100 Amps	0.44
T_19315PEACOCK-19314PEACOCKC1	230	Line	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	117.3	133.0	650 Amps	3.88
T_19315PEACOCK-19314PEACOCKC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	101.5	103.7	1100 Amps	0.90
T_66225PINTO-66235PINTOPSC1	**230**	**Line**	**KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1**	**90.8**	**101.0**	**816 Amps**	**3.13**

Transmission Facilities Requiring Mitigation	Voltage Level	Control Area
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	500	ARIZONA
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	500	ARIZONA
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	500	GILA
KAYENT&1 (79051) -> KAYENTA (79043) CKT 1 at KAYENT&1	230	WAPALC

Note: Thermal loading percentages in above tables are based on amp ratings for transmission lines. Pie charts in Appendix K3 reflect equivalent MVA ratings.

Arizona Transmission Analysis

Case 5: Clear Creek and Sunshine

Contingency	Overloaded Transmission Facility: Nom. Voltage (kV)	Type	Description	Thermal Loading (% of Rating): 2010 Base Case	975 MW Added	Rating	Distribution Factor (%)
None	**500**	**Line**	**PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1**	**95.1**	**100.8**	**1400 Amps**	**7.11**
None	**500**	**Line**	**PALOVR&2 (15023) -> N.GILA (22536) CKT 1**	**95.1**	**100.8**	**1400 Amps**	**7.08**
None	**500**	**Line**	**PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1**	**95.9**	**100.8**	**1400 Amps**	**6.18**
None	115	Line	MIRAGE (24807) -> TAMARISK (24821) CKT 1	100.0	101.1	1089 Amps	0.27
None	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1	94.3	96.6	100 MVA	0.24
None	115	Line	WESTMS_1 (10370) -> WESTMS_T (10374) CKT 1	100.6	101.4	670 Amps	0.10
L_10025B-A-10292SAN_JUANC&1-MS	345	Transformer	OJO (10232) -> OJO (12050) CKT 1 at OJO	99.4	100.8	180 MVA	0.27
L_10025B-A-10292SAN_JUANC&1-MS	115	Line	WESTMS_T (10374) -> IRVING (10143) CKT 1 at WESTMS_T	123.5	124.4	670 Amps	0.11
L_10232OJO-10292SAN_JUANC1	115	Line	WESTMS_T (10374) -> IRVING (10143) CKT 1 at IRVING	99.7	100.9	670 Amps	0.17
L_10369WESTMESA-14101FOURCORNC&1-MS	115	Line	LAGUNA (12044) -> WESTMS_P (12086) CKT 1 at LAGUNA	110.6	113.7	261 Amps	0.17
L_14002MOENKOPI-14006YAVAPAIC&1-MS	**230**	**Line**	**ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY**	**99.9**	**115.3**	**650 Amps**	**4.08**
L_14002MOENKOPI-14006YAVAPAIC&1-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	102.7	103.9	816 Amps	0.42
L_14003NAVAJO-14005WESTWINGC&1-MS	**500**	**Line**	**MOENKO&1 (14011) -> YAVAPAI (14006) CKT 1 at YAVAPAI**	**90.1**	**103.3**	**1722 Amps**	**20.17**
L_14003NAVAJO-14005WESTWINGC&1-MS	**500**	**Line**	**MOENKOPI (14002) -> MOENKO&1 (14011) CKT 1 at MOENKOPI**	**90.4**	**103.2**	**1722 Amps**	**19.50**
L_14005WESTWING-14006YAVAPAIC&1-MS	230	Line	SHIPROCK (79063) -> KAYENT&1 (79051) CKT 1 at SHIPROCK	99.0	100.0	816 Amps	0.34
L_14220PARADISE-14221PNPKAPSC1	230	Line	CTRYCLUB (14206) -> MEADOWBK (14218) CKT 1 at MEADOWBK	98.6	100.8	1300 Amps	1.21
L_19011MEADN-19022DAVISC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	99.2	101.4	1100 Amps	1.00
L_19022DAVIS-26046MCCULLGHC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	99.6	101.9	1100 Amps	1.03
L_19053LIBERTY-19315PEACOCKC&1-MS	**230**	**Line**	**ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY**	**101.1**	**113.6**	**650 Amps**	**3.33**
L_19053LIBERTY-19315PEACOCKC&1-MS	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	101.1	103.6	1100 Amps	1.11
T_15209PAPAGOBT-15612PAPAGOBTC2	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 3 at PAPAGOBT	106.7	108.3	210 MVA	0.35
T_15209PAPAGOBT-15612PAPAGOBTC2	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 4 at PAPAGOBT	107.1	108.7	202 MVA	0.34
T_15209PAPAGOBT-15612PAPAGOBTC3	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 4 at PAPAGOBT	111.6	113.4	202 MVA	0.38
T_15209PAPAGOBT-15612PAPAGOBTC3	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 2 at PAPAGOBT	105.9	107.7	203 MVA	0.36
T_15209PAPAGOBT-15612PAPAGOBTC4	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 3 at PAPAGOBT	109.2	111.0	210 MVA	0.38
T_15209PAPAGOBT-15612PAPAGOBTC4	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 2 at PAPAGOBT	104.1	105.7	203 MVA	0.35
T_15212ROGERS-15613ROGERSC2	230	Transformer	ROGERS (15212) -> ROGERS (15613) CKT 4 at ROGERS	101.1	102.0	309 MVA	0.28
T_15212ROGERS-15613ROGERSC4	230	Transformer	ROGERS (15212) -> ROGERS (15613) CKT 2 at ROGERS	101.1	102.0	309 MVA	0.28
T_19053LIBERTY-19054LIBTYPHSC1	**230**	**Line**	**ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY**	**100.8**	**113.4**	**650 Amps**	**3.34**
T_19053LIBERTY-19054LIBTYPHSC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	101.0	103.5	1100 Amps	1.11
T_19315PEACOCK-19314PEACOCKC1	**230**	**Line**	**ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY**	**117.3**	**134.5**	**650 Amps**	**4.58**
T_19315PEACOCK-19314PEACOCKC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	101.3	104.6	1100 Amps	1.48

Transmission Facilities Requiring Mitigation	Voltage Level	Control Area
MOENKOPI (14002) -> MOENKO&1 (14011) CKT 1 at MOENKOPI	500	ARIZONA
MOENKO&1 (14011) -> YAVAPAI (14006) CKT 1 at YAVAPAI	500	ARIZONA
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	500	ARIZONA
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	500	ARIZONA
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	500	SANDIEGO
ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	230	ARIZONA

Note: Thermal loading percentages in above tables are based on amp ratings for transmission lines. Pie charts in Appendix K3 reflect equivalent MVA ratings.

