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**IMPACT OF GEOTHERMAL TECHNOLOGY
IMPROVEMENTS ON ROYALTY COLLECTIONS
ON FEDERAL LAND
VOLUME II - APPENDICES**

October 1988

**SAN FRANCISCO OPERATIONS OFFICE
U.S. DEPARTMENT OF ENERGY**

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IMPACT OF GEOTHERMAL TECHNOLOGY IMPROVEMENTS ON ROYALTY COLLECTIONS ON FEDERAL LANDS

VOLUME II - APPENDICES

DOE/SF/16299--T10

DE89 004416

PREPARED FOR THE

SAN FRANCISCO OPERATIONS OFFICE
U.S. DEPARTMENT OF ENERGY
CONTRACT No. DE-AC03-86SF-16299

BY
MERIDIAN CORPORATION
ALEXANDRIA, VIRGINIA

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PREFACE

This volume contains the appendices for the "Impact of Geothermal Technology Improvements on Royalty Collections on Federal Lands - Final Report - Volume I." The material in this volume supports the conclusions presented in Volume I and details each Known Geothermal Resource Area's (KGRA's) royalty estimation.

Appendix A details the physical characteristics of each KGRA considered in Volume I. Appendix B supplies summary narratives on each state which has a KGRA.

The information presented in Appendix C shows the geothermal power plant area proxies chosen for each KGRA considered within the report. It also provides data ranges which fit into the IMGEO model for electric energy cost estimates.

Appendix D provides detailed cost information from the IMGEO model if a.) no Geothermal Program R&D goals were completed beyond 1987, and b.) if all the R&D goals were completed by the year 2000. This appendix gives an overall electric cost and major system costs, which add up to the overall electric cost.

Appendix E supplies information for avoided cost projections for each state involved in the study that were used in the IMGEO model run to determine at what cost/kWh a 50 MWe plant could come on line.

Appendix F supplies the code used in the determination of royalty income, as well as, tabled results of the royalty runs (detailed in Appendix G). The tabled results show royalty incomes, assuming a 10% discount rate, with and without R&D and with and without a \$0.01/kWh transmission cost. Individual data sheets for each KGRA royalty income run are presented in Appendix G.

 

APPENDIX A

SUMMARY OF KGRA PROFILES

A-1/A-2

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EXPLANATION OF TERMS FOR APPENDICES A AND B

BLM - Bureau of Land Management

BLM VRM - BLM Visual Resource Management Class

Class I: This class provides primarily for natural ecological changes only. It is applied to primitive areas, some natural areas, and other similar situations where management activities are to be restricted.

Class II: Changes in any of the basic elements (form, line, color or texture) caused by a management of activity should not be evident in the characteristic landscape.

Class III: Changes in the basic elements (form, line, color, or texture) caused by a management activity may be evident in the characteristic landscape. However, the changes should remain subordinate to the visual strength of the existing character.

Class IV: Changes may subordinate the original composition and character but must reflect what could be a natural occurrence within the characteristic landscape.

Class V: Change is needed. This class applies to areas where the naturalistic character has been disturbed to a point where rehabilitation is needed to bring it back into character with the surrounding countryside. This class would apply to areas identified in the scenery evaluation where the quality class has been reduced because of unacceptable intrusions. It should be considered an interim short term classification until one of the other objectives can be reached through rehabilitation or enhancement. The desired visual quality objective should be identified.

A proposed surface disturbing project can then be analyzed for its usual impacts on the landscape in terms of form, line, color and texture and determine whether or not it will be an "eyesore."

- C - Competitive lease(s)
- CI - Competitive interest; this means that the KGRA was designated only because the acreage applied for in two or more noncompetitive lease applications overlapped by at least 50 percent.
- DOGAMI - Oregon Department of Geology and Mineral Industries
- GC - Geologic criteria; this means that the KGRA was designated on the basis that USGS feels that there are geologic indications of commercial resource
- NC - Noncompetitive lease(s)
- Rel. - Relinquished
- Term. - Terminated
- WSA - Wilderness Study Area

APPENDIX A

SUMMARY OF KGRA PROFILES

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
ALASKA										
Geysers Spring Basin							None	None		
Okmok Caldera							None	None		
Pilgrim Springs							None	None		
CALIFORNIA										
Bodie	CI	640	Sensitive; BLM VRM II; two historic areas	NA	NA	NA	Minimal	None	None recorded	Leases in several areas would be issued only with NSO stipulation; 100% Federal ownership
A-5										
Brawley	GC	28,885	No scenic quality; some areas unsuitable for farming	250	487	1710	See "Current Status"		Full development	100% private land; 10 MWe plant dismantled
Calistoga	CI	9,055	SEE THE GEYSERS							
Coso HS	CI/GC	106,752	High desert environment; air quality typical of nonindustrial Upper Mojave Desert	230	446	650	20 ⁺	Little; leases issued still active	Full development	30 MWe California Energy Co. plant on line; 2 additional 67.5 MWe plants planned; Los Angeles Dept. of Water and Power plans 10 MWe plant for 1990.

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS	
				°C	°F		C	NC			
Dunes	GC	7,680	Concern for fragile desert environment and water use.	120	248	(0.168x10 ¹⁸ J beneficial heat)	None	Active for a time; all rel./ term	1973 well at extreme western edge of anomaly does not represent true geothermal potential	Through 3 lease sales, no bids received; sale notices contained many stipulations and advisory notices regarding use of the area as Army and Navy	bombing area and for maneuvers; no guarantee that free of unexploded bombs or other hazardous materials; 92% federal ownership
East Brawley	GC	70,211	See Brawley	120	248	1,710	Mini- mal	None	See Brawley	Through 4 lease sales only 1 C lease issued; contains only 14% Federal land	
East Mesa	GC	17,714	Agricultural priority for water; some areas habitat of rare, endangered, or sensitive species of wildlife; in proximity of recreational and cultural values	182	360	360	20- leases issued remain active	Little	Considerable activity- exploration, development injection	GEO Operator 12.5 MWe and Ormesa 20 MWe plants on line; second Ormesa plant in development and GEO plans 2 more at 37 MWe each; land 85% Federally owned	

<u>STATE AND KGRA</u>	<u>TYPE OF KGRA</u>	<u>SIZE ACRES</u>	<u>ENVIRONMENTAL SETTING</u>	<u>TEMPERATURE</u> <u>°C</u> <u>°F</u>		<u>ESTIMATED SIZE MWe/30 years</u>	<u>LEASING INTEREST</u> <u>C</u> <u>NC</u>		<u>WELLS DRILLED</u>	<u>CURRENT STATUS</u>	
Glamis	GC	25,460	See Dunes	120	248	(0.094x10 ¹⁸ J beneficial heat)	See Dunes		Several temperature gradient wells from 300 to 2,000 feet.	Drilling east of the sand dunes indicates that east of the Coachella Canal (approximate location of the San Andreas fault)	the desert sediments are a thin veneer, and bedrock of various lithologies are close to the surface; 100% Federal ownership

Glass Mountains CI/GC	134,254	Elevation above 6,000 feet; concern for outdoor recreation, both summer and winter; excellent visibility and air quality.	>200*	>392*	500**	Compe- titive lease sale pending; 20" in effect	One of the most active KGRA's; over 100 in effect; only small per- cen- tage rel./ term.	NA	BLM refused to issue a number of NC leases on lands determined to be KGRA; lease applicants appeal failed; BLM will conduct competitive sale.
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** Estimate from Forest Service Environmental Assessment

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Heber	GC	58,568	In one of the most agriculturally productive areas in U.S.; uses irrigation	175	347	650	See "Current Status"			<p>Since Heber lies almost exclusively on private land, only one small (10 acres) tract was offered for C leasing and leased. Two plants have been constructed at</p> <p>Heber -- a 49-MWe dual flash and the DOE/industry co-funded binary plant. The latter is shut down due to delay in 100% brine flow and, has been offered for sale.</p>
Knoxville	CI	1,319		NA	NA	NA	Only one active lease recorded	None	None on record	Land ownership is 100% Federal.
Lake City-Surprise Valley	CI/GC	72,940		152	306	1,490	-6 remain active; none rel./term.	-10 issued all rel./term.	One exploratory, 2 thermal gradients	Land ownership is 50% Federal
Lassen HS	GC	78,705		240	464	NA	See "Current Status"			<p>Surface features suggest a vapor-dominated system within</p> <p>Park, but not confirmed by drilling; leasing denied in adjacent KGRA hv. ISEFS.</p>

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS	
				°C	°F		C	NC			
Mono-Long Valley	GC	458,514	One of the least populated areas in California, but one of the most scenic and popular recreation areas; nearby Mammoth Mt. is largest ski area in the country, attracting over a million skiers a season and peak loads of over 40,000 visitors/day. Altitudes range from - 7,000- 8,000 feet; snow	230	444	2,100	20 ⁺ active with very low rate of rel./ term.	None	Full field development	USFS approved leasing, with stipulations, of 18 lease units in Lease Block I; industry appealed; an additional 55,000 acres in which industry had expressed interest were opened up in the previously established Geothermal Management Zone. One binary plant has been operating in	the area since 1984. Four other plants are in planning stages, all reported to be 9-10 MWe capacity. Early exploration focused on the Center of Long Valley Caldera, but attention has shifted more recently to the west side of the Caldera and Mono Craters. Land ownership is 78% Federal.
Randsburg	C1	12,896	Embraces 2 WSA's	172	342	84	6 issu- ed re- main active	20 ⁻ re- main active with only 5 rel./ term.	Temperature grad- ient recorded	Land ownership is 96% Federal	

STATE AND KGRA	TYPE OF FRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS		
				°C	°F		C	NC				
Saline Valley	CI	3,199	Embraces one WSA	57	133	NA	No record of leasing found	No record found		Land ownership is 100% Federal		
A-10	Salton Sea	GC	102,887	5 endangered species; KGRA located directly on Pacific Flyway; extensive marsh cover and mud flats.	330	626	3,400	4 remain active	5 remain active	Long history of drilling	Since the development at the Salton Sea centers on nonfederal land around its southern tip, no Federal royalty is foreseen until pattern changes. One 10 MWe demonstration plant, on line	since 1982, is to be enlarged to 30 MWe; a 34 MWe came on-line in 1985; another is under construction to be followed by two others, all to come on-line in 1988/89. A 47.5 MWe plant is also under construction.
	Sespe HS	GC	7,035	Extremely isolated and undeveloped	280	562	(0.062x10 ¹⁸ J beneficial heat)	No record of leasing.		NA	Calif. Div. of Mines and Geology believes geothermal development will be	retarded due to the area's pristine condition and abundant wildlife.

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS		
				°C	°F		C	NC				
South Brawley	GC	12,640	See Brawley	NA	NA	NA	No lease sales held		None	See Brawley	This KGRA is a relatively new one, and the last to be designated on the basis of a discovery. It is almost all private land.	An effort to build a 45 MWe plant failed because of potential brine handling problems that could have a severe impact on plant economics.
<hr/>												
The Geysers	GC	278,644	Mountainous, uninhabited terrain	220	459	1,610 (already exceeded)	~36	active	10	Full development	Nearly 1800 MWe are on line in 24 plants; a 130 MWe plant is under construction; and the start of a 140 MWe plant, to be the largest, is delayed. A 22 MWe plant has recently been announced. Only 28 percent of the land is Federally-owned, and only 4 plants	are on Federal leases; however, others draw part of their steam from Federal lands. One reason for the relatively small Federal ownership is that over 4,000 acres in six prime Federal leases were transferred to the state under school land requirements.

A-11

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Wendel-Amedee	GC	18,431	The area contains significant recreational and scenic values, archaeologically sensitive areas, and wildlife habitat areas, but there is also acreage where development would not create significant residual adverse impacts.	128	262	(0.190x10 ¹⁸ J beneficial heat)	1 issued and still active	2 issued, 1 still active	3 prior to 1982; 3 since, plus an exploratory well for direct use	In 1978, USGS stated that "Based on available data and demonstrated technology, the resource at Wendel-Amedee is inadequate for power generation. The temperature data obtained more recently from wells drilled to serve a DOE-assisted hybrid binary plant at Honey Lake tend to validate this assessment. However, a very small binary unit, 600 kWe, is in operation in the area which was economic under site-specific conditions; 51% of the land Federal-ly-owned.
Westmorland	NA	3,200		215	418	1,710	See "Current Status"			Land is 100% nonfederal.

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE °C °F	ESTIMATED SIZE HWe/30 years	LEASING INTEREST C NC	WELLS DRILLED	CURRENT STATUS
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COLORADO

Mineral HS	CI	4,485						
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Poncha	CI	3,200		71 160				
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Valley View HS	CI	1,913		37 99				
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IDAHO

Bruneau	CI	5,120		110 230				
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Castle Creek	CI/GC	79,722		107 224				
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Island Park	CI	28,539						
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Leasing
prohibited by
statute

Mountain Home	CI	9,520		72 162				
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Raft River	CI/GC	30,209		140 284				
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Vulcan HS	CI	3,836		138 280				
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Yellowstone	GC	14,164						
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Leasing
prohibited by
statute

A-13

<u>STATE AND KGRA</u>	<u>TYPE OF KGRA</u>	<u>SIZE ACRES</u>	<u>ENVIRONMENTAL SETTING</u>	<u>TEMPERATURE</u> <u>°C</u> <u>°F</u>		<u>ESTIMATED SIZE MWe/30 years</u>	<u>LEASING INTEREST</u> <u>C</u> <u>NC</u>		<u>WELLS DRILLED</u>	<u>CURRENT STATUS</u>
<u>MONTANA</u>										
Boulder HS	GC	6,343		136	277		None re- sulted from lease sales	Only 6 issued in en- tire state		
Corwin Springs	CI/GC	20,349		68	154					The tempera- ture is not suitable for power generation. National Parks and Conser- vation Assn. recommending KGRA as additional to Yellow- stone.
Marysville	CI/GC	19,200		103	217		None resul- ted from lease sales	See Boul- der HS above		
Yellowstone	GC	12,763								Leasing prohibited by statute

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
NEVADA										
Baltazor	CI	5,617	Conflict with one WSA	158	316	46	3 still in effect	All but 5 of 20+ rel./ term.	Max. temp. reached in 27 shallow temp. gradient holes was 97°C (205°F); 2 other temp. gradients and 1 well to 3,600 feet with temp. of 119°C (246°F)	This KGRA is a likely candidate for declas- sification
Beowawe	CI/GC	26,180	Characterized by a large sinter deposit (approx. 3/4 mi. long and 1/4 mi. wide), hot springs, pools, mud pots, fumaroles, and an intermittent geyser.	226	444	127	Current developer interest centered only on area under development. 10+ is- sued; all except those in Chevron's unit in- active	Of over 20+, only 2 sur- vive; one in the producing unit it- self	Magma Power drilled 11 shallow wells from 1959-1965; Chevron's extensive exploration program began in 1974.	One 16.6 MWe (gross) plant on line; if resource proves substantial and future economics for geothermal power are good, expan- sion is plan- ned. Well testing has

verified that
the system is
very large,
with no
production
boundaries
seen to date,
and very
prolific with
all wells
showing
extremely high
permeability.

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Brady-Hazen	CI/GC	98,508	Power plant site at Desert Peak is in a desolate range of hills with no scenic or unique features; current land uses limited to geothermal exploration, cattle grazing, and food processing utilizing geothermal fluids.	225 (Des- ert Peak) 155 (Brady HS)	436 (Des- ert Peak) 310 (Brady HS)	157 (Desert Peak)	Mixed record; through 5 lease sales many tracts offered 2 and 3 times received no bids; yet about 15 leases were issued. All but those at Desert Peak are now rel./ term.	Minimal	Full field development	9 MWe plant on line at Desert Peak; no further development announced. According to Environmental Assessment, the Brady Hot Springs reservoir is centered on a single fault and appears to be too small for power generation.
Colado	CI	640		101	213	(0.044X10 ¹⁸ J beneficial heat)	1 re- mains active	-5 active	None recorded	This very small KGRA located at the town of Colado in north-western Nevada is not likely to see power development with its temperature.

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Darrough H.S.	GC	8,363	In some areas, hillsides are scarred with mining activity, and numerous thermal springs are scattered throughout the area. Although protection of wild horses and burros is required, there	132	270	(28X10 ¹⁸ J beneficial heat)	Little	Very active- ~40 leases still active	A 248-ft. well reached 129°C; permitting is underway for development drilling.	Planning and permitting underway to produce power. Capacity not yet announced.
			are no threatened or endangered species. Forest Service Research Natural Areas and candidates for wilderness and primitive designation will have to be avoided.							
Dixie Valley	CI/GC	129,361	Very low sensitivity. BLM VRM Class IV.	145	293	>150*	-20 issued; 13 existing	120 ⁺ issued; 44 existing	A number of exploration wells drilled by several developers. 11 production wells are being used for power plant.	BLM strongly supports development in this area. Oxbow, which acquired the leases from Sun and Trans-Pacific, is building a 50 MWe plant and 220 mi. transmission line.

* Estimate from BLM Environmental Assessment on power plant construction.

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				$^{\circ}\text{C}$	$^{\circ}\text{F}$		C	NC		
Double H.S.	CI/GC	29,361	Adjacent to 2 WSA's	127	260	(0.22X10 ¹⁸ J beneficial heat)	None	30 ⁻ issued, but all rel./ term	None recorded.	
Elko H.S.	GC	8,960		86	187	(0.042X10 ¹⁸ J beneficial heat)	2 leases which have been termi- nated	None		Many direct uses, including a for-profit district heating system. Temperature precludes power generation.
Fly Ranch	CI	20,758	BLM has rejected many lease applications in this area--a very high percentage--and some have been for environmental reasons.	100	212	(0.067X10 ¹⁸ J beneficial heat)	Only half of the 10 tracts offered were leased, all now rel./term, and no bids were made on the other parcels through multiple sales.	20 ⁻ issued are no longer active.	Several temperature gradients.	A candidate for declas- sification.

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Gerlach	CI/GC	26,326	Slight overlap with WSA	170	338	32	Very simi- lar re- cord to to Fly Ranch	Group of leases unitized, but unit dissolved and the leases termi- nated.	1 exploratory and 2 temperature gradients	A 2.4 MWe binary unit has recently been announced.
Hot Springs Point	CI	8,549		87	189	(0.042X10 ¹⁸ J beneficial heat)	Very lit- tle	Very lit- tle	2 temperature gradients	
Kyle H.S.	GC	2,560		161	322	97	Very lit- tle	Very lit- tle		
Leach H.S.	CI/GC	12,846		160	320	77	5 issued, unitized, but unit was dis- solved and the leases termin- ated.	Very active for a time, but no leases remain active.	1 exploratory	
Moana Springs	GC			96	205	(0.143X10 ¹⁸ J beneficial heat)	No com- petitive sales	Very little		

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Pinto H.S.	CI/GC	8,015	Embraces 1 WSA	176	349	90	Very lit- tle	Very lit- tle		
Ruby Valley	CI/GC	5,743		96	205		Very lit- tle	Very lit- tle	None recorded.	
Rye Patch	CI	801		218	423		One com- pany has a lease for the entire KGRA	20" issued, and very low inci- dence of rel./ term.	Two developers have drilled 2 exploratory and 1 temperature gradient.	While no power development plans have been announc- ed, this KGRA was placed on the priority list because of its temperature and high developer interest.
San Emidio Desert	CI/GC	7,678		166	331		Little no ac- tive leases	Little- no ac- tive leases	2 exploratory wells found disappointing temperatures for power generation	

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Soldier Meadow	CI	5,967		64	147					No leases of either kind are recorded. However, some applications had to be filed for the competitive interest KGRA to be so classified.

Steamboat Springs	GC	8,912	A 40-acre tract has been set aside by BLM as the Steamboat Springs area of Critical Environmental Concern where no leasing is permitted to protect the natural geysers--one of only three such areas left in the U.S. If any springs are adversely affected by production, injection and/or	207	403	350				For development to be occurring at 2 sites in this area, there are relatively few leases--probably only 2 or 3	A 12.5 MWe single flash plant may be enlarged to 25 MWe; a nearby 5 MWe binary operates on lower temperature fluid. The former is located on private land, but 1-2 production wells are on BLM land.
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STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Stillwater- Soda Lake	GC	225,260	Sensitivity is very low; assigned a BLM VRM IV; there are no residen- ces on or adjacent to plant site; no rare or en- dangered species.	159 (Still-Still) water) water) 161 146 (Soda (Soda Lake) Lake)	318 water) 146 (Soda Lake)	450 (Stillwater) 146 (Soda Lake)	5 re- main ac- tive	Mini- mal -- 3 remain active	10 exploratory wells and 2 shallow tempera- ture gradient wells drilled prior to 1982 by several develop- ers. Highest temperature re- corded was 178°C.	Chevron plans to construct a 2.4 MWe plant to use wells previously drilled by Phillips, from whom Chevron purchased the property.

Trego	CI	7,013		124	255		None	Minimal -- only 2 remain active out of about 15 issued		
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Warm Springs	CI/GC			NA	NA		None	None		
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STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE °C °F		ESTIMATED SIZE MWe/30 years	LEASING INTEREST C NC		WELLS DRILLED	CURRENT STATUS
NEW MEXICO										
Baca Location No. 1	GC	164,696	Area en- compasses historical, archaeologic, scenic, and Indian religious sites; habitats for endangered species, considerable acreage potential wilderness	278	531	2,700 estimated by Circular 790; insufficient fluid found to support 50 MWe plant	8 re- main active although equal - no. rel./ term	None	Nearly 20 wells ranging from 671 - 5,502 feet	Unocal retains its properties in the area; no announced plans for smaller capacity development.
Gila H.S.	CI	3,202	Geothermal development compatible with purposes for which Gila National For- est was cre- ated, provided that the iden- tified areas of greatest environmental sensitivity are protected; abuts Gila Wilderness area.	77	171		No record was found of leasing in this area.		None recorded	One small binary unit operated briefly on 63 - 68°C (145- 155°F) feed- water. Oper- ation was not successful.

<u>STATE AND</u> <u>KGRA</u>	<u>TYPE</u> <u>OF KGRA</u>	<u>SIZE</u> <u>ACRES</u>	<u>ENVIRONMENTAL</u> <u>SETTING</u>	<u>TEMPERATURE</u>		<u>ESTIMATED</u> <u>SIZE</u> <u>MWe/30 years</u>	<u>LEASING</u> <u>INTEREST</u>		<u>WELLS</u> <u>DRILLED</u>	<u>CURRENT STATUS</u>
				<u>°C</u>	<u>°F</u>		<u>C</u>	<u>NC</u>		
Lightning Dock	CI	21,667		158	316	(0.070X10 ¹⁸ J beneficial heat)	10 remain active, one pro- ducing although several have been rel./term.	Of nearly 30 is- sued, only 3 remain active.	2 completed before 1982; a 7,000 foot development well completed and abandoned in 1982.	One small (<1 MWe) is operated in this area to supply power for a greenhouse.
Lower Frisco H.S.	CI	5,760		99	210		No record of leases in this area was found.			
Radium Springs	CI	6,862		96	205		5 remain in-force; 2 termi- nated	Most active area in N.M. with nearly 30 active; very low percen- tage of rel./ term.	In 1981, 2 wells completed to 8,000 and 9,000 feet; latter was abandoned.	
Socorro Peak	GC	28,715		33	91		More have been rel./ term than re-	Interest has waned; only 1 active. tained; about 10		

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE °C °F		ESTIMATED SIZE MWe/30 years	LEASING INTEREST C NC		WELLS- DRILLED	CURRENT STATUS
OREGON										
Alvord	CI/GC	176,835	The Alvord Desert where most of the KGRA lies is one of the more remote areas of Oregon. There is little man-made contamination, but several thousand acres are encrusted with a layer of sodium borate and other salts several inches thick. Other thermal manifestations exist. In one area, landslides may be a problem, and endangered species exist.	207 (Mickey H.S.) 164 (Alvord) 176 (Hot Borax Lake)	404 327 349	160, Mickey H.S.; 49, Alvord; 91, Hot Borax Lake	Of 30 issued only about 10 remain active	Many applications withdrawn/rejected; only 3 remain active		It is difficult to say why this area has fallen out of favor, but according to DOE reservoir expert, it is "dead."

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Belknap-Foley	CI	5,006	Highly sensitive; includes Research Natural Areas; development might cause degradation of visual and recreation resources; approx. 40 miles of the area overlaps, fronts on, or lies within 1 mile of wilderness areas.	56- 135	133- 275 (based on gradient holes)		Little	Little		Such stringent restraints are placed on operations under leases in many areas that it will be difficult to find sufficient acreage upon which development would be feasible.
Breitenbush	CI/CG	13,445	This is the largest thermal spring area in the Oregon Cascades. It is in rugged forested terrain, and is home to several threatened and endangered wildlife species.	127	260	(0.059X10 ¹⁸ J beneficial heat)	Minimal; all rel./ term	Approx. 40 is- sued; about half rel./ term.	One unsuccessful test hole is recorded.	There were two EA's on Breitenbush, the second covering the acreage closed to leasing by the first one and additional acreage.

