CALIFORNIA
ENERGY
COMMISSION

SCENARIO ANALYSES OF CALIFORNIA'S ELECTRICITY SYSTEM: PRELIMINARY RESULTS FOR THE *2007 INTEGRATED ENERGY POLICY REPORT*

APPENDICES

DRAFT STAFF REPORT

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APPENDIX A

CASE MATRIX PROVIDING BROAD FEATURES OF THE NINE THEMATIC SCENARIOS

Prepared by Navigant Consulting, Inc.

The case matrix was prepared by Navigant Consulting with the input of the project team, and it is based on a large spreadsheet layed out with Characterization of Case on the left-hand side and the nine thematic scenarios across the top. Because all nine scenarios cannot fit on an 8 1/2" x 11" sheet, the scenarios print out in two parts (6 pages total): the first 3 pages include Case 1 to Case 3B and all related characterizations of case; the second 3 pages include Case 4A to Case 5B with all characterizations of case repeated.

	Alternative Resource Portfolio Case Summary				
	Case 1	**Case 1 b**	**Case 2**	**Case 3a**	**Case 3b**
Characterization of Case	**Current Trends -**	**Modified Current Trends Case to Reflect Renewable Additions the California LSEs Propose to the CEC in Upcoming Proceeding and Assume Other WECC States Meet Respective Current RPS Goals**	**Current Trends & Sustained High Gas Prices**	**High Energy Efficiency and Variable Demand Reduction in Calif Only (Case 1b Modified by CA Higher Energy Efficiency and Demand Response Measures)**	**High Energy Efficiency and Demand Response Measures WECC-Wide**
Peak Load & Energy Forecasts					
Load Forecast	Global Energy's WECC Fall 2006 forecast and the CEC staff's June 2006 forecast for California	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions
Energy Efficiency and Variable Demand Reduction Programs					
Energy Efficiency - California	The CPUC's 2006 to 2008 commtted energy efficiency programs are included in the CEC staff's 2006 CA load forecast. This embedded EE is identified to note the level of energy and peak reduction included in the forecast. No further changes beyond 2008 (assume 2008 levels of savings continue)	The Long Term Procurement Plan (LTPP) filings of the IOUs in December 2006 EE contributions were incorporated as resources, extrapolated to 2020 by assuming that annual EE grows from 2016 proportional to load growth. POUs achieve similar levels of EE as the IOUs.	Case 3a assumptions	The economic potential (excluding the portion due to emerging technologies) from the Itron 2006 Potential Study net of utility accomplishment for 2004-2008 is used. POUs achieve similar levels of EE. By 2020, EE provides 44% more savings than in Case 1b	Case 3a assumptions
Energy Efficiency - Rest of WECC	Assume no incremental EE programs	Case 1 Assumptions	Assumed rest of WECC achieves 5% reduction of the Case 1 rest of WECC load forecast (approx 50% of the "best practices" assumption in Case 3b), w/ level annual ramp of that contribution from 2008 to 2020	The existing WECC forecast includes an approximate 9% of load contribution of EE by 2020 Case 1 assumptions for rest of WECC. No additional EE is assumed for this case, which is considered "current practices".	Assume that an additional 11% EE contribution to meet loads is achieved by 2020 to reflect "best practices" with a level annual ramp from 2008 to the 2020 goal.
Demand Reduction Programs - California	Global Energy Decision's Fall 2006 reference case Demand Reduction data.	Assume utility reported levels through 2018 and held constant to 2020, for a statewide capability of 3357 MW	Case 1 assumptions	Assume utilities achieve 21% more demand reduction by 2018, for a total statewide capability of 4057 MW	Case 3a assumptions
Demand Reduction Programs - Rest of WECC	Global Energy Decision's Fall 2006 reference case Demand Reduction data.	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions
Generation Resources					
Existing Generation - California	Global Energy Decisions Fall 2006 reference case resource database.	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions
Existing Generation - Rest of WECC	Global Energy Decisions Fall 2006 reference case resource database.	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions
Retirements - California	Global Energy Decisions Fall 2006 reference case resource database except for 2 changes: 1) Haynes 5 & 6 retirement date was delayed from 5/2008 to 1/2021 and 1/2022 due to the assumption that these units will not be retired unless they are replaced (or repowered to CC); and 2) Humboldt 1 & 2 retirement date was moved from 5/2008 to 9/2008.	Retirements reflect specific assumptions in December 2006 LTPP filings by the IOUs	Case 1 assumptions	Case 1b assumptions	Case 1b assumptions
Retirements - Rest of WECC	Global Energy Decisions Fall 2006 reference case resource database.	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions

	Alternative Resource Portfolio Case Summary				
	Case 1	Case 1 b	Case 2	Case 3a	Case 3b
Characterization of Case	**Current Trends -**	**Modified Current Trends Case to Reflect Renewable Additions the California LSEs Propose to the CEC in Upcoming Proceeding and Assume Other WECC States Meet Respective Current RPS Goals**	**Current Trends & Sustained High Gas Prices**	**High Energy Efficiency and Variable Demand Reduction in Calif Only (Case 1b Modified by CA Higher Energy Efficiency and Demand Response Measures)**	**High Energy Efficiency and Demand Response Measures WECC-Wide**
Non-Renewable Additions - in California	Assumed installation of projects that have IOU recent procurement approvals, projects well advanced in CEC AFC process, and others in logically located areas that have gone through interconnection study.. Beyond time of planned specific additions, after addition of renewables at base case levels, install in-state CT plants to meet Resource Adequacy targets.	Reduced level of CT generic additions from Case 1 to reflect IOU December 2006 LTPP filings of energy efficiency and renewable additions affect on net capacity required to meet Resource Adequacy	Removed CT generic additions to compensate for increased level of energy efficiency over Case 1.	Modified Case 1b to reduce CT generic additions in rest of WECC to reflect higher energy efficiency contributions to peak and annual energy requirements	Case 3a assumptions
Renewable Additions - California	Global Energy's WECC Fall 2006 reference case assumption of wind additions of 1600 MW between 2009-2020. Used California QF regional hourly wind data for wind resource additions and calculated dependable capacity using this hourly data.	Renewable resources were added based on December 2006 IOUs' LTPP filings and CEC staff estimates: SDG&E filing's 16.4% RE by 2010 is increased to 20% by 2013 and 30% by 2020. PG&E filing's 15.2% by 2009 is adjusted to 20% by 2013 and linear ramp to 25% by 2016 & level at 35% to 2020. SCE filing's 20% by 2011 assumed 20% by 2012 due to Tehachapi trans upgrade, then increased to 26% by 2016 and maintain 26% 2017 to 2020	Case 1 assumptions	Case 1b assumptions	Case 1b assumptions
End-User Solar PV Assumptions	Assumed any PV penetration that was already planned is reflected in the base load forecast	Used IOU-provided PV penetration estimates in 2006 LTPP	Case 1 assumptions	Case 1b assumptions	Case 1b assumptions
Non-Renewable Additions - Rest of WECC	Global Energy's Fall 2006 reference case was compared to the WECC spring 2006 list of planned future units. Named, planned generating units and assumed renewable generation additions were included in the future generation mix with generic CCCT, CT, and ST units added as needed to meet the 15% capacity reserve margin for individual transmission areas.	Case 1 assumptions, with reductions to CCCT, CT, and ST generic additions to reflect the effects of meeting the respective state-RPS requirements/goals, to minimize any excess capacity reserve margin.	Due to sustained high gas prices, CCCT units that were planned in Case 1 are replaced with ST and Geothermal resource types. CTs were removed to compensate for increased penetration of energy efficiency over Case 1.	Case 1b assumptions	Reduced generic non-renewable additions from Case 1b to reflect higher energy efficiency contributions to reducing capacity reserve margin requirements

	Alternative Resource Portfolio Case Summary				
	Case 1	Case 1 b	Case 2	Case 3a	Case 3b
Characterization of Case	**Current Trends -**	**Modified Current Trends Case to Reflect Renewable Additions the California LSEs Propose to the CEC in Upcoming Proceeding and Assume Other WECC States Meet Respective Current RPS Goals**	**Current Trends & Sustained High Gas Prices**	**High Energy Efficiency and Variable Demand Reduction in Calif Only (Case 1b Modified by CA Higher Energy Efficiency and Demand Response Measures)**	**High Energy Efficiency and Demand Response Measures WECC-Wide**
Renewable Additions - Rest of WECC	Included only named renewable additions included in utility resource plans or WECC capacity lists. Used NREL regional hourly wind data for wind resource additions and calculated dependable capacity using this hourly data.	Assumed other WECC states meet current respective state RPS requirements/targets as set forth in each states' RPS legislation. Renewable additions in those states without RPS were based on utility IRPs/news releases	Case 1 assumptions	Case 1b additions	Case 1b additions
Transmission Upgrades/Additions					
California Transmission	Assumed Palo Verde - Devers 2 and associated "down stream" upgrades inside of Lugo are installed, no others. Used a combination of Global Energy Decision's Fall 2006 transfer capability assumptions and the CEC's transfer capability assumptions.	Case 1 assumptions plus assumed that: (i) the SCE-proposed Tehachapi upgrade is developed; (2) the transfer capacity is increased between the IID and SCE areas and ; (3) the transfer capacity is increased between the IID and SDG&E areas	Case 1 assumptions	Case 1b assumptions	Case 1b assumptions
Rest of WECC Transmission	Global Energy Decision's Fall 2006 reference case transmission transfer capability assumptions	Case 1 assumptions, plus inter-regional transmission additions to increase transfer capabilities between: (1) Alberta and Montana; (2) Arizona and Southern Nevada; (3) British Columbia and the Pacific Northwest; (4) Wyoming and Idaho; (5) Montana and Northwest; (6) Alberta to BC; (7) Wyoming to Utah.	Case 1 assumptions	Case 1b assumptions	Case 1b assumptions

Source: California Energy Commission

	Case 4a	Case 4b	Case 5a	Case 5b
Characterization of Case	**High Renewables in California (in-state installation) w/ required associated transmission additions**	**High WECC-Wide Renewables w/ required associated transmission additions**	**California Maximized Preferred Resources (Energy Efficiency and Renewables - Combination of Case 3a and 4a assumptions)**	**WECC-Wide Maximized Preferred Resources (Energy Efficiency and Renewables - Combination of Case 3b and 4b assumptions)**
Peak Load & Energy Forecasts				
Load Forecast	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions
Energy Efficiency and Variable Demand Reduction Programs				
Energy Efficiency - California	Case 1b assumptions	Case 1b assumptions	Case 3a assumptions	Case 3a assumptions
Energy Efficiency - Rest of WECC	Case 1b assumptions	Case 1b assumptions	Case 1b assumptions	Case 3b assumptions
Demand Reduction Programs - California	Case 1b assumptions	Case 1b assumptions	Case 3a assumptions	Case 3b assumptions
Demand Reduction Programs - Rest of WECC	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions
Generation Resources				
Existing Generation - California	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions
Existing Generation - Rest of WECC	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions
Retirements - California	Case 1b assumptions	Case 1b assumptions	Case 1b assumptions	Case 1b assumptions
Retirements - Rest of WECC	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions	Case 1 assumptions

	Case 4a	Case 4b	Case 5a	Case 5b
Characterization of Case	**High Renewables in California (in-state installation) w/ required associated transmission additions**	**High WECC-Wide Renewables w/ required associated transmission additions**	**California Maximized Preferred Resources (Energy Efficiency and Renewables - Combination of Case 3a and 4a assumptions)**	**WECC-Wide Maximized Preferred Resources (Energy Efficiency and Renewables - Combination of Case 3b and 4b assumptions)**
Non-Renewable Additions - in California	Modifed Case 1b to reduce CT generic additions to reflect higher level of renewables contribution to capacity margins and Resource Adequacy requirements	Case 4a assumptions	Case 4a assumptions - no adjustments made to generic CT units as all have been removed.	Case 4a assumptions - no adjustments made to generic CT units as all have been removed.
Renewable Additions - California	2009-2011 used Case 1b assumptions. Starting in 2012, linearly ramped 2011 levels of renewables to meet 33% RPS by 2020 for IOUs and POUs. Assume all additions are developed in-state.	Case 4a assumptions for level of renewables in California, assumed that no "rest of WECC" renewable additions displace the need for California renewable additions	Case 4a assumptions	Case 4a assumptions
End-User Solar PV Assumptions	Assumed that the CA Solar Initiative goals are met (3000 MW of household and commercial PV by 2016) and after 2016, assumed that the rate of additions annually thereafter grow at 2%.	Same as Case 4a for California. For rest of WECC used accelerated rates of PV Solar in Arizona and Nevada based on NCI Solar Energy Roadmap Study for State of Arizona.	For California, Case 4a assumptions. For rest of WECC, Case 1b assumptions.	For California, Case 4a assumptions. For rest of WECC, Case 4b assumptions.
Non-Renewable Additions - Rest of WECC	Case 1b additions	Reduced Case 1b generic non-renewable additions for level of capacity reserve margin contribution of incremental renewable additions in rest of WECC	Case 1b assumptions	Reduced remaining generic non-renewable additions assumed in Case 3b to reflect contribution of Case 4b renewable additions to capacity reserve margin of each transmission subarea

	Case 4a	Case 4b	Case 5a	Case 5b
Characterization of Case	**High Renewables in California (in-state installation) w/ required associated transmission additions**	**High WECC-Wide Renewables w/ required associated transmission additions**	**California Maximized Preferred Resources (Energy Efficiency and Renewables - Combination of Case 3a and 4a assumptions)**	**WECC-Wide Maximized Preferred Resources (Energy Efficiency and Renewables - Combination of Case 3b and 4b assumptions)**
Renewable Additions - Rest of WECC	Case 1b additions	Case 1b assumptions for 2009-2011. For 2012 to 2020, used Western Governors Association study task force recommendations resulting in adding 35,500 MW (nameplate) of renewables by 2020, with the resource mix generally guided by estimated ratio of available types of renewable resources in WECC transmission subareas based on WGA study and relative estimated installed cost of resources. Used level annual ramp rate from 2011 levels to achieve the 2020 levels.	Case 1b assumptions	Case 4b assumptions,
Transmission Upgrades/Additions				
California Transmission	Case 1b assumptions plus transmission additions between the Imperial Valley area and SP 15 where required to deliver higher renewable portfolio assumed to be sourced from that region	Case 4a transmission assumptions	Case 4a transmission assumptions	Case 4a transmission assumptions
Rest of WECC Transmission	Case 1b assumptions	Case 1b assumptions, plus additonal inter-regional transmission additions between Utah and Wyoming and between New Mexico and Arizona to enable likely sources of renewable resources to be delivered to load centers.	Case 1b assumptions	Case 4b transmission assumptions plus additional interregional transmission additions to increase transfer capability from Wyoming to Utah

Source: California Energy Commission

APPENDIX B
INPUT ASSUMPTIONS

Prepared by Global Energy Decisions, Inc.