Arizona Transmission Analysis

Case 5: Clear Creek and Sunshine

	Overloaded Transmission Facility			Thermal Loading (% of Rating)			
Contingency	Nom. Voltage (kV)	Type	Description	2010 Base Case	850 MW Added	Rating	Distribution Factor (%)
None	**230**	**Transformer**	**GLEN PS (79028) -> GLENCANY (79031) CKT 1**	**69.6**	**135.6**	**350 MVA**	**27.16**
None	115	Line	WESTMS_1 (10370) -> WESTMS_T (10374) CKT 1	100.6	101.3	670 Amps	0.10
None	115	Line	MIRAGE (24807) -> TAMARISK (24821) CKT 1	100.0	100.6	1089 Amps	0.17
None	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1	94.3	104.3	100 MVA	1.18
None	**500**	**Line**	**PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1**	**95.1**	**100.3**	**1400 Amps**	**7.42**
None	**500**	**Line**	**PALOVR&2 (15023) -> N.GILA (22536) CKT 1**	**95.1**	**100.3**	**1400 Amps**	**7.42**
None	**500**	**Line**	**PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1**	**95.9**	**101.1**	**1400 Amps**	**7.51**
None	**230**	**Line**	**KAYENTA (79043) -> KAYENT&A (79055) CKT 1**	**67.9**	**127.5**	**1000 Amps**	**27.94**
None	**230**	**Line**	**NAVAJO (79093) -> LNGHOUSE (79096) CKT 1**	**62.1**	**121.8**	**1000 Amps**	**27.96**
None	**230**	**Line**	**KAYENT&A (79055) -> LNGHOUSE (79096) CKT 1**	**67.9**	**127.7**	**1000 Amps**	**28.04**
None	**230**	**Line**	**GLEN PS (79028) -> NAVAJO (79093) CKT 1**	**82.2**	**161.7**	**753 Amps**	**28.07**
L_10025B-A-10292SAN_JUANC&1-MS	115	Line	WESTMS_T (10374) -> IRVING (10143) CKT 1 at WESTMS_T	123.6	124.4	670 Amps	0.12
L_10232OJO-10292SAN_JUANC1	115	Line	WESTMS_T (10374) -> IRVING (10143) CKT 1 at IRVING	99.7	100.8	670 Amps	0.18
L_14100CHOLLA-14102PNPKAPSC&1-MS	230	Line	PINPK (19062) -> PNPKAPS (14221) CKT 1 at PNPKAPS	107.1	112.4	1757 Amps	4.35
L_14100CHOLLA-14103PRECHCYNC1	230	Line	PINPK (19062) -> PNPKAPS (14221) CKT 1 at PNPKAPS	107.6	113.1	1757 Amps	4.50
L_79028GLENPS-79093NAVAJOC1	**230**	**Line**	**KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1**	**18.1**	**113.7**	**816 Amps**	**36.57**
L_79028GLENPS-79093NAVAJOC1	**230**	**Line**	**KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA**	**14.0**	**116.9**	**816 Amps**	**39.37**
L_79043KAYENTA-79096LNGHOUSEC&1-MS	**230**	**Line**	**KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1**	**18.0**	**120.3**	**816 Amps**	**39.13**
L_79043KAYENTA-79096LNGHOUSEC&1-MS	**230**	**Line**	**KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA**	**10.0**	**123.5**	**816 Amps**	**43.40**
L_79093NAVAJO-79096LNGHOUSEC1	**230**	**Line**	**KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1**	**15.9**	**113.7**	**816 Amps**	**37.40**
L_79093NAVAJO-79096LNGHOUSEC1	**230**	**Line**	**KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA**	**13.9**	**116.9**	**816 Amps**	**39.38**
T_79028GLENPS-79031GLENCANYC1	**230**	**Line**	**KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1**	**19.6**	**113.7**	**816 Amps**	**35.99**
T_79028GLENPS-79031GLENCANYC1	**230**	**Line**	**KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA**	**14.5**	**116.9**	**816 Amps**	**39.17**
T_79032GLENCANY-79031GLENCANYC1	**345**	**Transformer**	**GLENCANY (79031) -> GLENCANY (79032) CKT 2 at GLENCANY**	**81.6**	**107.5**	**400 MVA**	**12.19**
T_79032GLENCANY-79031GLENCANYC2	**345**	**Transformer**	**GLENCANY (79031) -> GLENCANY (79032) CKT 1 at GLENCANY**	**81.6**	**107.5**	**400 MVA**	**12.19**

Transmission Facilities Requiring Mitigation	Voltage Level	Control Area
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	500	ARIZONA
PALOVR&1 (15022) -> PALOVR&2 (15023) CKT 1	500	ARIZONA
PALOVR&2 (15023) -> N.GILA (22536) CKT 1	500	AZ-GILA
KAYENTA (79043) -> KAYENT&A (79055) CKT 1	230	WAPALC
KAYENT&A (79055) -> LNGHOUSE (79096) CKT 1	230	WAPALC
NAVAJO (79093) -> LNGHOUSE (79096) CKT 1	230	WAPALC
GLEN PS (79028) -> GLENCANY (79031) CKT 1	230/230	WAPALC
GLEN PS (79028) -> NAVAJO (79093) CKT 1	230	WAPALC
GLENCANY (79031) -> GLENCANY (79032) CKT 1 at GLENCANY	230/345	WAPALC
GLENCANY (79031) -> GLENCANY (79032) CKT 2 at GLENCANY	230/345	WAPALC
KAYENTA (79043) -> KAYENT&1 (79051) CKT 1 at KAYENTA	230	WAPALC
KAYENT&1 (79051) -> SHIPROCK (79063) CKT 1 at KAYENT&1	230	WAPALC

Note: Thermal loading percentages in above tables are based on amp ratings for transmission lines. Pie charts in Appendix K3 reflect equivalent MVA ratings.