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Carey H.S.	GC	7,579		98	208	(0.048X10 ¹⁸ J beneficial heat)				
Crump Geyser	CI/GC	85,663	Abuts the Hart Mountain antelope refuge	173	343	61	10 ⁺ is- sued; none remain active.	40 ⁺ is- sued; all but 1 rel./ term.	One at 1,684 feet spouted boiling water for several months at 1,500 - 2,300 l/min; max. temp. 121 C (250°F)	
Klamath Falls	CI/GC	29,869		104	219	(1.79X10 ¹⁸ J Circular 790; beneficial heat)				Due to the fact that LBL estimated a much higher tem- perature than USGS after recent work in the area, Klamath Falls was placed on the list for royalty projection.
				150-	300-					
				190	374					
				LBL Model						

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Lakeview	GC	12,165		149 Circular 790; 105 produced	300 221	(0.33X10 ¹⁸ J beneficial heat)				Despite the fact that small binary units have operated at Lakeview, temperatures found would not economically operate units of a size to produce significant royalty revenues. However, on the basis of USGS and DOGAMI estimates, the reservoir cannot be written off for the future.
McCredie	CI	3,659		96	205	(0.041X10 ¹⁸ J beneficial heat)				
Mt. Hood	GC	8,671	Leasing is prohibited since the KGRA lies in the Mt. Hood Wilderness Area.	125	257	(0.058X10 ¹⁸ J beneficial heat)				Temp. of one test hole on the west flank at 4,000 feet was 82°C (180°F); a second at 6,000 feet recorded 121°C (250°F). Neither produced useful quantities. A well on the south side reached 80°C (176°F) at 4,000 feet. It supplies fluid for heating Timberline Lodge. A gradient hole on the north-west side reached 57°C (135°F) at

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Summer Lake	CI/GC	13,631		112	234	(0.130X10 ¹⁸ J beneficial heat)			3 prior to 1980. Data on one indicates 111°C (232°F) temp. at depth of 282 feet.	
Newberry Caldera	CI/GC	31,284	Special con- sideration must be given to nesting sites of several bird species; two threatened species are migrating visitors; 4,400 acres are part of critical deer migration route; Crater is listed on Natl. Registry of Historic Landmarks.	230 Circular 790; 190 at 2,656 feet 256 at 3,057 feet test well data	446 375 509	740	Lease sale plan- ned.	120+ issued; almost none rel./ term.	See "Temperature" for USGS well data. DOE cost sharing deep thermal gradient holes. A deep production well is planned for 1988.	Leasing is precluded by the Forest Service in the Caldera, but permitted in other areas.
Vale	CI/GC	22,998		188 Neal HS 127 Little Valley 157 Vale HS	370 260 314	36 - Neal 870 - Vale	Minimal only 2 ac- tive	-40 is- sued; about half remain active.	10 before 1980; only one temp. gradient of 1,000 feet is recorded since,	

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
UTAH										
Cove Fort-Sulphurdale	CI	24,074	The eastern and northern portions of the area are mountainous although Cove Ft., listed as a National and State Historic Site, is located in a valley in the central part of the	265	509	330	10 active; some rel./term.	Less than 10 remain active out of 70 ⁺ issued.	Full field development.	6.5 MWe binary capacity is operating on dry steam.
			KGRA. The area has been active seismically, and the mining of water could increase occurrence and severity of the activity.							
Crater H.S.	GC	17,321	Most of the area is relatively flat although mountain ranges and high peaks can be seen in all directions; little scenic appeal and no people living in the lease area, but nearby communities.	97	207		Only 1 active	Active early, but all have been rel./term.		Water appears to be a problem.

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE °C °F	ESTIMATED SIZE MWe/30 years	LEASING INTEREST C NC	WELLS DRILLED	CURRENT STATUS
Lund	CI	3,840		NA NA (Literature indicates probably below 90°C)		None Limited - none active		
Meadow-Hatten	CI	1,927		48 118		One ac- tive active	Minimal	
Monroe-Joseph	CI/GC	16,364	Irrigated agriculture and livestock major land uses; disturbance caused by development would be highly visible in some cases because leasable lands are located on the hillsides of both sides of the valley.	110 214 Monroe; 104 219 Joseph		Very little; none active	Very little; none active	Only 22 foot well is recorded with temp. of 20°C (68°F)

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE		ESTIMATED SIZE MWe/30 years	LEASING INTEREST		WELLS DRILLED	CURRENT STATUS
				°C	°F		C	NC		
Navajo Lake	CI	2,522		NA	NA (Literature indicates probably below 90°C)					No record of leases in this area.
Newcastle	CI	2,636		130	200		Only 1 rel./ term recorded.	None		
Roosevelt HS	CI	29,791	The KGRA is located in Utah's "Color Country" and provides a number of recreational activities; Class IV on BLM VRM system; no rare, threatened, or endangered species in area of existing power development.	265	509	970	~12 ac- tive	A few active	Full field development.	20 and 14 MWe plants on- line; no new announced plans.

STATE AND KGRA	TYPE OF KGRA	SIZE ACRES	ENVIRONMENTAL SETTING	TEMPERATURE °C °F	ESTIMATED SIZE MWe/30 years	LEASING INTEREST C NC	WELLS DRILLED	CURRENT STATUS
Thermo H.S.	CI	22,179		142 287		Only 2 50 ⁺ is- of 10 is- sued; all sued re- but 3 main ac- rel./ tive. term.	a 50-foot well reached 23°C (73°F).	

WASHINGTON

Kennedy HS

Closed to
development
since it is
within the
Glacier Peak
Wilderness
area.

Mt. St. Helens

Leasing is not
permitted in
the National
Monument area;
Forest Service
likely to
apply No
Surface
Occupancy
stipulations
in other
areas.

APPENDIX B

STATE SUMMARIES

APPENDIX B

STATE SUMMARIES

ARIZONA

Clifton and Gillard Hot Springs competitive interest KGRA's, the only ones ever designated in Arizona, have been declassified. Only one competitive lease was issued at Clifton and that to a company which is known to be involved in direct use only. It has since been terminated.

Just over 200 noncompetitive applications have been filed for acreage in the state, over a third of which were withdrawn and nearly a third of which were rejected. Many, although not all, were on acreage in National Forests. Twenty-five noncompetitive leases have been relinquished/terminated, and a great many were still pending action when the BLM data base was concluded.

Five noncompetitive leases near Kaiser and Cofer Hot Springs remain active, and two each near the Hassayampa Plain and northwest of Verde Hot Springs. Pumped wells in the Hassayampa Plain area drilled in connection with direct use feasibility investigations have produced fluids of 35-56°C (95-133°F) in temperature at depths between 1,000 and 2,000 feet. In the Kaiser/Cofer area, fluid temperatures of 37°C (99°F) have been found. These temperatures will not support economic power generation with current technology or with R&D developments envisioned in the foreseeable future.

Thus, in light of combined negative factors, it can be concluded that hydrothermal power generation of any significance cannot be expected in Arizona prior to 2010.

CALIFORNIA

California embraces 22 active KGRA's, ranging in size from the Mono-Long Valley KGRA with nearly 460,000 acres to Bodie which encompasses only 640

acres. The latter is a good example of a KGRA formed only because of acreage overlap in noncompetitive lease applications, while Mono-Long Valley was designated early on the basis of geologic indications of a commercial resource.

The major factor that will influence the lease royalty revenue to be derived from this state is land ownership in critical areas. While 57 percent of the total acreage in all California KGRA's is in federal ownership, the percentage varies widely from one area to another. For example, the acreage in the Brawley, Heber, and Westmorland KGRA's in Imperial Valley is virtually all nonfederal, while the nearby Glamis KGRA is 92 percent federally-owned. It cannot be concluded, however, that Glamis will be a great source of royalty revenue, because, as shown in Exhibit 10, for a number of reasons, significant development in that area is not expected for the foreseeable future. In fact, on the basis of available information, East Mesa, which is 85 percent federally owned, will be the only major source of royalty revenue in the Imperial Valley as long as the current development pattern prevails.

To the contrary, some of the more favorable prospects may return substantial revenues if development proceeds in those areas on a large scale. For example, Coso, where development is occurring, is 94 percent Federally-owned, and Mono-Long Valley is 78 percent Federal. While the small plant operating in the latter area is not using federal resources, several other plants are planned.

This leaves The Geysers KGRA where only 28 percent of the land is federally-owned. Currently, all UNOCAL development is on non-federal land, and only four plants in the area are on Federal leases -- the two Northern California Power Agency plants and those of the Sacramento Municipal Utility District and Santa Fe Geothermal. The Central California Power Agency Cold Water Creek plant and the small (22 MWe) plant of Freeport Geothermal Resources

Co. are being constructed on private land. Except for its Unit 21, to which PG&E is firmly committed, no other new plants have been announced. That utility and the others with facilities in the area currently have more than enough capacity. However, because of the size of the plants at The Geysers compared to hot water plants, existing and planned, this area will probably continue to be the largest royalty producer for the foreseeable future.

Those KGRA's in California that were not considered likely candidates for power development by 2010 include the following:

Bodie

This KGRA encompasses only 640 acres, and was given KGRA status only because of overlap in acreage applied for in noncompetitive applications. It has received no developer interest.

Brawley/East Brawley/South Brawley

This area is almost exclusively private land, and only one small noncompetitive federal lease is listed for its environs.

Dunes

There are no active leases in the area, and no bids have ever been received at competitive sales. Sale notices announce that the area has been used by the Army and Navy as a bombing area, and the government does not guarantee the area to be free of unexploded bombs or other hazardous materials.

Glamis

The above problems at Dunes also exist at Glamis.

Heber

This area is almost exclusively private land.

Knoxville

While this KGRA is very close to The Geysers, only one lease has ever been issued for its acreage. No current interest is indicated.

Lassen

The U.S. Forest Service has denied leasing in this area.

Saline Valley

The temperature of the resource in this area (57°C) would preclude power development with state-of-the-art technology or with any R&D developments currently envisioned. It is also a small area, and there is no record of any leases being issued.

Sespe Hot Springs

Although the temperature of geothermal fluids in this area is high and flows substantial, it is extremely isolated and undeveloped. Because of the area's pristine condition and abundant wildlife, geothermal development in the area is unlikely.

Salton Sea

All development envisioned in this area is on nonfederal land.

Wendel-Amedee

While efforts are underway to boost the low temperatures of the geothermal resource with wood combustion in a hybrid binary system, and one very small binary unit is on-line and another planned, significant power generation for this area cannot be foreseen over the next two decades.

Westmorland

All lands privately owned.

COLORADO

There are three remaining very small KGRA's in Colorado -- Mineral Hot Springs, Poncha, and Valley View Hot Springs -- all lying within a few miles of each other in south central Colorado. All were designated on the basis of competitive interest -- not geologic criteria -- as was a fourth KGRA, Alamoso County, which has now been declassified.

The level of interest in geothermal leasing in Colorado was never very high, and the record is most notable for the number of noncompetitive applications filed and withdrawn within very brief periods, possibly to serve some tax purpose or other interests not associated with serious development of the resource. The level of interest has now declined to the extent that there are only two active noncompetitive leases and no competitive leases in the entire state. One of the leases is for acreage near the Mineral Hot Springs KGRA and the other is in an area to the north called South Canyon Hot Springs. Both are held by individuals. If their purpose in holding the leases goes beyond speculation, it may be for direct use in which interest is growing in Colorado.

In fact, the only well in Colorado listed on the geothermal drilling records was a 155-foot exploration hole for direct use drilled in Garfield

County in 1981. No temperature gradient holes or exploratory wells are recorded associated with power generation.

The fluid temperature at Poncha, as estimated by USGS, is 71°C (160°F) and 37°C (99°F) at Valley View Hot Springs, which represents the temperature data available for Colorado. These temperatures will not support power generation with current technology or R&D developments envisioned for the foreseeable future.

Thus, in light of the combination of negative factors, it can be concluded that Colorado is not a likely candidate for significant geothermal power development by the year 2010.

IDAHO

Idaho embraces seven KGRA's, but which, for all practical purposes, are reduced to five with the elimination of Island Park and Yellowstone from leasing by statutory prohibition. Of the remaining areas, Raft River, site of earlier DOE binary R&D experimental operations, has the highest estimated temperature at 140°C (284°F). In descending order, the temperatures of the remaining areas are estimated as follows:

	°C	°F
Vulcan	138	280
Bruneau	110	230
Castle Creek	107	224
Mt. Home	72	162

The only two areas in Idaho that appear on the USGS list of identified hydrothermal hot water convection systems with temperatures in excess of 150°C (300°F) (USGS Circular 790) are the declassified KGRA area of Crane Creek with an estimated temperature of 163°C (325°F) and Big Creek Hot Springs at 157°C (314°F). The Idaho Department of Water Resources estimated the latter as high

as 175°C (346°F). At T. 23N, R. 18E, this area is far to the northeast of the southern Idaho systems in wide use for a variety of direct applications.

At the end of September 1986, there were only three active competitive and two active noncompetitive geothermal leases for acreage in the entire state.

While this state can by no means be written off for binary development in the future -- and earlier if there were a need for new power capacity -- no significant degree of power generation is foreseen for Idaho prior to 2010.

MONTANA

Although Montana is large and encompasses four KGRA's, leasing activity has been minimal, and there are no active leases today. No competitive leases resulted from sales at Boulder Hot Springs and Marysville, and leasing is not permitted in Yellowstone. The other KGRA, Corwin Springs, abuts Yellowstone Park and is also in close proximity to a large wilderness area. It will almost certainly be impacted by the new significant thermal features legislation, if not Class I PSD as well, and development of any kind is doubtful. Boulder Hot Springs and Yellowstone were designated KGRA's on the basis of geological criteria. The other KGRA's contain both categories of acreage -- competitive interest and geologic criteria.

Just over 120 noncompetitive applications have been filed, with half of them withdrawn and nearly half rejected. Only six noncompetitive leases were issued.

There are numerous direct uses of geothermal energy in Montana, and fluid temperature information gathered by the Montana Bureau of Mines and Geology indicates that such applications will continue to be the only major use of the resources in the state. For example, representative well temperatures obtained are:

	°C	°F
Alhambra Hot Springs	56	133
Boulder Hot Springs KGRA	136	277
Corwin Hot Springs KGRA	68	154
Ennis Hot Springs	94	201
Marysville KGRA	103	217

Thus, it is concluded that geothermal power generation in Montana will not likely occur before 2010.

NEVADA

Nevada embraces 24 KGRA's, seven of which are reported to be already under development along with an area in Fish Lake Valley on noncompetitive leases. This area will be classified as a KGRA, the old Salt Wells Basin KGRA will be reclassified due to a discovery, and several KGRA's, especially the northern-most ones, are to be declassified due to developer disinterest.

The KGRA's under development or in permitting stages include:

Beowawe	14 MWe Chevron/SCE
Brady-Hazen	9 MWe Chevron
	6 MWe Munson Geothermal
	5 MWe Munson Geothermal
Darrouh Hot Springs	NA Great Smokey Valley Geothermal
Dixie Valley	50 MWe Oxbow Geothermal
San Emidio Desert	2.5 MWe Empire Farms
Steamboat Springs	12.5 MWe Yankee-Caithness Joint Venture
	5 MWe Geothermal Development Associates/Ormat
Stillwater-Soda Lake	2.4 MWe Chevron
	1-2 MWe Trans-Pacific Geothermal (reported to come on-line in 1987 and to be expanded by 8-9 MWe)

In addition, Steam Reserve, a subsidiary of Amax, is planning a 5 MWe unit on noncompetitive acreage in Fish Lake Valley. Also, while Anadarko announced

a commercial discovery in the Salt Wells Basin area, capable of at least 30 MWe using binary technology, no construction plans have been found in the literature.

While there has been little competitive interest in the Darrough Hot Springs KGRA itself, its environs are the "hottest" in Nevada today in terms of noncompetitive leases, with at least 40 in force. The Rye Patch area is another center of noncompetitive interest. On the other hand, interest has decreased in some of the better known KGRA's which are currently under development. In Beowawe, for example, the leasing history indicates that developer interest is currently confined to the area under development. Over a dozen competitive leases have been issued in the KGRA portion of the area, but all except those in Chevron's unit have expired or have been terminated or relinquished. Only two of nearly 30 noncompetitive leases in the immediate environs survive, one in the producing unit itself. Similarly, in Brady-Hazen, only the leases in the Desert Peak area, site of the Chevron plant, remain in force.

The KGRA's under consideration for declassification include Baltazor, Colado, Double Hot Springs, Fly Ranch, Gerlach, Pinto Hot Springs, Soldier Meadow, Trego, and perhaps others.

The KGRA's which seem to have the best potential for development or continued development include:

Beowawe	Kyle Hot Springs
Brady-Hazen	Rye Patch
Darrough Hot Springs (Big Smoky Valley)	Steamboat Springs
Dixie Valley	Stillwater-Soda Lake

While the estimated temperature for Darrough is only 132°C, the leasing record indicates developer interest, planning and permitting is proceeding on a

power plant, and BLM strongly supports geothermal development for this area. Overall interest has been low at Kyle Hot Springs, but sufficient acreage is under lease to permit development, and the temperature is favorable for binary operations. Rye Patch is a candidate for flash technology if the temperature estimates are reasonably accurate, and, as noted above, interest is high.

NEW MEXICO

The best known KGRA in New Mexico is Baca Location No. 1 where Union Oil explored successfully for a number of years leading to selection of the site for construction of the DOE cost-shared 50 MWe flash plant. Even though the resource production was not sufficient for the large plant, Unocal retains the property, and its wells could conceivably be used for a smaller plant at some time in the future. However, there is very little Federal land involved so the impact on royalties would be minimal.

The only other KGRA with a USGS estimated temperature of over 125°C is Lightning Dock at 158°C. However, Circular 790 does not ascribe a power generation capacity to this area, and the only deep development well -- 7,000 feet drilled in 1985 -- has been abandoned. Fluids from this KGRA are used for commercial greenhouse operation, and one small (<1 MWe) binary unit is operated intermittently to supply power to a greenhouse. So far as is known, there are no plans for additional or larger power generation capacity.

The temperatures of the other KGRA's in the state are not suitable for substantial power generation, although it is understood that a very small binary unit of Rox International operated briefly at Gila Hot Springs on 63-68°C (145-155°F) fluid with little success.

OREGON

The state of Oregon embraces 12 KGRA's, although only four of them are on the USGS Circular 790 list of hot water hydrothermal convection systems with temperatures above 150°C (300°F). These include Alvord (it embraces Mickey Hot Springs and Hot (Borax) Lake area), Crump Geyser, Vale (includes Neal Hot Springs), and Newberry Caldera. This list also includes the Trout Creek area in the far southeast corner of the state. The other eight KGRA's appear on the list of hydrothermal systems with temperatures ranging from 90-150°C (194-300°F).

In attempting to develop power generation development scenarios for the geothermal prospects in Oregon for 1988 to 2010, factors such as their potential thermal capability, exploration status, and environmental acceptability are virtually eclipsed by another consideration -- the surplus of power in the Pacific Northwest. In addition, overcapacity in neighboring states -- e.g., California -- has probably removed the viability of regional markets for geothermal power which have been reported to be the panacea for developers working in the Cascades in Oregon. According to a spokesman for the Oregon Department of Energy, if they proceed to development, they will be dependent on an intrastate or an intraregional market.

There are some indications, according to regional spokesmen, that some additional capacity "may" be needed as early as 1995, but most predict that substantial capacity additions will not be needed until the early 2000 range. The Washington State Energy Office estimates that this prediction will require decisions in the 1993-1996 timeframe on the development scenario. Coal plants will require about 10 years to bring on-line and nuclear 10-12 years. Substantial geothermal exploration will have to occur before then for it to be seriously considered in the planning process, and competitive costs will have to be demonstrated.

For several reasons, the area of the Newberry Caldera KGRA in Oregon thus far appears to be the most viable candidate for consideration. It is described by knowledgeable geologists as the best geothermal candidate in Oregon, and it is the subject of the most extensive and costly exploration program underway in the Pacific Northwest. GEO Operator Inc. is using the results of four temperature gradient holes drilled on the flanks of the caldera, two of which were cost-shared by DOE, to guide its exploration activities, and has committed itself to drilling a deep production well in the summer of 1988. The long period of Forest Service indecision over the environmentally sensitive areas has ended with the caldera itself excluded from leasing, and GEO Operator has 170,000 acres under lease to work with.

DOE cost-shared deep gradient holes have also been drilled in the Clackamas area close to Breitenbush and east of Crater Springs. Because of this, Breitenbush has been placed on the list of the more promising areas for development, even though other factors are negative. Major development in the Crater Springs area will be put on hold while BLM studies its potential effects on the hot springs at the bottom of the lake which will reportedly take about four years. However, in a recent decision BLM and the Forest Service have agreed to a request to deepen temperature gradient wells on previously disturbed sites. No adverse effect on Crater Lake or the hydrologic system in the immediate vicinity of the Lake Caldera is anticipated.

The Klamath Falls area may be another possibility for power generation. A Lawrence Berkeley Laboratory model ("Conceptual Model of the Klamath Falls, Oregon, Geothermal Area," R.H. Prucha, et al., 1986) indicates that although the maximum source-water temperature has not yet been encountered, temperatures of 150-190°C (300-374°F) exist somewhere in the system.

Developer interest has waned considerably in nearly all of the KGRA's in Oregon and their environs except Newberry where over 40 percent of the leases in the state are located, encompassing nearly half of the total acreage under lease. A competitive lease sale is also planned. No active leases remain in Summer Lake, Mt. Hood, Klamath Falls, and Lakeview while in Alvord, Belknap-Foley, Breitenbush, and Carey, a few leases remain active for several thousand acres.

The environmental setting appears to be a major problem in some areas. One of these is Belknap-Foley where 21 percent of the Forest Service acreage approved for leasing carries a No Surface Occupancy stipulation; 43 percent is placed under Substantial Developer Constraints; and the remaining 35 percent is subject to such Unspecified/Substantial Development Constraints "as may be necessary." In the Bend and Crescent Ranger Districts of Deschutes National Forest, noncompetitive leasing is permitted on over 500,000 acres. However, of this total, nearly 70,000 acres will carry the NSO stipulation and the remaining acreage will have other protective stipulations. The "optional" stipulations are sufficiently stringent to give a potential developer considerable pause before the expenditure of money in this area. There has also been considerable dispute over Forest Service lease/no lease decisions for Breitenbush in the past, and caution would be advised on developer requirements there. Mt. Hood is, of course, excluded from geothermal leasing since it lies in the Mt. Hood Wilderness Area.

UTAH

Utah became the first state outside of California to have commercial-size hot-water geothermal power generation, and small units which came on-line somewhat later are operating on dry steam, the first such application in the U.S. outside The Geysers. However, it appears that, for now, geothermal power

generation in Utah will be limited to these two sites -- Roosevelt Hot Springs and Cove Fort-Sulphurdale.

The first development at Roosevelt KGRA, located 14.5 miles northeast of Milford in southwestern Utah, began in 1974 when Phillips Petroleum Co. obtained a lease and discovered a hydrothermal reservoir at about 2,000 feet. The fluid temperature is 260°C (500°F). Chevron Resources has since replaced Phillips as field operator. The first Utah Power and Light plant came on line in 1984, and, due to the high temperature, encountered some silica scaling problems that have now been overcome. Subsequently, a second plant at 14 MWe has been put in operation at the site, but Utah Power and Light reports that it does not need additional capacity in the near future.

Also located in southwestern Utah, the Cove Fort-Sulphurdale KGRA was first explored by the Department of Energy and Union Oil Co. The Mother Earth Co. acquired the Union leases and penetrated steam at less than 1,200 feet with a temperature of over 204°C (399°F). Beginning with 3.2 MWe capacity in binary units, the plant is being expanded in increments.

Low temperature and lack of industry interest suggest that the other KGRA's in Utah will not be developed in the foreseeable future as follows:

Crater Hot Springs

With an estimated temperature of 97°C (201°F), the fluids in this KGRA are not suitable for power generation. In addition, even though there were sufficient noncompetitive lease applications for acreage in this area to warrant a BLM study of the environmental impact of development, none of the leases issued as a result remains active today, and there is only one competitive lease.

Lund

No temperature estimate was found for Lund, and this area has attracted very little noncompetitive interest, and no competitive. No leases remain active.

Meadow - Hatton

At 48°C (118°F), the fluids in this KGRA are not suitable for power generation. The leasing situation is the same as in Lund.

Monroe - Joseph

Same problems.

Navajo Lake

No record of any leases or temperature estimates.

Newcastle

At 130°C (266°F), the fluids in this area have not attracted developer interest. Only one relinquished/terminated lease is recorded.

Thermo Hot Springs

With a marginal temperature for even binary application, 142°C (287°F), developer interest has waned. Over 50 noncompetitive leases were issued, but only three remain active. Only two competitive leases remain.

WASHINGTON

Only two KGRA's remain in force in Washington -- Mount St. Helens and Kennedy Hot Springs. Since the latter lies within the Glacier Peak Wilderness

Area, it is closed to development. Just how much development would be permitted in adjacent areas is open to question. At Mount St. Helens, leasing is not permitted in the National Monument area, and Forest Service approval of surface occupancy of sufficient land in the area outside the Monument to make exploration and development feasible there is another potential impediment. The low level of access to the KGRA's in Washington is borne out by the fact that only one tract in the Indian Heaven KGRA, now declassified, has ever been offered for competitive lease in the state.

Mt. Rainier is the largest of the stratovolcanoes in the Cascades Range, but, as a national park, it is withdrawn from geothermal exploration and development. While areas surrounding the park have been subjected to considerable exploration, the entire Park is listed as a Significant Thermal Feature, so that its environs will be impacted by the restrictions of the new legislation.

The only area in Washington on the USGS table of hot-water hydrothermal convection systems with temperatures in excess of 150°C (300°F) (Circular 790) is the Gamma Hot Springs area, which is in or near the Kennedy Hot Springs KGRA, within the Glacier Peak Wilderness area.

Twenty-six of the 27 noncompetitive leases in effect in December 1985 were for acreage immediately adjacent to the Adams Wilderness Area, in the same general area of the state as Mount St. Helens in the Gifford Pinchot National Forest. Although Mt. Adams is the second largest Quaternary stratovolcano in Washington, the geothermal potential is poorly defined due to the land status which restricts accessibility for assessment activities. In addition to the wilderness prohibition in part of this area, development in the other portion is restricted to projects approved by the Yakima Indian Nation.

Despite all of the foregoing problems, the Washington State Energy Office remains optimistic that geothermal power development will one day come to Washington where innovative direct use applications are already in operation. It is noted that the favorable findings to the north at Meager Creek in Canada and to the south at Newberry Crater in Oregon indicate that good potential may exist for the Washington portion of the Cascades. While only 30 percent of the land in Washington is Federally-owned, most of that lies along the Cascades range.

Since no exploration activity for power development is currently underway, or planned, so far as is known, no significant source of geothermal royalties from power development on Federal land is expected in Washington by 2010.

WYOMING

Wyoming is considered to be one of the community of geothermal states largely because of the surface manifestations in Yellowstone National Park. However, leasing is not permitted in the Park and will no doubt be precluded in surrounding areas in Wyoming if development would, in the judgment of the Secretary of the Interior, adversely affect the thermal features of the Park. Congress has already prohibited leasing in the Island Park KGRA in Idaho, which lies just to the west of Yellowstone, for this reason.

Most other areas in Wyoming with geothermal potential appear to be useful only for direct applications, but there are some potential long-range exceptions. For example, maximum oil well bottom hole temperatures of 191°C (376°F) have been recorded in the Washokie and Great Divide Basins; 132°C (306°F) in the Overthrust Belt in Wyoming and 210°C (410°F) in Idaho; and 152°C (306°F) in the Green River Basin. Since at least portions of these areas lie outside the

highly protected Park environs, their potential may be investigated at some time in the future.