Appendix B-1
Case 1 Resource Plan Input Assumptions

The input assumptions are comprised of:

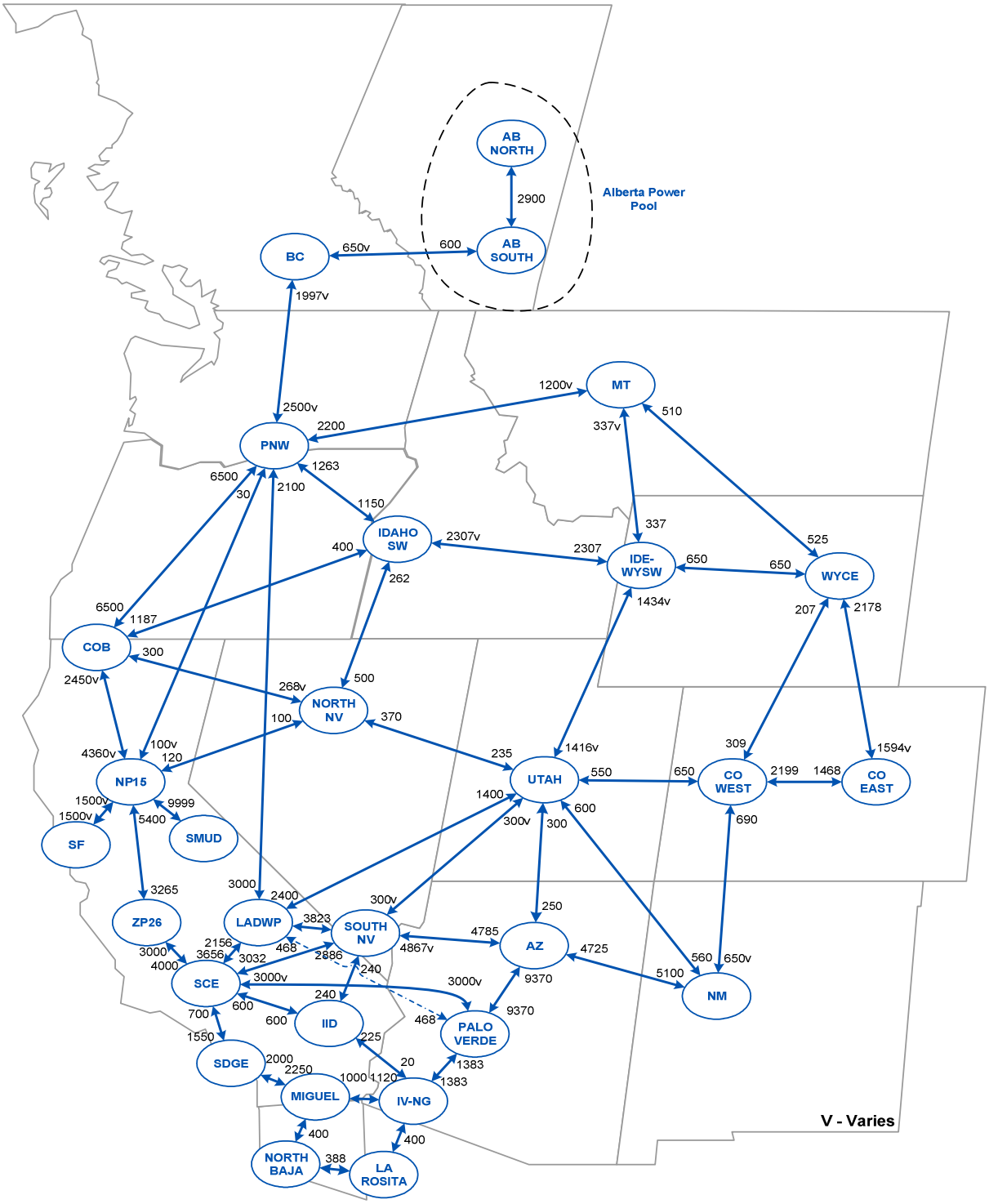
1. Topology
2. Capacity Mix
3. Initial Entry
4. Generic Additions
5. Renewables
6. Retirements
7. Load Forecast
8. TransArea Load and Resources

Global Energy Decisions

Case 1 Market Area Definitions and Topology

Market Area Definition

Abbreviation	Name	NERC Region	Geographic Location
AB_S	Alberta - South	WECC	AB (Canada)
ABCN	Alberta - Central-North	WECC	AB (Canada)
Arizona	Arizona	WECC	AZ
BC	British Columbia	WECC	BC (Canada)
CNP15 (CNORTH)	CAISO Northern California	WECC	CA
CO_East	Colorado - East	WECC	CO
CO_West	Colorado - West	WECC	CO
COB	California - Oregon Border Transmission Hub	WECC	CA, OR
CSCE	CAISO - Southern California Edison	WECC	CA
CSDGE	CAISO - San Diego Gas & Electric	WECC	CA
CZP26	CAISO - Zone Path 26 PG&E South	WECC	CA
La Rosita	La Rosita	WECC	Baja (Mexico)
IdE_WYSW (Wyoming W)	Idaho Power East -Wyoming South West	WECC	ID, WY
Id_ SW	Idaho Power West	WECC	ID
IID	Imperial Irrigation District	WECC	CA
IV-NG	Imperial Valley	WECC	CA
LADWP	Los Angeles Department of Water & Power	WECC	CA
Miguel	Miguel - East of San Diego	WECC	CA
Montana	Montana - Northwest Energy	WECC	MT
N Nevada	Northern Nevada - Sierra Pacific Power	WECC	NV
NBAJA	Northern Baja California - CFE	WECC	Baja (Mexico)
New Mexico	New Mexico	WECC	NM
Northwest (PNW)	Puget Sound	WECC	OR, WA
PV	Palo Verde	WECC	AZ
S Nevada	Southern Nevada	WECC	NV
SF	San Francisco	WECC	CA
SMUD	Sacramento Municipal Utility District	WECC	CA
Utah	Utah	WECC	UT
WYCE (Wyoming E)	Wyoming Central East	WECC	WY


AB NORTH
2900
Alberta Power Pool
BC
650v
600
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1997v
MT
1200v
510
337v
2500v
2200
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6500
30
2100
1150
IDAHO SW
2307v
400
2307
IDE-WYSW
337
650
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525
WYCE
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1434v
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COB
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NORTH NV
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UTAH
550
650
309
CO WEST
2199
1468
CO EAST
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1500v
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1500v
5400
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SMUD
1400
300v
300
600
690
3265
3000
2400
300v
250
ZP26
LADWP
3823
SOUTH NV
4785
AZ
4725
2156
3656
3032
468
2886
4867v
3000
4000
SCE
240
3000v
3000v
9370
560
650v
5100
NM
240
600
600
IID
468
PALO VERDE
9370
700
1550
225
SDGE
2000
2250
20
1383
1383
1000
1120
MIGUEL
IV-NG
400
400
NORTH BAJA
388
LA ROSITA
V - Varies

1. Topology

WECC Resource Mix, 2009

Type	2009	%
Coal	282,204	31%
Fuel Oil	67	0%
Hydro	248,569	28%
Natural Gas	227,961	25%
Nuclear	72,410	8%
Renewables/Other	67,655	8%
	898,868	

Transmission Area Generation Mix, 2009

																Generation Mix (%)
Type	AB_S	ABCN	Arizona	BC	CNP15	CO_East	CO_West	COB	CSCE	CSDGE	CZP26	ID_SW	IDE_WYSW	IID	IV-NG	La Rosita
Coal	60%	71%	70%	0%	1%	59%	93%	0%	2%	0%	3%	0%	84%	0%	0%	0%
Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Hydro	8%	1%	8%	90%	37%	2%	7%	0%	8%	1%	0%	91%	10%	4%	0%	0%
Natural Gas	18%	23%	20%	4%	42%	29%	0%	100%	51%	95%	42%	2%	0%	10%	100%	40%
Nuclear	0%	0%	0%	0%	0%	0%	0%	0%	25%	0%	55%	0%	0%	0%	0%	0%
Renewables/Other	14%	4%	1%	6%	19%	10%	0%	0%	14%	4%	0%	7%	6%	85%	0%	60%
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

WECC Resource Mix, 2009

Type
Coal
Fuel Oil
Hydro
Natural Gas
Nuclear
Renewables/Other

Transmission Area Generati

Type	LADWP	Miguel	Montana	N Nevada	NBAJA	NewMexico	Northwest	PV	S Nevada	SF	SMUD	Utah	WYCE
Coal	0%	0%	74%	46%	0%	83%	8%	0%	12%	0%	0%	89%	90%
Fuel Oil	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Hydro	8%	0%	21%	0%	0%	1%	72%	0%	18%	0%	23%	1%	4%
Natural Gas	90%	100%	0%	30%	100%	12%	9%	38%	69%	100%	75%	9%	1%
Nuclear	0%	0%	0%	0%	0%	0%	5%	62%	0%	0%	0%	0%	0%
Renewables/Other	3%	0%	5%	23%	0%	4%	6%	0%	1%	0%	2%	1%	5%
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Global Energy Decisions
Case 1 Defined Capacity Additions in the WECC

Initial Market Entry- Defined Capacity Additions in the WECC

Unit Name	Unit No.	Market Area	Unit Type	Max Rating	Installation Date	Fuel Type
Santan CC	6	Arizona	CC	275	3/1/2006	NG
Walnut Energy Center	1b	CNP15	CC	134	3/1/2006	NG
Walnut Energy Center	1a	CNP15	CC	134	3/1/2006	NG
Currant Creek CC	1b	Utah	CC	263	3/22/2006	NG
Currant Creek CC	1a	Utah	CC	263	3/22/2006	NG
Kettles Hill		AB_S	WT	63	4/1/2006	Wind
Palomar Escondido	1b	CSDGE	CC	252	4/1/2006	NG
Palomar Escondido	1a	CSDGE	CC	252	4/1/2006	NG
Millcreek Power	GT	Utah	GT	43	4/3/2006	NG
Luna Energy Facility	1b	NewMexico	CC	288	4/4/2006	NG
Luna Energy Facility	1a	NewMexico	CC	288	4/4/2006	NG
Shiloh Wind Project	WT	CNP15	WT	180	4/13/2006	Wind
Charles Lenzie	2b	S Nevada	CC	300	4/17/2006	NG
Charles Lenzie	2a	S Nevada	CC	300	4/17/2006	NG
Allen (NV)	2	S Nevada	GT	77	4/27/2006	NG
Valencia	GT4	Arizona	GT	20	6/6/2006	NG
Basin Creek Plant	3	Montana	IC	6	6/21/2006	NG
Basin Creek Plant	7	Montana	IC	6	6/21/2006	NG
Basin Creek Plant	6	Montana	IC	6	6/21/2006	NG
Basin Creek Plant	9	Montana	IC	6	6/21/2006	NG
Basin Creek Plant	8	Montana	IC	6	6/21/2006	NG
Basin Creek Plant	4	Montana	IC	6	6/21/2006	NG
Basin Creek Plant	1	Montana	IC	6	6/21/2006	NG
Basin Creek Plant	5	Montana	IC	6	6/21/2006	NG
Basin Creek Plant	2	Montana	IC	6	6/21/2006	NG
Ripon Power Plant	2	CNP15	GT	48	6/22/2006	NG
Ripon Power Plant	1	CNP15	GT	48	6/22/2006	NG
Riverside Energy	2	CSCE	GT	49	6/26/2006	NG
Riverside Energy	1	CSCE	GT	49	6/26/2006	NG
Springerville	3	Arizona	ST	418	7/28/2006	Coal
Soderglen Wind Power		AB_S	WT	71	8/19/2006	Wind
Big Horn Wind	133	Northwest	WT	200	9/30/2006	Wind
LANL TA-3	GT1	NewMexico	GT	25	9/30/2006	NG
Desert Peak Geo	2	N Nevada	GE	20	9/30/2006	Geothermal
Medicine Hat	11R	AB_S	GT	27	10/3/2006	NG
Chin Chute Wind Project	1	AB_S	WT	30	10/31/2006	Wind
Medicine Hat	10R	AB_S	GT	27	11/7/2006	NG
Wild Horse Wind	127	Northwest	WT	229	12/1/2006	Wind
Argonne Mesa	90	NewMexico	WT	90	12/1/2006	Wind
Leaning Juniper 1	67	Northwest	WT	101	12/31/2006	Wind
Prairie Home Wind	16	AB_S	WT	13	12/31/2006	Wind
Coram Tehachapi	WT1	CSCE	WT	12	12/31/2006	Wind
Buena Vista Wind Farm	38	CNP15	WT	38	12/31/2006	Wind
SDGE_Special GTs	GT1-3	CSDGE	GT	250	1/1/2007	NG
PG&E_Special GTs	GT1-2	CNP15	GT	200	1/1/2007	NG
OPTI/Nexen Long Lake	1	ABCN	CGGT	85	1/1/2007	Other
OPTI/Nexen Long Lake	2	ABCN	CGGT	85	2/1/2007	Other
Enmax Taber Wind Project		AB_S	WT	80	2/1/2007	Wind
Nevada Solar One		S Nevada	SS	64	3/1/2007	Sun/Solar
Steel Park Wind	15	S Nevada	WT	15	3/1/2007	Wind