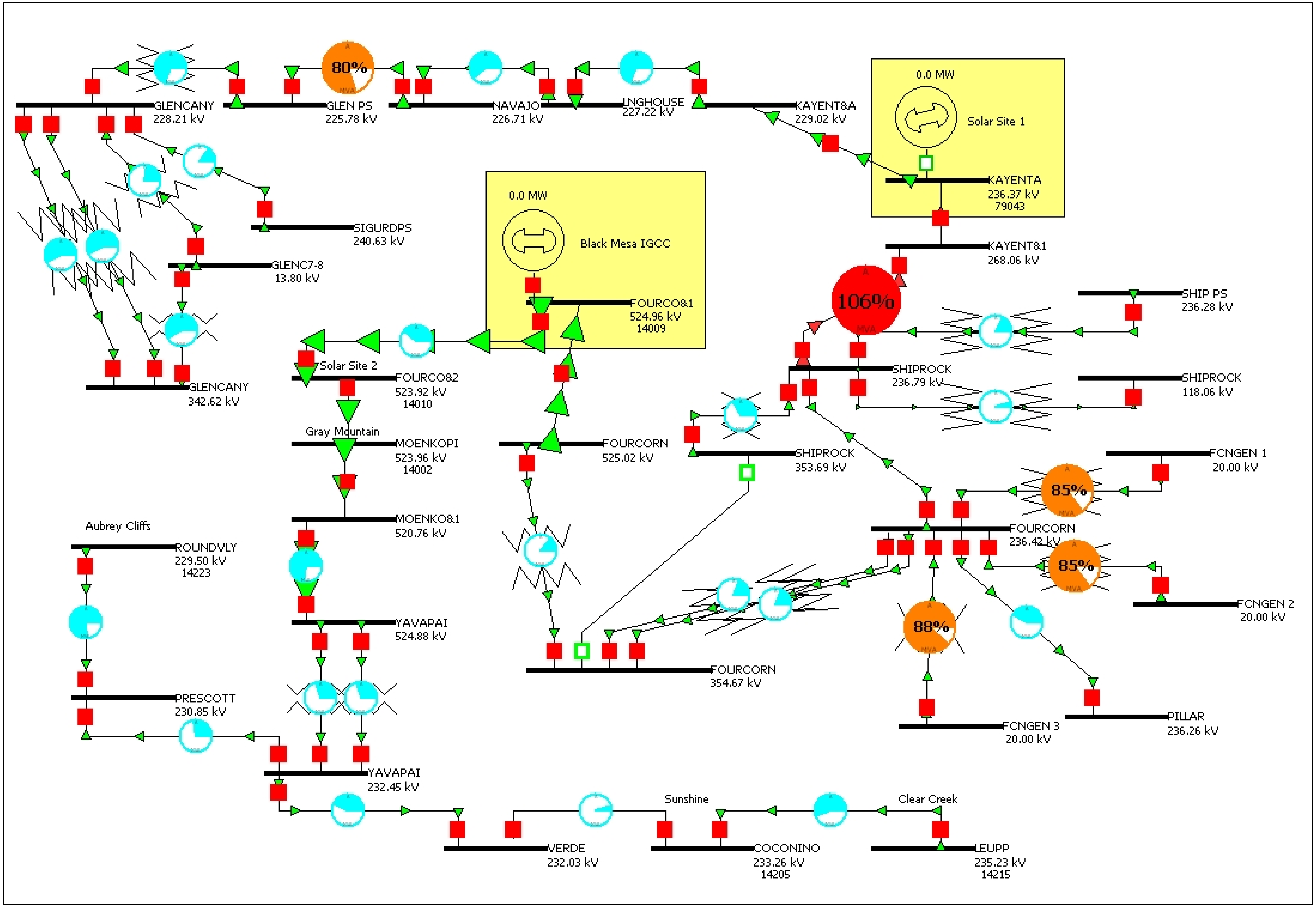
Arizona Transmission Analysis

Case 5: Clear Creek and Sunshine

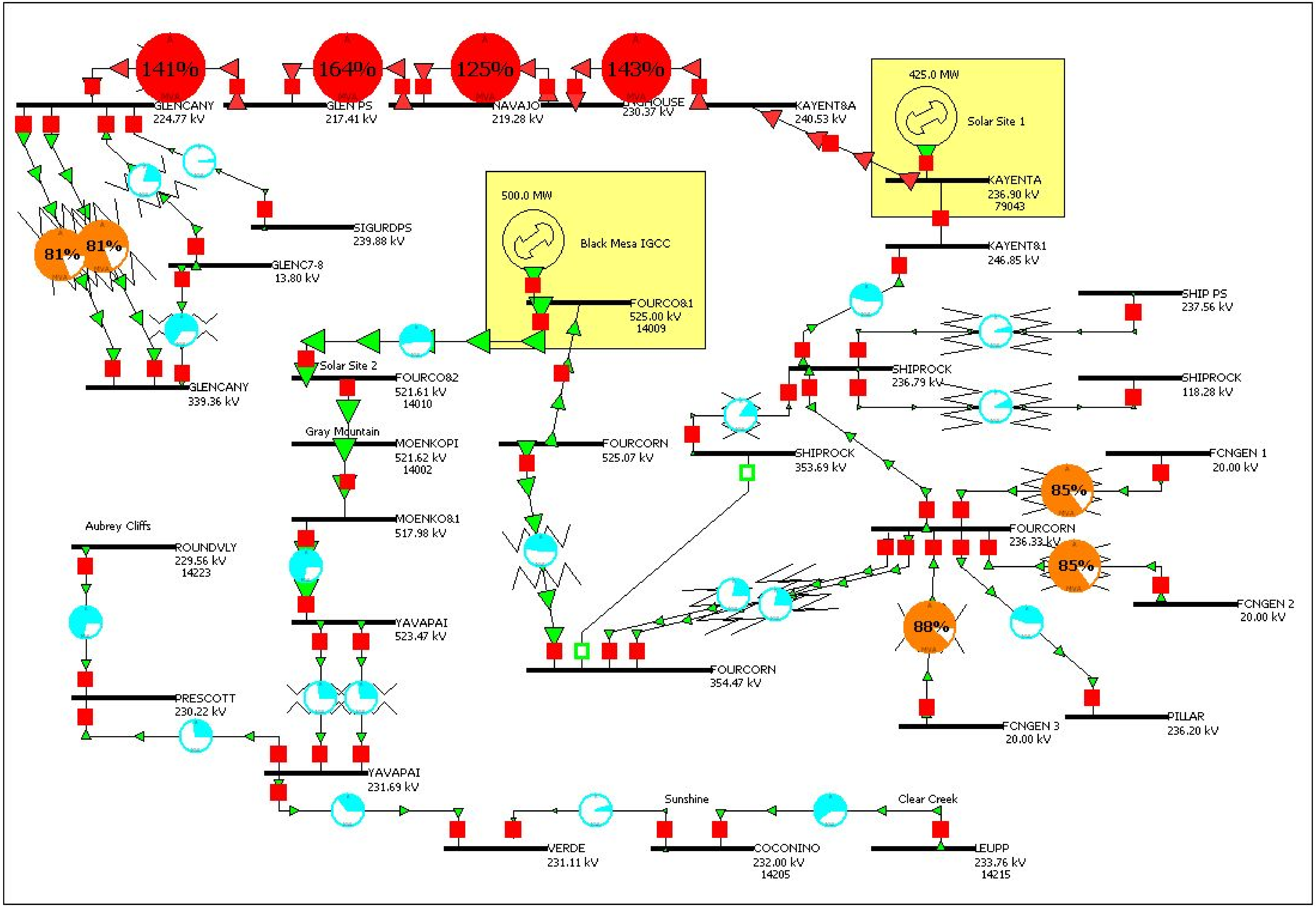
	Overloaded Transmission Facility			Thermal Loading (% of Rating)			
Contingency	Nom. Voltage (kV)	Type	Description	2010 Base Case	685 MW Added	Rating	Distribution Factor (%)
None	115	Line	WESTMS_1 (10370) -> WESTMS_T (10374) CKT 1	100.6	101.2	670 Amps	0.12
None	**500**	**Line**	**PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1**	**95.9**	**100.5**	**1400 Amps**	**8.15**
None	115	Line	MIRAGE (24807) -> TAMARISK (24821) CKT 1	100.0	100.7	1089 Amps	0.23
L_10369WESTMESA-14101FOURCORNC&1-MS	115	Line	LAGUNA (12044) -> WESTMS_P (12086) CKT 1 at LAGUNA	110.6	113.5	261 Amps	0.22
L_10369WESTMESA-14101FOURCORNC&1-MS	115	Line	GRANTS_T (12035) -> LAGUNA (12044) CKT 1 at GRANTS_T	119.0	120.5	261 Amps	0.11
L_14002MOENKOPI-14006YAVAPAIC&1-MS	**230**	**Line**	**ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY**	**99.9**	**110.0**	**650 Amps**	**3.82**
L_19011MEADN-19022DAVISC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	99.4	100.8	1100 Amps	0.86
L_19022DAVIS-26046MCCULLGHC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	99.6	101.3	1100 Amps	1.09
L_19053LIBERTY-19315PEACOCKC&1-MS	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	101.1	102.7	1100 Amps	0.98
L_19053LIBERTY-19315PEACOCKC&1-MS	230	Line	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	101.1	111.0	650 Amps	3.75
T_14001FOURCORN-14915FCNGN5CCC1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	98.4	102.0	100 MVA	0.53
T_14003NAVAJO-15981NAVAJO1C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	97.0	100.6	100 MVA	0.53
T_14003NAVAJO-15982NAVAJO2C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	97.0	100.6	100 MVA	0.53
T_14003NAVAJO-15983NAVAJO3C1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	97.0	100.6	100 MVA	0.53
T_14101FOURCORN-14914FCNGN4CCC1	161	Transformer	JFRSNPHA (65860) -> JEFFERSN (65850) CKT 1 at JEFFERSN	98.7	102.4	100 MVA	0.54
T_15209PAPAGOBT-15612PAPAGOBTC2	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 4 at PAPAGOBT	107.1	108.7	202 MVA	0.49
T_15209PAPAGOBT-15612PAPAGOBTC2	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 3 at PAPAGOBT	106.7	108.3	210 MVA	0.50
T_15209PAPAGOBT-15612PAPAGOBTC3	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 2 at PAPAGOBT	105.9	107.7	203 MVA	0.51
T_15209PAPAGOBT-15612PAPAGOBTC3	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 4 at PAPAGOBT	111.6	113.4	202 MVA	0.54
T_15209PAPAGOBT-15612PAPAGOBTC4	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 2 at PAPAGOBT	104.1	105.7	203 MVA	0.49
T_15209PAPAGOBT-15612PAPAGOBTC4	230	Transformer	PAPAGOBT (15209) -> PAPAGOBT (15612) CKT 3 at PAPAGOBT	109.2	111.0	210 MVA	0.53
T_15212ROGERS-15613ROGERSC2	230	Transformer	ROGERS (15212) -> ROGERS (15613) CKT 4 at ROGERS	101.1	102.0	309 MVA	0.40
T_15212ROGERS-15613ROGERSC4	230	Transformer	ROGERS (15212) -> ROGERS (15613) CKT 2 at ROGERS	101.1	102.0	309 MVA	0.40
T_19053LIBERTY-19054LIBTYPHSC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	101.0	102.5	1100 Amps	0.98
T_19053LIBERTY-19054LIBTYPHSC1	230	Line	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	100.8	110.8	650 Amps	3.76
T_19315PEACOCK-19314PEACOCKC1	230	Line	TOPOCK (19320) -> BLK MESA (19019) CKT 1 at BLK MESA	101.3	103.9	1100 Amps	1.66
T_19315PEACOCK-19314PEACOCKC1	230	Line	ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	117.3	132.6	650 Amps	5.80