Other maximum oil well bottom hole temperatures are not as promising for power development. For example:

	°C	°F
Midwest (Salt Creek oilfield)	50-85	122-185
Shirley Basin	60	140
Powder River Basin	135	275

Wyoming has no designated KGRA's, and thus, the minimal leasing activity which has occurred has all been noncompetitive. No leases remain active today.

In light of the above, it is conceivable that Wyoming might see geothermal power generation at some future time when costs, need for additional capacity, and other external influences are more favorable to expenditures for geothermal exploration. Under present conditions, this would not be expected to occur prior to 2010.

APPENDIX C

KGRA PROXIES AND DATA

c-1/c-2

AREA	TEMP (°F)	DEPTH (KF)	VOL (MW/30 YR)	CLASSIFICATION
Coso	640	9,000 - 3,000	650	YV-F1
East Mesa	360	3,000 - 9,000	360	IV-BI
Glass Mt.	392		500	CS-FL
Lake City	306	3K - 9K	1,490	BR-BI
Mono-Long Valley	536	3K	2,100	YV-F1
Randsburg	342	--	84	BR-BI
Beowawe	444	3K - 9K	127	BR-FL
Desert Peak	440	1.6K	157	BR-FL
Darrough H.S.	270	--	--	BR-BI
Dixie Valley	290	--	--	BR-FL
Kyle H.S.	322	--	97	BR-BI
Rye Patch	423	--	--	BR-FL
Steamboat Spr.	403	.9K	350	YV-F2
Stillwater/SL	318	--	450 + 146	BR-BI
Breitenbush	260	--	--	CS-BI
Klamath Falls	219	--	--	CS-BI
Newberry Caldera	509	3K	740	YV-F2
Vale	370	3K	870	BR-BI
Cove Fort	509	5K	330	BR-FL
Roosevelt	509	3K	970	BR-FL

Classification Key

IV-BI --> Imperial Valley Binary
 BR-FL --> Basin and Range Flash
 BR-BI --> Basin and Range Binary
 CS-FL --> Cascades Flash
 CS-BI --> Cascades Binary
 YV-F1 --> Young Volcanic Flash 1
 YV-F2 --> Young Volcanic Flash 2

	EASTMESA	BEOWAVE	LAKECITY	GLASS MT.	BREI'BUSH	MONO-LONG	STMBTSPRG	DESERTPK	RNDSBURG
1 ENERGY IN REGION MW*30YR	360.0 -14.2	127.0 -62.3	1490.0 -640.7	500.0 -171.0	300.0 -282.5	2100.0 -484.5	350.0 -80.7	453.5 -222.3	84.0 -36.1
2 ENERGY IN SUBAREA MW*30YR	86.4 0.0	10.4 0.0	212.7 0.0	54.8 0.0	1.5 0.0	161.5 0.0	26.9 0.0	37.0 0.0	12.0 0.0
3 RESERVIOR SATUR. TEMP. F	360.0 -20.0	444.0 -49.3	306.0 -20.4	392.0 -46.1	260.0 -9.3	446.0 -18.6	403.0 -54.9	373.0 -41.4	342.0 -22.8
4 WELLHEAD TEMP F	350.0 -20.0	394.0 -24.6	294.0 -10.2	342.0 -59.3	250.0 -9.3	231.0 -6.0	259.0 -19.8	323.0 -20.2	330.0 -11.5
5 TOTAL DISSOLVED SOLIDS, PPK	2.1 0.4	1.2 0.8	1.5 1.6	1.0 1.5	0.5 0.5	1.5 2.0	2.7 1.4	2.7 1.7	1.2 1.3
6 WELL DEPTH 1000 FEET	4.2 0.0	4.2 0.0	4.2 0.0	5.0 0.0	5.0 0.0	4.2 0.0	1.9 0.0	2.6 0.0	5.0 0.0

	KLAMATH	COSO	NEWBERRY	DIXIE VAL.	DARROUGH	GEYSERS	RYE PATCH	KYLE
1 ENERGY IN REGION MW*30YR	300.0 -282.5	650.0 -150.0	740.0 -170.7	300.0 -147.1	300.0 -129.0	1610.0 -371.4	300.0 -147.1	97.0 -41.7
2 ENERGY IN SUBAREA MW*30YR	1.5 0.0	50.0 0.0	56.9 0.0	24.5 0.0	42.8 0.0	123.8 0.0	24.5 0.0	13.8 0.0
3 RESERVIOR SATUR. TEMP. F	338.0 -12.1	543.0 -22.6	443.3 -60.4	293.0 -32.6	270.0 -18.0	459.0 -19.1	423.0 -47.0	322.0 -21.5
4 WELLHEAD TEMP F	328.0 -12.1	328.0 -8.5	299.3 -22.9	243.0 -15.2	258.0 -9.0	244.0 -6.3	373.0 -23.3	310.0 -10.8
5 TOTAL DISSOLVED SOLIDS, PPK	0.5 0.5	2.0 2.7	10.0 5.0	1.5 1.0	1.2 1.3	15.0 20.0	1.5 1.0	1.2 1.3
6 WELL DEPTH 1000 FEET	5.0 0.0	4.2 0.0	3.6 0.0	5.0 0.0	5.0 0.0	4.2 0.0	5.0 0.0	5.0 0.0

	COVE FORT	STILLWATER	ROOSEVELT	VALE
1 ENERGY IN REGION MW*30YR	330.0 -161.8	298.0 -128.1	970.0 -475.5	906.0 -389.6
2 ENERGY IN SUBAREA MW*30YR	27.0 0.0	42.5 0.0	79.2 0.0	129.4 0.0
3 RESERVIOR SATUR. TEMP. F	509.0 -56.6	320.0 -21.3	509.0 -56.6	314.7 -21.0
4 WELLHEAD TEMP F	459.0 -28.7	308.0 -10.7	459.0 -28.7	302.7 -10.5
5 TOTAL DISSOLVED SOLIDS, PPK	1.5 1.0	1.2 1.3	7.8 5.1	1.2 1.3
6 WELL DEPTH 1000 FEET	5.9 0.0	5.0 0.0	3.7 0.0	4.2 0.0

APPENDIX D

**IMGeo CALCULATED COSTS
(SPECIFIC AND GENERAL)**

EASTHESA BEOWAVE LAKECITY GLASS MT. BREI'BUSH MONO-LONG STNBTSPRG DESERTPK

BASE CASE VALUE, MILLS/KWH

EXPLR	7.8	48.6	3.4	17.8	1200.9	9.6	16.1	14.8
CNFRM	5.2	16.4	3.1	11.1	322.2	9.3	7.5	7.9
WELLS	14.8	11.2	35.1	46.6	128.8	71.0	9.1	11.2
PUMPS	2.0	0.0	5.2	0.0	26.5	0.0	0.0	0.0
GATHR	5.4	2.5	7.2	6.0	57.4	6.9	2.8	2.5

PLANT	30.1	18.5	52.5	26.5	323.9	31.7	30.4	24.6
HTXCH	7.2	0.0	12.6	0.0	77.6	0.0	0.0	0.0
STABL	0.0	0.0	0.0	0.0	0.0	2.3	2.3	0.0
ENVIR	0.0	0.0	0.0	0.0	0.0	8.3	7.6	0.0
INSUR	2.6	1.4	4.6	3.9	27.1	3.2	2.0	1.7

PLANT \$	39.9	19.9	69.7	30.4	428.6	45.5	42.3	26.3

TOTAL	75.1	98.6	123.7	111.9	2164.4	142.3	77.8	62.7

100% R&D VALUE, MILLS/KWH

EXPLR	6.4	41.3	2.8	14.9	482.5	8.1	13.6	12.6
CNFRM	4.5	14.1	2.7	9.4	133.2	7.8	6.4	6.8
WELLS	8.3	7.9	17.9	31.4	38.8	40.1	6.7	7.9
PUMPS	1.4	0.0	3.5	0.0	9.6	0.0	0.0	0.0
GATHR	3.3	2.0	3.9	4.7	14.3	3.5	2.3	2.0

PLANT	22.9	17.8	38.6	24.9	124.8	31.5	29.9	24.0
HTXCH	7.0	0.0	11.8	0.0	38.0	0.0	0.0	0.0
STABL	0.0	0.0	0.0	0.0	0.0	2.3	2.3	0.0
ENVIR	0.0	0.0	0.0	0.0	0.0	8.3	7.6	0.0
INSUR	1.8	1.1	3.0	2.8	9.7	2.8	1.8	1.4

PLANT \$	31.7	18.9	53.4	27.7	172.5	44.9	41.6	25.4

TOTAL	55.6	84.2	84.2	88.1	850.9	104.4	70.6	54.7

INGEO ACCOUNTS-BY-SITE COST OF POWER DATA

	RNDSBURG	KLAMATH	COSO	NEWBERRY	DIXIE VAL.	DARROUGH	GEYSERS	RYE PATCH

BASE CASE VALUE, MILLS/KWH								
EXPLR	32.6	196.4	20.5	8.6	20.8	21.3	11.0	21.6
CNFRM	11.0	54.7	11.9	5.6	9.4	7.9	9.6	9.6
WELLS	21.8	11.6	71.0	9.1	11.2	86.2	71.0	11.2
PUMPS	3.2	2.4	0.0	0.0	0.0	12.8	0.0	0.0
GATHR	4.0	2.4	6.9	2.8	2.5	23.5	6.9	2.5

PLANT	35.5	34.2	23.0	27.0	31.4	120.1	30.5	20.3
HTXCH	8.5	8.2	0.0	0.0	0.0	28.8	0.0	0.0
STABL	0.0	0.0	2.3	2.3	0.0	0.0	2.3	0.0
ENVIR	0.0	0.0	8.3	7.6	0.0	0.0	8.3	0.0
INSUR	2.9	2.5	2.8	1.9	2.0	11.1	3.2	1.5

PLANT \$	46.9	44.9	36.4	38.8	33.4	160.0	44.3	21.8

TOTAL	119.5	312.4	146.7	64.9	77.3	311.7	142.8	66.7
100% R&D VALUE, MILLS/KWH								
EXPLR	26.2	157.8	17.1	7.2	17.7	14.5	9.2	18.3
CNFRM	9.1	45.0	10.1	4.8	8.1	5.9	8.1	8.3
WELLS	11.8	7.2	40.1	6.7	7.9	38.5	40.1	7.9
PUMPS	2.3	1.7	0.0	0.0	0.0	7.6	0.0	0.0
GATHR	2.3	1.6	3.5	2.3	2.0	10.9	3.5	2.0

PLANT	27.0	26.4	22.8	26.4	31.0	76.6	30.4	19.7
HTXCH	8.2	8.1	0.0	0.0	0.0	23.3	0.0	0.0
STABL	0.0	0.0	2.3	2.3	0.0	0.0	2.3	0.0
ENVIR	0.0	0.0	8.3	7.6	0.0	0.0	8.3	0.0
INSUR	2.0	1.9	2.3	1.7	1.8	6.3	2.7	1.2

PLANT \$	37.2	36.4	35.7	38.0	32.8	106.2	43.7	20.9

TOTAL	88.9	249.7	106.5	59.0	68.5	183.6	104.6	57.4

IMGEO ACCOUNTS-BY-SITE COST OF POWER DATA

KYLE COVE FORT STILLWATER ROOSEVELT VALE

BASE CASE VALUE, MILLS/KWH

EXPLR	33.2	19.3	10.9	8.2	4.6
CNFRM	11.1	9.0	5.1	6.2	3.4
WELLS	27.6	11.1	28.2	11.1	30.5
PUMPS	4.1	0.0	4.2	0.0	4.5
GATHR	5.3	2.5	5.5	2.5	6.1

PLANT	43.0	16.5	44.0	16.5	47.3
HTXCH	10.3	0.0	10.5	0.0	11.3
STABL	0.0	0.0	0.0	0.0	0.0
ENVIR	0.0	0.0	0.0	0.0	0.0
INSUR	3.6	1.3	3.7	1.3	4.0

PLANT \$	56.9	17.8	58.2	17.8	62.6

TOTAL	138.2	59.7	112.1	45.8	111.7

100% R&D VALUE, MILLS/KWH

EXPLR	26.3	16.3	8.7	7.0	3.7
CNFRM	9.2	7.7	4.3	5.4	2.9
WELLS	14.7	7.8	15.2	7.8	16.0
PUMPS	2.9	0.0	2.9	0.0	3.1
GATHR	3.0	2.0	3.2	2.0	3.4

PLANT	32.3	16.4	33.0	16.4	35.1
HTXCH	9.8	0.0	10.1	0.0	10.7
STABL	0.0	0.0	0.0	0.0	0.0
ENVIR	0.0	0.0	0.0	0.0	0.0
INSUR	2.5	1.0	2.5	1.0	2.7

PLANT \$	44.6	17.4	45.6	17.4	48.5

TOTAL	100.7	51.2	79.9	39.6	77.6

	EASTHESA	BEOWAVE	LAKECITY	GLASS MT.	BREI'BUSH	MONO-LONG	STMBTSPRG	DESERTPK	RNDSBURG
1 BASE CASE COST- 1987	7.53	9.87	12.36	11.19	216.4	14.22	7.79	6.28	11.95
YEAR ON LINE	1998	1998	2004	2002	N/A	2005	1994	1990	2003
2 COST OF POWER -	5.57	8.42	8.42	8.81	85.09	10.44	7.07	5.47	8.89
W/100% R&D BY 2000									
EARLIEST YR ON LINE	1997	1997	2000	2000	N/A	2002	1993	1990	2000
W/ OR W/O R&D									

	KLAMATH	COSO	NEWBERRY	DIXIE VAL.	DARROUGH	GEYSERS	RYE PATCH	KYLE
1 BASE CASE COST- 1987 YEAR ON LINE	31.2 N/A	14.66 2005	6.49 2003	7.75 1994	31.18 N/A	14.27 2005	6.67 1991	13.83 2005
2 COST OF POWER - W/100% R&D BY 2000	24.97	10.65	5.91	6.84	18.37	10.46	5.73	10.06
EARLIEST YR ON LINE W/ OR W/O R&D	N/A	2002	2001	1993	2010	2002	1991	2000

	COVE FORT	STILLWATER	ROOSEVELT	VALE
1 BASE CASE COST- 1987	5.96	11.21	4.58	11.17
YEAR ON LINE	1998	2001	1992	N/A
2 COST OF POWER -	5.13	8	3.96	7.78
W/100% R&D BY 2000				
EARLIEST YR ON LINE	1997	1997	1991	2007
W/ OR W/O R&D				

APPENDIX E

AVOIDED COST INFORMATION

Appendix E

California

The state of California, through the California Energy Commission, provided unofficial avoided cost rates from The Economic Impacts of Self Generation; March 1987 - Staff Report for the California Energy Commission (C.E.C.). These figures were forwarded to us from the C.E.C. Economist, Mr. Sandy A. Miller. The figures used evolved from a weighted average of the three utilities for the state. The inflation rate average from these three tables was 5.63% and the escalation rate from 1990 to 2010 was 9%.

The following pages contain the data used for the avoided cost estimates.

California
Weighted Averages

<u>YEAR</u>	<u>¢/kWh</u> <u>WEIGHTED AVG.</u>
1987	2.42
1988	2.84
1989	3.74
1990	3.95
1991	4.35
1992	4.75
1993	5.19
1994	5.69
1995	6.06
1996	6.64
1997	7.23
1998	7.89
1999	8.66
2000	9.34
2001	10.18
2002	11.17
2003	12.13
2004	13.49
2005	14.76

THE ECONOMIC IMPACTS OF SELF GENERATION

FINAL

MARCH 1987

George Deukmejian, Governor

CALIFORNIA ENERGY COMMISSION

P500-87-002

suspended. The CPUC will soon begin compliance proceedings to implement the methodology to calculate long-term avoided costs and to develop another long-term contract offer.

b. Standby Rates

Standby rates are charged QFs or self-generators to be eligible for backup utility service. Backup utility service may be very important to self-generators requiring higher reliability. If and when standby utility service is provided, normal tariff charges apply.

Although the CPUC has previously required the utilities to provide standby service at nominal rates (\$1/kW/month for SCE [SCE, Cal P.U.C. Sheet No. 6042-E, Effective May 12, 1982] which may be waived for high capacity factor of cogeneration), its recent general rate case decision for SDG&E (SDG&E, Cal P.U.C. Sheet No. 5613-19-E, Effective January 1, 1986), appears to signal a trend towards higher standby rates. Standby charges for SDG&E are now \$5/kW/month, based on the CPUC public staff's proposal using avoided cost principles. There are incentives for reducing either the demand charge or the standby charges. If the customer maintains at least a 50 percent capacity factor during on-peak periods in the previous 12 months, normal demand charges are waived. If an 85 percent on-peak capacity factor is attained during the billing period, exclusive of maintenance, or if the customer facing time-of-use standby avoids using utility power during peak periods as specified by the schedule, the standby charge is reduced to \$2.50/kW/month.

SDG&E offers interruptible standby service with no minimum charge for customers with total load greater than 500kW.

In its current general rate increase application for test year 1987 (PGandE, Cal P.U.C. Sheet No. 839-E, Effective January 1, 1984), PGandE is proposing a standby charge of \$4.25/kW/month. This compares with an \$0.80/kW/month standby rate charged presently.

c. Avoided Cost Forecasts

The forecasted energy and capacity portions of avoided costs for PGandE, SCE, and SDG&E were calculated from preliminary ELFIN runs using the data input files developed by the CEC contractors, Bill Morrison of Kaiser Engineers and Ed Kahn. These preliminary forecasts (Tables 20-25) were used by staff in

performing the cashflow analysis for the various self-generation facilities. Due to time constraints, it was not possible to undertake an iterative approach, whereby the cashflow analyses would be redone to reflect any later updated forecasts generated by CEC staff. However, the analysis of self-generation facilities was intended to develop a general picture of the self-generators and was not intended to provide the definitive answer of what the economics of self-generation will be.

Table 20
PG&E AVOIDED COST ENERGY SERIES
 (Mills/kWh)

<u>Year</u>	<u>(Current \$)</u>	<u>(Constant 1986 \$)</u>
1987	22.1	20.89
1988	25.6	22.87
1989	31.6	26.68
1990	35.9	28.65
1991	39.9	30.13
1992	43.2	30.86
1993	47.9	32.40
1994	53.9	34.53
1995	56.1	34.06
1996	60.5	34.82
1997	66.2	36.15
1998	70.6	36.58
1999	77.2	37.98
2000	84.2	39.34
2001	92.1	40.91
2002	100.1	42.26
2003	109.2	43.87
2004	121.7	46.52
2005	132.6	48.27

Table 21

PG&E
AVOIDED COST CAPACITY
(\$/KW)

<u>Year</u>	<u>(Current \$)</u>	<u>(Constant 1986 \$)</u>
1987	0	0
1988	9.28	8.29
1989	20.40	17.23
1990	32.78	26.16
1991	45.63	34.45
1992	58.95	42.11
1993	82.13	50.40
1994	88.63	56.78
1995	105.07	63.80
1996	110.85	63.80
1997	116.83	63.80
1998	123.15	63.80
1999	129.67	63.80
2000	136.55	63.80
2001	143.64	63.80
2002	151.12	63.80
2003	158.82	63.80
2004	166.92	63.80
2005	175.27	63.80

Table 22

SCE
AVOIDED COST ENERGY SERIES
(Mills/kWh)

<u>Year</u>	<u>464 MW</u> <u>(Current \$)</u>	<u>(Constant</u> <u>1986 \$)</u>
1987	26.3	24.86
1988	30.4	27.16
1989	36.5	30.82
1990	42.3	33.76
1991	45.7	34.54
1992	50.7	36.22
1993	54.7	37.00
1994	58.8	37.67
1995	64.1	38.92
1996	70.5	40.58
1997	78.2	42.70
1998	86.0	44.55
1999	95.2	46.84
2000	102.2	47.75
2001	111.2	49.39
2002	122.9	51.89
2003	134.1	53.87
2004	148.9	56.91
2005	163.6	59.55

Table 23

SCE
AVOIDED COST CAPACITY
(\$/kW In Current \$)

<u>Year</u>	<u>(Current \$)</u>	<u>(Constant 1986 \$)</u>
1987	0	0
1988	9.95	8.89
1989	19.99	16.88
1990	31.17	24.88
1991	44.71	33.76
1992	59.71	42.65
1993	77.49	52.42
1994	99.86	63.97
1995	127.31	77.30
1996	154.37	88.85
1997	162.71	88.85
1998	171.50	88.85
1999	180.59	88.85
2000	190.16	88.85
2001	200.04	88.85
2002	210.45	88.85
2003	221.18	88.85
2004	232.46	88.85
2005	244.09	88.85

Table 24

SDG&E
AVOIDED COST ENERGY SERIES
(Mills/kwh)

<u>Year</u>	<u>(Current \$)</u>	<u>(Constant 1986 \$)</u>
1987	27.4	25.90
1988	32.5	29.03
1989	37.6	31.75
1990	46.3	36.95
1991	50.0	37.75
1992	53.5	38.22
1993	57.8	39.10
1994	62.2	39.85
1995	67.5	40.99
1996	71.6	41.21
1997	77.0	42.05
1998	83.6	43.31
1999	94.2	46.35
2000	99.7	46.58
2001	105.7	46.95
2002	114.5	48.34
2003	121.1	48.65
2004	129.0	49.31
2005	137.8	50.16

Table 25

SDG&E
 AVOIDED COST CAPACITY
 (\$/KW)

<u>Year</u>	<u>(Current \$)</u>	<u>(Constant 1986 \$)</u>
1987	18.26	17.26
1988	41.27	36.87
1989	68.75	58.05
1990	98.29	78.45
1991	103.90	78.45
1992	109.82	78.45
1993	115.97	78.45
1994	122.46	78.45
1995	129.20	78.45
1996	136.31	78.45
1997	143.67	78.45
1998	151.43	78.45
1999	159.45	78.45
2000	167.91	78.45
2001	176.63	78.45
2002	185.82	78.45
2003	195.29	78.45
2004	205.26	78.45
2005	215.52	78.45

Nevada

The Public Utility Commissions' Economist - Ms. Cynthia Mitchell - provided the latest avoided cost rate and escalation figure for Northern Nevada. The avoided cost, based on coal, is 5.5 cents/kWh with an escalation figure of 5.557%. The following page lists the prices for each year.

Nevada
Weighted Averages

<u>YEAR</u>	<u>¢/kWh</u> <u>WEIGHTED AVG.</u>
1987	5.51
1988	5.81
1989	6.13
1990	6.47
1991	6.83
1992	7.21
1993	7.61
1994	8.03
1995	8.48
1996	8.95
1997	9.45
1998	9.97
1999	10.52
2000	11.10
2001	11.70
2002	12.35
2003	13.04
2004	13.76
2005	14.52
2006	15.33
2007	16.18
2008	17.08
2009	18.03
2010	19.03

Oregon

The avoided cost information was sent to us by W.A. McNamee, an economist with the Public Utility Commission. The avoided cost rates used for the study are weighted averages from the three utilities within the Oregon service area. The inflation rate used is 4.5% with the escalation rate average from 1990 to 2010 at 9.4%.

Oregon
Weighted Averages

<u>YEAR</u>	<u>¢/kWh</u> <u>WEIGHTED AVG.</u>
1987	1.32
1988	1.44
1989	1.56
1990	1.66
1991	1.76
1992	1.93
1993	2.03
1994	2.26
1995	2.40
1996	3.50
1997	3.76
1998	5.43
1999	5.68
2000	5.89
2001	6.11
2002	6.37
2003	6.63
2004	6.98
2005	7.29
2006	7.56
2007	8.03
2008	8.39
2009	8.74
2010	9.06

**1987
AVOIDED COST INFORMATION**

**Filed With
Public Utility Commission of Oregon**

PORTLAND GENERAL ELECTRIC COMPANY

Effective July 1, 1987

5/29/87

PORTLAND GENERAL ELECTRIC COMPANY 1987 AVOIDED COST STUDY

Introduction

Portland General Electric Company's (PGE) 1987 avoided cost study is presented in two sections which incorporate information required by the rules and regulations of the Oregon Public Utility Commission. Section I - Electric Utility System Cost Data is prepared according to OAR 860-29-080(2). The information in this section of the study consists of estimates of resources and resource costs incurred to meet future energy needs on the PGE system. Section II - Avoided Costs and PUC Informational Tables summarizes and expands the information from Section I in order to describe and estimate the power purchase prices based on avoided costs.

Projected electric utility costs are the basic information from which avoided costs are calculated. Avoided costs are "... the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, the utility would generate itself or purchase from another source...", OAR 860-29-010(1). Avoided costs are calculated from estimated future year-by-year utility system costs. These cost estimates are intended to represent overall PGE system power supply costs which can be saved in the future because power is available from substitute resources. Therefore, the avoided costs applicable to any specific substitute resource are dependent on the power production characteristics of that resource compared to the system supply costs.

Section I

PGE SYSTEM COST DATA

PGE system cost data are summarized in Tables 1 and 2. Table 1 on Page 5 is an estimate of avoided energy costs by calendar quarter for five years beginning in 3rd quarter, 1987. The average annual avoided energy costs range between 1.6 and 2.2 cents per kWh expressed in then current year dollars.

Table 2 on Page 6 is a summary of planned plant additions and potential firm capacity purchases. PGE's forecast of power needs shows that an additional resource is anticipated in 1996/97 to meet projected load requirements under critical water planning criteria. Plant additions are based on matching PGE's expectation of future loads with the contribution of existing and unavoidable future resource additions and avoidable resources. The projections of avoidable resource additions represent the lowest cost alternatives reasonably available to PGE.

The following sections provide additional information and the assumptions used to develop Tables 1 and 2.

Load Forecast

The avoided energy cost analysis is based on forecast retail loads and existing PGE firm wholesale power commitments. Load levels include estimated, nonfirm sales for resale. System generating resources and purchases of energy are used to supply retail loads, firm wholesale loads and any nonfirm loads that can be economically served.