Unit Name	Unit No.	Market Area	Unit Type	Max Rating	Installation Date	Fuel Type
Port Westward	1	Northwest	CC	400	5/1/2007	NG
Afton CC	1	NewMexico	CC	272	5/1/2007	NG
Roseville Energy	1a	CNP15	CC	88	5/1/2007	NG
Roseville Energy	1b	CNP15	CC	88	5/1/2007	NG
Bone Creek		BC	Hydro	20	6/1/2007	Hydro
Clemina Creek		BC	Hydro	10	6/1/2007	Hydro
Spindle Hill	GT1	CO_East	GT	157	6/1/2007	NG
Spindle Hill	GT2	CO_East	GT	157	6/1/2007	NG
Desert Power CC	1a	Utah	CC	45	6/1/2007	NG
Desert Power CC	1b	Utah	CC	45	6/1/2007	NG
Lake Side	1a	Utah	CC	267	6/1/2007	NG
Lake Side	1b	Utah	CC	267	6/1/2007	NG
Oregon Trail Wind Park		ID_SW	WT	11	6/1/2007	Wind
Pilgrim Stage Station		ID_SW	WT	11	6/1/2007	Wind
Thousand Springs Wind	39089	ID_SW	WT	11	6/1/2007	Wind
Tuana Gulch Wind Park		ID_SW	WT	11	6/1/2007	Wind
Schwendiman Wind	18	IDE_WYSW	WT	20	7/31/2007	Wind
Pine Tree Wind		LADWP	WT	120	9/1/2007	Wind
Windstar I	60	CSCE	WT	120	9/1/2007	Wind
Raft River Geotherma		ID_SW	GE	10	11/1/2007	Geothermal
Mount Hays Wind Farm	14	BC	WT	25	11/1/2007	Wind
Biglow Canyon	63	Northwest	WT	450	12/1/2007	Wind
Peetz Wind (FPL)	133	CO_East	WT	200	12/1/2007	Wind
Twin Buttes Wind Farm	50	CO_East	WT	75	12/1/2007	Wind
Elkhorn Wind Power	70	Northwest	WT	66	12/31/2007	Wind
White Creek Wind Project	87	Northwest	WT	200	12/31/2007	Wind
Cedar Creek Wind Energy	200	CO_East	WT	300	12/31/2007	Wind
Burley Butte Wind Park	17	ID_SW	WT	11	12/31/2007	Wind
Lava Beds Wind		ID_SW	WT	18	12/31/2007	Wind
Milner Dam Wind		ID_SW	WT	18	12/31/2007	Wind
Notch Butte Wind		ID_SW	WT	18	12/31/2007	Wind
Salmon Falls Wind		ID_SW	WT	21	12/31/2007	Wind
Salt Wells Geothermal	GE1	N Nevada	GE	11	12/31/2007	Geothermal
Stillwater II	GE1	N Nevada	GE	26	12/31/2007	Geothermal
_150 Mile House ERG	ST	BC	ST	6	12/31/2007	Waste Heat
Savona ERG Project	ST	BC	ST	6	12/31/2007	Waste Heat
Glacier Creek		BC	Hydro	40	1/1/2008	Hydro
Kookipi Creek		BC	Hydro	10	1/1/2008	Hydro
Log Creek		BC	Hydro	10	1/1/2008	Hydro
Snowflake White Mountai	ST	Arizona	ST	20	1/1/2008	Wood
Lamar Plant	AB	CO_East	AB	18	1/1/2008	Coal
Wygen II	1	WYCE	ST	90	1/1/2008	Coal
Yuma Peaker	GT1	Arizona	GT	50	1/1/2008	NG
Yuma Peaker	GT2	Arizona	GT	50	1/1/2008	NG
Galena 3	GE	N Nevada	GE	25	1/1/2008	Geothermal
Ely Wind	1	N Nevada	WT	200	1/1/2008	Wind
Sumas Recovered Energy	ST	Northwest	ST	5	1/1/2008	Waste Heat
Princeton Power Project	ST1	BC	ST	49	1/1/2008	Wood
Niland	GT1	IID	GT	47	1/1/2008	NG
Niland	GT2	IID	GT	47	1/1/2008	NG
Olivenhain Hodges Pumped Storage		CSDGE	Pump Storage	40	3/1/2008	Pump Storage
Rainy River Hydro		BC	Hydro	15	3/1/2008	Hydro
East Toba River		BC	Hydro	120	5/1/2008	Hydro
Forrest Kerr		BC	Hydro	112	5/1/2008	Hydro
Montrose Creek		BC	Hydro	50	5/1/2008	Hydro
Kwoiek Creek		BC	Hydro	50	6/1/2008	Hydro
SFERP Potrero 1		SF	GT	49	6/1/2008	NG

Unit Name	Unit No.	Market Area	Unit Type	Max Rating	Installation Date	Fuel Type
SFERP Potrero 2		SF	GT	49	6/1/2008	NG
SFERP Potrero 3		SF	GT	49	6/1/2008	NG
Reeves	CC	NewMexico	CC	206	6/1/2008	NG
Mountain Home	3	ID_SW	GT	170	6/1/2008	NG
TS Power Plant	1	N Nevada	ST	200	6/1/2008	Coal
Tracy (NV)	1a	N Nevada	CC	250	6/1/2008	NG
Tracy (NV)	1b	N Nevada	CC	250	6/1/2008	NG
Salton Sea #6		IID	GE	215	6/1/2008	Geothermal
Inland Empire Energy	1	CSCE	CS	405	6/1/2008	NG
Inland Empire Energy	2	CSCE	CS	405	6/1/2008	NG
Pacific Wind	WT	CSCE	WT	206	6/1/2008	Wind
Panoche Energy Center	GT2	CNP15	GT	100	7/1/2008	NG
Panoche Energy Center	GT1	CNP15	GT	100	7/1/2008	NG
Panoche Energy Center	GT3	CNP15	GT	100	7/1/2008	NG
Panoche Energy Center	GT4	CNP15	GT	100	7/1/2008	NG
Gold River Power Project	ST1	BC	ST	35	9/1/2008	Biomass
Gold River Power Project	ST2	BC	ST	40	9/1/2008	Biomass
Bear Mountain Wind	60	BC	WT	120	9/8/2008	Wind
Humboldt Bay	C1	CNP15	IC	16	10/1/2008	NG
Humboldt Bay	C2	CNP15	IC	16	10/1/2008	NG
Humboldt Bay	C3	CNP15	IC	16	10/1/2008	NG
Humboldt Bay	C4	CNP15	IC	16	10/1/2008	NG
Humboldt Bay	C5	CNP15	IC	16	10/1/2008	NG
Humboldt Bay	C6	CNP15	IC	16	10/1/2008	NG
Humboldt Bay	C7	CNP15	IC	16	10/1/2008	NG
Humboldt Bay	C8	CNP15	IC	16	10/1/2008	NG
Humboldt Bay	C9	CNP15	IC	16	10/1/2008	NG
Humboldt Bay	C10	CNP15	IC	16	10/1/2008	NG
Raft River Geothermal	E2	ID_SW	GE	26	12/1/2008	Geothermal
Galena 2		N Nevada	GE	10	12/1/2008	Geothermal
Anyox River Hydro		BC	Hydro	30	12/31/2008	Hydro
Howser Creek		BC	Hydro	50	12/31/2008	Hydro
Kitsault River Hydro		BC	Hydro	27	12/31/2008	Hydro
Dokie Wind Energy Proje	100	BC	WT	180	12/31/2008	Wind
Eastshore Energy	IC	SF	IC	116	1/1/2009	NG
Torrance County Biomass	ST1	NewMexico	ST	35	1/1/2009	Wood
Blue Mountain Geotherma	GE	N Nevada	GE	30	1/1/2009	Geothermal
Mackenzie Green Ener	ST	BC	CGST	50	1/1/2009	Wood
El Centro CC	3	IID	CC	120	1/1/2009	NG
EIF Bullard	GT	CNP15	GT	196	6/1/2009	NG
Starwood Power Firebaug	GT	CNP15	GT	120	7/1/2009	NG
Comanche (CO)	3	CO_East	ST	750	10/1/2009	Coal
Contra Costa Power	8a	CNP15	CC	235	11/1/2009	NG
Contra Costa Power	8b	CNP15	CC	235	11/1/2009	NG
Otay Mesa	1a	Miguel	CC	255	12/1/2009	NG
Otay Mesa	1b	Miguel	CC	255	12/1/2009	NG
Springerville	4	Arizona	ST	400	12/1/2009	Coal
Buffalo Valley	ST	N Nevada	GE	30	12/1/2009	Geothermal
Carson Lake	ST	N Nevada	GE	30	12/1/2009	Geothermal
Newberry Volcano	GE1	Northwest	GE	30	12/31/2009	Geothermal
Songhees Creek Hydro		BC	Hydro	15	1/1/2010	Hydro
Wapiti Energy	ST1	BC	ST	184	1/1/2010	Coal
PG&E Colusa County	1B	CNP15	CC	330	1/1/2010	NG
PG&E Colusa County	1A	CNP15	CC	330	1/1/2010	NG
Russell City	CC	SF	CC	620	6/1/2010	NG
Upper Stave Creek		BC	Hydro	34	10/1/2010	Hydro
Keephills	3	ABCN	ST	450	1/1/2011	Coal
SCE_Special GTs	GT1-16	CSCE	GT	1550	1/1/2007 - 1/1/2010	NG

Global Energy Decisions
Case 1 Generic Resource Additions in the WECC

Generic Entry- Generic Capacity Additions in the WECC
Nameplate Capacity (MW)

Market Area	Unit Type	2007-2010	2011	2012	2013	2014	2015-2020	Cumulative Additions 2007-2020
AB_S	CC	0	0	0	0	0	490	490
	Coal	500	500	0	0	0	0	1,000
	GT	1,440	0	0	360	360	720	2,880
	Wind	150	50	100	50	100	300	750
AB_S Total		2,090	550	100	410	460	1,510	5,120
ABCN	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	500	500
	GT	360	180	0	0	0	0	540
	Wind	0	0	0	0	0	0	0
ABCN Total		360	180	0	0	0	500	1,040
Arizona	CC	0	0	0	0	0	0	0
	Coal	0	500	0	0	0	500	1,000
	GT	1,260	720	540	720	1,260	5,220	9,720
	Wind	100	100	50	50	50	250	600
Arizona Total		1,360	1,320	590	770	1,310	5,970	11,320
BC	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	360	0	0	0	0	360
	Wind	100	100	50	100	100	500	950
BC Total		100	460	50	100	100	500	1,310
CNP15	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	0	2,300	2,300
	Wind	150	100	100	50	100	350	850
CNP15 Total		150	100	100	50	100	2,650	3,150
CO_East	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	500	500
	GT	0	0	180	540	540	1,800	3,060
	Wind	150	50	100	100	0	350	750
CO_East Total		150	50	280	640	540	2,650	4,310
CO_West	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	0
CO_West Total		0	0	0	0	0	0	0
CSCE	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	1,540	0	0	0	0	1,100	2,640
	Wind	150	50	50	100	0	400	750
CSCE Total		1,690	50	50	100	0	1,500	3,390

Market Area	Unit Type	2007-2010	2011	2012	2013	2014	2015-2020	Cumulative Additions 2007-2020
CSDGE	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	200	2,600	2,800
	Wind	0	0	0	0	0	0	0
CSDGE Total		0	0	0	0	200	2,600	2,800
ID_SW	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	540	1,260	1,800
	Wind	0	0	0	0	0	0	0
ID_SW Total		0	0	0	0	540	1,260	1,800
IDE_WYSW	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	0	540	540
	Wind	200	50	50	50	50	350	750
IDE_WYSW Total		200	50	50	50	50	890	1,290
IID	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	0	600	600
	Wind	0	0	0	0	0	0	0
IID Total		0	0	0	0	0	600	600
La Rosita	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	0	180	180
	Wind	0	0	0	0	0	0	0
La Rosita Total		0	0	0	0	0	180	180
LADWP	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	800	1,800	2,600
	Wind	0	0	0	0	0	0	0
LADWP Total		0	0	0	0	800	1,800	2,600
Miguel	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	0	100	100
	Wind	0	0	0	0	0	0	0
Miguel Total		0	0	0	0	0	100	100
Montana	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	0	540	540
	Wind	150	50	50	100	50	400	800
Montana Total		150	50	50	100	50	940	1,340
N Nevada	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	500	500
	GT	0	0	0	0	0	0	0
	Wind	50	0	0	0	50	300	400
N Nevada Total		50	0	0	0	50	800	900
NBAJA	CC	0	0	0	0	0	245	245
	Coal	0	0	0	0	0	0	0
	GT	360	180	0	0	0	1,260	1,800
	Wind	0	0	0	0	0	0	0
NBAJA Total		360	180	0	0	0	1,505	2,045

Market Area	Unit Type	2007-2010	2011	2012	2013	2014	2015-2020	Cumulative Additions 2007-2020
NewMexico	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	500	500
	GT	0	0	180	0	0	720	900
	Wind	0	0	0	0	0	0	0
NewMexico Total		0	0	180	0	0	1,220	1,400
Northwest	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	0	540	540
	Wind	250	100	100	50	100	600	1,200
Northwest Total		250	100	100	50	100	1,140	1,740
PV	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	0	0
	GT	0	0	0	0	0	0	0
	Wind	0	0	0	0	0	0	0
PV Total		0	0	0	0	0	0	0
S Nevada	CC	0	0	0	0	0	0	0
	Coal	0	500	0	0	0	500	1,000
	GT	0	0	0	0	0	1,260	1,260
	Wind	100	50	50	50	50	300	600
S Nevada Total		100	550	50	50	50	2,060	2,860
Utah	CC	0	0	0	0	0	0	0
	Coal	0	0	0	0	0	1,000	1,000
	GT	0	0	0	0	540	1,800	2,340
	Wind	0	0	0	0	0	100	100
Utah Total		0	0	0	0	540	2,900	3,440
WYCE	CC	0	0	0	0	0	0	0
	Coal	0	300	0	0	0	0	300
	GT	0	0	0	0	0	0	0
	Wind	150	50	50	50	100	300	700
WYCE Total		150	350	50	50	100	300	1,000
Grand Total		7,160	3,990	1,650	2,370	4,990	33,575	53,735

Global Energy Decisions
Case 1 Renewable Assumptions

Assumed Renewable Capacity Additions in the Western Interconnect
Nameplate and Dependable Capacity (MW)

Year	Biomass & Landfill Nameplate	Biomass & Landfill Dependable	Geothermal Nameplate	Geothermal Dependable	Hydro Nameplate	Hydro Dependable	Solar Nameplate	Solar Dependable	Wind Nameplate	Wind Dependable	Total Nameplate	Total Dependable
2007	0	0	47	47	30	30	64	64	1,798	360	**1,939**	**501**
2008	144	144	276	276	553	553	0	0	906	181	**1,879**	**1,154**
2009	85	85	120	120	0	0	0	0	750	150	**955**	**355**
2010	0	0	0	0	49	49	0	0	750	150	**799**	**199**
2011	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2012	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2013	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2014	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2015	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2016	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2017	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2018	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2019	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2020	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2021	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2022	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2023	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2024	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2025	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2026	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2027	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2028	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2029	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2030	0	0	0	0	0	0	0	0	750	150	**750**	**150**
2006-2029	**229**	**229**	**443**	**443**	**632**	**632**	**64**	**64**	**19,204**	**3,841**	**20,571**	**5,208**

Global Energy Decisions
Case 1 Capacity Retirements

Capacity Retirements in the WECC Markets
Nameplate Capacity (MW)

WECC Capacity Retirements, 2007–2020; MW

Year	Coal	Natural Gas	Nuclear	Oil	Other	Annual Total	Cumulative Retirements
2007	0	720	0	251	0	971	**971**
2008	0	338	0	75	0	413	**1,384**
2009	0	742	0	180	0	922	**2,305**
2010	293	190	0	0	0	483	**2,788**
2011	0	279	0	0	0	279	**3,067**
2012	0	554	0	0	0	554	**3,621**
2013	10	990	0	0	0	1,000	**4,621**
2014	19	770	0	0	0	790	**5,411**
2015	0	858	0	0	0	858	**6,269**
2016	48	1348	0	10	0	1,406	**7,675**
2017	10	1149	0	32	0	1,191	**8,866**
2018	0	1333	0	0	0	1,333	**10,199**
2019	69	1927	0	0	0	1,996	**12,195**
2020	19	563	0	0	0	582	**12,777**
Total	**469**	**11,760**	**0**	**548**	**0**	**12,777**	**12,777**

SOURCE: Global Energy.