Transmission Facilities Requiring Mitigation	Voltage Level	Control Area
PALOVRDE (15021) -> PALOVR&1 (15022) CKT 1	500	ARIZONA
ROUNDVLY (14223) -> PRESCOTT (14222) CKT 1 at ROUNDVLY	230	ARIZONA

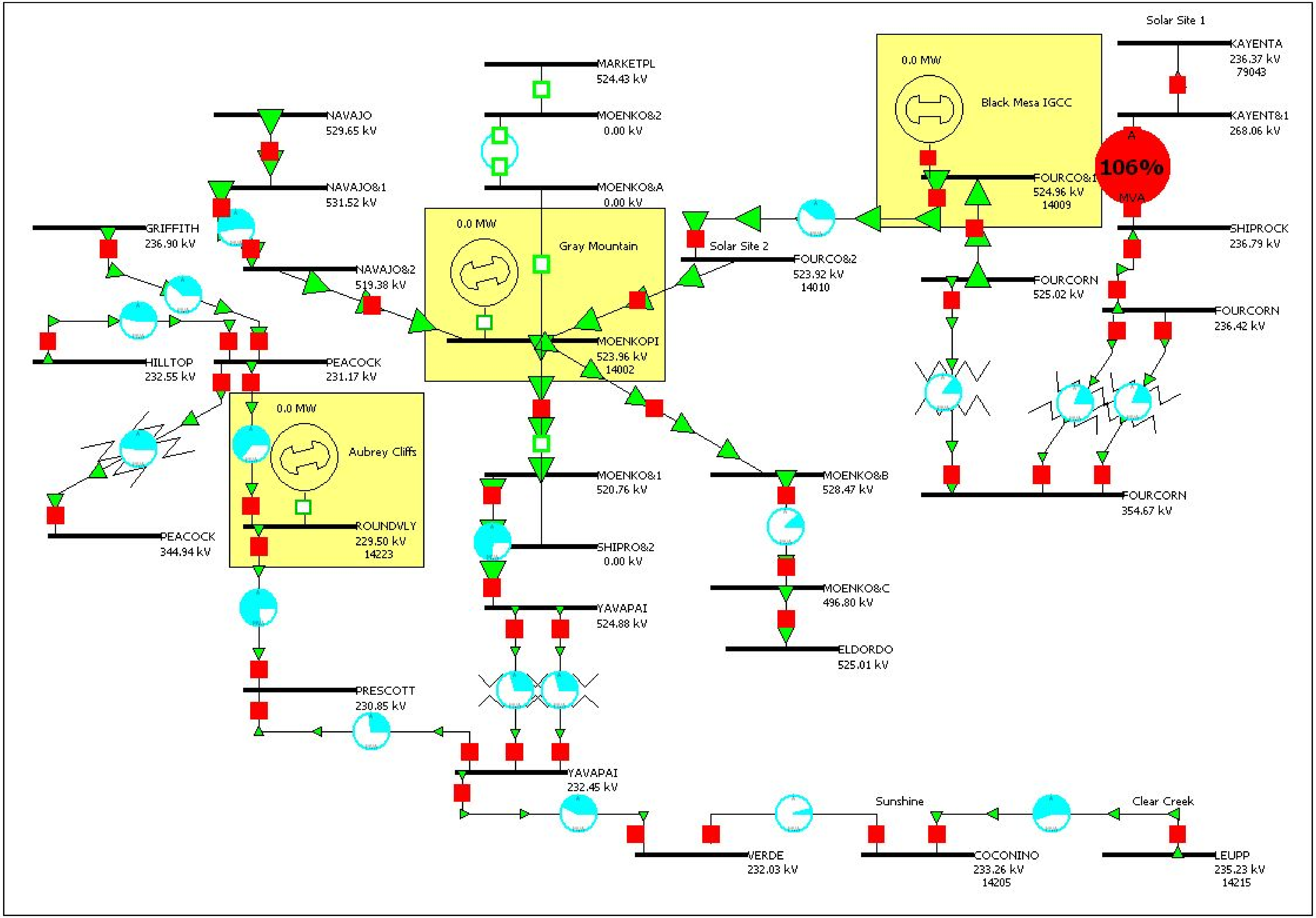
Note: Thermal loading percentages in above tables are based on amp ratings for transmission lines. Pie charts in Appendix K3 reflect equivalent MVA ratings.