Avoided Costs

Avoided Energy Costs

Table 1 contains estimates of avoidable system energy costs expressed in cents/kWh for each calendar quarter of the five-year period 1987 through 1992. Avoided energy costs are based on a comparison of two power cost model simulations: a base case simulation and a second simulation with loads 10 average megawatts (mW) lower than the base case. The difference in total costs between the base case and the decremental load case measures the energy costs that are potentially avoided when qualifying facility power is substituted for other PGE power resources. The power costs incurred to meet both the base and the 10 megawatt load decrement cases are calculated to reflect typical or expected costs. These power cost estimates are based on simulated system operations reflecting 106 years of hydrological data. The model also evaluates the availability of energy to PGE from other utilities and makes appropriate economy purchases of this energy. Avoided energy costs are derived by calculating the difference in power costs between the base case and the alternative case (which has the 10 mW load reduction) and then dividing the dollar difference by the load change.

Estimated avoided energy costs shown in this filing may deviate from actual avoided costs as actual load and resource conditions deviate from assumptions used in the forecast. At the beginning of each calendar quarter, PGE submits to the PUC, in accordance with OAR 860-29-080(2) supplemental avoided energy cost

information for the upcoming quarter which reflects the then current power supply conditions.

Avoidable Resource Additions

Table 2 describes planned and potential additions to PGE's energy and capacity resource base necessary to meet load during the time horizon of this filing. The group of qualifying facilities and the Capacity/Energy Exchange are not avoidable resources because PGE has no ability to replace these resources with new qualifying facility resources.

PGE's next avoidable resource is a facility producing energy and capacity which has an 1996 in-service date. PGE's projected load/resource balance shows a deficiency in energy delivery capability in 1997 and a capacity deficiency in 1996. The load/resource balance projects total system resource capabilities based on adverse hydro supply conditions. Under normal hydro conditions, the PGE system can meet load requirements beyond the 1996/97 dates noted above.

A combustion turbine facility (CT) is used in this filing as a proxy for any resource options and technologies that will be available to PGE as the actual need for resource additions approaches. PGE's actual choice of resources, whether from qualifying facilities, load management and conservation programs, power purchases, industrial cogeneration or power plant additions and improvements is intended to be the least cost source of power required to meet the loads and reliability requirements of PGE's customers. The cost computations in this filing are consistent with this approach.

The costs of the avoidable resource are based on construction cost estimates of CT facilities prepared by the Northwest Power Planning Council.

Inclusion of the CT resource as the avoidable resource does not represent a commitment to the installation of such a facility. PGE has no current plans for construction of any particular technology. The Company has full flexibility with regard to the plant and does not have to make any construction decisions for many years. Construction schedules, budgets, and siting considerations are not a part of this study. The CT fuel and O & M costs are the estimated costs of operating the CT and are estimates of system avoided energy costs.

The addition of a generating resource to the PGE system in 1996 would provide sufficient reserves if adverse hydro conditions caused the existing PGE system to be unable to meet projected loads. Under typical or average conditions, however, the resource would not normally be operated, but would be available in the event of the low water conditions. For this filing, the power cost estimates used to develop avoided energy costs include the expected operation of the energy (CT) resource, but only to the extent that it would be operated during periods when other less expensive resources are unavailable.

The construction or acquisition of the resource is assumed to take up to four years to bring to operating capability. This is based on the expected construction time for a combustion turbine.

Capacity Retirements

PGE has no planned retirements of existing plant capacity during the next fifteen years. For planning purposes, certain capacity purchase and exchange contracts with BPA and California utilities will be reduced from a current level of 650 mW to zero by 1992.

Table 1

**Portland General Electric Company
Avoided Energy Costs
OAR 860-29-080(2)(a)**

Decremental Energy Costs 1987-1992

<u>YEAR</u>	<u>Calendar Quarter</u>	<u>Costs (Cents/kWh)</u>
1987	Third	1.3
	Fourth	1.9
1988	First	2.0
	Second	1.3
	Third	1.6
	Fourth	2.3
1989	First	2.2
	Second	1.4
	Third	1.8
	Fourth	2.3
1990	First	2.4
	Second	1.5
	Third	1.8
	Fourth	2.5
1991	First	2.4
	Second	1.6
	Third	1.9
	Fourth	2.5
1992	First	2.5
	Second	1.6

Note: Costs are based on a 10 mW_a load decrement and are expressed in current year dollars.

Table 2

PORTLAND GENERAL ELECTRIC COMPANY
Plans for Capacity Additions
OAR 860-29-080(2)(b)(c)

	<u>Committed Qualifying Facilities</u>	<u>Capacity/ Energy Exchange</u>	<u>Capacity/ Energy Resource</u>
In-Service Year	Various	1990	1996
Size (MW)-PGE	30	225	105
In-Service Cost (\$ millions)	N/A	N/A	49.04
In-Service Cost (\$/kW)	N/A	N/A	467.00
Life (Years)	20-30	20	20
Fuel Costs (1st Year - Cents/kWh)	N/A	N/A	4.2
O&M Costs (1st Year - Cents/kWh)	N/A	N/A	0.33
Purchase Price (1st Year - Cents/kWh)	3.6-6.6		

E-23 / E-24

SECTION II AVOIDED COST AND PUC INFORMATIONAL TABLES

Avoided Cost and Purchase Rate

The purchase rate for power produced by qualifying facilities is based on the Company's estimated avoided costs for power with the specific delivery characteristics of the qualifying facility. The avoided costs represent the economic value of the power delivered to PGE. The purpose of this section is to describe the important elements which are evaluated to determine the appropriate power purchase price for any particular qualifying facility. Section I system cost data is expanded and converted to year-by-year system avoided costs in Attachment 1-PUC Informational Tables and in Attachment 2 which sets out additional, summary, avoided cost information. These tables are based on the assumption that the power from a qualifying facility is a direct substitute for PGE system resources.

PGE's actual avoided costs applicable to a particular qualifying facility may differ significantly from the avoided costs applicable to other facilities and from costs set out in this document. These avoided cost differences and resulting price differences depend on variations in qualifying facility power supply characteristics. OAR 860-29-040(6) summarized below, describes many of the power supply differences which result in avoided cost differences and will affect resultant power purchase prices:

- (1) The data provided pursuant to OAR 860-29-080(2) and the Commission's evaluation of the data;
- (2) The availability of capacity or energy from a qualifying facility during PGE's system daily and seasonal peak periods, including:
 - (a) The ability of the utility to dispatch output of the qualifying facility;
 - (b) The expected or demonstrated reliability of the qualifying facility;
 - (c) The terms of any contract or other legally enforceable obligation;
 - (d) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
 - (e) The use of energy and/or capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
 - (f) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility system; and
 - (g) The smaller capacity increments and the shorter lead times available, if any, with additions of capacity from qualifying facilities.

The list of factors influencing purchase prices for power from QFs establishes the fundamental relationship between PGE avoidable costs and the price PGE can pay QF's for electric energy supplied to PGE.

The avoided cost/purchase price evaluation will separate power deliveries into firm

and nonfirm categories. Firm power deliveries from QF's may allow PGE to defer or cancel power supply arrangements including new plant construction. The ability to schedule and dispatch the resource also affects the value of a QF to PGE. In order to be considered firm power, PGE requires assurances from the QF that the qualifying facility will meet its stated, firm delivery obligations over the life of the agreement. This is necessary to avoid undue burdens on utility customers as a result of nonperformance by a qualifying facility. The avoided costs for a firm power supply of sufficient length may include the costs of the 1996 avoidable resource. The avoided costs of firm deliveries may be further refined to accommodate specific power delivery characteristics of the qualifying facility which differ from the basic assumptions used in this filing to develop avoided cost/price tables.

Nonfirm power deliveries will generally be those deliveries made by QF's on an "as available" basis. Avoided costs associated with QF nonfirm power deliveries will be based on variable operating costs the PGE system would incur to acquire nonfirm power as delivered by the QF. Non-firm avoided costs do not include costs associated with plant construction and long-term power purchase contracts between utilities. Non-firm delivered power purchase prices cannot be contractually set significantly in advance of actual delivery of power. As power supply conditions change in the future, the non-firm purchase prices may change, potentially including time of delivery (day/night) differentials.

PUC Informational Appendices

Attachment 1 to this filing contains tables which PGE has completed pursuant to the requirements of the Public Utility Commission. The tables provide estimated prices based on the avoided fixed (capital) costs of the future resource that is avoidable and system variable operating costs by year. Qualifying facilities must provide firm power to allow PGE to avoid the capital costs of the avoidable resource in order to qualify for purchase rates which include the fixed costs of the avoidable resource. The primary manner to qualify is by setting a firm power delivery schedule. Actual purchase prices (determined at the time of delivery or contractually) depend on the important power supply considerations previously described and on QF options for levelization and purchase price arrangements.

The Attachment 1 tables set out prices calculated with and without levelization for QF firm power contracts of varying start dates and terms (in years). Appendices A and B provide optional levelized fixed costs for firm energy deliveries that would displace the 1996 resource. The levelized cost/price options are computed to begin with deliveries starting in 1992 or in the first year of the purchase contract, whichever is later. This cost levelization starts four years prior to the in-service date for the avoidable resource to accommodate the lead time required to construct the avoidable resource. As a result, levelization increases the effective QF contract purchase price above nonlevelized prices in the four years prior to 1996, but decreases prices in the post-1996 period.

Appendix C summarizes the avoided energy costs which reflect the avoided costs shown on Table I of Section I. This table is used with Appendix A and/or B to derive an estimated purchase price for firm QF power deliveries.

Appendices D and E are similar to Appendices A and B, except the cost figures are applicable to QF contracts which do not request levelized fixed costs prior to 1996. From 1996 through the remainder of a QF contract, the QF's estimated rate would consist of the fixed costs described in Appendix D and E and the avoided energy costs shown in Appendix C.

Additional Information

Attachment 2, Table A provides the year-by-year fixed costs of the 1996 CT resource. These costs are first expressed in annual cents per kilowatt-hour in 1996 dollars. The costs are then escalated at the inflation rate to yield year-by-year annual fixed costs in nominal dollars. This technique allows for varying contract lengths and is reflected (on a levelized basis) in the Attachment 1, Appendix A and C.

Table B of Attachment 2 is a summary of the year by year avoided costs of a firm power delivery for the twenty year period, 1987 through 2006.

PORTLAND GENERAL ELECTRIC COMPANY

Levelized Fixed Cost Capacity Payments
(\$/KW-Mo.)

NUMBER YEARS IN CONTRACT	YEAR IN WHICH DELIVERIES BEGIN									
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
5	0.00	0.00	0.00	0.00	0.00	0.17	0.36	0.59	0.85	1.14
10	0.17	0.29	0.38	0.45	0.50	0.53	0.69	0.86	1.04	1.25
15	0.55	0.59	0.63	0.67	0.70	0.72	0.85	1.00	1.16	1.34
20	0.72	0.75	0.77	0.79	0.82	0.84	0.96	1.10	1.25	1.43
25	0.84	0.85	0.87	0.89	0.90	0.92	1.04	1.18	1.33	1.50
30	0.92	0.93	0.94	0.96	0.97	0.98	1.10	1.24	1.40	1.57
35	0.98	0.99	1.00	1.01	1.02	1.03	1.16	1.29	1.45	1.62

Prices shown above become effective and a part of the purchase price no earlier than 1992 for purchases which begin on or before 1992. 5/27/87

ATTACHMENT 1
APPENDIX 8

PORTLAND GENERAL ELECTRIC COMPANY

Levelized Fixed Cost Energy Payments
(Cents/KWH)

NUMBER YEARS IN CONTRACT	YEAR IN WHICH DELIVERIES BEGIN									
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
5	0.00	0.00	0.00	0.00	0.00	0.12	0.25	0.40	0.58	0.78
10	0.12	0.20	0.26	0.31	0.35	0.38	0.48	0.59	0.71	0.86
15	0.38	0.41	0.43	0.46	0.48	0.50	0.59	0.69	0.80	0.92
20	0.50	0.51	0.53	0.55	0.56	0.57	0.66	0.76	0.86	0.98
25	0.57	0.59	0.60	0.61	0.62	0.63	0.72	0.81	0.92	1.03
30	0.63	0.64	0.65	0.66	0.67	0.67	0.76	0.85	0.96	1.08
35	0.67	0.68	0.69	0.70	0.70	0.71	0.79	0.89	0.99	1.11

Prices shown above become effective and a part of the purchase price no earlier than 1992 for purchases which begin on or before 1992. 5/27/87

PORTLAND GENERAL ELECTRIC COMPANY

APPENDIX C

Estimated Variable Energy Prices
(Cents/KWH)

YEAR	<u>Firm Energy</u>		
	<u>Winter</u>	<u>Summer</u>	<u>Annual</u>
1987	1.9	1.3	1.6
1988	2.1	1.5	1.8
1989	2.3	1.6	1.9
1990	2.4	1.7	2.1
1991	2.5	1.7	2.1
1992	2.5	1.8	2.2
1993	2.7	1.9	2.3
1994	2.8	2.0	2.4
1995	3.0	2.2	2.6
1996	3.2	2.3	2.8
1997	3.3	2.5	2.9
1998	3.9	2.7	3.3
1999	4.2	2.9	3.6
2000	4.4	3.1	3.7
2001	4.6	3.3	4.0
2002	4.8	3.6	4.2
2003	5.1	3.7	4.4
2004	5.8	4.0	4.9
2005	6.1	4.2	5.2
2006	6.3	4.5	5.4

Note: For variable cost estimates beyond 2006, escalate
6.6% per year.

5/27/87

PORTLAND GENERAL ELECTRIC COMPANY

APPENDIX D

Nonlevelized Fixed Cost Capacity Prices
\$/Kw-Month

Year of completion of avoidable generating facility by utility: 1996

A. Prior Nonlevelized Capacity Payments

Year

Payment

No Capacity Payments

B. Subsequent Levelized Capacity Payments

Remaining Contract Years Payment	<u>1</u> 1.05	<u>2</u> 1.07	<u>3</u> 1.10	<u>4</u> 1.12	<u>5</u> 1.14	<u>6</u> 1.16	<u>7</u> 1.18	<u>8</u> 1.21	<u>9</u> 1.23
Remaining Contract Years Payment	<u>10</u> 1.25	<u>11</u> 1.27	<u>12</u> 1.29	<u>13</u> 1.31	<u>14</u> 1.32	<u>15</u> 1.34	<u>16</u> 1.36	<u>17</u> 1.38	<u>18</u> 1.40
Remaining Contract Years Payment	<u>19</u> 1.41	<u>20</u> 1.43	<u>21</u> 1.45	<u>22</u> 1.46	<u>23</u> 1.48	<u>24</u> 1.49	<u>25</u> 1.50	<u>26</u> 1.52	<u>27</u> 1.53
Remaining Contract Years Payment	<u>28</u> 1.54	<u>29</u> 1.56	<u>30</u> 1.57	<u>31</u> 1.58	<u>32</u> 1.59	<u>33</u> 1.60	<u>34</u> 1.61	<u>35</u> 1.62	

Applicable to firm delivery commitments by GF.

5/27/87

PORTLAND GENERAL ELECTRIC COMPANY

APPENDIX E

Nonlevelized Fixed Cost Energy Prices
Cents/ Kwh

Year of completion of avoidable generating facility by utility: 1996

A. Prior Nonlevelized Fixed Cost Energy Payments

Year

Payment

No Fixed Cost Energy Payments 1987-1995

B. Subsequent Levelized Fixed Cost Energy Payments

Remaining Contract Years Payment	<u>1</u> 0.72	<u>2</u> 0.74	<u>3</u> 0.75	<u>4</u> 0.77	<u>5</u> 0.78	<u>6</u> 0.80	<u>7</u> 0.81	<u>8</u> 0.83	<u>9</u> 0.84
Remaining Contract Years Payment	<u>10</u> 0.86	<u>11</u> 0.87	<u>12</u> 0.88	<u>13</u> 0.90	<u>14</u> 0.91	<u>15</u> 0.92	<u>16</u> 0.94	<u>17</u> 0.95	<u>18</u> 0.96
Remaining Contract Years Payment	<u>19</u> 0.97	<u>20</u> 0.98	<u>21</u> 0.99	<u>22</u> 1.00	<u>23</u> 1.01	<u>24</u> 1.02	<u>25</u> 1.03	<u>26</u> 1.04	<u>27</u> 1.05
Remaining Contract Years Payment	<u>28</u> 1.06	<u>29</u> 1.07	<u>30</u> 1.08	<u>31</u> 1.08	<u>32</u> 1.09	<u>33</u> 1.10	<u>34</u> 1.11	<u>35</u> 1.11	

Applicable to firm delivery commitments by GF.

5/27/87

PORTLAND GENERAL ELECTRIC COMPANY

APPENDIX F

(Description of Utility's Next Generating Facility)

Name and Location: Energy Resource, PGE Service Area

Type of Plant: Combustion Turbine

Planned Completion Date: 1996

Total Capacity (mw): 105

Utility's Share (mw): 105

Estimated Total Plant Cost: \$49,040,000

Estimated Cost per KW: \$467

First Year Estimated Fuel Cost (cents/kwh): 4.2

First Year Estimated Other Variable O&M Cost (Cents/kwh): 0.33

First Year Estimated Fixed O&M cost (\$/kw-year): 2.04

5/27/87

Portland General Electric Company
Estimated Fixed Costs of the 1996 Energy Resource*
Cents/kWh

<u>Year</u>	<u>Annual Cost</u>
1996	0.91
1997	0.96
1998	1.00
1999	1.04
2000	1.09
2001	1.14
2002	1.19
2003	1.25
2004	1.30
2005	1.36
2006	1.42
2007	1.49
2008	1.56
2009	1.63
2010	1.70
2011	1.78
2012	1.86
2013	1.94
2014	2.03
2015	2.12

*Estimated fixed costs of a combustion turbine.

Annual costs constant in real dollars and escalating at an inflation rate of 4.53% per year.

Portland General Electric Company

Summary - Estimated Year by Year Avoided Costs*
1987 - 2006

Components of Avoided Costs (Cents/kWh)

<u>Year</u>	<u>Variable</u>	<u>Fixed</u>	<u>X</u> <u>Total</u>
1987	1.60		1.60
1988	1.81		1.81
1989	1.93		1.93
1990	2.05		2.05
1991	2.11		2.11
1992	2.19		2.19
1993	2.33		2.33
1994	2.40		2.40
1995	2.60		2.60
1996	2.75	.91	3.66
1997	2.89	.96	3.85
1998	3.31	1.00	4.31
1999	3.55	1.04	4.59
2000	3.73	1.09	4.82
2001	3.95	1.14	5.09
2002	4.23	1.19	5.42
2003	4.40	1.25	5.65
2004	4.91	1.30	6.21
2005	5.16	1.36	6.52
2006	5.39	1.42	6.81

* Assuming firm power deliveries equivalent to PGE operation and dispatch of the resources.

PACIFIC POWER & LIGHT COMPANY

920 S.W. SIXTH AVENUE · PORTLAND, OREGON 97204 · (503) 243-1122

Fredric D. Reed
Senior Vice President

May 29, 1987

Dr. Barbara J. Combs, Administrator
Economic Research Division
Public Utility Commission of Oregon
300 Labor & Industries Building
Salem, OR 97310

Dear Dr. Combs:

Pacific Power & Light Company hereby withdraws Schedule 5 tariff which was submitted May 30, 1986, and hereby submits revised PURPA Section 210 avoided cost information:

OAR 860-29-040 (5)

Standard rates for purchases from qualifying facilities with a generating design capacity of 100 kw or less are set forth in revised Schedule 5. Pacific hereby submits an original and four copies bearing an effective date of July 1, 1987.

OAR 860-29-080 (3) (a)

Nonfirm Energy: The prices for purchases of nonfirm energy, expressed in cents per kWh on a seasonally differentiated basis, and on an average basis, for the calendar year 1987 and next nine years, are set forth in Exhibit 1, Appendix C.

Firm Energy: The prices for purchases of firm energy, expressed in cents per kWh on a seasonally differentiated basis, and on an average basis, for calendar year 1987 and next nine years, are set forth in Exhibit 1, Appendix C.

OAR 860-29-080 (3) (b)

Pacific currently plans on meeting its future load requirements with purchases under the Power Sales Contract with BPA. The planned purchases will be of a quantity necessary to bring Pacific into load and resource balance.

Pacific does not presently plan to retire any existing generating plant during the succeeding 15 years.

Dr. Barbara J. Combs
May 29, 1987
Page 2

OAR 860-29-080 (3) (c)

Pacific's anticipated costs of future purchases under the Power Sales Contract are listed in Exhibit 1, Appendix F.

OAR 860-29-090

Pacific's prices for purchases from qualifying facilities are set forth in Exhibit 1.

Pacific intends to have this filing supersede all previously filed avoided costs, and Pacific will use these avoided costs beginning July 1, 1987.

If you have any questions regarding this filing, please contact Jerry Rust (503) 243-4942.

Very truly yours,

Fredric D Reed

FDR/JR:tjc

jdrcombx.ltr

**SCHEDULE 5
PARTIAL REQUIREMENTS SERVICE
100 KW OR LESS**

In all territory served by Company in Oregon.

To qualifying facilities with a generating design capacity of 100 kw or less.

The monthly billing to the qualifying facility shall be the sum of the Basic Charge specified hereunder and the monthly billing for takings from Company, in accordance with the applicable schedule or schedules for the type of service received.

Basic Charge: \$5.00

Company, in accordance with the terms of a contract between the qualifying facility and Company, shall pay, for all separately metered kilowatt-hours of qualifying facility generation, 1.88 cents per kilowatt-hour for the period November through April, and 1.65 cents per kilowatt-hour for the period May through October.

(I)
(D)

Interconnection of a qualifying facility with Company's system will be permitted only under the terms of a contract between the qualifying facility and Company. Such contract shall include but not be limited to the following:

- (1) The qualifying facility shall indemnify and hold harmless the Company from any and all liability arising from the operation and interconnection of qualifying facility.
- (2) Qualifying facility shall provide a lockable disconnect switch to isolate qualifying facility's generation from Company's system. Such switch shall be accessible to Company and Company shall have the right to lock such disconnect switch open whenever necessary to maintain safe electrical operating conditions, or whenever the qualifying facility adversely affects Company's system.
- (3) Qualifying facility shall provide an additional meter base adjacent to the delivery meter to measure the qualifying facility's total generation independently from the qualifying facility's load. For three-phase generation the qualifying facility will also provide a meter base for a kvar meter.

(Continued)

Issued May 29, 1987

Fredric Reed

**Effective with service rendered
on and after July 1, 1987**

Issued by PACIFIC POWER & LIGHT COMPANY
Fredric D. Reed, Senior Vice President
Public Service Building, Portland, Oregon

EXHIBIT 1

PACIFIC POWER & LIGHT COMPANY
AVOIDED COST PRICES FOR PURCHASE POWER
EFFECTIVE
JULY 1, 1987

23-May-87

PACIFIC POWER & LIGHT COMPANY

AVOIDED COST PRICES FOR PURCHASE POWER

APPENDIX A

LEVELIZED CAPACITY PRICES

SEASONALLY DIFFERENTIATED

DECEMBER-APRIL: 1.354 TIMES AVERAGE PRICE.

MAY-NOVEMBER: 0.747 TIMES AVERAGE PRICE.

NUMBER OF YEARS IN CONTRACT	AVERAGE PRICES \$/KM/MO YEAR IN WHICH DELIVERIES BEGIN									
	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
1										7.63
2									3.64	7.93
3								2.31	5.04	8.32
4							1.66	3.61	5.95	8.60
5						1.26	2.75	4.53	6.56	8.86
6					1.00	2.18	3.60	5.20	7.03	9.08
7				0.82	1.78	2.93	4.24	5.73	7.40	9.30
8			0.68	1.48	2.44	3.53	4.77	6.16	7.74	9.52
9		0.68	1.25	2.06	2.98	4.03	5.20	6.53	8.04	9.74
10	0.68	1.25	1.76	2.55	3.44	4.44	5.58	6.87	8.32	9.95
15	2.91	3.23	3.50	4.24	5.07	6.00	7.04	8.21	9.50	10.95
20	4.23	4.43	4.63	5.36	6.18	7.09	8.10	9.23	10.48	11.87
25	5.17	5.33	5.47	6.21	7.04	7.95	8.96	10.08	11.32	12.69
30	5.89	6.02	6.15	6.90	7.74	-	-	-	-	-
35	6.50	-	-	-	-	-	-	-	-	-

NOTE: Pursuant to Pacific's current load/resource balance, if a Qualifying Facility can demonstrate that it is reliable and dispatchable to permit a reduction in Pacific's capacity contract with BPA, there will be an additional capacity payment to be determined in the course of contract negotiations.

The avoided cost prices may be adjusted to reflect losses when applicable.

Prices shown above become effective and a part of the purchase price in 1989. No levelized prices available prior to 1989.

23-May-87

PACIFIC POWER & LIGHT COMPANY

AVOIDED COST PRICES FOR PURCHASE POWER

APPENDIX B

LEVELIZED FIXED ENERGY PRICES

SEASONALLY DIFFERENTIATED

DECEMBER-APRIL: 1.082 TIMES AVERAGE PRICE.

MAY-NOVEMBER: 0.885 TIMES AVERAGE PRICE.

NUMBER OF
YEARS IN
CONTRACT

AVERAGE PRICES
CENTS/KWH

YEAR IN WHICH DELIVERIES BEGIN

	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
15										
20										
25										
30										
35										

23-May-87

PACIFIC POWER & LIGHT COMPANY

AVOIDED COST PRICES FOR PURCHASE POWER

APPENDIX C

VARIABLE ENERGY PRICES

CENTS/KWH

SEASONALLY DIFFERENTIATED

SUMMER MONTHS ARE MAY - OCTOBER

WINTER MONTHS ARE NOVEMBER - APRIL

NON-FIRM ENERGY PRICES

DELIVERIES DURING CONTRACT YEAR	WINTER CENT/KWH	SUMMER CENT/KWH	AVERAGE CENT/KWH
1987	1.21	1.26	1.23
1988	1.24	1.34	1.28
1989	1.35	1.43	1.38
1990	1.42	1.54	1.47
1991	1.51	1.68	1.55
1992	1.59	1.70	1.63
1993	1.71	1.82	1.75
1994	1.80	1.90	1.84
1995	1.90	2.02	1.94

FIRM ENERGY PRICES

DELIVERIES DURING CONTRACT YEAR	WINTER CENT/KWH	SUMMER CENT/KWH	AVERAGE CENT/KWH
1987	1.21	1.26	1.23
1988	1.24	1.34	1.28
1989	1.35	1.43	1.38
1990	1.42	1.54	1.47
1991	1.51	1.68	1.55
1992	1.59	1.70	1.63
1993	1.71	1.82	1.75
1994	1.80	1.90	1.84
1995	1.90	2.02	1.94

23-May-87

PACIFIC POWER & LIGHT COMPANY

AVOIDED COST PRICES FOR PURCHASE POWER
APPENDIX D
NON-LEVELIZED CAPACITY PRICES
\$/KW/MO

SEASONALLY DIFFERENTIATED

December - April: 1.354 TIMES AVERAGE PRICE.
May - November: 0.747 TIMES AVERAGE PRICE.