Global Energy Decisions
Case 1 Peak and Energy Forecast

WECC Peak and Energy Load Forecast

Year	WECC	
	Peak Load (MW)	Total Energy (GWh)
2007	150,150	865,169
2008	153,637	885,361
2009	155,659	900,628
2010	158,944	918,758
2011	162,121	936,603
2012	165,334	955,504
2013	168,526	972,080
2014	171,826	988,578
2015	174,951	1,006,294
2016	178,044	1,023,194
2017	181,229	1,040,670
2018	184,566	1,058,423
2019	187,935	1,076,818
2020	191,372	1,095,656
Growth Rate	**1.88%**	**1.83%**

WECC Summary Demand Statistics, 2009

Transmission Area	Peak (MW)	Growth*	Energy (GWh)	Growth*	Load Factor
AB_S	4,007	1.9%	28,006	1.96%	79.79%
ABCN	6,582	2.0%	45,987	2.08%	79.76%
Arizona	17,668	3.0%	78,420	2.96%	50.67%
BC	11,403	1.2%	63,949	1.47%	64.02%
CNP15	20,112	1.3%	104,346	1.24%	59.23%
CO_East	9,390	2.0%	49,907	2.02%	60.67%
CO_West	1,171	2.1%	6,513	2.13%	63.50%
COB	295	1.4%	1,718	1.30%	66.48%
CSCE	24,193	1.2%	113,577	1.07%	53.59%
CSDGE	4,601	1.4%	22,517	1.35%	55.87%
CZP26	1,537	1.2%	9,414	0.96%	69.92%
ID_SW	3,017	1.9%	15,591	1.70%	58.99%
IDE_WYSW	1,506	1.5%	9,089	1.46%	68.90%
IID	905	1.3%	3,623	1.28%	45.71%
IV-NG	N/A	N/A	N/A	N/A	N/A
La Rosita	1,128	4.3%	6,008	4.70%	60.80%
LADWP	6,391	0.1%	30,214	0.18%	53.97%
Miguel	N/A	N/A	N/A	N/A	N/A
Montana	1,896	2.0%	11,622	1.97%	69.97%
N Nevada	2,284	2.9%	13,571	2.91%	67.83%
NBAJA	1,128	4.3%	6,008	4.70%	60.80%
NewMexico	4,261	2.8%	25,231	2.78%	67.60%
Northwest	27,725	1.4%	157,775	1.47%	64.96%
PV	N/A	N/A	N/A	N/A	N/A
S Nevada	7,745	2.4%	32,164	2.32%	47.41%
SF	899	1.2%	5,350	1.25%	67.94%
SMUD	3,213	2.6%	12,167	2.33%	43.23%
Utah	6,378	3.4%	34,677	3.08%	62.07%
WYCE	2,260	2.1%	14,511	2.20%	73.30%
***12 Year Annualized Growth Rate (2009-2020)**					

WECC Transarea Load and Resource Report - Case 1													
Market Area	**Fuel**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
AB_S	Load	4,007	4,086	4,167	4,247	4,349	4,421	4,502	4,583	4,666	4,751	4,837	4,924
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	4,007	4,086	4,167	4,247	4,349	4,421	4,502	4,583	4,666	4,751	4,837	4,924
	Coal	1,272	1,272	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772	1,772
	Hydro	411	411	411	411	411	411	411	411	411	411	411	411
	Natural Gas	1,809	2,149	2,149	2,149	2,489	2,829	2,829	3,169	3,394	3,959	3,959	3,959
	Other	330	387	415	472	501	558	587	615	672	701	729	729
	Purchases	250	250	250	250	250	250	250	250	250	250	250	250
	Resources Total	4,072	4,469	4,998	5,055	5,424	5,821	5,849	6,218	6,500	7,093	7,122	7,122
Reserve Margin		**2%**	**9%**	**20%**	**19%**	**25%**	**32%**	**30%**	**36%**	**39%**	**49%**	**47%**	**45%**
ABCN	Load	6,582	6,763	6,935	7,086	7,182	7,359	7,447	7,581	7,719	7,858	8,001	8,146
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	6,582	6,763	6,935	7,086	7,182	7,359	7,447	7,581	7,719	7,858	8,001	8,146
	Coal	5,371	5,078	5,528	5,528	5,528	5,528	5,528	5,528	5,528	5,528	5,528	6,028
	Hydro	468	468	468	468	468	468	468	468	468	468	468	468
	Natural Gas	2,961	3,301	3,461	3,442	3,442	3,442	3,442	3,442	3,442	3,442	3,442	3,442
	Other	338	338	338	338	338	338	338	338	338	338	338	338
	Purchases	0	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	9,138	9,185	9,795	9,776	9,776	9,776	9,776	9,776	9,776	9,776	9,776	10,276
Reserve Margin		**39%**	**36%**	**41%**	**38%**	**36%**	**33%**	**31%**	**29%**	**27%**	**24%**	**22%**	**26%**
Arizona	Load	17,668	18,284	18,901	19,405	20,015	20,703	21,304	21,882	22,475	23,086	23,715	24,360
	Sale	1,655	1,680	1,705	1,726	1,753	1,786	1,815	1,845	1,876	1,907	1,940	1,974
	Load Total	19,323	19,964	20,606	21,131	21,768	22,489	23,119	23,727	24,351	24,993	25,655	26,334
	Coal	5,754	6,154	6,654	6,654	6,654	6,654	6,654	7,154	7,154	7,154	7,154	7,154
	Fuel Oil	149	149	149	149	149	149	149	149	149	149	149	149
	Hydro	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133	1,133
	Natural Gas	8,473	8,883	9,583	9,970	10,416	11,596	11,975	12,834	13,409	14,429	15,449	15,887
	Other	44	44	49	51	53	56	58	61	61	63	63	68
	Pumped Storage	217	217	217	217	217	217	217	217	217	217	217	217
	Purchases	1,071	1,071	1,071	1,071	1,071	1,071	1,071	1,071	921	921	921	921
	Resources Total	16,840	17,650	18,855	19,244	19,693	20,875	21,256	22,618	23,043	24,065	25,085	25,528
Reserve Margin		**-13%**	**-12%**	**-8%**	**-9%**	**-10%**	**-7%**	**-8%**	**-5%**	**-5%**	**-4%**	**-2%**	**-3%**
BC	Load	11,403	11,499	11,631	11,767	11,930	11,974	12,105	12,282	12,463	12,652	12,844	13,062
	Sale	368	368	368	368	368	368	368	368	368	368	368	368
	Load Total	11,771	11,867	11,999	12,135	12,298	12,342	12,473	12,650	12,831	13,020	13,212	13,430
	Coal	0	184	184	184	184	184	184	184	184	184	184	184
	Hydro	12,369	12,449	12,982	12,982	12,982	12,982	12,982	12,982	12,982	12,982	12,982	12,982
	Natural Gas	832	832	1,152	1,152	1,152	1,152	1,152	1,152	1,152	1,152	1,152	1,152
	Other	530	587	644	673	730	787	815	872	901	958	1,015	1,072
	Purchases	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176	1,176
	Resources Total	14,906	15,227	16,137	16,166	16,223	16,280	16,308	16,365	16,394	16,451	16,508	16,565
Reserve Margin		**27%**	**28%**	**34%**	**33%**	**32%**	**32%**	**31%**	**29%**	**28%**	**26%**	**25%**	**23%**
CNP15	Load	20,112	20,405	20,730	21,004	21,309	21,547	21,805	22,060	22,335	22,615	22,897	23,185
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	20,112	20,405	20,730	21,004	21,309	21,547	21,805	22,060	22,335	22,615	22,897	23,185
	Coal	114	114	114	114	114	114	114	114	114	114	114	114
	Fuel Oil	270	270	270	270	270	270	270	270	270	270	270	270
	Geothermal	1,223	1,223	1,223	1,223	1,223	1,223	1,223	1,223	1,223	1,223	1,223	1,223
	Hydro	7,474	7,474	7,474	7,474	7,474	7,474	7,474	7,474	7,474	7,474	7,474	7,474
	Natural Gas	11,605	12,735	12,735	12,735	12,735	12,735	12,623	12,466	12,686	13,146	12,674	13,614
	Other	972	988	1,020	1,052	1,068	1,100	1,116	1,132	1,148	1,180	1,196	1,212
	Pumped Storage	1,613	1,613	1,613	1,613	1,613	1,613	1,613	1,613	1,613	1,613	1,613	1,613
	Purchases	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260	2,260
	Resources Total	25,529	26,675	26,707	26,739	26,755	26,787	26,691	26,550	26,786	27,278	26,822	27,778
Reserve Margin		**27%**	**31%**	**29%**	**27%**	**26%**	**24%**	**22%**	**20%**	**20%**	**21%**	**17%**	**20%**
CO_East	Load	9,390	9,597	9,796	10,012	10,218	10,431	10,655	10,854	11,057	11,265	11,476	11,692
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	9,390	9,597	9,796	10,012	10,218	10,431	10,655	10,854	11,057	11,265	11,476	11,692
	Coal	3,032	3,782	3,782	3,782	3,782	3,782	3,782	3,734	4,234	4,234	4,234	4,215
	Fuel Oil	100	100	100	100	100	100	100	100	100	100	100	100
	Hydro	258	258	258	258	258	258	258	258	258	258	258	258
	Natural Gas	4,450	4,450	4,450	4,587	5,107	5,627	6,647	7,347	7,347	7,347	7,347	7,347
	Other	943	984	1,024	1,105	1,186	1,186	1,227	1,267	1,348	1,348	1,429	1,470
	Pumped Storage	554	554	554	554	554	554	554	554	554	554	554	554
	Purchases	799	799	799	799	799	799	799	799	799	799	799	799
	Resources Total	10,137	10,927	10,968	11,186	11,787	12,307	13,367	14,059	14,640	14,640	14,721	14,743
Reserve Margin		**8%**	**14%**	**12%**	**12%**	**15%**	**18%**	**25%**	**30%**	**32%**	**30%**	**28%**	**26%**

Market Area	Fuel	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
CO_West	Load	1,171	1,196	1,223	1,249	1,278	1,307	1,334	1,361	1,388	1,416	1,445	1,473
	Sale	336	336	336	336	336	336	336	336	336	336	336	336
	Load Total	1,507	1,532	1,559	1,585	1,614	1,643	1,670	1,697	1,724	1,752	1,781	1,809
	Coal	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900	1,900
	Hydro	350	350	350	350	350	350	350	350	350	350	350	350
	Natural Gas	84	84	84	84	84	84	84	84	84	84	84	84
	Purchases	0	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	2,333	2,333	2,333	2,333	2,333	2,333	2,333	2,333	2,333	2,333	2,333	2,333
Reserve Margin		**55%**	**52%**	**50%**	**47%**	**45%**	**42%**	**40%**	**37%**	**35%**	**33%**	**31%**	**29%**
COB	Load	295	299	302	305	311	317	321	325	329	334	338	342
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	295	299	302	305	311	317	321	325	329	334	338	342
	Natural Gas	564	564	564	564	564	564	564	564	564	564	564	564
	Purchases	0	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	564	564	564	564	564	564	564	564	564	564	564	564
Reserve Margin		**91%**	**89%**	**87%**	**85%**	**81%**	**78%**	**76%**	**74%**	**72%**	**69%**	**67%**	**65%**
CSCE	Load	24,193	24,514	24,830	25,174	25,485	25,811	26,124	26,395	26,720	27,050	27,382	27,720
	Sale	208	208	208	208	208	208	208	208	208	208	208	208
	Load Total	24,401	24,722	25,038	25,382	25,693	26,019	26,332	26,603	26,928	27,258	27,590	27,928
	Coal	200	200	200	200	200	200	200	200	200	200	200	200
	Geothermal	371	371	371	371	371	371	371	371	371	371	371	371
	Hydro	1,438	1,438	1,438	1,438	1,438	1,438	1,438	1,438	1,438	1,438	1,438	1,438
	Natural Gas	15,098	15,598	15,423	15,073	14,621	14,191	14,191	13,444	13,269	12,749	12,008	12,092
	Nuclear	2,232	2,232	2,232	2,232	2,232	2,232	2,232	2,232	2,232	2,232	2,232	2,232
	Other	945	958	970	982	1,006	1,006	1,030	1,042	1,054	1,066	1,078	1,102
	Pumped Storage	207	207	207	207	207	207	207	207	207	207	207	207
	Purchases	1,823	1,823	1,823	1,823	1,823	1,823	1,823	1,823	1,823	1,823	1,823	1,823
	Resources Total	22,314	22,826	22,663	22,325	21,898	21,468	21,492	20,757	20,594	20,086	19,357	19,465
Reserve Margin		**-9%**	**-8%**	**-9%**	**-12%**	**-15%**	**-17%**	**-18%**	**-22%**	**-24%**	**-26%**	**-30%**	**-30%**
CSDGE	Load	4,601	4,669	4,735	4,803	4,870	4,935	4,997	5,059	5,127	5,195	5,264	5,334
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	4,601	4,669	4,735	4,803	4,870	4,935	4,997	5,059	5,127	5,195	5,264	5,334
	Fuel Oil	14	14	14	14	14	14	14	14	14	14	14	14
	Hydro	2	2	2	2	2	2	2	2	2	2	2	2
	Natural Gas	2,537	2,537	2,433	2,433	2,323	2,523	3,177	3,677	3,907	4,467	4,492	4,492
	Other	50	50	50	50	50	50	50	50	50	50	50	50
	Pumped Storage	40	40	40	40	40	40	40	40	40	40	40	40
	Purchases	81	81	81	81	81	81	81	81	81	81	81	81
	Resources Total	2,724	2,724	2,620	2,620	2,510	2,710	3,364	3,864	4,094	4,654	4,679	4,679
Reserve Margin		**-69%**	**-71%**	**-81%**	**-83%**	**-94%**	**-82%**	**-49%**	**-31%**	**-25%**	**-12%**	**-13%**	**-14%**
CZP26	Load	1,537	1,557	1,578	1,598	1,619	1,637	1,654	1,672	1,691	1,711	1,731	1,751
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	1,537	1,557	1,578	1,598	1,619	1,637	1,654	1,672	1,691	1,711	1,731	1,751
	Coal	102	102	102	102	102	102	102	102	102	102	102	102
	Hydro	6	6	6	6	6	6	6	6	6	6	6	6
	Natural Gas	3,674	3,674	3,674	3,674	3,674	3,674	3,674	3,674	3,337	3,001	3,001	3,001
	Nuclear	2,248	2,248	2,248	2,248	2,248	2,248	2,248	2,248	2,248	2,248	2,248	2,248
	Purchases	0	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	6,030	6,030	6,030	6,030	6,030	6,030	6,030	6,030	5,693	5,357	5,357	5,357
Reserve Margin		**292%**	**287%**	**282%**	**277%**	**272%**	**268%**	**265%**	**261%**	**237%**	**213%**	**209%**	**206%**
ID_SW	Load	3,017	3,080	3,136	3,193	3,259	3,326	3,398	3,455	3,512	3,572	3,631	3,693
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	3,017	3,080	3,136	3,193	3,259	3,326	3,398	3,455	3,512	3,572	3,631	3,693
	Geothermal	36	36	36	36	36	36	36	36	36	36	36	36
	Hydro	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668	1,668
	Natural Gas	451	451	451	451	451	971	1,311	1,471	1,651	1,811	1,991	2,151
	Other	17	17	17	17	17	17	17	17	17	17	17	17
	Purchases	83	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	2,255	2,172	2,172	2,172	2,172	2,692	3,032	3,192	3,372	3,532	3,712	3,872
Reserve Margin		**-25%**	**-29%**	**-31%**	**-32%**	**-33%**	**-19%**	**-11%**	**-8%**	**-4%**	**-1%**	**2%**	**5%**
IDE_WYSW	Load	1,506	1,529	1,537	1,559	1,580	1,609	1,637	1,662	1,687	1,713	1,740	1,766
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	1,506	1,529	1,537	1,559	1,580	1,609	1,637	1,662	1,687	1,713	1,740	1,766
	Coal	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150	2,150
	Hydro	442	442	442	442	442	442	442	442	442	442	442	442
	Natural Gas	0	0	0	0	0	0	0	160	160	160	500	500
	Other	303	391	435	479	522	566	610	654	742	786	830	873
	Purchases	0	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	2,895	2,983	3,027	3,071	3,114	3,158	3,202	3,406	3,494	3,538	3,922	3,965
Reserve Margin		**92%**	**95%**	**97%**	**97%**	**97%**	**96%**	**96%**	**105%**	**107%**	**107%**	**125%**	**125%**