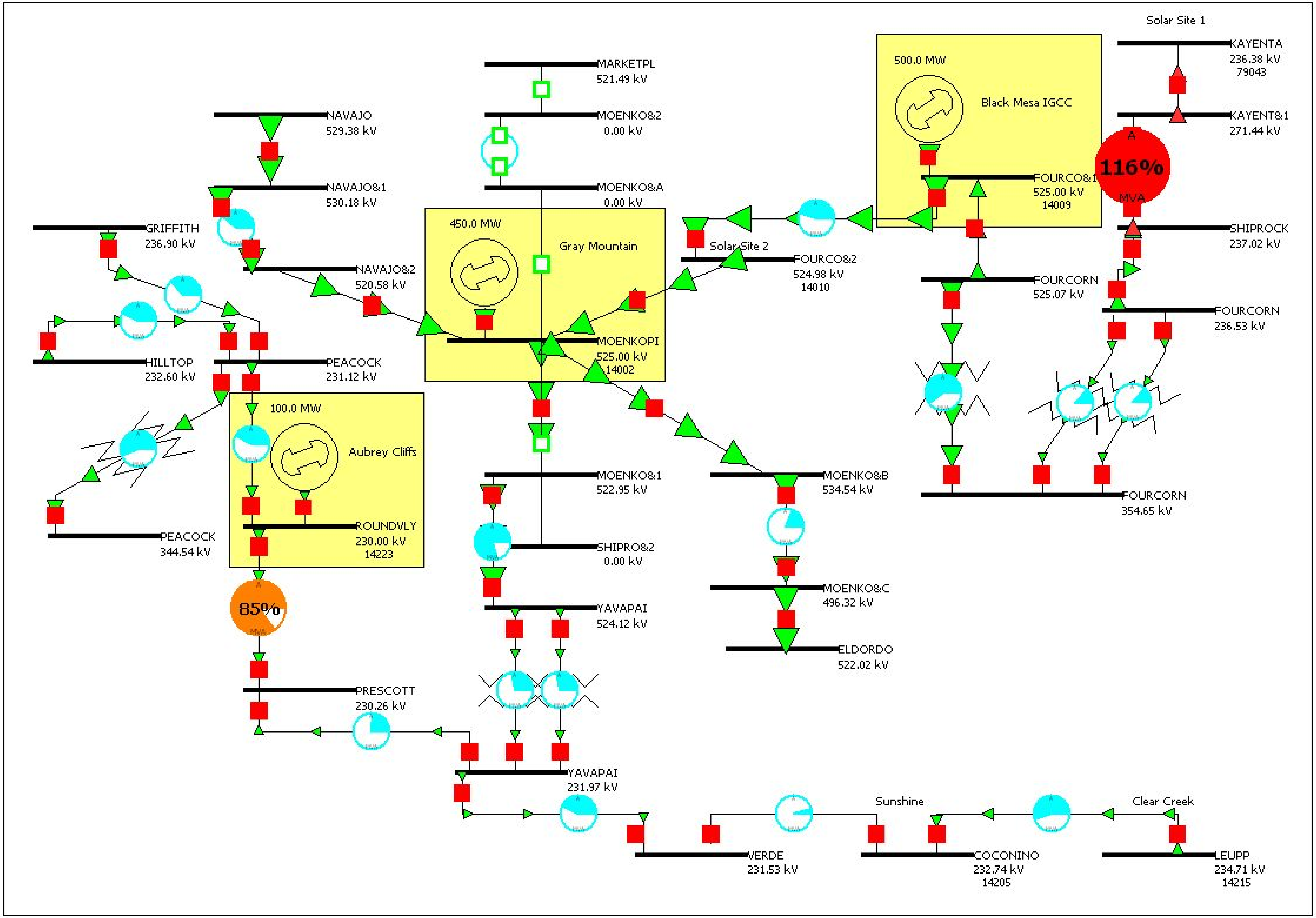
Appendix K3-1: Case 1 Base



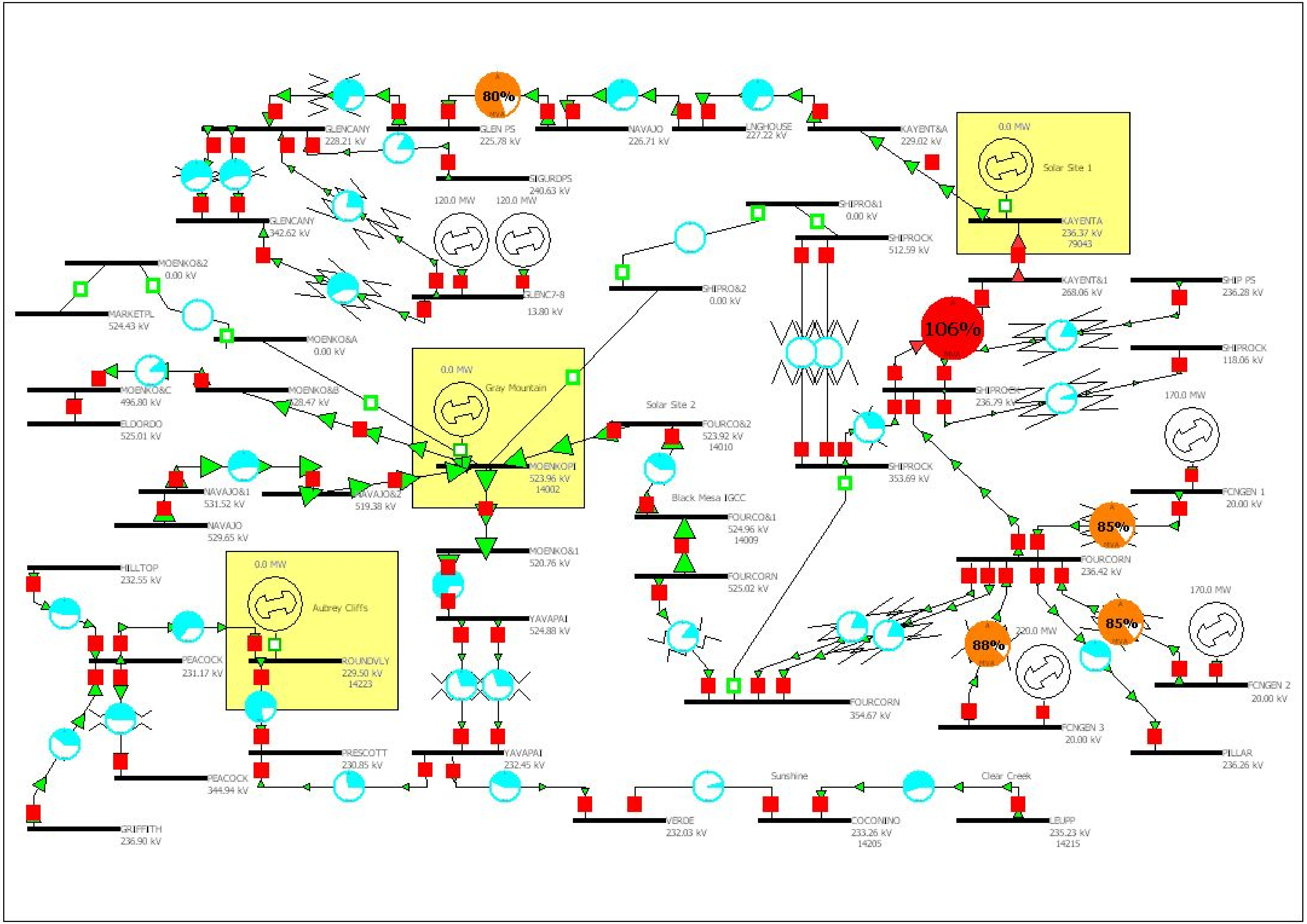
Appendix K3-2: Case 1 Base Plus 925 MW