A. PRIOR NON-LEVELIZED CAPACITY PAYMENTS

YEAR:	1987	1988	1989	1990	1991	1992	1993	1994	1995
-------	------	------	------	------	------	------	------	------	------

AVERAGE PAYMENTS:

- NO CAPACITY PAYMENTS -

B. SUBSEQUENT LEVELIZED CAPACITY PAYMENTS

REMAINING CONTRACT YEARS:	1	2	3	4	5	6	7	8
AVERAGE PAYMENTS:	7.63	7.93	8.32	8.60	8.86	9.08	9.30	9.52
REMAINING CONTRACT YEARS:	9	10	11	12	13	14	15	16
AVERAGE PAYMENTS:	9.74	9.95	10.16	10.36	10.56	10.76	10.95	11.14
REMAINING CONTRACT YEARS:	17	18	19	20	21	22	23	24
AVERAGE PAYMENTS:	11.33	11.51	11.69	11.87	12.04	12.21	12.37	12.54
REMAINING CONTRACT YEARS:	25	26						
AVERAGE PAYMENTS:	12.69	12.85						

NOTE: Pursuant to Pacific's current load/resource balance, if a Qualifying Facility can demonstrate that it is reliable and dispatchable to permit a reduction in Pacific's capacity contract with BPA, there will be an additional capacity payment to be determined in the course of contract negotiations.

23-May-87

PACIFIC POWER & LIGHT COMPANY

AVOIDED COST PRICES FOR PURCHASE POWER
APPENDIX E
NON-LEVELIZED ENERGY PRICES
CENTS/KWH

SEASONALLY DIFFERENTIATED

September - March: 1.082 TIMES AVERAGE PRICE.
April - August: 0.885 TIMES AVERAGE PRICE.

NON-LEVELIZED ENERGY PAYMENTS

YEAR:	1987	1988	1989	1990	1991	1992	1993	1994	1995
-------	------	------	------	------	------	------	------	------	------

AVERAGE PAYMENTS:

- SEE APPENDIX C -

SUBSEQUENT NON-LEVELIZED ENERGY PAYMENTS

CONTRACT YEAR:	1996	1997	1998	1999	2000	2001	2002	2
AVERAGE PAYMENTS:	2.69	2.91	3.25	3.40	3.57	3.72	3.94	4
CONTRACT YEAR:	2004	2005	2006	2007	2008	2009	2010	2
AVERAGE PAYMENTS:	4.38	4.60	4.83	5.07	5.33	5.59	5.87	6
CONTRACT YEAR:	2012	2013	2014	2015	2016	2017	2018	2
AVERAGE PAYMENTS:	6.47	6.79	7.12	7.48	7.85	8.24	8.65	9
CONTRACT YEAR:	2020	2021						
AVERAGE PAYMENTS:	9.53	10.00						

23-May-87

PACIFIC POWER & LIGHT COMPANY

AVOIDED COST PRICES FOR PURCHASE POWER

APPENDIX F

ESTIMATED NEW RESOURCES RATE - 7(4)
CENTS/KWH

YEAR	NR RATE CENTS/KWH
1996	4.10
1997	4.53
1998	5.05
1999	5.28
2000	5.55
2001	5.78
2002	6.12
2003	6.44
2004	6.81
2005	7.16
2006	7.52
2007	7.89
2008	8.28
2009	8.69
2010	9.13
2011	9.58
2012	10.05
2013	10.55
2014	11.08
2015	11.63
2016	12.21
2017	12.81
2018	13.45
2019	14.12
2020	14.82
2021	15.56

NOTE: 1996-2005 VALUES ARE DPA'S 8/85 BASE FORECAST; 2006 TO 2021
BASED ON 1985 THROUGH 2005 TREND WHICH YIELDS A 4.97% AVE ANNUAL GROWTH RATE.

Avoided Cost Estimation
(For Use by Potential Qualifying Facility Sponsors)

The attached worksheet can be used to compute an estimate of the per kwh payments you can receive in each year of a contract under which you sell power (firm energy and capacity) to Idaho Power Company. Actual contract payments will be determined in accordance with Appendices A, B, C and D, and may include both capacity and energy payments.

The payments you receive for power sold will reflect a combination of the utility's short-term and long-term avoided costs. Short-term avoided cost payments, which reflect power supply operating costs, are paid throughout the lifetime of the contract. Levelized payments for long-term avoided costs of new resources will begin in 1998, four years in advance of the expected need of Idaho Power for new generating plant capacity.

To estimate the annual amounts you will receive under a power sales contract, follow the steps outlined below.

1. Decide on the year that you expect to begin delivering power.
2. Decide how long the contract will last.
3. On the worksheet, fill in Column B with all the years during which the contract will be effective. Example: if you will begin delivering power under a 35-year contract in 1987 put 1987 in Column B next to the number 1, 1988 next to the number 2, and so forth. In this example, you would end up with 2021 in Column B next to the number 35.
4. If you plan on less than a 35-year contract, cross out the remaining rows in every column.
5. If your contract will begin in or before 1998, find the levelized capacity from Appendix A which corresponds to the number of contract years remaining after 1997. Enter that number in all rows of Column C on the worksheet starting in 1998. Enter zero in all rows of Column C for contract years prior to 1998.
6. Calculate the cents per kwh available from the capacity payment by multiplying the numbers in Column C by .1826. Put these results in each row of Column D. As in Column C, all of the numbers in Column D should be zero prior to 1998 and a levelized amount for 1998 and all subsequent years of the contract.
7. In a manner similar to your procedure in Step 5, find the levelized seasonal fixed energy payments from Appendix B that correspond to

the year you plan to begin deliveries and the length of contract you desire. Multiply each seasonal energy rate by the expected generation in that season to estimate seasonal fixed energy payments. Then add together the three seasonal payments and divide the total by the expected annual generation from the project. Put that number under Column E of the worksheet for all years of your contract beginning with the year 1998. As in Step 6, all of the numbers in Column E should be zero for years prior to 1998.

8. The variable energy payments for your contract can be obtained from Appendix C. Annual variable energy prices should be calculated for your project from the seasonal rates using the procedure described in Step 7. To obtain variable energy payments for contract years not given directly by Appendix C, multiply each year's payment by 1.055 to obtain an estimate for the following year's payments. Place variable energy payments for each year of the contract in Column F.

If your contract will start in 1998 or earlier, the variable energy payments for all years through 1997 are given on page 1, section (a). Your payments for 1998 are given on page 1, section (b) under the heading corresponding to the number of years remaining in your contract after 1997. Subsequent year's payments may be estimated by escalating the 1998 payment at a rate of 5.5 percent per year.

9. Add Columns D, E, and F. The result is an estimate of the price you could be paid in each year of your contract.

If you do several of these computations, you will notice that you gain a price advantage both when you increase the length of a contract and when you delay a contract's beginning date to a later time (when power surpluses may be smaller).

FOR COMPUTING PRICES TO BE PAID TO QUALIFYING FACILITIES

A	B	C	D	E	F	G
YEAR IN CONTRACT	CALENDAR YEAR	CAPACITY PRICE (\$/KW-MONTH)	CONVERTED CAPACITY PRICE (CENTS/KWH)	FIXED ENERGY PRICE (CENTS/KWH)	VARIABLE ENERGY PRICE (CENTS/KWH)	TOTAL PRICE (CENTS/KWH) D + E + F
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
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21						
22						
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25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						

APPENDIX A

LEVELIZED CAPACITY PAYMENTS

(\$/KW-MONTH)

FOR QUALIFYING FACILITIES BEGINNING DELIVERY
DURING THE 1987-1998 PERIOD

YEAR OF COMMENCEMENT OF LEVELIZED CAPACITY PAYMENTS: 1998

A. PRIOR CAPACITY PAYMENTS

YEAR:	YR87	YR88	YR89	YR90	YR91	YR92	YR93	YR94	YR95	YR96	YR97
PAYMENT:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

B. SUBSEQUENT CAPACITY PAYMENTS

REMAINING CONTRACT YEARS:	1	2	3	4	5	6	7	8	9
PAYMENTS:	0.00	0.00	0.00	0.00	1.33	2.25	2.94	3.49	3.94
REMAINING CONTRACT YEARS:	10	11	12	13	14	15	16	17	18
PAYMENTS:	4.32	4.65	4.94	5.21	5.44	5.66	5.86	6.04	6.22
REMAINING CONTRACT YEARS:	19 ✓	20	21	22	23	24	25	26	27
PAYMENTS:	6.38	6.53	6.67	6.81	6.94	7.06	7.17	7.28	7.39
REMAINING CONTRACT YEARS:	28	29	30	31	32	33	34	35	
PAYMENTS:	7.49	7.58	7.67	7.76	7.84	7.91	7.99	8.06	

APPENDIX B

LEVELIZED FIXED ENERGY PAYMENTS

(CENTS/KWH)

**FOR QUALIFYING FACILITIES BEGINNING DELIVERY
DURING THE 1987-1998 PERIOD**

YEAR OF COMMENCEMENT OF LEVELIZED CAPACITY PAYMENTS: 1998

A. PRIOR FIXED ENERGY PAYMENTS

YEAR:	YR87	YR88	YR89	YR90	YR91	YR92	YR93	YR94	YR95	YR96	YR97
PAYMENT:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

B. SUBSEQUENT FIXED ENERGY PAYMENTS

REMAINING CONTRACT YEARS:	1	2	3	4	5	6	7	8	9
OCT-FEB	0.00	0.00	0.00	0.00	0.54	0.92	1.20	1.42	1.60
MAR-MAY	0.00	0.00	0.00	0.00	0.34	0.58	0.76	0.90	1.02
JUN-SEP	0.00	0.00	0.00	0.00	0.63	1.07	1.39	1.65	1.87
REMAINING CONTRACT YEARS:	10	11	12	13	14	15	16	17	18
OCT-FEB	1.78	1.89	2.01	2.12	2.22	2.30	2.38	2.46	2.53
MAR-MAY	1.12	1.20	1.28	1.34	1.41	1.46	1.51	1.56	1.61
JUN-SEP	2.05	2.20	2.34	2.47	2.58	2.68	2.77	2.86	2.94
REMAINING CONTRACT YEARS:	19	20	21	22	23	24	25	26	27
OCT-FEB	2.60	2.66	2.72	2.77	2.82	2.87	2.92	2.96	3.01
MAR-MAY	1.65	1.69	1.72	1.76	1.79	1.82	1.85	1.88	1.91
JUN-SEP	3.02	3.09	3.16	3.23	3.29	3.34	3.40	3.45	3.50
REMAINING CONTRACT YEARS:	28	29	30	31	32	33	34	35	
OCT-FEB	3.05	3.09	3.12	3.16	3.19	3.22	3.25	3.28	
MAR-MAY	1.93	1.96	1.98	2.00	2.02	2.04	2.06	2.08	
JUN-SEP	3.55	3.59	3.63	3.67	3.71	3.75	3.78	3.82	

APPENDIX C

VARIABLE ENERGY PAYMENTS
FOR FIRM POWER PURCHASE CONTRACTS

(CENTS/KWH)

FOR QUALIFYING FACILITIES BEGINNING DELIVERY
DURING THE 1987-1998 PERIOD

A. PRIOR VARIABLE ENERGY PAYMENTS

	YR87	YR88	YR89	YR90	YR91	YR92	YR93	YR94	YR95	YR96	YR97
OCT-FEB ⁵	1.23	1.32	1.43	1.55	1.67	1.82	2.00	2.25	2.40	2.58	2.78
MAR-MAY ³	0.78	0.84	0.90	0.98	1.06	1.15	1.27	1.43	1.53	1.63	1.76
JUN-SEP ⁴	1.43	1.53	1.66	1.80	1.95	2.11	2.33	2.62	2.80	3.00	3.23

B. 1998 VARIABLE ENERGY PAYMENTS(*)

REMAINING CONTRACT YEARS:	1	2	3	4	5	6	7	8	9
OCT-FEB	3.12	3.12	3.15	3.20	2.72	2.40	2.18	2.00	1.87
MAR-MAY	1.98	1.98	2.00	2.03	1.73	1.53	1.38	1.27	1.19
JUN-SEP	3.63	3.63	3.67	3.73	3.17	2.80	2.53	2.33	2.18
REMAINING CONTRACT YEARS:	10	11	12	13	14	15	16	17	18
OCT-FEB	1.77	1.68	1.61	1.55	1.49	1.45	1.41	1.38	1.34
MAR-MAY	1.12	1.07	1.02	0.98	0.95	0.92	0.89	0.87	0.85
JUN-SEP	2.05	1.95	1.87	1.80	1.74	1.69	1.64	1.60	1.56
REMAINING CONTRACT YEARS:	19	20	21	22	23	24	25	26	27
OCT-FEB	1.32	1.29	1.27	1.25	1.23	1.22	1.20	1.19	1.17
MAR-MAY	0.84	0.82	0.81	0.79	0.78	0.77	0.76	0.75	0.75
JUN-SEP	1.53	1.50	1.48	1.46	1.43	1.41	1.40	1.38	1.37
REMAINING CONTRACT YEARS:	28	29	30	31	32	33	34	35	
OCT-FEB	1.16	1.15	1.14	1.13	1.12	1.12	1.11	1.10	
MAR-MAY	0.74	0.73	0.72	0.72	0.71	0.71	0.70	0.70	
JUN-SEP	1.35	1.34	1.33	1.32	1.31	1.30	1.29	1.28	

(*) VARIABLE ENERGY PAYMENTS FOR EACH CONTRACT YEAR AFTER 1998 MAY BE ESTIMATED BY INCREASING THE VALUES FROM THIS TABLE BY 5.5%, PER YEAR. ACTUAL CHANGES IN VARIABLE ENERGY PAYMENTS DURING A CONTRACT TERM WILL BE DETERMINED BY THE RATE OF ESCALATION OF VARIABLE COSTS ACTUALLY EXPERIENCED BY THE UTILITY.

APPENDIX C

**VARIABLE ENERGY PAYMENTS
FOR NON-FIRM POWER PURCHASE CONTRACTS**

(CENTS/KWH)

SEASON

YEAR

	YR87	YR88	YR89	YR90	YR91	YR92	YR93
OCT-FEB	1.23	1.32	1.43	1.55	1.67	1.82	2.00
MAR-MAY	0.78	0.84	0.90	0.98	1.06	1.15	1.27
JUN-SEP	1.43	1.53	1.66	1.80	1.95	2.11	2.33
	YR94	YR95	YR96				
OCT-FEB	2.25	2.40	2.58				
MAR-MAY	1.43	1.53	1.63				
JUN-SEP	2.62	2.80	3.00				

E-55 / E-56

APPENDIX D

IDAHO POWER COMPANY

DEFINITION OF CAPACITY AND CAPACITY PAYMENT FOR COGENERATION AND SMALL POWER PRODUCTION FACILITIES

Contract Capacity

The contract capacity of a qualifying facility is (1) the maximum one-hour reliable generating capacity of the facility if the full capacity of the facility is available to and dispatchable by Idaho Power Company at all times other than during scheduled maintenance periods and periods of forced outage, or (2) the contract annual firm energy production of the facility divided by the total hours in the year if the delivery of energy to Idaho Power Company is not dispatchable by the Company.

Monthly Capacity Payment

The monthly capacity payment to the qualifying facility during the contract period shall be the product of the contract capacity in kilowatts multiplied by the capacity payment per kilowatt. Capacity payments are based on the contract term and commercial starting date of power delivery from the qualifying facility.

Utah

The 1987 avoided cost rates used came from Public Service Commission Case # 80-999-06 which gives an avoided cost of 3.9 cents/kWh. Kevin Higgins, Assistant Director for the Utah Energy Office, provided us with the 4% escalation rate (same as the inflation rate). The rates used for this state follow on the next page.

Utah

Weighted Averages

<u>YEAR</u>	<u>¢/kWh</u> <u>WEIGHTED AVG.</u>
1987	3.90
1988	4.06
1989	4.22
1990	4.39
1991	4.57
1992	4.75
1993	4.94
1994	5.14
1995	5.34
1996	5.55
1997	5.78
1998	6.01
1999	6.26
2000	6.50
2001	6.76
2002	7.03
2003	7.31
2004	7.60
2005	7.91
2006	8.22
2007	8.55
2008	8.89
2009	9.25
2010	9.62

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Implementa-)
tion of Rules Governing Cogener-)
ation and Small Power Production)
in the State of Utah.)

CASE NO. 80-999-06

REPORT AND ORDER

ISSUED: April 3, 1987

Appearances:

Fred W. Finlinson
Sheryl Simpson
Lee M. Goodwin

For Sunnyside Cogeneration

Gregory Probst

" Utah Council of Independent
Power Producers

Edward Hunter

" Utah Power & Light Co.

Michael Ginsberg
Assistant Attorney General

" Division of Public Utilities
Department of Business
Regulation, State of Utah

David S. Christensen
Assistant Attorney General

" Utah Energy Office

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By the Commission:

I. BACKGROUND

This case was instigated by the filing of an application by Utah Power and Light Company (Utah Power, the Company) to reduce the prices offered by the Company for the capacity and energy of FERC-certified Qualifying Facility (QF) cogenerators and small power producers (i.e., the "buy back" rates). These prices were established in our Report and Order in this case, dated March 14, 1985. The application requested that capacity prices be recalculated using relevant current data, estimates, and projections. In direct testimony, the Company requested that the capacity price for 20-year contracts be reduced from \$202 to \$158 per kW-yr based on an assumed 15 MW per year expected future increase in QF capacity. The Company further requested that the energy price be reduced from 21 to 13 mills per kWh, and that the energy price floor of 20 mills per kWh be removed entirely.

On July 18, 1986, the Company filed an application for the suspension of availability of new QF contracts at current capacity and energy prices. The Commission decided to reopen Case No. 80-999-06, to require the Company to file new avoided cost data, and to determine what, if any changes should be made to the existing avoided cost based prices. Notice was given, and a prehearing conference was held on August 6, 1986. On September 30, 1986, the Company submitted the prefiled testimony of several witnesses. Testimony was also filed by the

staff improved the operation of this model such that it could be used quickly and easily to compute the avoided capacity cost derived from any set of input assumptions. This version was made available to all parties and was used by most parties to develop their final positions. The availability of this model allowed the hearing to focus on the appropriateness of proposed input assumptions. Once these issues were settled, the computation of the resulting capacity prices, as ordered herein, was carried out by Commission staff.

The hearing also addressed the issue of the determination of the avoided cost based price for QF energy. Questions dealing with the appropriate values were resolved and the resulting QF energy price established.

Many issues regarding specific quantitative assumptions were discussed at a Commission-ordered technical conference in which representatives of the parties and the Commission's staff participated. This conference lead to the resolution of a number of significant disagreements which existed in the parties' prefiled testimony, thereby eliminating the need for extensive argumentation on these points in the hearing. The technical conference also lead to the clarification of points of disagreement, thereby enhancing the efficiency with which the hearing was conducted.

To implement this philosophy, our policy is to set prices for QF capacity and energy which reflect market conditions, including the value of existing generation capacity surpluses or shortages, and to change these prices as market conditions change. Our intention is that the responses of QF developers to these market signals will serve to keep realized development in line with that level of development which serves the interests of the ratepayers without unduly subsidizing the QF developers. Specifically, lower QF capacity prices in periods of excess capacity reflect the limited value to ratepayers of additional capacity. Such prices are likely to limit the quantity of QF capacity that will be developed. In periods of capacity shortage, higher capacity prices would reflect the higher value to ratepayers of additional capacity. Such higher rates would be expected to result in a more rapid development of realized QF capacity. We recognize that our reliance on this surrogate for market forces to promote efficient investment in QF capacity may prove inadequate. In such event, direct intervention may be required to suspend purchase of new QF capacity and/or to establish new QF capacity and energy prices.

III. FINAL POSITIONS OF PARTIES

This section summarizes the position arrived at by each party at the end of the hearing. Input assumptions and resulting capacity and energy prices as well as certain operational/policy matters are considered. The Company's final position will be

forecast was prepared. Since that forecast reflected none of those changes, it was an outdated and inaccurate picture of future load requirements.

c. Non-deferrable Generation Capacity: The Company's current generation capacity is 3161 MW. Additional non-deferrable capacity consists of: 60 MW at IPP starting in 1987, 21 MW at Gem State starting in 1989 (summers only), and 15 MW of geothermal starting in 1992.

d. Committed QF Capacity: QF capacity to which the Company is already committed will rise from 8 MW in 1986 to 22 MW by the winter of 1987. It will remain at this level until the 45 MW Sunnyside Cogeneration Associates project comes on line in the winter of 1990.

e. Plant Life/Replacement Refurbishment: The Company contended that no evidence had been presented which would justify an increase in avoided capacity costs due to retirement or refurbishment of the Company's existing units. The Company stated that it had no plans to retire any units during the 20-year forecast period used to determine avoided capacity costs.

f. Assumed Annual Flow of New QF Capacity: The Company postulates future growth of QF capacity to be 15 MW per year starting in 1987, reaching a level of 300 MW in 2006. This capacity should be assumed to operate with a load factor of 75 percent. This new capacity is in addition to committed QF capacity. It represents the new QF developments which would be subject to the pricing and policy decisions made in this and

capitalized plant cost. The plant would have a book life of 35 years and would operate with a 75 percent capacity factor.

i. Inflation: The Company supports the use of a four percent general inflation rate.

j. Tax and Depreciation Rates/Investment Tax Credit: The Company asserted that tax rates, the modified Accelerated Cost Recovery System (ACRS), and treatment of the Investment Tax Credit (ITC) associated with the new federal tax laws should be used. The composite income tax rate is, therefore, 37.2 percent and the ITC rate is zero (0) percent. Required changes in the ACRS were incorporated into the revenue requirement formula component of the avoided capacity cost computation.

k. Cost of Capital: The Company's position is that its current realized capital structure and rates of return on debt and preferred stock, and authorized rate of return on common equity should be used in computing cost of capital. The capital structure should be 48.7 percent debt, 5.6 percent preferred, and 45.7 percent common. Rates of return should be 9.75 percent on debt, 8.13 percent on preferred, and 15 percent on common. The resulting cost of capital is 12.06 percent.

l. Energy Credit: The Company proposed a figure of 7 mills per kWh for the energy credit required by the SCA method to correct the potential overpayment associated with paying QF's marginal energy costs even though capacity payments are based on displacing base-load units having lower energy costs.

capacity assumed in calculating the price; i.e., to the 15 MW per year recommended in subsection III.A.1.f., above.

B. Final Position of the Division of Public Utilities

The Division's case was presented by Nile W. Eatmon. He developed a set of assumptions and calculated and presented the resulting capacity price. He also presented a QF energy price and recommended a price floor-balancing account mechanism for dealing with energy payments. Mr. Eatmon's assumptions will be discussed in Section 1. Presentation of other aspects of the Division's position will follow.

1. Inputs/Assumptions--The Division

As indicated, consensus regarding most SCA inputs/assumptions was reached in the technical conference. Only those inputs/assumptions concerning which the Division maintained a different position are discussed here.

a. Load Forecast: The Division recommended using the forecast developed by Commission staff in the spring of 1986, as modified by Utah Power personnel in the Hunter III sale case, Case No. 85-035-08.

b. Plant Life/Replacement/Refurbishment: Though the original SCA did not adjust for retirement of generating plants, the Division recognized that Utah Power can avoid paying new plant cost by refurbishing existing plant. The Division therefore recommended that in calculating avoided cost, it should be assumed that plant is refurbished at the 45th year of its life at a cost equal to one-half of then-current new plant construction costs.

mills until the accumulated overpayment plus accumulated interest is eliminated. The Division testified that its proposal provides stable revenues for the QF while preventing any subsidy by ratepayers.

4. Capacity Limitation--The Cap--The Division

The Division agrees with the Company's proposal for a 15 MW per year cap on the amount of QF capacity accepted. The Commission should establish guidelines on how the 15 MW would be allocated by distinguishing projects on the basis of price, terms of the contract, type of resource, location, reliability, security, and other factors. According to the Division, projects that provide reliable service at the lowest possible costs should receive priority.

C. Final Position of the Utah Energy Office

UEO witness Kevin Higgins proposed a number of assumptions which differed from those of most of the other parties. These assumptions are addressed in Section 1. Resulting price proposals and a number of policy suggestions follow.

1. Inputs/Assumptions--UEO

a. Load forecast: The average of the Commission staff spring, 1986, forecast and the forecast presented by Utah Power witness Hutchinson should be used.

b. Plant Life/Replacement/Refurbishment: Existing Utah Power facilities should be assumed to be retired and replaced at 45 years of age.

b. Energy Price: UEO contends that avoided marginal energy cost should be calculated as 125 percent of system average energy cost.

3. The Floor and the Balancing Account--UEO

The UEO's position on the energy floor is that it should be lowered from 20 mills to 18 mills to account for lower energy costs. UEO argues both ratepayer and QF interests would be best served by setting the price for QF energy equal to 125 percent of system average energy cost because the existing method yields results which are volatile, assumption-sensitive, and open to dispute. The current approach will encourage future decision making by the utility which may not be economically efficient.

4. Annual Limit--The Cap--UEO

The UEO agrees that a "cap" on QF capacity should be initiated. Approval of front-end loaded contracts should be restricted so the total system QF capacity grows no more than 30 MW per year. This cap should apply to new QF capacity and the Sunnyside project, as well as to QF capacity currently under contract in Utah Power's Idaho or Wyoming service territory, or is otherwise considered "committed."

5. Diversity--UEO

To allow some diversity of opportunity and of resource development, UEO advocates that five MW of capacity should be "reserved" each year for Utah renewable energy (non-cogeneration) projects. Because QF capacity will be limited, an equitable and administratively-feasible rationing procedure, based on factors

e. Cost of Capital: UCIPP proposes an "idealized" capital structure and rate of return on its components. Their proposed structure is 45 percent each for debt and common and 10 percent for preferred, with rates of return of 10.1 percent on debt, 9.40 percent on preferred, and 15 percent on common. This produces a cost of capital value of 12.24 percent.

f. Working Capital: UCIPP proposes 2.08 percent of plant cost as a working capital requirement figure. All other parties accept 2.02 percent. The difference is too small to affect the resulting capacity price calculation.