Market Area	Fuel	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
IID	Load	905	918	931	942	955	965	978	990	1,003	1,015	1,028	1,041
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	905	918	931	942	955	965	978	990	1,003	1,015	1,028	1,041
	Fuel Oil	61	61	61	61	61	61	61	61	43	43	43	43
	Geothermal	745	745	745	745	745	745	745	745	745	745	745	745
	Hydro	46	46	46	46	46	46	46	46	46	46	46	46
	Natural Gas	573	573	573	573	573	498	738	898	898	1,058	1,058	1,058
	Other	47	47	47	47	47	47	47	47	47	47	47	47
	Purchases	33	33	33	33	33	33	33	33	33	33	33	33
	Resources Total	1,504	1,504	1,504	1,504	1,504	1,429	1,669	1,829	1,811	1,971	1,971	1,971
Reserve Margin		**66%**	**64%**	**62%**	**60%**	**57%**	**48%**	**71%**	**85%**	**81%**	**94%**	**92%**	**89%**
IV-NG	Load	0	0	0	0	0	0	0	0	0	0	0	0
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	0	0	0	0	0	0	0	0	0	0	0	0
	Natural Gas	866	866	866	866	866	866	866	866	866	866	866	866
	Purchases	0	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	866	866	866	866	866	866	866	866	866	866	866	866
Reserve Margin		**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
LADWP	Load	6,391	6,407	6,418	6,431	6,444	6,453	6,457	6,461	6,471	6,480	6,488	6,497
	Sale	77	77	77	77	77	77	77	77	77	77	77	77
	Load Total	6,468	6,484	6,495	6,508	6,521	6,530	6,534	6,538	6,548	6,557	6,565	6,574
	Hydro	247	247	247	247	247	247	247	247	247	247	247	247
	Natural Gas	4,145	4,145	4,145	4,145	3,966	4,463	4,683	4,843	4,621	4,779	5,060	5,620
	Other	35	35	35	35	35	35	35	35	35	35	35	35
	Pumped Storage	1,495	1,495	1,495	1,495	1,495	1,495	1,495	1,495	1,495	1,495	1,495	1,495
	Purchases	737	737	737	737	737	737	737	737	737	737	737	737
	Resources Total	6,659	6,659	6,659	6,659	6,480	6,977	7,197	7,357	7,135	7,293	7,574	8,134
Reserve Margin		**3%**	**3%**	**3%**	**2%**	**-1%**	**7%**	**10%**	**13%**	**9%**	**11%**	**15%**	**24%**
La Rosita	Load	1,128	1,180	1,234	1,301	1,361	1,410	1,460	1,520	1,583	1,648	1,716	1,786
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	1,128	1,180	1,234	1,301	1,361	1,410	1,460	1,520	1,583	1,648	1,716	1,786
	Geothermal	685	685	685	685	685	685	685	685	685	685	685	685
	Natural Gas	767	767	767	767	767	767	767	767	767	927	927	927
	Purchases	0	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,452	1,612	1,612	1,612
Reserve Margin		**29%**	**23%**	**18%**	**12%**	**7%**	**3%**	**-1%**	**-4%**	**-8%**	**-2%**	**-6%**	**-10%**
Miguel	Load	0	0	0	0	0	0	0	0	0	0	0	0
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	0	0	0	0	0	0	0	0	0	0	0	0
	Natural Gas	192	702	702	702	702	702	702	802	802	802	802	802
	Purchases	0	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	192	702	702	702	702	702	702	802	802	802	802	802
Reserve Margin		**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
Montana	Load	1,896	1,935	1,976	2,018	2,059	2,102	2,147	2,186	2,226	2,268	2,312	2,355
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	1,896	1,935	1,976	2,018	2,059	2,102	2,147	2,186	2,226	2,268	2,312	2,355
	Coal	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400	2,400
	Hydro	834	834	834	834	834	834	834	834	834	834	834	834
	Natural Gas	55	55	55	55	55	55	55	55	215	215	575	575
	Other	173	234	265	295	356	387	417	478	509	539	600	631
	Purchases	229	229	229	229	229	229	229	229	229	229	229	229
	Resources Total	3,692	3,753	3,783	3,814	3,875	3,905	3,936	3,997	4,187	4,218	4,639	4,669
Reserve Margin		**95%**	**94%**	**91%**	**89%**	**88%**	**86%**	**83%**	**83%**	**88%**	**86%**	**101%**	**98%**
N Nevada	Load	2,284	2,354	2,427	2,500	2,577	2,656	2,737	2,813	2,890	2,970	3,052	3,135
	Sale	75	75	75	75	75	75	75	75	75	75	75	75
	Load Total	2,359	2,429	2,502	2,575	2,652	2,731	2,812	2,888	2,965	3,045	3,127	3,210
	Coal	721	721	721	721	721	721	721	721	721	1,221	1,221	1,221
	Fuel Oil	20	20	20	20	20	20	20	10	0	0	0	0
	Geothermal	262	322	322	322	322	322	322	322	322	322	322	322
	Hydro	7	7	7	7	7	7	7	7	7	7	7	7
	Natural Gas	1,425	1,425	1,425	1,425	1,425	1,425	1,425	1,425	1,425	1,372	1,372	1,289
	Other	33	33	33	33	33	37	42	47	47	56	56	65
	Purchases	730	730	730	730	730	730	730	730	730	730	730	730
	Resources Total	3,198	3,258	3,258	3,258	3,258	3,262	3,267	3,261	3,251	3,707	3,707	3,633
Reserve Margin		**36%**	**34%**	**30%**	**27%**	**23%**	**19%**	**16%**	**13%**	**10%**	**22%**	**19%**	**13%**
NBAJA	Load	1,128	1,180	1,234	1,301	1,361	1,410	1,460	1,520	1,583	1,648	1,716	1,786
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	1,128	1,180	1,234	1,301	1,361	1,410	1,460	1,520	1,583	1,648	1,716	1,786
	Fuel Oil	88	88	88	88	88	88	88	88	88	88	88	88
	Natural Gas	1,439	1,439	1,599	1,599	1,599	1,599	1,959	2,119	2,459	2,639	2,864	3,024
	Purchases	0	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	1,527	1,527	1,687	1,687	1,687	1,687	2,047	2,207	2,547	2,727	2,952	3,112
Reserve Margin		**35%**	**29%**	**37%**	**30%**	**24%**	**20%**	**40%**	**45%**	**61%**	**65%**	**72%**	**74%**

Market Area	Fuel	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
NewMexico	Load	4,261	4,394	4,524	4,656	4,796	4,935	5,073	5,205	5,341	5,480	5,625	5,767
	Sale	150	150	150	150	150	150	150	150	0	0	0	0
	Load Total	4,411	4,544	4,674	4,806	4,946	5,085	5,223	5,355	5,341	5,480	5,625	5,767
	Coal	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	4,430	4,430
	Hydro	82	82	82	82	82	82	82	82	82	82	82	82
	Natural Gas	2,424	2,424	2,424	2,536	2,482	2,482	2,564	2,564	2,564	2,643	2,823	2,983
	Other	103	103	103	103	103	103	103	103	103	103	103	103
	Purchases	363	363	213	213	213	213	213	213	213	213	213	213
	Resources Total	6,901	6,901	6,751	6,863	6,809	6,809	6,891	6,891	6,891	6,970	7,650	7,810
Reserve Margin		**56%**	**52%**	**44%**	**43%**	**38%**	**34%**	**32%**	**29%**	**29%**	**27%**	**36%**	**35%**
Northwest	Load	27,725	28,108	28,486	28,882	29,304	29,768	30,190	30,612	31,037	31,470	31,910	32,359
	Sale	2,048	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045	2,045
	Load Total	29,773	30,153	30,531	30,927	31,349	31,813	32,235	32,657	33,082	33,515	33,955	34,404
	Coal	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961	1,961
	Geothermal	0	30	30	30	30	30	30	30	30	30	30	30
	Hydro	30,454	30,465	30,478	30,492	30,505	30,519	30,629	30,629	30,629	30,629	30,629	30,629
	Natural Gas	5,756	5,756	5,756	5,756	5,756	5,756	6,096	6,096	6,096	6,096	6,096	6,276
	Nuclear	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122	1,122
	Other	788	811	834	856	868	891	913	936	959	981	1,004	1,027
	Purchases	655	655	655	655	655	655	655	655	655	655	655	655
	Resources Total	40,737	40,800	40,836	40,872	40,897	40,933	41,407	41,429	41,452	41,475	41,497	41,700
Reserve Margin		**37%**	**35%**	**34%**	**32%**	**30%**	**29%**	**28%**	**27%**	**25%**	**24%**	**22%**	**21%**
PV	Load	0	0	0	0	0	0	0	0	0	0	0	0
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	0	0	0	0	0	0	0	0	0	0	0	0
	Natural Gas	3,751	3,751	3,751	3,751	3,751	3,751	3,751	3,751	3,751	3,751	3,751	3,751
	Nuclear	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946	3,946
	Purchases	0	0	0	0	0	0	0	0	0	0	0	0
	Resources Total	7,697	7,697	7,697	7,697	7,697	7,697	7,697	7,697	7,697	7,697	7,697	7,697
Reserve Margin		**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**	**0%**
S Nevada	Load	7,745	8,005	8,183	8,424	8,568	8,791	8,988	9,221	9,379	9,639	9,849	10,051
	Sale	1,692	1,692	1,692	1,692	1,692	1,692	1,692	1,692	1,692	1,692	1,692	1,692
	Load Total	9,437	9,697	9,875	10,116	10,260	10,483	10,680	10,913	11,071	11,331	11,541	11,743
	Coal	595	595	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,095	1,595
	Hydro	2,231	2,231	2,231	2,231	2,231	2,231	2,231	2,231	2,231	2,231	2,231	2,231
	Natural Gas	6,189	6,189	6,189	6,189	6,189	6,189	6,189	6,189	6,709	7,209	7,129	7,309
	Other	79	90	101	113	124	136	147	158	170	181	192	204
	Purchases	1,161	1,186	1,211	1,232	1,259	1,292	1,321	1,351	1,382	1,413	1,446	1,480
	Resources Total	10,255	10,292	10,828	10,860	10,899	10,943	10,983	11,025	11,587	12,130	12,094	12,819
Reserve Margin		**9%**	**6%**	**10%**	**7%**	**6%**	**4%**	**3%**	**1%**	**5%**	**7%**	**5%**	**9%**
San Francis	Load	899	906	921	933	947	957	969	980	992	1,005	1,018	1,030
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	899	906	921	933	947	957	969	980	992	1,005	1,018	1,030
	Natural Gas	263	883	883	883	883	883	883	883	883	883	883	883
	Purchases	66	66	66	66	66	66	66	66	66	66	66	66
	Resources Total	329	949	949	949	949	949	949	949	949	949	949	949
Reserve Margin		**-63%**	**5%**	**3%**	**2%**	**0%**	**-1%**	**-2%**	**-3%**	**-4%**	**-6%**	**-7%**	**-8%**
SMUD	Load	3,213	3,291	3,380	3,473	3,567	3,663	3,757	3,844	3,944	4,046	4,152	4,260
	Sale	0	0	0	0	0	0	0	0	0	0	0	0
	Load Total	3,213	3,291	3,380	3,473	3,567	3,663	3,757	3,844	3,944	4,046	4,152	4,260
	Hydro	711	711	711	711	711	711	711	711	711	711	711	711
	Natural Gas	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019	1,019
	Other	33	33	33	33	33	33	33	33	33	33	33	33
	Purchases	100	100	100	100	100	100	100	100	100	100	100	100
	Resources Total	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862	1,862
Reserve Margin		**-42%**	**-43%**	**-45%**	**-46%**	**-48%**	**-49%**	**-50%**	**-52%**	**-53%**	**-54%**	**-55%**	**-56%**
Utah	Load	6,378	6,650	6,924	7,198	7,456	7,741	7,968	8,198	8,435	8,680	8,929	9,189
	Sale	947	947	947	947	947	947	947	947	947	947	947	947
	Load Total	7,325	7,597	7,871	8,145	8,403	8,688	8,915	9,145	9,382	9,627	9,876	10,136
	Coal	5,405	5,405	5,405	5,405	5,405	5,396	5,896	5,896	5,896	6,396	6,329	6,329
	Fuel Oil	14	14	14	14	14	14	14	14	14	14	14	14
	Geothermal	79	79	79	79	79	79	79	79	79	79	79	79
	Hydro	148	148	148	148	148	148	148	148	148	148	148	148
	Natural Gas	1,797	1,697	1,697	1,697	1,697	2,197	2,877	3,037	3,037	3,377	3,717	3,877
	Other	0	0	0	0	0	0	7	7	7	7	7	7
	Purchases	331	331	331	331	331	331	331	331	331	331	331	331
	Resources Total	7,774	7,674	7,674	7,674	7,674	8,165	9,352	9,512	9,512	10,352	10,625	10,785
Reserve Margin		**6%**	**1%**	**-2%**	**-6%**	**-9%**	**-6%**	**5%**	**4%**	**1%**	**8%**	**8%**	**6%**
WYCE	Load	2,260	2,301	2,327	2,383	2,438	2,494	2,550	2,604	2,657	2,716	2,774	2,833
	Sale	346	346	346	346	346	346	346	346	346	346	346	346
	Load Total	2,606	2,647	2,673	2,729	2,784	2,840	2,896	2,950	3,003	3,062	3,120	3,179
	Coal	2,541	2,541	2,841	2,841	2,830	2,820	2,820	2,820	2,810	2,810	2,810	2,810
	Hydro	281	281	281	281	281	281	281	281	281	281	281	281
	Natural Gas	225	225	225	225	225	225	225	225	225	225	225	225
	Other	12	15	17	20	22	27	30	32	35	37	42	42
	Purchases	313	313	313	313	313	313	313	313	313	313	313	313
	Resources Total	3,371	3,374	3,676	3,679	3,671	3,666	3,669	3,671	3,663	3,666	3,671	3,671
Reserve Margin		**29%**	**27%**	**38%**	**35%**	**32%**	**29%**	**27%**	**24%**	**22%**	**20%**	**18%**	**15%**

Appendix B-2
Capacity Balance Tables

Capacity Balance tables for California and the Rest-of-WECC are available at:
http://www.energy.ca.gov/2007publications/CEC-200-2007-010/appendices/appendixB-2_excel-1.xls

Capacity Balance tables by transmission planning area are available at:
http://www.energy.ca.gov/2007publications/CEC-200-2007-010/appendices/appendixB-2_excel-2.xls

APPENDIX C

CALIFORNIA VERSUS REST-OF-WECC SCORECARD RESULTS

Prepared by Global Energy Decisions, Inc.