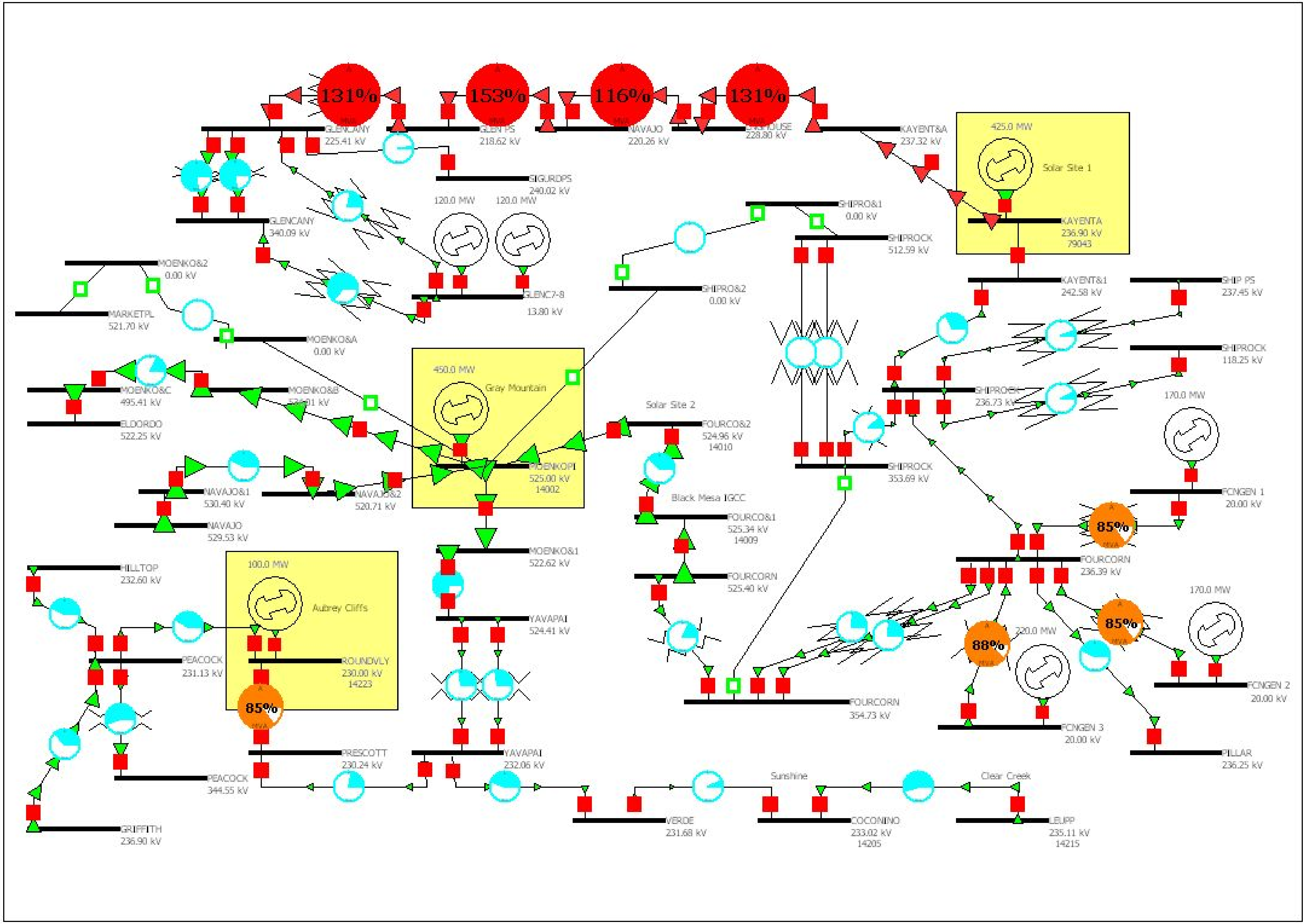
Appendix K3-3: Case 2 Base



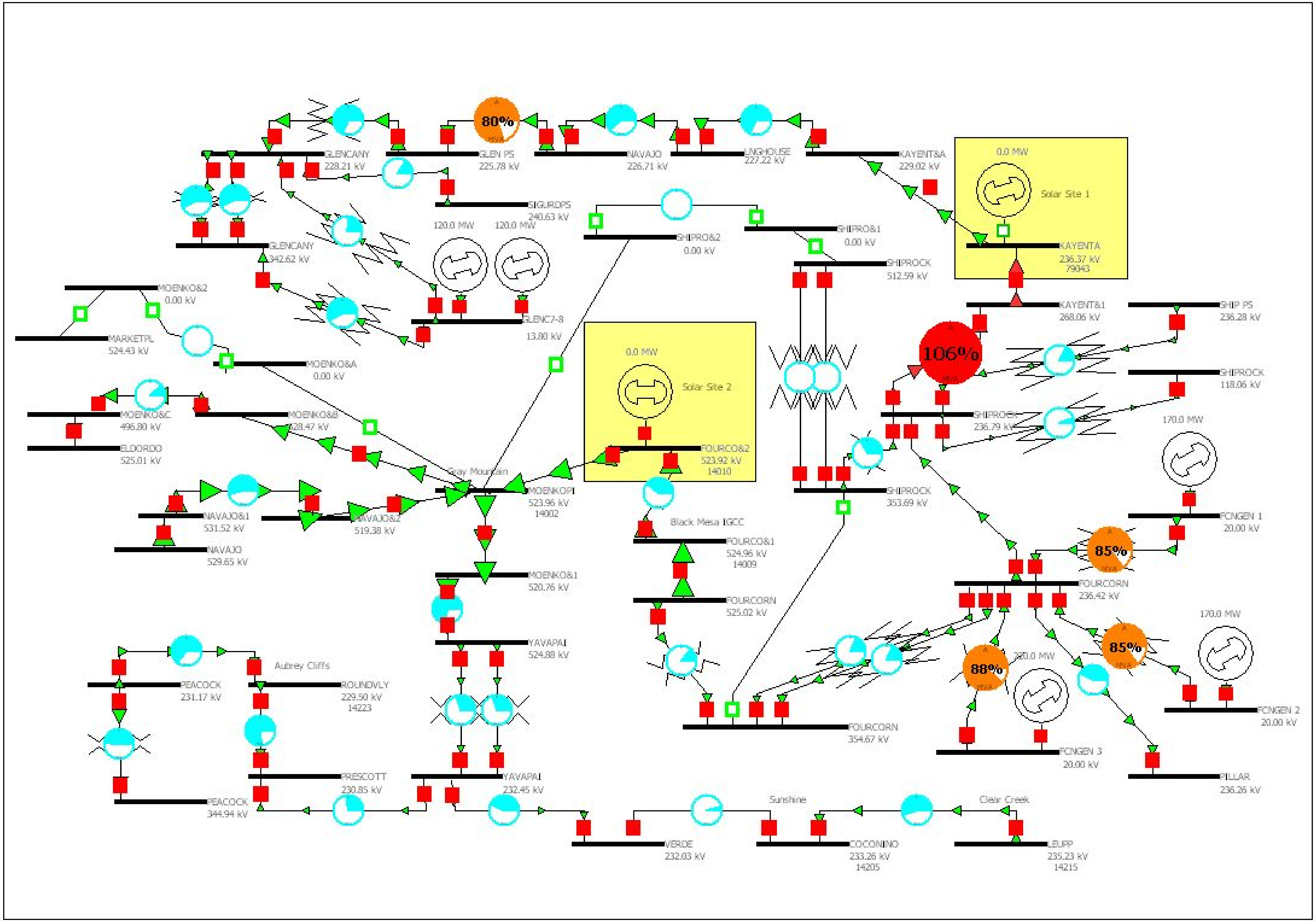
Appendix K3-4: Case 2 Base Plus 1050 MW