2. QF Capacity Price--UCIPP

The avoided cost based capacity price derived from the UCIPP assumptions and proposed by them for a 20-year QF contract is \$258/kW-yr.

3. Further Discussion

UCIPP and Snowbird Development Company President A. Colin Jackson discussed UCIPP's purpose, positions, and historical participation in Case No. 80-999-06. Don R. Asher of Power Systems Engineering discussed the difficulty of developing QF's, stated that QF "oversupply" statements of utilities are unfounded, and suggested that a project development milestone procedure would be desirable.

William B. Marcus of JBS Energy, provided an alternative method for QF pricing and commented on avoided energy cost calculation methods and other contractual issues. Mr. Marcus proposed that the Commission allow Utah Power to defer some of the capacity costs of QF's instead of immediately collecting them

existing projects and commitments into consideration. Sunnyside's proposal could be used with or without an annual cap on capacity.

b. Plant Life/Replacement/Refurbishment: Sunnyside argued that the assumption of an unlimited life for Utah Power plants is inappropriate in light of the realities of utility plant experience, and particularly in light of the significant expenses associated with power plant refurbishment. Sunnyside recommends that rehabilitation costs be included in the model at 40 percent of the replacement cost, and that the life extension be included as 20 years.

2. QF Energy Price--Sunnyside

Sunnyside agrees that UEO's proposal to use 125 percent of Utah Power's average energy cost is the most practical method to establish the QF energy price.

3. The Floor and Balancing Account--Sunnyside

Sunnyside recommends that the energy floor be retained, with a balancing account similar to that approved by the Commission in the Sunnyside proceeding (Case No. 86-2018-01).

4. Annual Limit--The Cap--Sunnyside

Sunnyside does not object in principal to the concept of an annual cap on QF capacity, but specific problems and issues must be resolved in implementing a cap. These include the manner in which single projects with capacity in excess of the annual cap will be treated. The cap should be administered so that once a project's contract has been approved by the Commission, that

A... Capacity Cost Calculation Assumptions**1. Consensus Assumptions**

As indicated in the summary of parties' positions, all parties have agreed to a number of input assumptions. These are set out in the following table. We find them appropriate for use in this case.

<u>Consensus Capacity Payment Input Assumptions</u>	
<u>Item</u>	<u>Value</u>
Base Year	1987
Inflation Rate	4.0% per year
Composite Corporate Income Tax Rate (Federal plus State)	37.2%
Investment Tax Credit Rate	0.0%
MW Per Year New Cogeneration	15 MW per year*
Cogeneration Load Factor	75%

Exchange Capacity Purchases

Summer Months	3 months per year
Transmission Limitation on Summer Exchange Purchases	210 MW
Price (In 1985 Dollars)	\$2.31 per kW-mo
Winter Months	6 months per year
Winter Exchange Purchase Price (In 1985 Dollars)	\$4.42 per kW-mo

Deferrable Plant

Net Capacity	100 MW
Book Life	35 years
Capacity Factor	75%
Other Fixed Costs (% of Capital Cost)	
Working Capital	2.02%**
Ad Valorem Taxes	1.17%
Insurance	0.18%

Non-Tariff Sales

Margin	6.0 mills per kWh
Probability	37%

* UEO also considers a 30 MW per year case

** UCIPP maintains 2.08%; the difference is insignificant.

of a major growth spurt in the second decade of the 20-year projection interval to be questionable at best.

The UEO forecast, being an average of the PSC and UP&L forecasts, is a reasonable resolution of the issues discussed above. Therefore the Commission finds that the UEO forecast is appropriate and acceptable for use in this case.

b. Plant Refurbishment/Retirement/Replacement: We find it appropriate to consider replacement or refurbishment of existing plant in the SCA procedure's "capacity expansion plan" component. The UEO proposal to impose the assumption of retirement and replacement at a plant life of 45 years appears unrealistically restrictive. The Division proposal to approximate the complex process of gradual and continuous upgrade and refurbishment with an assumed one-time capital expenditure equal to one-half the cost per kilowatt of building new plant, with the expenditure occurring at the 45th year of plant life, is the best option available on the record for dealing with this complex issue. Thus, we adopt the Division's refurbishment proposal for this case.

c. Treatment of the Sunnyside Cogeneration Associates Facility: We find that the most reasonable and equitable treatment of the Sunnyside facility is to assign that facility's 45 MW to the "Committed Cogeneration" category of the SCA procedure in mid-year 1990, and to impose no associated reduction in the assumed 15 MW per year stream of new QF capacity upon which the avoided capacity cost calculation is based. This procedure

it is appropriate to rely on an approach utilizing the actual values. The Division and the Company both present actual marginal cost based energy credit proposals. The Division proposes 5.0 mills per kWh, while the Company proposes 7.0 mills per kWh. The evidence is insufficient to affirm the propriety of either proposal. We, therefore, find that the average of the two, i.e., 6.0 mills per kWh, is appropriate for use in this case.

g. Assumptions Regarding Cost of Capital: Since the Company's actual capital structure would impose the costs subject to deferral by QF capacity, no proposal to use any other capital structure, however derived, is acceptable in this case. We, therefore, find that the Company's actual capital structure, as listed below, is appropriate for use in this case.

Rates of return on debt and preferred stock should reflect current returns on these components since they are unlikely to change significantly in any predictable way in the future. The Division's proposal to use a lower value for return on common equity rather than the current allowed rate reflects the reasonable assumption that the cost of capital under current market conditions is at least 100 basis points less than the Company's current authorized rate. Thus the Division's recommended 14 percent per year for the rate of return on common is selected as the most appropriate figure on the record. The capital structure and rate of return figures found appropriate and accepted for use in this case are set out in the following table. The resulting cost of capital is 11.60 percent.

Contested Inputs/Assumptions and 20-Year Contract Capacity Price

Summary of Parties' Positions
and Commission Findings

Input/Assumption	Proposing Party					Commission Finding
	UP&L	DPU	UEO	UCIPP	Sunny-side*	
Load Forecast (MW)	UP&L	PSC	UEO	PSC	---	UEO
<u>Assumptions Related to Deferrable Plant</u>						
Capital Cost (\$/kW)	\$1,489	\$1,489	\$1,549	\$1,771	---	\$1,489
O&M Cost mills/kWh	5.79	5.79	7.60	9.86	---	5.79
Energy Credit (mills/kWh)	7.00	5.00	3.50	3.00	3.00	6.00
<u>Assumptions Related to Cost of Capital</u>						
<u>Capital Structure</u>						
Percent Debt	48.70%	48.70%	48.70%	45.00%	---	48.70%
Percent Preferred	5.60%	5.60%	5.60%	10.00%	---	5.60%
Percent Common	45.70%	45.70%	45.70%	45.00%	---	45.70%
<u>Rate of Return (% per year)</u>						
Debt	9.75%	9.75%	9.80%	10.10%	---	9.75%
Preferred	8.13%	8.13%	8.10%	9.40%	---	8.13%
Common	15.00%	14.00%	14.00%	15.00%	---	14.00%
Cost of Capital	12.05%	11.60%	11.62%	12.24%	---	11.60%
Plant Retirement	none	refurb**	retire @ 45 years	refurb**	refurb**	refurb**
Treatment of Kaiser Sunnyside	<u>Committed</u>	---	---	---	<u>Committed</u>	<u>Committed</u>
Indicated Capacity Price (\$ per kW-yr)						
20-Year Contract	\$151	\$177	\$196	\$258	---	\$160***

* Sunnyside expresses general agreement with UEO on most assumptions.

** Refurbishment: 50 percent of Utah Power's AFBC plant new construction cost with associated O&M expense adjustment. UCIPP maintains that refurbishment should be costed at 40 percent of new plant capital cost. This adjustment adds one dollar per kW-yr to the capacity cost figure produced by the model.

*** The Commission computes the 30-year contract capacity price to be \$171 per kW-yr for QF's which qualify for a 30-year contract.

plus accumulated, as yet unused, portions of previous years' limits, at the existing approved capacity price. Any proposed QF contract which would exceed a given year's accumulated cap limit would trigger a recalculation of the avoided capacity cost using the SCA procedure and then-current input assumptions. In this recalculation, the capacity associated with all QF contracts signed to that date, and of the particular project that triggers the recalculation, i.e., of the project whose capacity would exceed the accumulated cap, will be included in the "committed cogeneration" category. Upon recalculation, the project which triggered the recalculation would have the option of accepting the newly calculated QF capacity price offer. If the new price is accepted, it then becomes the new approved price and remains in force until a subsequent recalculation occurs. If it is not accepted, the previous approved price remains in effect for all QF's which do not exceed the accumulated cap. The QF project which triggered the recalculation would, of course, still be ineligible for the previous price, at least until a later year, since its capacity would still exceed the accumulated cap limit in the current year.

This procedure protects against a glut of overpriced QF capacity while permitting the Company and its ratepayers to take advantage of any level of QF capacity which may be forthcoming at capacity prices which meet the test of ratepayer neutrality. The Commission's concern is not to prevent the development of any specific quantity of QF capacity, rather it is to insure that any

of energy is approximately 13 mills per kWh. The Company proposes that this figure be adopted as the QF energy price. UEO proposes that marginal energy cost be estimated as 125% of system average energy cost. The Commission finds that the Company's ability to measure system marginal energy cost is sufficiently reliable and accurate that the expediency of a UEO-type estimate is not justified. Thus, we find that the Company's proposed marginal energy cost figure of 13 mills per kWh is appropriate for use in this case. We further find that in future years, measured actual system marginal energy costs should be the basis for QF energy prices and for energy credit calculation.

2. The Energy Floor and the Balancing Account

The Commission finds that the public interest is served by assuring a reliable revenue stream for QF projects. To achieve this objective, the energy price floor mechanism will be maintained. The floor value will be set at 13 mills per kWh.

The Commission recognizes that if realized marginal energy cost drops below the 13 mills per kWh figure, the floor by itself would impose a subsidy from the ratepayers to the QF's, thereby violating the principle of ratepayer neutrality. To remedy this situation, we find that an interest-bearing energy payment balancing account should be established for each QF with the interest rate being equal to, and changing with, the rate applied to the Company's Energy Balancing Account. This rate is currently nine (9) percent. (Note: This energy payments balancing account is separate from and for a different purpose than the balancing account established in the 1985 Order.)

D. The Floor and the Energy Payments Balancing Account

The minimum energy price, or floor, will be 13 mills per kWh and will remain at this level, unless changed by the Commission, in any year in which measured realized system marginal energy cost is less than the minimum. An interest-bearing energy payments balancing account will be established for each QF and will operate as discussed in Section IV.E.2. Balances in the account will accrue interest at the rate established for the Company's Energy Balancing Account; i.e., at nine (9) percent currently.

E. Annual Limit--The Cap

These QF prices will be available to all new QF's up to a maximum accumulated contracted new QF capacity of 15 MW per year. The QF capacity price will be recalculated, as described in Discussion, Findings and Conclusions above, any time an applicant QF offers capacity which would cause accumulated QF capacity to exceed the accumulated capacity limitation for the year in which that facility would come on line. The triggering facility will face the recalculated capacity price, which will become the standing offer price if it is accepted.

F. Contract Term

The standard QF contract will be for a 20-year term. Any QF developer applying for a longer term contract will be required to meet the renewable resource/fuel cost stability test established in the 1985 Order. A positive showing before the Commission that the project meets the test will be required for approval of any extended term contract.

G. Duration of Order

These provisions will remain in effect until further notice from this Commission. The Commission may institute a proceeding to recalculate prices, and may suspend purchase of new QF capacity at the rates established in this Order at any time, when in its judgment, changing market conditions and the public interest warrant.

H. Close Case No. 80-999-06

With this Order the Commission will close Case No. 80-999-06. Henceforth, all actions concerning cogeneration and small power production will be assigned to separate dockets.

I. Phase II--Redesign of Methodology

The Commission will establish an investigative docket for the purpose of reconsidering methods for calculating avoided cost based capacity and energy prices. A prehearing conference will be called by the Commission for the purposes of identifying parties and scheduling proceedings. It is our intention at this time that the proceeding will begin with a technical conference, chaired by staff. Staff is instructed to prepare and circulate to parties a memorandum introducing the subject.

DATED at Salt Lake City, Utah, this 3rd day of April, 1987.

(SEAL)

Attest:

/s/ Stephen C. Hewlett
Commission Secretary

/s/ Brian T. Stewart, Chairman

/s/ Brent H. Cameron, Commissioner

/s/ James M. Byrne, Commissioner

APPENDIX F

ROYALTIES PROGRAM COMPUTER CODE


```

10 'ROY2.BAS
20 'One-Site Version of Impacts of R&D on Geothermal Royalties
30 '           Meridian Corp.   5 August 1987
40 '
50 '--- INITIALIZE:
60 '
70 DIM ROYS(30)      'DISCOUNTED ROYALTIES, ONE SITE, $
80 'DIM ROYT(30)     'SUM OF DISCOUNTED ROYALTIES, ALL SITES, $
90 DIM POWS(30)      'POWER AT ONE SITE, MW
100 DIM ROYNON(30)   'SUM, ONE SITE, NON-DISCOUNTED
110 '
120 '--- GLOBAL FACTORS -----
130 DISC      = 0.10  'DISCOUNT RATE
140 DISC.OFF  = 3     'OFFSET, 1990 $ TO 1987 $
150 ROYRATE   = 0.10  'ROYALTY RATE
160 TRANS     = 0.00  'TRANSMISSION COST, $/KWH
170 YBASE     = 0     'FIRST YEAR OF ANALYSIS
180 Y.BTWN    = 3     'YEARS BETWEEN PLANTS
190 CAP.FACT  = 0.80  'CAPACITY FACTOR
200 '
210 '--- STATE FACTORS -----
220 PRICEO    = 0.0395 'Avoided Cost, $/KWH, 1990
230 ESC.P     = 0.090  'Escalator on price
240 '
250 '--- SITE FACTORS -----
260 CAPTOT    = 360    ' Capacity of Site, MW
270 ECOSTO    = 0.0753 ' Electricity, NO R&D, $/KWH (1987)
280 ECOST9    = 0.0557 ' Electricity, AFTER ALL R&D, $/KWH (1987)
290 PCOSTO    = 0.0399 ' Plant only, NO R&D, $/KWH (1987)
300 PCOST9    = 0.0317 ' Plant only, AFTER ALL R&D, $/KWH (1987)
310 '
320 '----- MAIN PROGRAM -----
330 RAND$ = "FALSE" : GOSUB 450 : ROYSUM0 = ROYSUM
340 RAND$ = "TRUE"  : GOSUB 450 : ROYSUM1 = ROYSUM
350 DELTA = ROYSUM1 - ROYSUM0
360 PRINT "1987 NET PRESENT VALUE OF ROYALTIES"
370 PRINT "-----"
380 PRINT "WITH R&D      W/O R&D      DIFFERENCE"
390 PRINT
400 PRINT USING "$$#####,. "; ROYSUM1, ROYSUM0, DELTA
410 PRINT: PRINT "INSTALLED MW = "; CAPTOT - CAP.REM
420 END
430 '----- END OF MAIN PROGRAM -----
440 '
450 '-- SUBR: SUMMED DISCOUNTED ROYALTIES FOR ONE SITE
460 '--- START THE RUN FOR ONE SITE -----
470 YEAR = 0
480 Y.NEXT.PLANT = 0 'FIRST POSSIBLE YEAR
490 CAP.REM = CAPTOT 'REMAINING CAPACITY
500 FOR I = 0 TO 20
510   ROYS(I)=0 : ROYNON(I)=0 : POWS(I)=0
520 NEXT I 'ZERO
530 '
540 '
550 DONE$ = "FALSE"

```

```

560 '-----
570 WHILE DONE$ = "FALSE" ' THE LOOP = THE RUN
580 '-----
590 YEAR = Y.NEXT.PLANT 'NOT SOONER THAN THIS
600 IF YEAR > 20 THEN DONE$ = "TRUE" : GOTO 1020
610 '-- TRY TO TRIGGER NEXT PLANT:
620 '---- PLANT COST
630 IF RAND$ = "FALSE" THEN ECOST = ECOST0 : GOTO 660
640 IF YEAR <= 10 THEN ECOST = ECOST9 + ((10-YEAR)/10)*(ECOST0-ECOST9)
650 IF YEAR > 10 THEN ECOST = ECOST9
660 ETOT = ECOST + TRANS ' ADD TRANSMISION COST
670 '---- AVOIDED COST
680 AVCOST = PRICE0 * (1+ESC.P)^YEAR
690 '---- TRIGGER TEST:
700 IF AVCOST < ETOT THEN YEAR = YEAR + 1 : GOTO 600
710 '----- (PLANT WAS NOT TRIGGERED, TRY THE NEXT YEAR)
720 '-- PLANT HAS BEEN TRIGGERED:
730 '---- CAP = PLANT CAPACITY -----
740 IF CAP.REM => 50 THEN CAP = 50 ELSE CAP = CAP.REM
750 CAP.REM = CAP.REM - CAP
760 Y.NEXT.PLANT = YEAR + Y.BTWN 'FOR NEXT PLANT
770 '---- PCOST = COST OF PLANT ONLY:
780 IF RAND$ = "FALSE" THEN PCOST = PCOST0 : GOTO 820
790 IF YEAR <= 10 THEN PCOST = PCOST9 + ((10-YEAR)/10)*(PCOST0-PCOST9)
800 IF YEAR > 10 THEN PCOST = PCOST9
810 '
820 '---- PLACE ROYALTIES OF TRIGGERED PLANT INTO ROYS(Y)
830 FOR YR = YEAR TO 20
840 '---- R = Royalty Rate, $/KWH:
850 AVCOST = PRICE0 * (1+ESC.P)^YR ' Avoided cost in YR
860 R = ROYRATE*(AVCOST - PCOST - TRANS)
870 RMIN = ROYRATE*((AVCOST - TRANS)/3) '1987 Dollars/KWH
880 IF RMIN > R THEN R = RMIN
890 '---- Multiply by KWH/Year to get Royalty in Dollars:
900 ROYL = R * 8760 * CAP.FACT * CAP * 1000 'Dollars
910 D = 1/((1+DISC)^(YR+DISC.OFF)) 'Discount factor
920 ROYD = D * ROYL 'Royalty, discounted
930 '---- Accumulate site totals:
940 ROYNON(YR) = ROYNON(YR) + ROYL 'Non-disc'd royalty
950 ROYS(YR) = ROYS(YR) + ROYD 'Disc'd royalty
960 POWS(YR) = POWS(YR) + CAP 'Cumulative capacity, MW
970 NEXT YR
980 '
990 '-- Other ending points:
1000 IF CAP.REM < 20 THEN DONE$ = "TRUE"
1010 '
1020 WEND '----- End of Main Loop, (DONE$) -----
1030 '
1040 ROYSUM=0 : NON=0 : CAPSUM = 0
1050 FOR I = 0 TO 20
1060 NON = NON + ROYNON(I)
1070 ROYSUM = ROYSUM + ROYS(I)
1080 CAPSUM = CAPSUM + POWS(I)
1090 PRINT USING "## "; I;
1100 PRINT USING "_$#####.. "; ROYNON(I) ; ROYS(I);

```



```
1110 PRINT USING "####" ; POWS(I)
1120 NEXT I
1130 PRINT
1140 '
1150 RETURN
1160 '-- END SUBR: Royalty at one site
```

TABLED RESULTS OF ROYALTY INCOME

	EASTHESA	BEOWAVE	LAKECITY	GLASS MT.	BREI'BUSH	MONO-LONG	STMBTSPRG	DESERTPK	RNDSBURG
NO TRANS. COSTS									
WITH R&D(DISC. 10%)	\$30,706,480	\$23,863,250	\$15,310,890	\$19,149,840	\$0	\$11,706,820	\$41,164,750	\$66,796,330	\$11,015,560
W/O R&D(DISC. 10%)	\$22,865,740	\$21,299,670	\$6,486,632	\$10,972,540	\$0	\$5,978,024	\$36,934,740	\$66,526,560	\$7,296,091
DIFFERENCE	\$7,840,740	\$2,563,580	\$8,824,258	\$8,177,300	\$0	\$5,728,796	\$4,230,010	\$269,770	\$3,719,469

\$0.01/KWH TRANS. CASE									
WITH R&D(DISC. 10%)	\$25,102,710	\$19,675,090	\$11,934,920	\$15,059,160	\$0	\$9,089,490	\$29,543,350	\$49,194,280	\$9,132,841
W/O R&D(DISC. 10%)	\$17,986,020	\$15,422,850	\$4,502,450	\$8,221,180	\$0	\$4,370,129	\$25,931,540	\$43,851,370	\$5,807,249
DIFFERENCE	\$7,116,690	\$4,252,240	\$7,432,470	\$6,837,980	\$0	\$4,719,361	\$3,611,810	\$5,342,910	\$3,325,592

	KLAMATH	COSO	NEWBERRY	DIXIE VAL.	DARROUGH	GEYSERS	RYE PATCH	KYLE
NO TRANS. COSTS								
WITH R&D(DISC. 10%)	\$0	\$12,592,640	\$1,924,963	\$45,431,130	\$331,596	\$11,822,370	\$62,265,790	\$12,793,590
W/O R&D(DISC. 10%)	\$0	\$4,983,395	\$1,520,062	\$40,650,550	\$0	\$6,029,798	\$61,992,490	\$4,767,923
DIFFERENCE	\$0	\$7,609,245	\$404,901	\$4,780,580	\$331,596	\$5,792,572	\$273,300	\$8,025,667

\$0.01/KWH TRANS. CASE								
WITH R&D(DISC. 10%)	\$0	\$9,796,593	\$1,224,667	\$32,704,520	\$0	\$9,181,720	\$46,293,430	\$10,448,190
W/O R&D(DISC. 10%)	\$0	\$4,662,313	\$894,358	\$28,639,790	\$0	\$4,408,658	\$41,318,560	\$3,382,849
DIFFERENCE	\$0	\$5,134,280	\$330,309	\$4,064,730	\$0	\$4,773,062	\$4,974,870	\$7,065,341

TABLED RESULTS OF ROYALTY INCOME

	COVE FORT	STILLWATER	ROOSEVELT	VALE	TOTALS
NO TRANS. COSTS					
WITH R&D(DISC. 10%)	\$17,646,420	\$24,354,910	\$32,549,410	\$553,441	\$441,980,180
W/O R&D(DISC. 10%)	\$13,193,800	\$11,850,070	\$29,023,450	\$0	\$352,371,535
DIFFERENCE	\$4,452,620	\$12,504,840	\$3,525,960	\$553,441	\$89,608,645

\$0.01/KWH TRANS. CASE					
WITH R&D(DISC. 10%)	\$9,421,134	\$19,174,460	\$16,697,100	\$304,872	\$323,978,527
W/O R&D(DISC. 10%)	\$5,413,681	\$8,726,629	\$12,736,480	\$0	\$236,276,106
DIFFERENCE	\$4,007,453	\$10,447,831	\$3,960,620	\$304,872	\$87,702,421

	TOTALS	50% OF TOTAL
BASE CASE	\$89,608,645	\$44,804,323
TRANS. CASE	\$87,702,421	\$43,851,211

APPENDIX G

KGRA ROYALTY RESULTS

KGRA ROYALTY RESULTS

(Detailed Version)

This Appendix contains the results of the royalties program runs. Each run is presented on a separate sheet. The first information is the projected nondiscounted (left column) and discounted (right column) royalty income without R&D benefits for years 0-20 (corresponding to 1990-2010). This is followed by the results incorporating R&D benefits.

RESULTS ASSUMING NO TRANSMISSION COSTS

G-7 / G-8

EAST MESA, CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	1,359,771.	\$	476,591.	50
9	\$	1,607,979.	\$	512,352.	50
10	\$	1,878,526.	\$	544,142.	50
11	\$	4,346,845.	\$	1,144,660.	100
12	\$	4,989,719.	\$	1,194,499.	100
13	\$	5,690,451.	\$	1,238,408.	100
14	\$	9,681,374.	\$	1,915,408.	150
15	\$	10,930,180.	\$	1,965,889.	150
16	\$	12,291,390.	\$	2,009,739.	150
17	\$	18,366,800.	\$	2,730,106.	200
18	\$	20,523,120.	\$	2,773,301.	200
19	\$	22,873,520.	\$	2,809,919.	200
20	\$	31,794,320.	\$	3,550,729.	250

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	1,095,542.	\$	464,617.	50
7	\$	1,304,454.	\$	502,923.	50
8	\$	1,532,168.	\$	537,015.	50
9	\$	3,646,951.	\$	1,162,031.	100
10	\$	4,188,045.	\$	1,213,127.	100
11	\$	4,777,837.	\$	1,258,154.	100
12	\$	8,202,899.	\$	1,963,709.	150
13	\$	9,253,996.	\$	2,013,939.	150
14	\$	10,399,690.	\$	2,057,524.	150
15	\$	15,579,230.	\$	2,802,060.	200
16	\$	17,394,170.	\$	2,844,085.	200
17	\$	19,372,450.	\$	2,879,590.	200
18	\$	26,946,890.	\$	3,641,346.	250
19	\$	29,884,880.	\$	3,671,236.	250
20	\$	33,087,300.	\$	3,695,127.	250

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
----------	---------	------------

\$30,706,480.	\$22,865,740.	\$7,840,740.
---------------	---------------	--------------

INSTALLED MW = 250

Ok

BEOVAWE, NV

RUN				
0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	0.	\$	0.
3	\$	0.	\$	0.
4	\$	0.	\$	0.
5	\$	0.	\$	0.
6	\$	0.	\$	0.
7	\$	0.	\$	0.
8	\$	2,797,836.	\$	980,624.
9	\$	2,992,165.	\$	953,396.
10	\$	3,197,299.	\$	926,143.
11	\$	6,827,677.	\$	1,797,940.
12	\$	7,284,835.	\$	1,743,931.
13	\$	7,767,411.	\$	1,690,415.
14	\$	10,511,560.	\$	2,079,656.
15	\$	11,194,480.	\$	2,013,425.
16	\$	11,915,370.	\$	1,948,257.
17	\$	12,676,340.	\$	1,884,256.
18	\$	13,479,620.	\$	1,821,508.
19	\$	14,327,560.	\$	1,760,083.
20	\$	15,222,650.	\$	1,700,037.