Appendix C-1
CA vs. Rest-of-WECC scorecard for 2020 for the Base Gas, Low Gas, and High Gas cases

The scorecard results are a sample of results for 2020 and are based on a large spreadsheet with the list of results on the left-hand side and the nine thematic scenarios across the top. Because all nine scenarios cannot fit on an 8 1/2" x 11" sheet, the scenarios print out in two parts: the first includes the first five scenarios and all related results; the second includes the last four scenarios with the list of results repeated. The results include load, generation, production costs, capital costs, import energy, export energy, emissions data, and fuel data.

The full spreadsheet of results is available at:
http://www.energy.ca.gov/2007publications/CEC-200-2007-010/appendices/appendixC-1_excel-1.xls

Source: Global Energy Decisions

Line Definitions and Notes

1		**Definition**
2	**Total WECC System Cost ($000)**	Sum of Lines 4 and 64
3	**California**	
4	**CA System Production Cost ($000)**	Sum of Lines 29, 38, 53, and 59
5	**CA Per Unit Production Cost ($/MWh)**	Line 4 divided by the difference of Line 7 and 23
6	**CA Peak Load (MW)**	California coincident peak load in MW
7	**CA Energy Load (GWh)**	California energy load in GWh (Includes Losses and Pumping Load)
8	**CA "Energy Not Served" (GWh)**	California Loss of load in GWh
9	**CA Generation By Fuel (GWh)**	
10	***Coal***	California Coal-fired Generation (GWh)
11	***Fuel Oil***	California Fuel Oil-fired Generation (GWh)
12	***Geothermal***	California Geothermal Generation (GWh)
13	***Hydro***	California Hydro Generation (GWh)
14	***Natural Gas***	California Natural Gas-fired Generation (GWh)
15	***Nuclear***	California Nuclear Generation (GWh)
16	***Biomass/Other***	California plants including Biomass, Solar, Refuse, Wood, Jet Fuel-fired plants, Petroleum Coke-fired plants, and Variable Demand Reduction (GWh)
17	***Pumped Storage***	California Pumped Storage Generation (GWh)
18	***Wind***	California Wind Generation (GWh)
19	***Total CA Generation (GWh)***	Sum of lines 10 through 18
20	**CA Energy Efficiency and PV Solar (GWh)**	
21	***Energy Efficiency***	California Energy Efficiency Load Reduction (GWh)
22	***PV Solar***	California PV Solar Load Reduction (GWh)
23	***Total CA Energy Efficiency and PV Solar (GWh)***	Sum of Lines 21 and 22
24	**CA O&M Costs**	
25	**CA Fuel Costs ($000)**	California Located Generation Fuel Costs
26	**CA VOM Costs ($000)**	California Located Generation Variable Operations and Maintanence Costs
27	**CA Start Costs ($000)**	California Located Generation Start Costs
28	**CA FOM Costs ($000)**	California Located Generation Fixed Operations and Maintenance Costs
29	***Total CA O&M Costs ($000)***	Sum of Lines 25 through 28
30	**CA Other Costs**	
31	**CA Wheeling Costs ($000)**	California incurred Wheeling Costs
32	**CA Energy Efficiency Costs ($000)**	California Energy Efficiency Program Capital Costs
33	**CA PV Solar Costs ($000)**	California PV Solar Program Capital Costs
34	**CA Variable Demand Response Costs ($000)**	California Variable Demand Response Costs (includes Program Capital Costs and Variable Costs)
35	**CA Transmission Capital Costs ($000)**	California Transmission Capital Costs relative to Line 36
36	**CA Transmission Miles**	California Transmission Miles relative to Line 35
37	**CA Incremental Resource Capital Costs ($000)**	California cost of generic resource additions including the following resource types: Gas Turbines, Combined Cycles, Wind, Geothermal, Concentrated Solar Power, and Biomass
38	***Total CA Other Costs ($000)***	Sum of of Lines 31 through 35, and Line 37
39	**CA Renewable Generation**	
40	**CA Renewable Generation (GWh) - without Hydro**	California renewable generation excluding hydro and pumped storage generation
41	**CA Renewable Energy (%) - without Hydro**	California renewable generation excluding hydro and pumped storage as a percent of California Load (Line 7) net of California EE and PV Solar (Line 23)
42	**CA Renewable Generation (GWh) - with Hydro**	California renewable generation including hydro and pumped storage generation
43	**CA Renewable Energy (%) - with Hydro**	California renewable generation including hydro and pumped storage as a percent of California Load (Line 7) net of California EE and PV Solar (Line 23)
44	**CA Emissions**	
45	**CA CO2 Production (000 tons)**	California CO2 production from generation located within California only
46	**CA GHG 2020/1990 Ratio**	
47	**CA SO2 (000 tons)**	California SO2 production from generation located within California only
48	**CA NOx (000 tons)**	California NOx production from generation located within California only
49	**CA HG (000 tons)**	California HG production from generation located within California only
50	**CA Emission Costs SO2/NOx/HG ($000)**	California Total Emission Costs from generation located within California only
51	**CA Remote Generation**	
52	**CA Remote Generation (GWh)**	California share of generation from remote located plants
53	**CA Remote Generation Cost ($000)**	California share of generation costs from remote located plants including costs associated with Fuel, VOM , Start-up , FOM, and Emissions.
54	**CA Remote CO2 (000 tons)**	California share of CO2 emissions from remote located plants
55	**CA Remote SO2 (000 tons)**	California share of SO2 emissions from remote located plants
56	**CA Remote NOx (000 tons)**	California share of NOx emissions from remote located plants
57	**CA Remote HG (000 tons)**	California share of HG emissions from remote located plants
58	**CA Imports**	
59	**CA Net Import ($000)**	Cost of energy imports from the Rest of WECC priced at California marginal clearing price (SP15)

1		Definition
60	**CA Net Import (GWh)**	Net Energy imports from the Rest of WECC (i.e. the difference in California load and generation)
61	**CA Import CO2 (000 tons)**	CO2 from imported energy from plants in the Rest of WECC into California
62	**CA Gas and Water Consumption**	
63	**CA Gas Consumption (Gbtu)**	Natural gas fuel burn from plants located within California
64	**CA Water Consumption**	Water consumption used in power generation by plants located within California
65	**Rest of WECC (excludes California results)**	
66	**WECC System Production Cost ($000)**	Sum of Lines 93, 102, 108, and 111
67	**WECC Per Unit Production Cost ($/MWh)**	Line 66 divided by the difference of Line 69 and 87
68	**WECC Peak Load (MW)**	Rest of WECC coincident peak load in MW
69	**WECC Energy Load (GWh)**	Rest of WECC energy load in GWh (Includes Losses and Pumping Load)
70	**WECC "Energy Not Served" (GWh)**	Rest of WECC Loss of load in GWh
71	**Rest of WECC Generation by Fuel (GWh)**	
72	***Coal***	Rest of WECC Coal-fired Generation (GWh)
73	***Fuel Oil***	Rest of WECC Fuel Oil-fired Generation (GWh)
74	***Geothermal***	Rest of WECC Geothermal Generation (GWh)
75	***Hydro***	Rest of WECC Hydro Generation (GWh)
76	***Natural Gas***	Rest of WECC Natural Gas-fired Generation (GWh)
77	***Nuclear***	Rest of WECC Nuclear Generation (GWh)
78	***Biomass/Other***	Rest of WECC plants including Biomass, Solar, Refuse, Wood, Jet Fuel-fired plants, Petroleum Coke-fired plants, and Variable Demand Reduction (GWh)
79	***Pumped Storage***	Rest of WECC Pumped Storage Generation (GWh)
80	***Wind***	Rest of WECC Wind Generation (GWh)
81	***Total Rest of WECC Generation (GWh)***	Sum of Lines 71 through 80
82	***Total Rest ofWECC Exports (GWh)***	Net energy exports from the Rest of WECC into California
83	***Total Rest of WECC Generation Serving WECC Load (GWh)***	The difference of Lines 81 and 82
84	**Rest of WECC Energy Efficiency and PV Solar (GWh)**	
85	***Energy Efficiency***	Rest of WECC Energy Efficiency Load Reduction (GWh)
86	***PV Solar***	Rest of WECC PV Solar Load Reduction (GWh)
87	***Total Rest of WECC Energy Efficiency and PV Solar (GWh)***	Sum of Lines 86 and 87
88	**Rest of WECC O&M Costs**	
89	**WECC Fuel Costs ($000)**	Rest of WECC Located Generation Fuel Costs (excludes cost from WECC/CA shared generation)
90	**WECC VOM Costs ($000)**	Rest of WECC Located Generation Variable Operations and Maintanence Costs(excludes cost from WECC/CA shared generation)
91	**WECC Start Costs ($000)**	Rest of WECC Located Generation Start Costs(excludes cost from WECC/CA shared generation)
92	**WECC FOM Costs ($000)**	Rest of WECC Located Generation Fixed Operations and Maintenance Costs(excludes cost from WECC/CA shared generation)
93	***Total Rest of WECC O&M Costs ($000)***	Sum of Lines 89 through 92
94	**Rest of WECC Other Costs**	
95	**WECC Wheeling Costs ($000)**	Rest of WECC incurred Wheeling Costs
96	**WECC Energy Efficiency Costs ($000)**	Rest of WECC Energy Efficiency Program Capital Costs
97	**WECC PV Solar Costs ($000)**	Rest of WECC PV Solar Program Capital Costs
98	**WECC Variable Demand Response Costs ($000)**	Rest of WECC Variable Demand Response Costs (includes Program Capital Costs and Variable Costs)
99	**WECC Transmission Capital Costs ($000)**	Rest of WECC Transmission Capital Costs relative to Line 100
100	**WECC Transmission Miles**	Rest of WECC Transmission Miles relative to Line 99
101	**WECC Incremental Resource Capital Costs ($000)**	Rest of WECC cost of generic resource additions including the following resource types: Gas Turbines, Combined Cycles, Wind, Geothermal, Concentrated Solar Power, and Biomass
102	***Total Rest of WECC Other Costs ($000)***	Sum of of Lines 95 through 99, and Line 101
103	**Rest of WECC Emissions**	
104	**WECC CO2 Production (000 tons)**	Rest of WECC CO2 production from generation (excludes CO2 from WECC/CA shared generators) also excludes CO2 accounting to CA exports
105	**WECC SO2 (000 tons)**	Rest of WECC SO2 production from generation (excludes SO2 from WECC/CA shared generators)
106	**WECC NOx (000 tons)**	Rest of WECC NOx production from generation (excludes NOx from WECC/CA shared generators)
107	**WECC HG (000 tons)**	Rest of WECC HG production from generation (excludes HG from WECC/CA shared generators)
108	**WECC Emission Costs SO2/NOx/HG ($000)**	Rest of WECC Total Emission Costs (exlcludes emission costs from WECC/CA shared generators)
109	**Rest of WECC Remote Generation**	
110	**WECC Remote Generation (GWh)**	WECC share of generation from WECC/CA shared plants
111	**WECC Remote Generation Cost ($000)**	WECC share of generation costs from WECC/CA shared plants including costs associated with Fuel, VOM , Start-up , FOM, and Emissions.
112	**WECC Remote CO2 (000 tons)**	WECC share of CO2 emissions from WECC/CA shared plants
113	**WECC Remote SO2 (000 tons)**	WECC share of SO2 emissions from WECC/CA shared plants
114	**WECC Remote NOx (000 tons)**	WECC share of NOx emissions from WECC/CA shared plants
115	**WECC Remote HG (000 tons)**	WECC share of HG emissions from WECC/CA shared plants
116	**Rest of WECC Gas Consumption**	
117	**WECC Gas Consumption (Gbtu)**	Natural gas fuel burn from plants located in the Rest of WECC