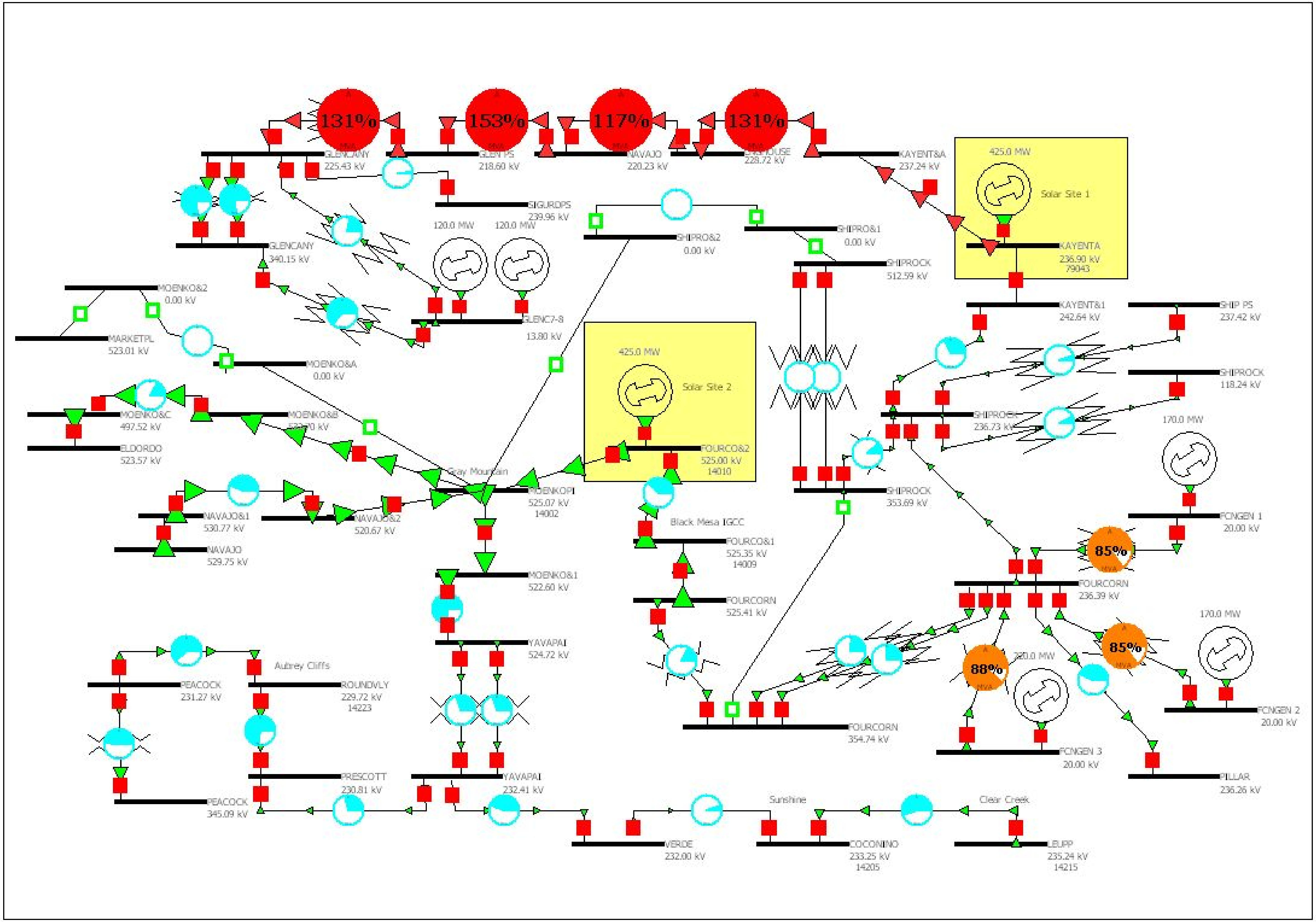
Appendix K3-5: Case 3 Base



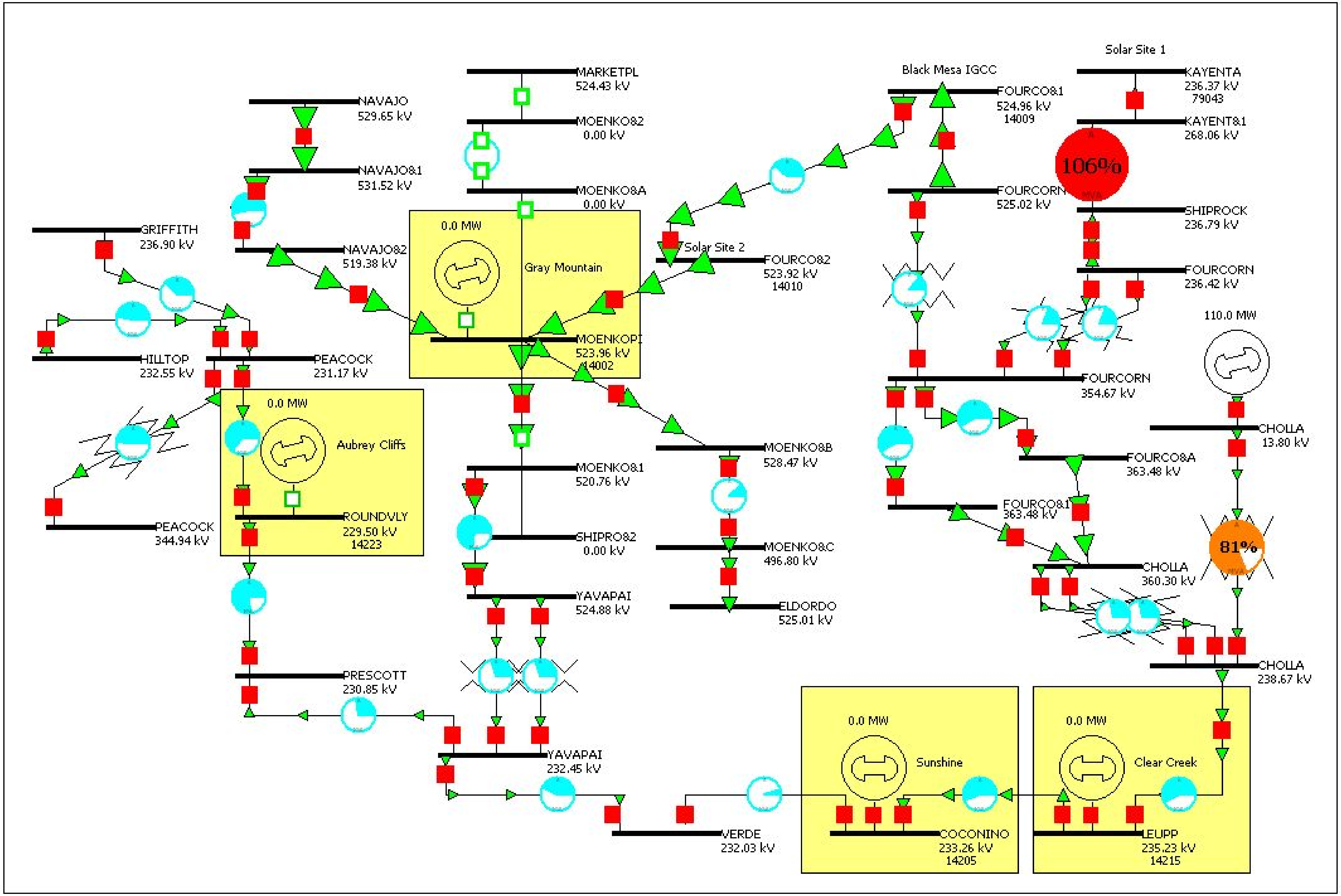
Appendix K3-6: Case 3 Base Plus 975 MW



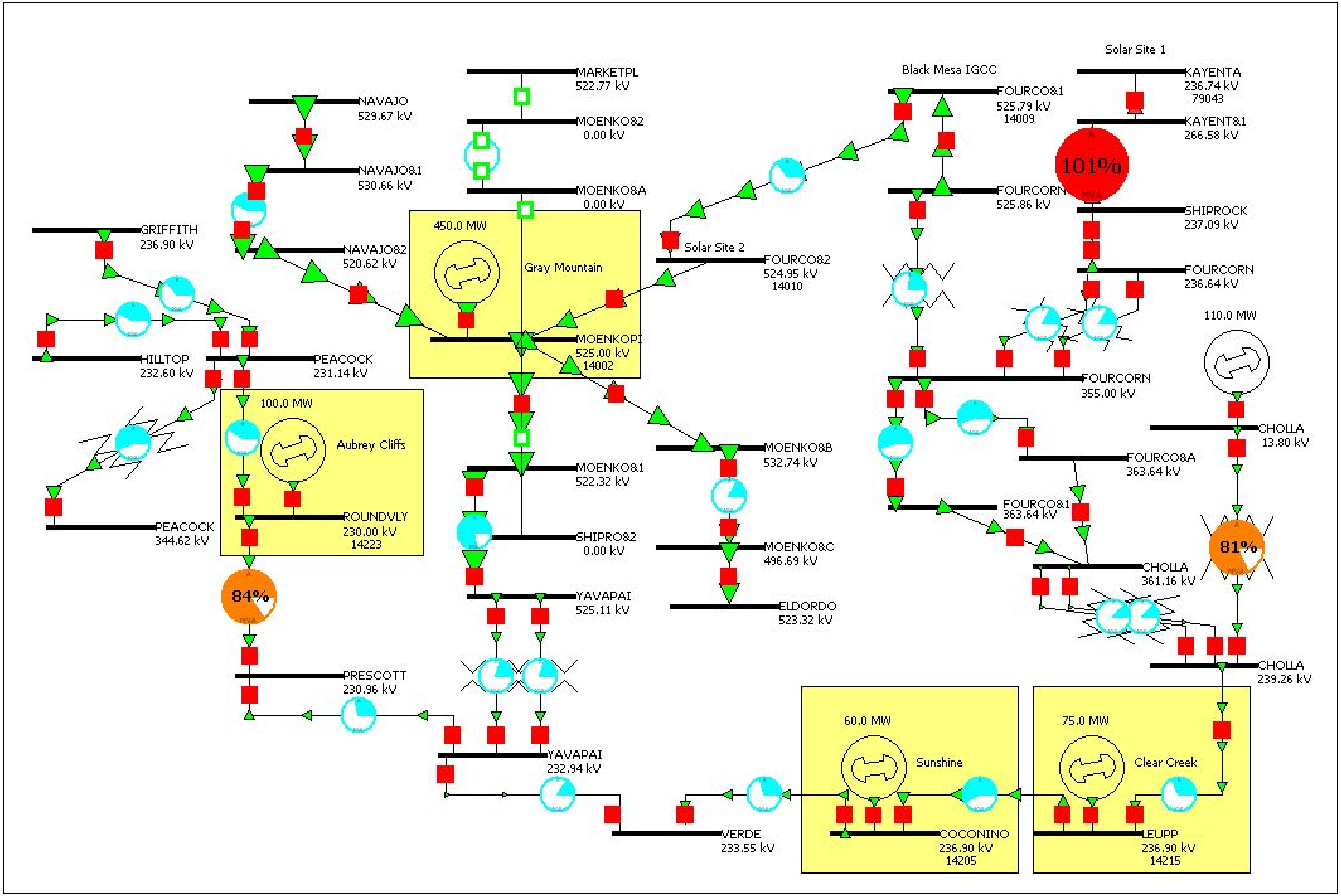
Appendix K3-7: Case 4 Base



Appendix K3-8: Case 4 Base Plus 850 MW



Appendix K3-9: Case 5 Base



Appendix K3-10: Case 5 Base Plus 685 MW