0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	0.	\$	0.
3	\$	0.	\$	0.
4	\$	0.	\$	0.
5	\$	0.	\$	0.
6	\$	0.	\$	0.
7	\$	2,638,270.	\$	1,017,167.
8	\$	2,822,364.	\$	989,221.
9	\$	3,016,693.	\$	961,211.
10	\$	6,454,166.	\$	1,869,542.
11	\$	6,887,245.	\$	1,813,627.
12	\$	7,344,403.	\$	1,758,191.
13	\$	9,943,103.	\$	2,163,909.
14	\$	10,590,050.	\$	2,095,184.
15	\$	11,272,970.	\$	2,027,542.
16	\$	11,993,860.	\$	1,961,091.
17	\$	12,754,830.	\$	1,895,923.
18	\$	13,558,110.	\$	1,832,114.
19	\$	14,406,050.	\$	1,769,725.
20	\$	15,301,140.	\$	1,708,802.

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$23,863,250.	\$21,299,670.	\$2,563,580.

INSTALLED MW = 127

Ok

LAKE CITY - SURPRISE VALLEY, CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	2,182,932.	\$	431,881.	50
15	\$	2,599,203.	\$	467,489.	50
16	\$	3,052,937.	\$	499,179.	50
17	\$	7,095,015.	\$	1,054,629.	100
18	\$	8,173,178.	\$	1,104,446.	100
19	\$	9,348,377.	\$	1,148,410.	100
20	\$	15,944,020.	\$	1,780,598.	150
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	1,405,487.	\$	407,119.	50
11	\$	1,700,383.	\$	447,764.	50
12	\$	2,021,820.	\$	484,007.	50
13	\$	4,744,371.	\$	1,032,513.	100
14	\$	5,508,170.	\$	1,089,762.	100
15	\$	6,340,710.	\$	1,140,432.	100
16	\$	10,872,270.	\$	1,777,702.	150
17	\$	12,355,980.	\$	1,836,637.	150
18	\$	13,973,220.	\$	1,888,209.	150
19	\$	20,981,370.	\$	2,577,475.	200
20	\$	23,543,300.	\$	2,629,271.	200

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$15,310,890.	\$6,486,632.	\$8,824,260.

INSTALLED MW = 200
Ok

GLASS MT., CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	3,178,106.	\$	691,648.	50
14	\$	3,560,005.	\$	704,328.	50
15	\$	3,976,275.	\$	715,168.	50
16	\$	8,860,018.	\$	1,448,683.	100
17	\$	9,849,158.	\$	1,464,014.	100
18	\$	10,927,320.	\$	1,476,615.	100
19	\$	18,153,780.	\$	2,230,118.	150
20	\$	20,075,230.	\$	2,241,964.	150
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	2,306,015.	\$	667,970.	50
11	\$	2,600,911.	\$	684,901.	50
12	\$	2,922,348.	\$	699,587.	50
13	\$	6,545,427.	\$	1,424,475.	100
14	\$	7,309,225.	\$	1,446,091.	100
15	\$	8,141,765.	\$	1,464,368.	100
16	\$	13,573,850.	\$	2,219,433.	150
17	\$	15,057,560.	\$	2,238,210.	150
18	\$	16,674,810.	\$	2,253,276.	150
19	\$	24,583,480.	\$	3,019,980.	200
20	\$	27,145,410.	\$	3,031,548.	200

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$19,149,840.	\$10,972,540.	\$8,177,300.

INSTALLED MW = 200

Ok

BREITENBUSH, OR

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	0.	\$	0.	0
17	\$	0.	\$	0.	0
18	\$	0.	\$	0.	0
19	\$	0.	\$	0.	0
20	\$	0.	\$	0.	0
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	0.	\$	0.	0
17	\$	0.	\$	0.	0
18	\$	0.	\$	0.	0
19	\$	0.	\$	0.	0
20	\$	0.	\$	0.	0

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$0.	\$0.	\$0.

INSTALLED MW = 0
Ok

MONO-LONG VALLEY, CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	3,447,171.	\$	620,004.	50
16	\$	3,900,906.	\$	637,829.	50
17	\$	4,395,476.	\$	653,359.	50
18	\$	9,869,114.	\$	1,333,619.	100
19	\$	11,044,310.	\$	1,356,749.	100
20	\$	12,325,280.	\$	1,376,464.	100

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	2,319,660.	\$	555,308.	50
13	\$	2,670,026.	\$	581,075.	50
14	\$	3,051,925.	\$	603,807.	50
15	\$	6,936,389.	\$	1,247,570.	100
16	\$	7,843,859.	\$	1,282,533.	100
17	\$	8,832,999.	\$	1,312,969.	100
18	\$	14,866,740.	\$	2,008,951.	150
19	\$	16,629,540.	\$	2,042,872.	150
20	\$	18,550,990.	\$	2,071,740.	150

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$11,706,820.	\$5,978,024.	\$5,728,801.

INSTALLED MW = 150
Ok

STEAMBOAT SPRINGS, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	1,332,727.	\$	683,900.	50
5	\$	1,489,237.	\$	694,740.	50
6	\$	1,654,448.	\$	701,648.	50
7	\$	3,657,691.	\$	1,410,198.	100
8	\$	4,025,880.	\$	1,411,046.	100
9	\$	4,414,538.	\$	1,406,607.	100
10	\$	7,237,208.	\$	2,096,361.	150
11	\$	7,886,828.	\$	2,076,848.	150
12	\$	8,572,564.	\$	2,052,203.	150
13	\$	12,395,240.	\$	2,697,565.	200
14	\$	13,414,050.	\$	2,653,899.	200
15	\$	14,489,520.	\$	2,606,067.	200
16	\$	19,530,970.	\$	3,193,469.	250
17	\$	21,028,940.	\$	3,125,818.	250
18	\$	22,610,200.	\$	3,055,328.	250
19	\$	29,135,260.	\$	3,579,147.	300
20	\$	31,249,630.	\$	3,489,900.	300

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	1,191,820.	\$	672,751.	50
4	\$	1,340,086.	\$	687,676.	50
5	\$	1,496,595.	\$	698,173.	50
6	\$	3,330,972.	\$	1,412,657.	100
7	\$	3,679,767.	\$	1,418,709.	100
8	\$	4,047,954.	\$	1,418,783.	100
9	\$	6,665,957.	\$	2,123,979.	150
10	\$	7,281,359.	\$	2,109,150.	150
11	\$	7,930,978.	\$	2,088,474.	150
12	\$	11,498,770.	\$	2,752,713.	200
13	\$	12,463,920.	\$	2,712,511.	200
14	\$	13,482,730.	\$	2,667,486.	200
15	\$	18,205,100.	\$	3,274,347.	250
16	\$	19,624,180.	\$	3,208,709.	250
17	\$	21,122,150.	\$	3,139,671.	250
18	\$	27,249,980.	\$	3,682,303.	300
19	\$	29,252,990.	\$	3,593,611.	300
20	\$	31,367,370.	\$	3,503,048.	300

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
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\$41,164,750.	\$36,934,740.	\$4,230,012.
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INSTALLED MW = 300

Ok

BRADY-HAZEN (DESERT PEAK), NV

RUN

0	\$ 1,345,536.	\$ 1,010,921.	50
1	\$ 1,471,587.	\$ 1,005,113.	50
2	\$ 1,604,645.	\$ 996,358.	50
3	\$ 3,490,203.	\$ 1,970,128.	100
4	\$ 3,786,735.	\$ 1,943,193.	100
5	\$ 4,099,754.	\$ 1,912,565.	100
6	\$ 6,645,266.	\$ 2,818,241.	150
7	\$ 7,168,457.	\$ 2,763,750.	150
8	\$ 7,720,739.	\$ 2,706,072.	150
9	\$11,071,640.	\$ 3,527,764.	200
10	\$11,892,170.	\$ 3,444,738.	200
11	\$12,758,330.	\$ 3,359,667.	200
12	\$17,090,810.	\$ 4,091,403.	250
13	\$18,297,250.	\$ 3,982,014.	250
14	\$19,570,770.	\$ 3,871,971.	250
15	\$25,098,120.	\$ 4,514,116.	300
16	\$26,801,010.	\$ 4,382,177.	300
17	\$28,598,570.	\$ 4,250,994.	300
18	\$35,578,760.	\$ 4,807,777.	350
19	\$37,915,610.	\$ 4,657,778.	350
20	\$40,382,380.	\$ 4,509,829.	350

0	\$ 1,345,536.	\$ 1,010,921.	50
1	\$ 1,471,587.	\$ 1,005,113.	50
2	\$ 1,604,645.	\$ 996,358.	50
3	\$ 3,499,664.	\$ 1,975,469.	100
4	\$ 3,796,196.	\$ 1,948,048.	100
5	\$ 4,109,214.	\$ 1,916,979.	100
6	\$ 6,673,648.	\$ 2,830,278.	150
7	\$ 7,196,839.	\$ 2,774,693.	150
8	\$ 7,749,121.	\$ 2,716,020.	150
9	\$11,128,400.	\$ 3,545,850.	200
10	\$11,948,940.	\$ 3,461,181.	200
11	\$12,815,100.	\$ 3,374,614.	200
12	\$17,179,110.	\$ 4,112,541.	250
13	\$18,385,550.	\$ 4,001,231.	250
14	\$19,659,070.	\$ 3,889,441.	250
15	\$25,217,950.	\$ 4,535,669.	300
16	\$26,920,840.	\$ 4,401,771.	300
17	\$28,718,410.	\$ 4,268,807.	300
18	\$35,730,130.	\$ 4,828,232.	350
19	\$38,066,990.	\$ 4,676,374.	350
20	\$40,533,760.	\$ 4,526,733.	350

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$66,796,330.	\$66,526,560.	\$269,764

INSTALLED MW = 350
Ok

RANDBURG, CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$ 2,599,946.		\$ 565,824.		50
14	\$ 2,981,844.		\$ 589,942.		50
15	\$ 3,398,115.		\$ 611,181.		50
16	\$ 6,471,107.		\$ 1,058,077.		84
17	\$ 7,301,984.		\$ 1,085,393.		84
18	\$ 8,207,641.		\$ 1,109,103.		84
19	\$ 9,194,809.		\$ 1,129,545.		84
20	\$10,270,820.		\$ 1,147,026.		84

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$ 1,973,134.		\$ 571,547.		50
11	\$ 2,268,030.		\$ 597,243.		50
12	\$ 2,589,467.		\$ 619,898.		50
13	\$ 4,938,921.		\$ 1,074,853.		84
14	\$ 5,580,511.		\$ 1,104,074.		84
15	\$ 6,279,845.		\$ 1,129,485.		84
16	\$ 7,042,119.		\$ 1,151,442.		84
17	\$ 7,872,997.		\$ 1,170,270.		84
18	\$ 8,778,653.		\$ 1,186,264.		84
19	\$ 9,765,820.		\$ 1,199,691.		84
20	\$10,841,830.		\$ 1,210,796.		84

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$11,015,560.	\$7,296,091.	\$3,719,472.

INSTALLED MW = 84
Ok

KLAMATH FALLS, OR

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	00
2	\$	0.	\$	0.	00
3	\$	0.	\$	0.	00
4	\$	0.	\$	0.	00
5	\$	0.	\$	0.	00
6	\$	0.	\$	0.	00
7	\$	0.	\$	0.	00
8	\$	0.	\$	0.	00
9	\$	0.	\$	0.	00
10	\$	0.	\$	0.	00
11	\$	0.	\$	0.	00
12	\$	0.	\$	0.	00
13	\$	0.	\$	0.	00
14	\$	0.	\$	0.	00
15	\$	0.	\$	0.	00
16	\$	0.	\$	0.	00
17	\$	0.	\$	0.	00
18	\$	0.	\$	0.	00
19	\$	0.	\$	0.	00
20	\$	0.	\$	0.	0
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	00
2	\$	0.	\$	0.	00
3	\$	0.	\$	0.	00
4	\$	0.	\$	0.	00
5	\$	0.	\$	0.	00
6	\$	0.	\$	0.	00
7	\$	0.	\$	0.	00
8	\$	0.	\$	0.	00
9	\$	0.	\$	0.	00
10	\$	0.	\$	0.	00
11	\$	0.	\$	0.	00
12	\$	0.	\$	0.	00
13	\$	0.	\$	0.	00
14	\$	0.	\$	0.	00
15	\$	0.	\$	0.	00
16	\$	0.	\$	0.	00
17	\$	0.	\$	0.	00
18	\$	0.	\$	0.	00
19	\$	0.	\$	0.	00
20	\$	0.	\$	0.	0

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
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\$0.

\$0.

\$0.

INSTALLED MW = 0

Ok

COSO, CA

RUN				
0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	0.	\$	0.
3	\$	0.	\$	0.
4	\$	0.	\$	0.
5	\$	0.	\$	0.
6	\$	0.	\$	0.
7	\$	0.	\$	0.
8	\$	0.	\$	0.
9	\$	0.	\$	0.
10	\$	0.	\$	0.
11	\$	0.	\$	0.
12	\$	0.	\$	0.
13	\$	0.	\$	0.
14	\$	0.	\$	0.
15	\$	0.	\$	0.
16	\$ 4,219,770.	\$	689,966.	50
17	\$ 4,714,340.	\$	700,756.	50
18	\$ 5,253,421.	\$	709,898.	50
19	\$11,682,040.	\$	1,435,091.	100
20	\$12,963,010.	\$	1,447,684.	100

0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	0.	\$	0.
3	\$	0.	\$	0.
4	\$	0.	\$	0.
5	\$	0.	\$	0.
6	\$	0.	\$	0.
7	\$	0.	\$	0.
8	\$	0.	\$	0.
9	\$	0.	\$	0.
10	\$	0.	\$	0.
11	\$	0.	\$	0.
12	\$ 2,642,028.	\$	632,480.	50
13	\$ 2,992,394.	\$	651,232.	50
14	\$ 3,374,293.	\$	667,586.	50
15	\$ 7,581,126.	\$	1,363,532.	100
16	\$ 8,488,595.	\$	1,387,953.	100
17	\$ 9,477,735.	\$	1,408,805.	100
18	\$15,833,850.	\$	2,139,636.	150
19	\$17,596,650.	\$	2,161,677.	150
20	\$19,518,090.	\$	2,179,744.	150

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$12,592,640.	\$4,983,395.	\$7,609,247.

INSTALLED MW = 150
Ok

NEWBERRY CALDERA, OR

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	1,089,226.	\$	178,097.	50
17	\$	1,319,411.	\$	196,122.	50
18	\$	1,571,234.	\$	212,322.	50
19	\$	3,693,455.	\$	453,726.	100
20	\$	4,296,236.	\$	479,796.	100
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	906,851.	\$	163,105.	50
16	\$	1,117,258.	\$	182,681.	50
17	\$	1,347,443.	\$	200,289.	50
18	\$	3,198,532.	\$	432,219.	100
19	\$	3,749,519.	\$	460,613.	100
20	\$	4,352,300.	\$	486,057.	100

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$1,924,963.	\$1,520,062.	\$404,901.

INSTALLED MW = 100
Ok

DIXIE VALLEY, NV

RUN				
0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	0.	\$	0.
3	\$	0.	\$	0.
4	\$	1,644,584.	\$	843,931.
5	\$	1,801,093.	\$	840,223.
6	\$	1,966,305.	\$	833,905.
7	\$	4,281,404.	\$	1,650,666.
8	\$	4,649,591.	\$	1,629,653.
9	\$	5,038,250.	\$	1,605,341.
10	\$	8,172,777.	\$	2,367,362.
11	\$	8,822,395.	\$	2,323,212.
12	\$	9,508,133.	\$	2,276,171.
13	\$	13,642,660.	\$	2,969,040.
14	\$	14,661,480.	\$	2,900,695.
15	\$	15,736,940.	\$	2,830,427.
16	\$	21,090,250.	\$	3,448,423.
17	\$	22,588,220.	\$	3,357,594.
18	\$	24,169,480.	\$	3,266,035.
19	\$	31,006,390.	\$	3,809,009.
20	\$	33,120,770.	\$	3,698,865.

0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	0.	\$	0.
3	\$	1,502,625.	\$	848,192.
4	\$	1,650,891.	\$	847,168.
5	\$	1,807,400.	\$	843,165.
6	\$	3,951,530.	\$	1,675,835.
7	\$	4,300,325.	\$	1,657,961.
8	\$	4,668,513.	\$	1,636,285.
9	\$	7,595,218.	\$	2,420,070.
10	\$	8,210,620.	\$	2,378,324.
11	\$	8,860,240.	\$	2,333,178.
12	\$	12,736,380.	\$	3,048,987.
13	\$	13,701,530.	\$	2,981,852.
14	\$	14,720,340.	\$	2,912,341.
15	\$	19,751,070.	\$	3,552,402.
16	\$	21,170,140.	\$	3,461,486.
17	\$	22,668,110.	\$	3,369,469.
18	\$	29,104,290.	\$	3,932,878.
19	\$	31,107,310.	\$	3,821,406.
20	\$	33,221,680.	\$	3,710,135.

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$45,431,130.	\$40,650,550.	\$4,780,584.

INSTALLED MW = 300
Ok

DARROUGH HOT SPRINGS: WARM SPRINGS, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	0.	\$	0.	0
17	\$	0.	\$	0.	0
18	\$	0.	\$	0.	0
19	\$	0.	\$	0.	0
20	\$	0.	\$	0.	0
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	0.	\$	0.	0
17	\$	0.	\$	0.	0
18	\$	0.	\$	0.	0
19	\$	0.	\$	0.	0
20	\$ 2,969,216.	\$	331,596.	50	

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$331,596.	\$0.	\$331,596.

INSTALLED MW = 50
Ok

RYE PATCH, NV

RUN				
0	\$	0.	\$	0.
1	\$	1,629,266.	\$	1,112,811.
2	\$	1,762,325.	\$	1,094,265.
3	\$	1,902,781.	\$	1,074,070.
4	\$	4,102,094.	\$	2,105,023.
5	\$	4,415,114.	\$	2,059,683.
6	\$	4,745,536.	\$	2,012,570.
7	\$	7,641,497.	\$	2,946,127.
8	\$	8,193,779.	\$	2,871,869.
9	\$	8,776,766.	\$	2,796,548.
10	\$	12,522,890.	\$	3,627,435.
11	\$	13,389,050.	\$	3,525,755.
12	\$	14,303,370.	\$	3,424,111.
13	\$	19,085,650.	\$	4,153,593.
14	\$	20,359,170.	\$	4,027,952.
15	\$	21,703,500.	\$	3,903,564.
16	\$	27,747,090.	\$	4,536,869.
17	\$	29,544,650.	\$	4,391,623.
18	\$	31,442,160.	\$	4,248,796.
19	\$	33,445,180.	\$	4,108,604.
20	\$	35,559,550.	\$	3,971,224.

0	\$	0.	\$	0.	0
1	\$	1,632,420.	\$	1,114,965.	50
2	\$	1,765,478.	\$	1,096,223.	50
3	\$	1,905,935.	\$	1,075,851.	50
4	\$	4,117,863.	\$	2,113,114.	100
5	\$	4,430,882.	\$	2,067,039.	100
6	\$	4,761,305.	\$	2,019,258.	100
7	\$	7,679,340.	\$	2,960,718.	150
8	\$	8,231,622.	\$	2,885,133.	150
9	\$	8,814,610.	\$	2,808,606.	150
10	\$	12,592,270.	\$	3,647,532.	200
11	\$	13,458,430.	\$	3,544,024.	200
12	\$	14,372,750.	\$	3,440,721.	200
13	\$	19,186,560.	\$	4,175,554.	250
14	\$	20,460,080.	\$	4,047,917.	250
15	\$	21,804,410.	\$	3,921,714.	250
16	\$	27,879,540.	\$	4,558,525.	300
17	\$	29,677,100.	\$	4,411,311.	300
18	\$	31,574,610.	\$	4,266,694.	300
19	\$	33,577,630.	\$	4,124,874.	300
20	\$	35,692,010.	\$	3,986,016.	300

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$62,265,790.	\$61,992,490.	\$273,300.

INSTALLED MW = 300
Ok

KYLE HOT SPRINGS, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	3,110,796.	\$	559,504.	50
16	\$	3,394,610.	\$	555,046.	50
17	\$	3,694,204.	\$	549,120.	50
18	\$	7,780,285.	\$	1,051,354.	97
19	\$	8,427,925.	\$	1,035,336.	97
20	\$	9,111,574.	\$	1,017,563.	97
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	2,083,578.	\$	663,892.	50
10	\$	2,288,712.	\$	662,958.	50
11	\$	2,505,252.	\$	659,711.	50
12	\$	5,344,145.	\$	1,279,345.	97
13	\$	5,812,244.	\$	1,264,913.	97
14	\$	6,306,368.	\$	1,247,681.	97
15	\$	6,827,968.	\$	1,228,070.	97
16	\$	7,378,569.	\$	1,206,455.	97
17	\$	7,959,782.	\$	1,183,171.	97
18	\$	8,573,310.	\$	1,158,516.	97
19	\$	9,220,950.	\$	1,132,756.	97
20	\$	9,904,600.	\$	1,106,127.	97

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$12,793,590.	\$4,767,923.	\$8,025,672.

INSTALLED MW = 97

Ok

COVE FORT - SULPHURDALE, UT

RUN				
0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	0.	\$	0.
3	\$	0.	\$	0.
4	\$	0.	\$	0.
5	\$	0.	\$	0.
6	\$	0.	\$	0.
7	\$	0.	\$	0.
8	\$	1,481,497.	\$	519,256.
9	\$	1,565,706.	\$	498,882.
10	\$	1,653,282.	\$	478,897.
11	\$	3,488,724.	\$	918,690.
12	\$	3,678,170.	\$	880,524.
13	\$	3,875,193.	\$	843,355.
14	\$	6,120,148.	\$	1,210,838.
15	\$	6,439,798.	\$	1,158,254.
16	\$	6,772,235.	\$	1,107,314.
17	\$	9,490,627.	\$	1,410,721.
18	\$	9,970,043.	\$	1,347,257.
19	\$	10,468,640.	\$	1,286,030.
20	\$	13,733,970.	\$	1,533,784.

0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	0.	\$	0.
3	\$	0.	\$	0.
4	\$	0.	\$	0.
5	\$	0.	\$	0.
6	\$	1,331,082.	\$	564,509.
7	\$	1,408,937.	\$	543,206.
8	\$	1,489,907.	\$	522,203.
9	\$	3,152,435.	\$	1,004,463.
10	\$	3,327,589.	\$	963,884.
11	\$	3,509,748.	\$	924,226.
12	\$	5,552,295.	\$	1,329,175.
13	\$	5,847,830.	\$	1,272,658.
14	\$	6,155,187.	\$	1,217,771.
15	\$	8,635,453.	\$	1,553,162.
16	\$	9,078,703.	\$	1,484,440.
17	\$	9,539,681.	\$	1,418,012.
18	\$	12,525,630.	\$	1,692,595.
19	\$	13,148,870.	\$	1,615,285.
20	\$	13,797,050.	\$	1,540,828.

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$17,646,420.	\$13,193,800.	\$4,452,615.

INSTALLED MW = 250
Ok

STILLWATER-SODA LAKE, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	2,071,807.	\$	545,571.	50
12	\$	2,300,386.	\$	550,694.	50
13	\$	2,541,674.	\$	553,142.	50
14	\$	5,592,754.	\$	1,106,496.	100
15	\$	6,130,487.	\$	1,102,622.	100
16	\$	6,698,116.	\$	1,095,195.	100
17	\$	10,945,960.	\$	1,627,046.	150
18	\$	11,894,710.	\$	1,607,339.	150
19	\$	12,896,220.	\$	1,584,248.	150
20	\$	18,604,540.	\$	2,077,720.	200

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	1,580,763.	\$	609,452.	50
8	\$	1,764,856.	\$	618,571.	50
9	\$	1,959,186.	\$	624,257.	50
10	\$	4,461,090.	\$	1,292,219.	100
11	\$	4,894,170.	\$	1,288,788.	100
12	\$	5,351,328.	\$	1,281,065.	100
13	\$	8,817,082.	\$	1,918,854.	150
14	\$	9,581,192.	\$	1,895,587.	150
15	\$	10,387,790.	\$	1,868,335.	150
16	\$	15,029,800.	\$	2,457,491.	200
17	\$	16,228,170.	\$	2,412,214.	200
18	\$	17,493,180.	\$	2,363,863.	200
19	\$	23,568,770.	\$	2,895,327.	250
20	\$	25,330,750.	\$	2,828,890.	250

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
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\$24,354,910.	\$11,850,070.	\$12,504,840.
---------------	---------------	---------------

INSTALLED MW = 250

Ok

system

system

ROOSEVELT HS, UT

RUN				
0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	1,040,066.	\$	645,799.
3	\$	1,106,617.	\$	624,656.
4	\$	1,175,830.	\$	603,387.
5	\$	2,495,623.	\$	1,164,227.
6	\$	2,645,345.	\$	1,121,885.
7	\$	2,801,056.	\$	1,079,928.
8	\$	4,444,492.	\$	1,557,767.
9	\$	4,697,117.	\$	1,496,646.
10	\$	4,959,847.	\$	1,436,691.
11	\$	6,977,447.	\$	1,837,380.
12	\$	7,356,340.	\$	1,761,049.
13	\$	7,750,387.	\$	1,686,710.
14	\$	10,200,250.	\$	2,018,064.
15	\$	10,733,000.	\$	1,930,423.
16	\$	11,287,060.	\$	1,845,524.
17	\$	14,235,940.	\$	2,116,081.
18	\$	14,955,070.	\$	2,020,886.
19	\$	15,702,960.	\$	1,929,044.
20	\$	19,227,560.	\$	2,147,298.

0	\$	0.	\$	0.
1	\$	977,476.	\$	667,629.
2	\$	1,041,467.	\$	646,669.
3	\$	1,108,018.	\$	625,447.
4	\$	2,358,668.	\$	1,210,369.
5	\$	2,502,631.	\$	1,167,496.
6	\$	2,652,353.	\$	1,124,857.
7	\$	4,218,403.	\$	1,626,377.
8	\$	4,461,311.	\$	1,563,662.
9	\$	4,713,936.	\$	1,502,005.
10	\$	6,643,965.	\$	1,924,519.
11	\$	7,008,282.	\$	1,845,499.
12	\$	7,387,175.	\$	1,768,431.
13	\$	9,732,834.	\$	2,118,148.
14	\$	10,245,100.	\$	2,026,937.
15	\$	10,777,850.	\$	1,938,490.
16	\$	13,603,340.	\$	2,224,254.
17	\$	14,294,800.	\$	2,124,831.
18	\$	15,013,930.	\$	2,028,841.
19	\$	18,393,000.	\$	2,259,506.
20	\$	19,300,450.	\$	2,155,438.