	CEC IEPR - Draft Score Card	Case 1			Case 1b			Case2	Case 3a			Case 3b		
		Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas	Base Gas	Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas
YEAR	2020 2020 2020	2020			2020			2020	2020			2020		
		Case 1			Case 1b			Case2	Case 3a			Case 3b		
1														
2	Total WECC System Cost ($000)	35,741,173	45,074,700	50,069,654	35,957,386	43,847,073	48,004,420	47,729,998	35,445,740	42,983,772	46,942,420	34,213,448	40,524,229	43,735,749
3	California											0	0	0
4	CA System Cost ($000)	12,265,962	16,684,128	19,177,074	13,004,270	16,354,098	18,224,842	18,253,593	12,617,673	15,701,704	17,434,336	12,569,545	15,576,942	17,257,192
5	CA Per Unit System Cost ($/MWh)	36	49	56	42	53	59	61	43	53	59	43	53	58
6	CA Peak Load (MW)	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903
7	CA Energy Load (GWh) *Includes Losses and Pumping Load*	340,458	340,458	340,458	339,831	339,831	339,831	339,687	339,597	339,597	339,597	339,606	339,606	339,606
8	CA "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
9	CA (Excludes Remote*) Generation By Fuel (GWh)													
10	*Coal*	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,157	3,158	3,158
11	*Fuel Oil*	1	11	23	3	31	53	64	0	4	6	2	22	22
12	*Geothermal*	15,632	15,632	15,632	20,022	20,022	20,022	15,640	20,022	20,022	20,022	20,022	20,022	20,022
13	*Hydro*	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910
14	*Natural Gas*	143,636	145,878	146,510	115,507	116,771	116,953	111,370	107,221	108,511	109,041	96,795	95,115	94,944
15	*Nuclear*	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694
16	*Other*	7,439	7,729	7,763	12,921	13,290	13,324	7,755	12,891	13,285	13,319	12,800	13,243	13,287
17	*Pumped Storage Output*	2,805	2,805	2,805	2,370	2,370	2,370	2,271	2,204	2,204	2,204	2,215	2,215	2,215
18	*Wind*	10,360	10,360	10,360	16,813	16,813	16,813	10,360	16,813	16,813	16,813	16,813	16,813	16,813
19	*Total CA Generation*	250,634	253,176	253,853	238,397	240,059	240,297	218,222	229,913	231,600	232,166	219,409	218,191	218,063
20	CA Distributed Generation (GWh)													
21	*Energy Efficiency*	0	0	0	29,638	29,638	29,638	42,263	42,263	42,263	42,263	42,263	42,263	42,263
22	*PV Solar*	0	0	0	1,629	1,629	1,629	0	1,629	1,629	1,629	1,629	1,629	1,629
23	*Total Distributed Generation*	0	0	0	31,267	31,267	31,267	42,263	43,892	43,892	43,892	43,892	43,892	43,892
24	CA (Excludes Remote*) O&M Costs													
25	CA Fuel Costs ($000)	5,815,276	9,140,077	11,042,596	4,844,243	7,505,968	8,998,775	10,370,577	4,470,456	6,955,756	8,378,646	4,169,058	6,328,400	7,564,997
26	CA VOM Costs ($000)	480,295	488,000	490,502	454,618	457,798	458,796	413,728	437,529	441,083	442,446	417,978	415,560	415,699
27	CA Start Costs ($000)	43,091	64,897	74,380	45,209	67,112	75,402	92,470	40,180	59,217	69,276	44,850	68,389	79,821
28	CA FOM Costs ($000)	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892
29	*Total CA Ot&M Costs*	7,492,553	10,846,866	12,761,371	6,497,963	9,184,771	10,686,864	12,030,666	6,102,058	8,609,947	10,044,261	5,785,777	7,966,241	9,214,410
30	CA Other Costs													
31	CA Wheeling Costs ($000)	34,742	36,007	36,412	30,752	33,060	33,409	41,945	29,773	32,134	32,881	40,008	45,952	47,598
32	CA Energy Efficiency Costs ($000)	0	0	0	1,100,203	1,100,203	1,100,203	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481
33	CA PV Solar Costs ($000)	0	0	0	633,822	633,822	633,822	0	633,822	633,822	633,822	633,822	633,822	633,822
34	CA Variable Demand Response Costs ($000)	2,148	2,506	3,260	135,544	135,544	135,571	144	230,000	230,009	230,009	230,000	230,009	230,009
35	CA Transmission Capital Costs ($000)	0	0	0	315,567	315,567	315,567	0	315,567	315,567	315,567	315,567	315,567	315,567
36	CA Transmission Miles	0	0	0	258	258	258	0	258	258	258	258	258	258
37	CA Incremental Resource Capital Costs ($000)	1,929,457	1,929,457	1,929,457	2,273,399	2,273,399	2,273,399	649,836	2,182,693	2,182,693	2,182,693	2,179,565	2,179,565	2,179,565
38	*Total CA Other Costs*	1,966,347	1,967,970	1,969,129	4,489,286	4,491,594	4,491,970	1,963,406	4,663,335	4,665,706	4,666,452	4,670,442	4,676,395	4,678,042
39	CA Renewable Generation													
40	CA Renewable Generation (GWh)	32,284	32,299	32,299	45,553	45,586	45,587	32,317	48,699	48,740	48,741	48,678	48,737	48,738
41	CA Renewable Energy (%)	9%	9%	9%	15%	15%	15%	11%	16%	16%	16%	16%	16%	16%
42	CA Renewable Generation (GWh) - with Hydro	72,048	72,062	72,063	84,882	84,915	84,916	71,547	87,861	87,902	87,903	87,851	87,911	87,912
43	CA Renewable Energy (%) - with Hydro	21%	21%	21%	28%	28%	28%	24%	30%	30%	30%	30%	30%	30%
44	CA (Excludes Remote*) Emissions													
45	CA CO2 Production (000 tons)	74,630	75,803	76,034	63,100	63,907	63,850	60,164	59,156	60,032	60,221	55,004	54,868	54,762
46	CA GHG 2020/1990 Ratio	0	0	0	0	0	0	0	0	0	0	0	0	0
47	CA SO2 (000 tons)	59	69	70	56	68	70	70	55	68	69	52	67	68
48	CA NOx (000 tons)	236	238	244	236	238	243	249	235	237	237	234	237	238
49	CA HG (000 tons)	13	13	13	13	13	13	13	13	13	13	13	13	13
50	CA Emission Costs SO2/NOx/HG ($000)	87,310	98,867	100,515	85,210	98,239	99,387	93,998	83,548	97,017	98,374	80,422	94,778	96,265
51	CA Remote* Generation													
52	CA Remote* Generation (GWh)	38,650	38,717	38,685	38,315	38,307	38,255	38,017	38,202	38,228	38,167	37,684	37,688	37,629
53	CA Remote* Generation Cost ($000)	837,530	971,493	1,019,571	827,042	950,937	993,433	1,020,973	823,585	947,054	988,284	808,858	922,448	958,949
54	CA Remote* CO2 (000 tons)	27,150	27,267	27,255	26,988	27,087	27,064	26,946	26,930	27,048	27,023	26,609	26,755	26,722
55	CA Remote* SO2 (000 tons)	14	14	14	14	14	14	14	14	14	14	14	14	14
56	CA Remote* NOx (000 tons)	46	47	47	46	47	46	46	46	46	46	46	46	46
57	CA Remote* HG (000 tons)	221	222	222	220	222	222	222	220	222	222	220	221	221
58	CA Imports													
59	CA Net Import ($000)	1,882,223	2,798,933	3,326,489	1,104,769	1,628,557	1,953,188	3,144,549	945,147	1,381,980	1,636,965	1,224,046	1,917,080	2,309,527
60	CA Net Import (GWh)	51,175	48,566	47,920	31,851	30,197	30,012	41,186	27,591	25,877	25,372	38,620	39,835	40,022
61	CA Import CO2 (000 tons)	28,440	27,211	26,876	17,747	16,982	16,894	23,477	15,390	14,572	14,303	21,678	22,671	22,818
62	CA Gas and Water Consumption													
63	CA Gas Consumption (Gbtu)	1,149,438	1,147,817	1,146,368	929,258	921,037	917,710	882,382	865,767	861,060	862,504	781,794	767,818	767,446
64	CA Water Consumption													

	CEC IEPR - Draft Score Card	Case 1			Case 1b			Case2	Case 3a			Case 3b		
		Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas	Base Gas	Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas
YEAR	2020 2020 2020	2020			2020			2020	2020			2020		
		Case 1			Case 1b			Case2	Case 3a			Case 3b		
2020	65 Rest of WECC (excluding California results)													
	66 Rest of WECC System Cost ($000)	23,475,211	28,390,572	30,892,581	22,953,116	27,492,976	29,779,579	29,476,406	22,828,066	27,282,068	29,508,084	21,643,904	24,947,286	26,478,556
	67 Rest of WECC Per Unit System Cost ($/MWh)	31	37	41	30	36	39	41	30	36	39	32	37	39
	68 Rest of WECC Peak Load (MW)	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514
	69 Rest of WECC Energy Load (GWh) *Includes Losses and Pumping Load*	757,759	757,759	757,759	757,743	757,743	757,743	757,721	757,750	757,750	757,750	757,673	757,673	757,673
	70 Rest of WECC "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0	0	0	0	0
	71 Rest of WECC (Excludes Remote*) Generation by Fuel (GWh)													
2020	72 *Coal*	271,075	275,537	275,934	266,780	271,629	272,074	278,967	266,579	271,510	271,988	256,605	263,129	264,107
	73 *Fuel Oil*	27	55	121	20	80	128	431	26	127	109	21	100	175
	74 *Geothermal*	9,337	9,337	9,337	16,407	16,407	16,407	11,267	16,407	16,407	16,407	16,407	16,407	16,407
	75 *Hydro*	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385
	76 *Natural Gas*	193,961	186,469	185,384	173,377	166,441	165,808	136,958	169,461	162,303	161,469	110,007	103,463	102,611
	77 *Nuclear*	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251
	78 *Other*	11,456	11,863	11,878	18,803	19,315	19,335	11,730	18,786	19,309	19,330	17,818	19,127	19,213
	79 *Pumped Storage Output*	459	459	459	448	448	448	432	452	452	452	398	398	398
	80 *Wind*	43,538	43,538	43,538	34,609	34,609	34,609	43,538	34,609	34,609	34,609	34,609	34,609	34,609
	81 *Total Rest of WECC Generation*	746,488	743,893	743,286	727,079	725,565	725,444	699,959	722,956	721,353	720,999	652,501	653,868	654,156
	82 *Total Rest of WECC Exports*	51,175	48,566	47,920	31,851	30,197	30,012	41,186	27,591	25,877	25,372	38,620	39,835	40,022
	83 *Total Excluding Remote* Generation and Exports*	695,314	695,327	695,367	695,228	695,368	695,433	658,773	695,365	695,476	695,627	613,881	614,033	614,134
	84 Rest of WECC Distributed Generation (GWh)													
	85 *Energy Efficiency*	0	0	0	0	0	0	37,463	0	0	0	82,408	82,408	82,408
	86 *PV Solar*	0	0	0	527	527	527	0	527	527	527	527	527	527
	87 *Total Distributed Generation*	0	0	0	527	527	527	37,463	527	527	527	82,935	82,935	82,935
	88 Rest of WECC (Excludes Remote*) O&M Costs													
2020	89 Rest of WECC Fuel Costs ($000)	11,305,265	15,971,375	18,372,064	10,783,935	15,083,628	17,271,734	17,731,952	10,668,534	14,882,260	17,018,453	8,745,163	11,808,473	13,251,854
	90 Rest of WECC VOM Costs ($000)	1,096,860	1,097,990	1,098,061	1,100,611	1,103,652	1,104,442	1,019,523	1,092,506	1,095,073	1,095,998	937,006	943,587	944,372
	91 Rest of WECC Start Costs ($000)	45,048	57,520	63,111	49,745	65,791	75,756	84,592	53,398	70,967	78,061	57,984	80,878	91,350
	92 Rest of WECC FOM Costs ($000)	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561
	93 *Total Rest of WECC O&M Costs*	14,159,734	18,839,446	21,245,797	13,646,853	17,965,633	20,164,493	20,548,629	13,526,999	17,760,862	19,905,073	11,452,715	14,545,499	16,000,137
	94 Rest of WECC Other Costs													
	95 Rest of WECC Wheeling Costs ($000)	215,957	221,769	223,881	208,210	213,979	215,809	232,547	207,184	212,746	214,934	233,027	244,700	248,232
	96 Rest of WECC Energy Efficiency Costs ($000)	0	0	0	0	0	0	1,150,849	0	0	0	2,531,869	2,531,869	2,531,869
	97 Rest of WECC PV Solar Costs ($000)	0	0	0	208,108	208,108	208,108	0	208,108	208,108	208,108	208,108	208,108	208,108
	98 Rest of WECC Variable Demand Response Costs ($000)	0	0	0	0	0	0	0	0	0	0	0	0	0
	99 Rest of WECC Transmission Capital Costs ($000)	0	0	0	1,187,588	1,187,588	1,187,588	0	1,187,588	1,187,588	1,187,588	1,187,588	1,187,588	1,187,588
	100 Rest of WECC Transmission Miles	0	0	0	4,535	4,535	4,535	0	4,535	4,535	4,535	4,535	4,535	4,535
	101 Rest of WECC Incremental Resource Capital Costs ($000)	7,445,604	7,445,604	7,445,604	6,063,888	6,063,888	6,063,888	5,528,480	6,063,888	6,063,888	6,063,888	4,434,785	4,434,785	4,434,785
	102 *Total Rest of WECC Other Costs*	7,661,562	7,667,374	7,669,486	7,667,793	7,673,562	7,675,393	6,911,876	7,666,767	7,672,330	7,674,517	8,595,377	8,607,050	8,610,582
2020	103 Rest of WECC (Excludes Remote*) Emissions													
	104 Rest of WECC CO2 Production (000 tons)	349,933	353,053	353,479	351,085	354,757	355,203	339,384	351,652	355,389	355,957	308,901	313,679	314,391
	105 Rest of WECC SO2 (000 tons)	394	402	403	393	402	403	403	393	401	402	380	395	397
	106 Rest of WECC NOx (000 tons)	451	457	458	455	462	463	453	454	461	462	437	449	450
	107 Rest of WECC HG (000 tons)	2,732	2,766	2,768	2,687	2,724	2,726	2,803	2,685	2,723	2,726	2,595	2,643	2,648
	108 Rest of WECC Emission Costs SO2/NOx/HG ($000)	226,601	232,657	233,363	225,174	231,442	232,206	233,343	224,937	231,333	232,055	215,163	225,968	227,443
	109 Rest of WECC Remote* Generation													
	110 Rest of WECC Remote* Generation (GWh)	62,446	62,433	62,393	61,989	61,849	61,784	61,486	61,858	61,747	61,596	60,857	60,705	60,604
	111 Rest of WECC Remote* Generation Cost ($000)	1,427,314	1,651,096	1,743,935	1,413,296	1,622,338	1,707,487	1,782,558	1,409,362	1,617,543	1,696,438	1,380,649	1,568,769	1,640,395
	112 Rest of WECC Remote* CO2 (000 tons)	36,477	36,533	36,518	36,277	36,294	36,267	36,138	36,219	36,247	36,186	35,687	35,782	35,740
2020	113 Rest of WECC Remote* SO2 (000 tons)	27	27	27	27	27	27	27	27	27	27	26	27	27
	114 Rest of WECC Remote* NOx (000 tons)	61	61	61	61	61	61	61	61	61	61	60	61	61
	115 Rest of WECC Remote* HG (000 tons)	342	343	343	342	343	343	343	342	343	343	340	342	342
	116 Rest of WECC Gas Consumption													
	117 Rest of WECC Gas Consumption (Gbtu)	1,499,355	1,463,538	1,461,694	1,339,496	1,309,985	1,308,315	1,102,342	1,309,530	1,276,222	1,273,089	882,804	848,449	840,564