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$32,549,410.	\$29,023,450.	\$3,525,960.

INSTALLED MW = 350

Ok

VALE, OR

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	00
2	\$	0.	\$	0.	00
3	\$	0.	\$	0.	00
4	\$	0.	\$	0.	00
5	\$	0.	\$	0.	00
6	\$	0.	\$	0.	00
7	\$	0.	\$	0.	00
8	\$	0.	\$	0.	00
9	\$	0.	\$	0.	00
10	\$	0.	\$	0.	00
11	\$	0.	\$	0.	00
12	\$	0.	\$	0.	00
13	\$	0.	\$	0.	00
14	\$	0.	\$	0.	00
15	\$	0.	\$	0.	00
16	\$	0.	\$	0.	00
17	\$	0.	\$	0.	00
18	\$	0.	\$	0.	00
19	\$	0.	\$	0.	00
20	\$	0.	\$	0.	0
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	00
2	\$	0.	\$	0.	00
3	\$	0.	\$	0.	00
4	\$	0.	\$	0.	00
5	\$	0.	\$	0.	00
6	\$	0.	\$	0.	00
7	\$	0.	\$	0.	00
8	\$	0.	\$	0.	00
9	\$	0.	\$	0.	00
10	\$	0.	\$	0.	00
11	\$	0.	\$	0.	00
12	\$	0.	\$	0.	00
13	\$	0.	\$	0.	00
14	\$	0.	\$	0.	00
15	\$	0.	\$	0.	00
16	\$	0.	\$	0.	00
17	\$	0.	\$	0.	0
18	\$ 1,231,346.	\$	166,392.		50
19	\$ 1,506,840.	\$	185,109.		50
20	\$ 1,808,230.	\$	201,940.		50

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$553,441.	\$0.	\$553,441.

INSTALLED MW = 50
Ok

RESULTS ASSUMING \$0.01/KW-HR TRANSMISSTION COSTS

EAST MESA, CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	1,257,579.	\$	400,703.	50
10	\$	1,528,126.	\$	442,644.	50
11	\$	1,823,022.	\$	480,059.	50
12	\$	4,288,919.	\$	1,026,733.	100
13	\$	4,989,652.	\$	1,085,893.	100
14	\$	5,753,449.	\$	1,138,289.	100
15	\$	9,878,984.	\$	1,776,822.	150
16	\$	11,240,190.	\$	1,837,860.	150
17	\$	12,723,900.	\$	1,891,326.	150
18	\$	19,121,520.	\$	2,583,902.	200
19	\$	21,471,920.	\$	2,637,738.	200
20	\$	24,033,860.	\$	2,684,056.	200

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	982,787.	\$	378,907.	50
8	\$	1,210,501.	\$	424,273.	50
9	\$	1,458,709.	\$	464,790.	50
10	\$	3,544,711.	\$	1,026,776.	100
11	\$	4,134,502.	\$	1,088,744.	100
12	\$	4,777,377.	\$	1,143,666.	100
13	\$	8,260,263.	\$	1,797,673.	150
14	\$	9,405,958.	\$	1,860,918.	150
15	\$	10,654,770.	\$	1,916,354.	150
16	\$	16,050,030.	\$	2,624,307.	200
17	\$	18,028,310.	\$	2,679,793.	200
18	\$	20,184,630.	\$	2,727,561.	200
19	\$	28,190,340.	\$	3,463,069.	250
20	\$	31,392,760.	\$	3,505,885.	250

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
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\$25,102,710.	\$17,986,020.	\$7,116,688.
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INSTALLED MW = 250

Ok

BEOWAWE, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$ 2,846,899.		\$ 824,645.		50
11	\$ 3,063,439.		\$ 806,699.		50
12	\$ 3,292,017.		\$ 788,083.		50
13	\$ 7,066,612.		\$ 1,537,900.		100
14	\$ 7,576,019.		\$ 1,498,875.		100
15	\$ 8,113,751.		\$ 1,459,329.		100
16	\$11,025,350.		\$ 1,802,733.		127
17	\$11,786,320.		\$ 1,751,961.		127
18	\$12,589,600.		\$ 1,701,240.		127
19	\$13,437,540.		\$ 1,650,748.		127
20	\$14,332,630.		\$ 1,600,641.		127

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$ 2,475,468.		\$ 867,636.		50
9	\$ 2,669,797.		\$ 850,679.		50
10	\$ 2,874,931.		\$ 832,765.		50
11	\$ 6,189,950.		\$ 1,630,007.		100
12	\$ 6,647,107.		\$ 1,591,264.		100
13	\$ 7,129,684.		\$ 1,551,627.		100
14	\$ 9,703,537.		\$ 1,919,793.		127
15	\$10,386,460.		\$ 1,868,095.		127
16	\$11,107,350.		\$ 1,816,139.		127
17	\$11,868,320.		\$ 1,764,149.		127
18	\$12,671,600.		\$ 1,712,319.		127
19	\$13,519,540.		\$ 1,660,820.		127
20	\$14,414,620.		\$ 1,609,798.		127

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
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\$19,675,090.	\$15,422,850.	\$4,252,237.
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INSTALLED MW = 127

Ok

LAKE CITY - SURPRISE VALLEY, CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	2,248,803.	\$	404,467.	50
16	\$	2,702,538.	\$	441,886.	50
17	\$	3,197,108.	\$	475,230.	50
18	\$	7,472,378.	\$	1,009,746.	100
19	\$	8,647,577.	\$	1,062,320.	100
20	\$	9,928,544.	\$	1,108,801.	100

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	1,349,982.	\$	355,492.	50
12	\$	1,671,420.	\$	400,124.	50
13	\$	2,021,786.	\$	439,999.	50
14	\$	4,807,369.	\$	951,112.	100
15	\$	5,639,910.	\$	1,014,387.	100
16	\$	6,547,380.	\$	1,070,549.	100
17	\$	11,304,780.	\$	1,680,383.	150
18	\$	12,922,020.	\$	1,746,160.	150
19	\$	14,684,820.	\$	1,803,971.	150
20	\$	22,141,700.	\$	2,472,743.	200

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$11,934,920.	\$4,502,450.	\$7,432,472.

INSTALLED MW = 200
Ok

GLASS MT., CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	3,209,605.	\$	635,003.	50
15	\$	3,625,875.	\$	652,145.	50
16	\$	4,079,610.	\$	667,049.	50
17	\$	9,148,358.	\$	1,359,845.	100
18	\$	10,226,520.	\$	1,381,915.	100
19	\$	11,401,720.	\$	1,400,655.	100
20	\$	19,024,030.	\$	2,124,568.	150

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	2,250,511.	\$	592,630.	50
12	\$	2,571,948.	\$	615,704.	50
13	\$	2,922,314.	\$	635,980.	50
14	\$	6,608,425.	\$	1,307,441.	100
15	\$	7,440,966.	\$	1,338,323.	100
16	\$	8,348,435.	\$	1,365,035.	100
17	\$	14,006,360.	\$	2,081,956.	150
18	\$	15,623,610.	\$	2,111,226.	150
19	\$	17,386,400.	\$	2,135,849.	150
20	\$	25,743,810.	\$	2,875,020.	200

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
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\$15,059,160.	\$8,221,180.	\$6,837,985.
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INSTALLED MW = 200

Ok

MONO-LONG VALLEY, CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	3,550,506.	\$	580,536.	50
17	\$	4,045,076.	\$	601,275.	50
18	\$	4,584,157.	\$	619,460.	50
19	\$	10,343,510.	\$	1,270,659.	100
20	\$	11,624,480.	\$	1,298,200.	100

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	2,319,626.	\$	504,818.	50
14	\$	2,701,525.	\$	534,482.	50
15	\$	3,117,795.	\$	560,763.	50
16	\$	7,143,059.	\$	1,167,947.	100
17	\$	8,132,199.	\$	1,208,799.	100
18	\$	9,210,362.	\$	1,244,601.	100
19	\$	15,578,340.	\$	1,913,736.	150
20	\$	17,499,790.	\$	1,954,344.	150

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
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\$9,089,490.	\$4,370,129.	\$4,719,362.
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INSTALLED MW = 150

Ok

STEAMBOAT SPRINGS, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	1,304,048.	\$	553,044.	50
7	\$	1,478,446.	\$	570,005.	50
8	\$	1,662,540.	\$	582,710.	50
9	\$	3,713,738.	\$	1,183,311.	100
10	\$	4,124,006.	\$	1,194,577.	100
11	\$	4,557,086.	\$	1,200,023.	100
12	\$	7,521,365.	\$	1,800,555.	150
13	\$	8,245,229.	\$	1,794,402.	150
14	\$	9,009,340.	\$	1,782,450.	150
15	\$	13,087,920.	\$	2,353,977.	200
16	\$	14,223,180.	\$	2,325,602.	200
17	\$	15,421,550.	\$	2,292,315.	200
18	\$	20,858,200.	\$	2,818,580.	250
19	\$	22,527,380.	\$	2,767,396.	250
20	\$	24,289,360.	\$	2,712,590.	250

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	1,151,101.	\$	536,997.	50
6	\$	1,316,312.	\$	558,245.	50
7	\$	1,490,710.	\$	574,733.	50
8	\$	3,356,966.	\$	1,176,596.	100
9	\$	3,745,624.	\$	1,193,471.	100
10	\$	4,155,893.	\$	1,203,814.	100
11	\$	6,892,042.	\$	1,814,890.	150
12	\$	7,577,780.	\$	1,814,060.	150
13	\$	8,301,644.	\$	1,806,679.	150
14	\$	12,093,400.	\$	2,392,613.	200
15	\$	13,168,860.	\$	2,368,534.	200
16	\$	14,304,120.	\$	2,338,837.	200
17	\$	19,382,410.	\$	2,881,071.	250
18	\$	20,963,670.	\$	2,832,832.	250
19	\$	22,632,850.	\$	2,780,353.	250
20	\$	29,277,230.	\$	3,269,626.	300

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$29,543,350.	\$25,931,540.	\$3,611,818.

INSTALLED MW = 300

Ok

BRADY-HAZEN (DESERT PEAK), NV

RUN				
0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	0.	\$	0.
3	\$	1,394,702.	\$	787,273.
4	\$	1,542,967.	\$	791,786.
5	\$	1,699,477.	\$	792,819.
6	\$	3,729,377.	\$	1,581,620.
7	\$	4,078,172.	\$	1,572,311.
8	\$	4,446,360.	\$	1,558,422.
9	\$	7,252,527.	\$	2,310,878.
10	\$	7,867,928.	\$	2,279,058.
11	\$	8,517,548.	\$	2,242,936.
12	\$	12,271,050.	\$	2,937,591.
13	\$	13,236,200.	\$	2,880,582.
14	\$	14,255,010.	\$	2,820,278.
15	\$	19,163,100.	\$	3,446,651.
16	\$	20,582,170.	\$	3,365,348.
17	\$	22,080,140.	\$	3,282,071.
18	\$	28,393,680.	\$	3,836,853.
19	\$	30,396,700.	\$	3,734,110.
20	\$	32,511,070.	\$	3,630,775.

0	\$	0.	\$	0.
1	\$	0.	\$	0.
2	\$	1,260,552.	\$	782,704.
3	\$	1,401,009.	\$	790,833.
4	\$	1,549,274.	\$	795,023.
5	\$	3,421,029.	\$	1,595,935.
6	\$	3,751,452.	\$	1,590,982.
7	\$	4,100,247.	\$	1,580,822.
8	\$	6,716,843.	\$	2,354,212.
9	\$	7,299,831.	\$	2,325,951.
10	\$	7,915,233.	\$	2,292,761.
11	\$	11,435,570.	\$	3,011,342.
12	\$	12,349,890.	\$	2,956,464.
13	\$	13,315,040.	\$	2,897,740.
14	\$	17,929,140.	\$	3,547,185.
15	\$	19,273,470.	\$	3,466,503.
16	\$	20,692,550.	\$	3,383,395.
17	\$	26,638,080.	\$	3,959,580.
18	\$	28,535,590.	\$	3,856,030.
19	\$	30,538,610.	\$	3,751,543.
20	\$	38,103,030.	\$	4,255,275.

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$49,194,280.	\$43,851,370.	\$5,342,916.

INSTALLED MW = 350
Ok

RANDBURG, CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	2,631,444.	\$	520,617.	50
15	\$	3,047,715.	\$	548,158.	50
16	\$	3,501,449.	\$	572,515.	50
17	\$	6,713,313.	\$	997,891.	84
18	\$	7,618,969.	\$	1,029,555.	84
19	\$	8,606,136.	\$	1,057,229.	84
20	\$	9,682,150.	\$	1,081,284.	84

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	1,917,630.	\$	504,972.	50
12	\$	2,239,068.	\$	536,015.	50
13	\$	2,589,434.	\$	563,536.	50
14	\$	4,991,838.	\$	987,608.	84
15	\$	5,691,172.	\$	1,023,607.	84
16	\$	6,453,447.	\$	1,055,190.	84
17	\$	7,284,324.	\$	1,082,768.	84
18	\$	8,189,980.	\$	1,106,716.	84
19	\$	9,177,148.	\$	1,127,375.	84
20	\$	10,253,160.	\$	1,145,054.	84

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
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\$9,132,841.	\$5,807,249.	\$3,325,592.
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INSTALLED MW = 84

Ok

COSO, CA

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	3,869,369.	\$	632,673.	50
17	\$	4,363,940.	\$	648,672.	50
18	\$	4,903,021.	\$	662,548.	50
19	\$	10,981,240.	\$	1,349,001.	100
20	\$	12,262,210.	\$	1,369,420.	100

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	2,641,994.	\$	574,975.	50
14	\$	3,023,893.	\$	598,261.	50
15	\$	3,440,163.	\$	618,743.	50
16	\$	7,787,796.	\$	1,273,366.	100
17	\$	8,776,934.	\$	1,304,635.	100
18	\$	9,855,098.	\$	1,331,725.	100
19	\$	16,545,440.	\$	2,032,541.	150
20	\$	18,466,900.	\$	2,062,348.	150

1987 NET PRESENT VALUE OF ROYALTIES

 WITH R&D W/O R&D DIFFERENCE

\$9,796,593. \$4,662,313. \$5,134,280.

INSTALLED MW = 150

Ok

NEWBERRY CALDERA, OR

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	0.	\$	0.	0
17	\$	969,011.	\$	144,037.	50
18	\$	1,220,834.	\$	164,972.	50
19	\$	1,496,328.	\$	183,818.	50
20	\$	3,595,435.	\$	401,531.	100

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	766,858.	\$	125,387.	50
17	\$	997,043.	\$	148,204.	50
18	\$	1,248,866.	\$	168,760.	50
19	\$	3,048,719.	\$	374,523.	100
20	\$	3,651,499.	\$	407,793.	100

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$1,224,667.	\$894,358.	\$330,308.

INSTALLED MW = 100
Ok

DIXIE VALLEY, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	1,615,904.	\$	685,301.	50
7	\$	1,790,302.	\$	690,239.	50
8	\$	1,974,396.	\$	692,014.	50
9	\$	4,337,450.	\$	1,382,045.	100
10	\$	4,747,718.	\$	1,375,245.	100
11	\$	5,180,798.	\$	1,364,266.	100
12	\$	8,456,933.	\$	2,024,522.	150
13	\$	9,180,798.	\$	1,998,009.	150
14	\$	9,944,909.	\$	1,967,547.	150
15	\$	14,335,340.	\$	2,578,337.	200
16	\$	15,470,600.	\$	2,529,566.	200
17	\$	16,668,980.	\$	2,477,736.	200
18	\$	22,417,480.	\$	3,029,286.	250
19	\$	24,086,660.	\$	2,958,948.	250
20	\$	25,848,640.	\$	2,886,727.	250

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	1,461,205.	\$	681,663.	50
6	\$	1,626,416.	\$	689,759.	50
7	\$	1,800,814.	\$	694,292.	50
8	\$	3,976,123.	\$	1,393,607.	100
9	\$	4,364,782.	\$	1,390,754.	100
10	\$	4,775,049.	\$	1,383,161.	100
11	\$	7,819,551.	\$	2,059,132.	150
12	\$	8,505,289.	\$	2,036,098.	150
13	\$	9,229,152.	\$	2,008,532.	150
14	\$	13,329,260.	\$	2,637,122.	200
15	\$	14,404,720.	\$	2,590,815.	200
16	\$	15,539,980.	\$	2,540,910.	200
17	\$	20,926,620.	\$	3,110,608.	250
18	\$	22,507,880.	\$	3,041,502.	250
19	\$	24,177,060.	\$	2,970,054.	250
20	\$	31,129,790.	\$	3,476,516.	300

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
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\$32,704,520.	\$28,639,790.	\$4,064,736.
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INSTALLED MW = 300

Ok

DARROUGH HOT SPRINGS; WARM SPRINGS, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	0.	\$	0.	0
17	\$	0.	\$	0.	0
18	\$	0.	\$	0.	0
19	\$	0.	\$	0.	0
20	\$	0.	\$	0.	0
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	0.	\$	0.	0
17	\$	0.	\$	0.	0
18	\$	0.	\$	0.	0
19	\$	0.	\$	0.	0
20	\$	0.	\$	0.	0

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$0.	\$0.	\$0.

INSTALLED MW = 0
Ok

RYE PATCH, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	1,700,647.	\$	872,701.	50
5	\$	1,857,157.	\$	866,377.	50
6	\$	2,022,368.	\$	857,682.	50
7	\$	4,393,531.	\$	1,693,896.	100
8	\$	4,761,719.	\$	1,668,953.	100
9	\$	5,150,378.	\$	1,641,069.	100
10	\$	8,340,968.	\$	2,416,081.	150
11	\$	8,990,588.	\$	2,367,503.	150
12	\$	9,676,324.	\$	2,316,435.	150
13	\$	13,866,920.	\$	3,017,845.	200
14	\$	14,885,730.	\$	2,945,062.	200
15	\$	15,961,200.	\$	2,870,761.	200
16	\$	21,370,570.	\$	3,494,258.	250
17	\$	22,868,540.	\$	3,399,262.	250
18	\$	24,449,800.	\$	3,303,915.	250
19	\$	31,342,780.	\$	3,850,332.	300
20	\$	33,457,150.	\$	3,736,431.	300

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	1,561,842.	\$	881,619.	50
4	\$	1,710,108.	\$	877,556.	50
5	\$	1,866,617.	\$	870,791.	50
6	\$	4,073,119.	\$	1,727,400.	100
7	\$	4,421,914.	\$	1,704,839.	100
8	\$	4,790,102.	\$	1,678,901.	100
9	\$	7,782,332.	\$	2,479,690.	150
10	\$	8,397,734.	\$	2,432,524.	150
11	\$	9,047,352.	\$	2,382,450.	150
12	\$	12,990,070.	\$	3,109,719.	200
13	\$	13,955,220.	\$	3,037,062.	200
14	\$	14,974,030.	\$	2,962,532.	200
15	\$	20,071,330.	\$	3,610,005.	250
16	\$	21,490,410.	\$	3,513,852.	250
17	\$	22,988,380.	\$	3,417,075.	250
18	\$	29,491,130.	\$	3,985,152.	300
19	\$	31,494,150.	\$	3,868,928.	300
20	\$	33,608,530.	\$	3,753,337.	300

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$46,293,430.	\$41,318,560.	\$4,974,868.

INSTALLED MW = 300

Ok

KYLE HOT SPRINGS, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	3,044,210.	\$	497,753.	50
17	\$	3,343,804.	\$	497,035.	50
18	\$	3,660,057.	\$	494,585.	50
19	\$	7,748,150.	\$	951,829.	97
20	\$	8,431,799.	\$	941,647.	97
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	1,981,411.	\$	573,944.	50
11	\$	2,197,951.	\$	578,789.	50
12	\$	2,426,530.	\$	580,892.	50
13	\$	5,175,567.	\$	1,126,354.	97
14	\$	5,669,692.	\$	1,121,718.	97
15	\$	6,191,292.	\$	1,113,558.	97
16	\$	6,741,892.	\$	1,102,353.	97
17	\$	7,323,105.	\$	1,088,533.	97
18	\$	7,936,634.	\$	1,072,482.	97
19	\$	8,584,273.	\$	1,054,543.	97
20	\$	9,267,923.	\$	1,035,024.	97

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$10,448,190.	\$3,382,849.	\$7,065,340.

INSTALLED MW = 97
Ok

COVE FORT - SULPHURDALE, UT

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	1,488,685.	\$	356,379.	50
13	\$	1,587,197.	\$	345,420.	50
14	\$	1,689,649.	\$	334,288.	50
15	\$	3,592,399.	\$	646,124.	100
16	\$	3,814,023.	\$	623,623.	100
17	\$	4,044,513.	\$	601,191.	100
18	\$	6,426,332.	\$	868,394.	150
19	\$	6,800,279.	\$	835,387.	150
20	\$	7,189,184.	\$	802,875.	150

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	1,227,920.	\$	391,253.	50
10	\$	1,315,497.	\$	381,052.	50
11	\$	1,406,576.	\$	370,395.	50
12	\$	3,004,000.	\$	719,134.	100
13	\$	3,201,024.	\$	696,636.	100
14	\$	3,405,928.	\$	673,845.	100
15	\$	5,429,245.	\$	976,497.	150
16	\$	5,761,682.	\$	942,081.	150
17	\$	6,107,415.	\$	907,828.	150
18	\$	8,623,107.	\$	1,165,245.	200
19	\$	9,121,702.	\$	1,120,564.	200
20	\$	9,640,242.	\$	1,076,604.	200

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$9,421,134.	\$5,413,681.	\$4,007,454.

INSTALLED MW = 200
Ok

STILLWATER-SODA LAKE, NV

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	1,949,986.	\$	466,811.	50
13	\$	2,191,274.	\$	476,885.	50
14	\$	2,445,977.	\$	483,923.	50
15	\$	5,429,687.	\$	976,577.	100
16	\$	5,997,316.	\$	980,609.	100
17	\$	6,596,505.	\$	980,528.	100
18	\$	10,843,510.	\$	1,465,290.	150
19	\$	11,845,020.	\$	1,455,112.	150
20	\$	12,902,210.	\$	1,440,894.	150
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	1,458,607.	\$	511,233.	50
9	\$	1,652,936.	\$	526,676.	50
10	\$	1,858,070.	\$	538,217.	50
11	\$	4,237,521.	\$	1,115,872.	100
12	\$	4,694,679.	\$	1,123,869.	100
13	\$	5,177,255.	\$	1,126,721.	100
14	\$	8,574,144.	\$	1,696,348.	150
15	\$	9,380,742.	\$	1,687,209.	150
16	\$	10,232,180.	\$	1,673,043.	150
17	\$	14,870,720.	\$	2,210,438.	200
18	\$	16,135,730.	\$	2,180,430.	200
19	\$	17,471,070.	\$	2,146,250.	200
20	\$	23,622,900.	\$	2,638,161.	250

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
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\$19,174,460.	\$8,726,629.	\$10,447,840.
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INSTALLED MW = 250

Ok

ROOSEVELT HS, UT

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	1,050,128.	\$	404,870.	50
8	\$	1,131,097.	\$	396,443.	50
9	\$	1,215,306.	\$	387,234.	50
10	\$	2,605,765.	\$	754,797.	100
11	\$	2,787,923.	\$	734,147.	100
12	\$	2,977,370.	\$	712,758.	100
13	\$	4,761,590.	\$	1,036,261.	150
14	\$	5,068,947.	\$	1,002,864.	150
15	\$	5,388,599.	\$	969,187.	150
16	\$	7,628,047.	\$	1,247,246.	200
17	\$	8,089,027.	\$	1,202,382.	200
18	\$	8,568,443.	\$	1,157,858.	200
19	\$	11,333,800.	\$	1,392,311.	250
20	\$	11,981,970.	\$	1,338,124.	250

0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	904,420.	\$	421,918.	50
6	\$	979,280.	\$	415,310.	50
7	\$	1,057,136.	\$	407,571.	50
8	\$	2,280,415.	\$	799,272.	100
9	\$	2,448,832.	\$	780,273.	100
10	\$	2,623,986.	\$	760,075.	100
11	\$	4,214,122.	\$	1,109,710.	150
12	\$	4,498,291.	\$	1,076,855.	150
13	\$	4,793,827.	\$	1,043,276.	150
14	\$	6,804,849.	\$	1,346,303.	200
15	\$	7,231,051.	\$	1,300,568.	200
16	\$	7,674,300.	\$	1,254,809.	200
17	\$	10,171,550.	\$	1,511,936.	250
18	\$	10,770,820.	\$	1,455,467.	250
19	\$	11,394,070.	\$	1,399,715.	250
20	\$	14,452,650.	\$	1,614,045.	300

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$16,697,100.	\$12,736,480.	\$3,960,624.

INSTALLED MW = 300
Ok

VALE, OR

RUN					
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	0.	\$	0.	0
17	\$	0.	\$	0.	0
18	\$	0.	\$	0.	0
19	\$	0.	\$	0.	0
20	\$	0.	\$	0.	0
0	\$	0.	\$	0.	0
1	\$	0.	\$	0.	0
2	\$	0.	\$	0.	0
3	\$	0.	\$	0.	0
4	\$	0.	\$	0.	0
5	\$	0.	\$	0.	0
6	\$	0.	\$	0.	0
7	\$	0.	\$	0.	0
8	\$	0.	\$	0.	0
9	\$	0.	\$	0.	0
10	\$	0.	\$	0.	0
11	\$	0.	\$	0.	0
12	\$	0.	\$	0.	0
13	\$	0.	\$	0.	0
14	\$	0.	\$	0.	0
15	\$	0.	\$	0.	0
16	\$	0.	\$	0.	0
17	\$	0.	\$	0.	0
18	\$	0.	\$	0.	0
19	\$ 1,156,440.	\$	142,064.		50
20	\$ 1,457,830.	\$	162,808.		50

1987 NET PRESENT VALUE OF ROYALTIES

WITH R&D	W/O R&D	DIFFERENCE
\$304,872.	\$0.	\$304,872.

INSTALLED MW = 50
Ok