		CEC IEPR - Draft Score Card	Case 4a			Case 4b			Case 5a			Case 5b		
			Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas
YEAR		2020 2020 2020	2020			2020			2020			2020		
			Case 4a			Case 4b			Case 5a			Case 5b		
	1													
2020	2	**Total WECC System Cost ($000)**	38,885,260	45,528,410	48,961,013	41,708,857	47,523,895	50,478,462	38,454,005	44,744,362	47,976,354	40,523,678	45,136,436	47,392,493
	3	**California**	0	0	0	0	0	0						
	4	**CA System Cost ($000)**	16,452,327	18,935,010	20,318,987	16,443,014	18,904,156	20,272,379	16,184,232	18,407,604	19,636,497	16,145,825	18,238,302	19,369,073
	5	**CA Per Unit System Cost ($/MWh)**	54	63	67	54	63	67	56	64	68	56	63	67
	6	**CA Peak Load (MW)**	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903
	7	**CA Energy Load (GWh)** *Includes Losses and Pumping Load*	339,750	339,750	339,750	339,743	339,743	339,743	339,558	339,558	339,558	339,535	339,535	339,535
	8	**CA "Energy Not Served" (GWh)**	0	0	0	0	0	0	0	0	0	0	0	0
	9	**CA (Excludes Remote*) Generation By Fuel (GWh)**												
	10	***Coal***	3,155	3,157	3,157	3,148	3,155	3,155	3,153	3,157	3,157	3,097	3,120	3,123
	11	***Fuel Oil***	0	26	21	0	42	32	0	6	23	2	40	17
	12	***Geothermal***	33,178	33,178	33,178	33,178	33,178	33,178	33,178	33,178	33,178	33,178	33,178	33,178
	13	***Hydro***	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910	33,910
2020	14	***Natural Gas***	94,177	95,282	95,885	85,237	84,663	84,974	87,264	88,108	88,601	68,403	64,976	64,386
	15	***Nuclear***	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,687	33,688	33,687
	16	***Other***	22,207	22,668	22,711	22,053	22,590	22,638	22,163	22,650	22,698	21,585	22,217	22,291
	17	***Pumped Storage Output***	2,302	2,302	2,302	2,297	2,297	2,297	2,165	2,165	2,165	2,158	2,158	2,158
	18	***Wind***	31,220	31,220	31,220	31,220	31,220	31,220	31,220	31,220	31,220	31,220	31,220	31,220
	19	***Total CA Generation***	253,842	255,437	256,078	244,736	244,748	245,098	246,746	248,088	248,645	227,239	224,506	223,969
	20	**CA Distributed Generation (GWh)**												
	21	***Energy Efficiency***	29,638	29,638	29,638	29,638	29,638	29,638	42,263	42,263	42,263	42,263	42,263	42,263
	22	***PV Solar***	8,036	8,036	8,036	8,036	8,036	8,036	8,036	8,036	8,036	8,036	8,036	8,036
	23	***Total Distributed Generation***	37,674	37,674	37,674	37,674	37,674	37,674	50,299	50,299	50,299	50,299	50,299	50,299
	24	**CA (Excludes Remote*) O&M Costs**												
	25	**CA Fuel Costs ($000)**	4,486,014	6,723,190	8,011,132	4,237,637	6,242,839	7,399,353	4,169,493	6,246,597	7,438,616	3,663,178	5,238,327	6,127,105
	26	**CA VOM Costs ($000)**	504,062	506,803	508,210	486,672	486,566	487,462	489,998	492,168	493,393	453,627	447,965	446,749
2020	27	**CA Start Costs ($000)**	41,783	60,141	69,870	45,909	69,126	80,677	34,871	51,870	56,854	37,290	56,414	63,733
	28	**CA FOM Costs ($000)**	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892
	29	***Total CA Ot&M Costs***	6,185,750	8,444,026	9,743,104	5,924,110	7,952,422	9,121,384	5,848,255	7,944,527	9,142,756	5,307,988	6,896,598	7,791,478
	30	**CA Other Costs**												
	31	**CA Wheeling Costs ($000)**	29,462	30,792	31,206	26,777	28,805	29,250	28,612	29,951	30,733	31,773	36,830	38,674
	32	**CA Energy Efficiency Costs ($000)**	1,100,203	1,100,203	1,100,203	1,100,203	1,100,203	1,100,203	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481
	33	**CA PV Solar Costs ($000)**	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984
	34	**CA Variable Demand Response Costs ($000)**	135,579	135,583	135,727	135,579	135,611	135,766	230,008	230,059	230,242	230,020	230,035	230,136
	35	**CA Transmission Capital Costs ($000)**	365,982	365,982	365,982	365,982	365,982	365,982	365,982	365,982	365,982	365,982	365,982	365,982
	36	**CA Transmission Miles**	618	618	618	618	618	618	618	618	618	618	618	618
	37	**CA Incremental Resource Capital Costs ($000)**	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736
	38	***Total CA Other Costs***	9,047,947	9,049,280	9,049,838	9,045,262	9,047,322	9,047,921	9,312,803	9,314,194	9,315,158	9,315,976	9,321,048	9,322,994
	39	**CA Renewable Generation**												
	40	**CA Renewable Generation (GWh)**	85,625	85,710	85,712	85,557	85,695	85,700	85,607	85,707	85,710	85,267	85,519	85,543
	41	**CA Renewable Energy (%)**	28%	28%	28%	28%	28%	28%	30%	30%	30%	29%	30%	30%
	42	**CA Renewable Generation (GWh) - with Hydro**	124,886	124,971	124,973	124,813	124,950	124,955	124,731	124,830	124,834	124,384	124,635	124,659
	43	**CA Renewable Energy (%) - with Hydro**	41%	41%	41%	41%	41%	41%	43%	43%	43%	43%	43%	43%
	44	**CA (Excludes Remote*) Emissions**												
	45	**CA CO2 Production (000 tons)**	57,233	58,078	58,338	53,804	54,172	54,268	54,047	54,836	55,030	46,848	46,356	46,068
	46	**CA GHG 2020/1990 Ratio**	0	0	0	0	0	0	0	0	0	0	0	0
	47	**CA SO2 (000 tons)**	53	67	69	49	65	66	52	67	68	42	57	59
	48	**CA NOx (000 tons)**	242	243	247	240	244	245	241	242	244	237	239	244
2020	49	**CA HG (000 tons)**	13	13	13	12	13	13	13	13	13	12	12	12
	50	**CA Emission Costs SO2/NOx/HG ($000)**	92,516	106,817	108,381	88,301	103,267	104,769	90,540	105,313	106,839	79,632	93,797	95,629
	51	**CA Remote* Generation**												
	52	**CA Remote* Generation (GWh)**	37,833	37,855	37,805	37,096	37,222	37,079	37,658	37,757	37,670	34,768	34,968	34,843
	53	**CA Remote* Generation Cost ($000)**	812,760	930,590	969,521	795,272	909,418	940,015	807,533	926,531	961,665	742,185	839,046	863,766
	54	**CA Remote* CO2 (000 tons)**	26,706	26,843	26,816	26,035	26,314	26,224	26,606	26,777	26,730	23,833	24,257	24,158
	55	**CA Remote* SO2 (000 tons)**	14	14	14	14	14	14	14	14	14	13	13	13
	56	**CA Remote* NOx (000 tons)**	46	46	46	45	46	45	46	46	46	42	42	42
	57	**CA Remote* HG (000 tons)**	220	221	221	218	220	220	219	221	221	211	214	213
	58	**CA Imports**												
	59	**CA Net Import ($000)**	313,354	404,297	448,144	590,069	891,727	1,058,289	125,100	117,039	110,079	700,044	1,087,812	1,295,207
	60	**CA Net Import (GWh)**	10,402	8,784	8,194	20,237	20,099	19,892	4,855	3,414	2,944	27,229	29,762	30,424
2020	61	**CA Import CO2 (000 tons)**	5,824	4,970	4,641	10,384	10,451	10,361	2,722	1,934	1,670	13,426	14,932	15,308
	62	**CA Gas and Water Consumption**												
	63	**CA Gas Consumption (Gbtu)**	772,791	770,884	774,024	701,372	697,557	701,685	720,279	719,623	722,398	583,028	566,556	562,932
	64	**CA Water Consumption**												

		CEC IEPR - Draft Score Card	Case 4a			Case 4b			Case 5a			Case 5b		
			Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas	Low Gas	Base Gas	High Gas
YEAR			2020	2020	2020	2020			2020			2020		2020
			Case 4a			Case 4b			Case 5a			Case 5b		
2020	65	**Rest of WECC (excluding California results)**												
	66	**Rest of WECC System Cost ($000)**	22,432,933	26,593,399	28,642,026	25,265,843	28,619,739	30,206,082	22,269,773	26,336,758	28,339,856	24,377,853	26,898,134	28,023,420
	67	**Rest of WECC Per Unit System Cost ($/MWh)**	30	35	38	33	38	40	29	35	37	36	40	42
	68	**Rest of WECC Peak Load (MW)**	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514
	69	**Rest of WECC Energy Load (GWh)** *Includes Losses and Pumping Load*	757,749	757,749	757,749	757,888	757,888	757,888	757,749	757,749	757,749	757,824	757,824	757,824
	70	**Rest of WECC "Energy Not Served" (GWh)**	0	0	0	0	0	0	0	0	0	0	0	0
	71	**Rest of WECC (Excludes Remote*) Generation by Fuel (GWh)**												
	72	***Coal***	265,365	270,692	271,212	253,815	260,102	260,933	265,043	270,370	270,901	224,843	231,618	232,986
	73	***Fuel Oil***	28	89	162	24	120	193	21	102	160	43	154	207
	74	***Geothermal***	16,407	16,407	16,407	27,822	27,822	27,822	16,407	16,407	16,407	27,822	27,822	27,822
	75	***Hydro***	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385	207,385
	76	***Natural Gas***	154,217	146,781	145,708	113,747	106,498	105,569	149,299	141,907	140,995	72,017	66,362	65,614
	77	***Nuclear***	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,246	9,246	9,246
2020	78	***Other***	18,675	19,275	19,294	24,236	25,084	25,121	18,652	19,261	19,281	22,751	24,113	24,281
	79	***Pumped Storage Output***	452	452	452	546	546	546	452	452	452	502	502	502
	80	***Wind***	34,609	34,609	34,609	79,670	79,670	79,670	34,609	34,609	34,609	79,670	79,670	79,670
	81	***Total Rest of WECC Generation***	706,387	704,940	704,479	716,494	716,477	716,489	701,119	699,742	699,440	644,278	646,871	647,712
	82	***Total Rest of WECC Exports***	10,402	8,784	8,194	20,237	20,099	19,892	4,855	3,414	2,944	27,229	29,762	30,424
	83	***Total Excluding Remote* Generation and Exports***	695,986	696,156	696,286	696,257	696,378	696,596	696,263	696,329	696,497	617,048	617,109	617,288
	84	**Rest of WECC Distributed Generation (GWh)**												
	85	***Energy Efficiency***	0	0	0	0	0	0	0	0	0	82,408	82,408	82,408
	86	***PV Solar***	527	527	527	1,317	1,317	1,317	527	527	527	1,317	1,317	1,317
	87	***Total Distributed Generation***	527	527	527	1,317	1,317	1,317	527	527	527	83,725	83,725	83,725
	88	**Rest of WECC (Excludes Remote*) O&M Costs**												
	89	**Rest of WECC Fuel Costs ($000)**	10,219,933	14,145,567	16,101,182	9,087,962	12,203,531	13,706,409	10,071,645	13,900,091	15,817,219	7,416,088	9,707,213	10,756,796
	90	**Rest of WECC VOM Costs ($000)**	1,060,745	1,063,024	1,062,734	1,019,507	1,025,336	1,026,564	1,050,993	1,052,572	1,053,393	853,591	859,866	861,979
	91	**Rest of WECC Start Costs ($000)**	62,233	87,192	103,683	69,888	98,210	114,232	64,985	93,852	106,176	76,289	119,380	139,001
2020	92	**Rest of WECC FOM Costs ($000)**	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561
	93	***Total Rest of WECC O&M Costs***	13,055,472	17,008,345	18,980,160	11,889,919	15,039,637	16,559,767	12,900,184	16,759,076	18,689,349	10,058,529	12,399,020	13,470,336
	94	**Rest of WECC Other Costs**												
	95	**Rest of WECC Wheeling Costs ($000)**	208,400	213,593	215,350	249,953	258,444	260,699	209,429	214,389	216,759	266,324	281,847	285,609
	96	**Rest of WECC Energy Efficiency Costs ($000)**	0	0	0	0	0	0	0	0	0	2,531,869	2,531,869	2,531,869
	97	**Rest of WECC PV Solar Costs ($000)**	208,108	208,108	208,108	451,623	451,623	451,623	208,108	208,108	208,108	451,623	451,623	451,623
	98	**Rest of WECC Variable Demand Response Costs ($000)**	0	0	0	0	0	0	0	0	0	0	0	0
	99	**Rest of WECC Transmission Capital Costs ($000)**	1,308,908	1,308,908	1,308,908	2,350,642	2,350,642	2,350,642	1,308,908	1,308,908	1,308,908	2,452,282	2,452,282	2,452,282
	100	**Rest of WECC Transmission Miles**	4,535	4,535	4,535	8,126	8,126	8,126	4,535	4,535	4,535	8,536	8,536	8,536
	101	**Rest of WECC Incremental Resource Capital Costs ($000)**	6,037,957	6,037,957	6,037,957	8,743,438	8,743,438	8,743,438	6,037,957	6,037,957	6,037,957	7,142,004	7,142,004	7,142,004
	102	***Total Rest of WECC Other Costs***	7,763,373	7,768,566	7,770,323	11,795,657	11,804,147	11,806,403	7,764,401	7,769,362	7,771,732	12,844,102	12,859,624	12,863,386
2020	103	**Rest of WECC (Excludes Remote*) Emissions**												
	104	**Rest of WECC CO2 Production (000 tons)**	353,796	357,924	358,539	321,977	326,713	327,564	354,525	358,607	359,245	271,555	276,607	277,712
	105	**Rest of WECC SO2 (000 tons)**	390	400	401	378	391	393	390	399	401	347	366	369
	106	**Rest of WECC NOx (000 tons)**	451	459	460	439	449	450	450	458	459	402	415	417
	107	**Rest of WECC HG (000 tons)**	2,675	2,717	2,719	2,560	2,613	2,618	2,672	2,714	2,717	2,282	2,333	2,339
	108	**Rest of WECC Emission Costs SO2/NOx/HG ($000)**	223,330	230,189	231,181	213,271	222,291	223,754	222,873	229,785	230,791	187,250	201,408	203,674
	109	**Rest of WECC Remote* Generation**												
	110	**Rest of WECC Remote* Generation (GWh)**	61,236	61,066	60,936	60,314	60,193	59,974	60,958	60,893	60,725	57,051	56,990	56,812
	111	**Rest of WECC Remote* Generation Cost ($000)**	1,390,758	1,586,300	1,660,362	1,366,997	1,553,663	1,616,159	1,382,314	1,578,536	1,647,984	1,287,973	1,438,082	1,486,023
	112	**Rest of WECC Remote* CO2 (000 tons)**	35,913	35,932	35,876	35,279	35,390	35,277	35,779	35,840	35,763	32,686	32,996	32,879
	113	**Rest of WECC Remote* SO2 (000 tons)**	26	27	27	26	27	27	26	27	27	24	25	25
	114	**Rest of WECC Remote* NOx (000 tons)**	60	61	61	60	60	60	60	61	61	56	57	57
	115	**Rest of WECC Remote* HG (000 tons)**	341	342	342	339	340	340	341	342	342	324	328	328
2020	116	**Rest of WECC Gas Consumption**												
	117	**Rest of WECC Gas Consumption (Gbtu)**	1,203,288	1,163,891	1,157,599	920,137	879,790	871,109	1,167,223	1,126,281	1,120,726	630,439	595,856	589,813
	118	**Total WECC Load** *Includes Losses and Pumping Load*	1,097,499	1,097,499	1,097,499	1,097,631	1,097,631	1,097,631	1,097,306	1,097,306	1,097,306	1,097,359	1,097,359	1,097,359
	119	**Total WECC Load - Distributed Generation**	1,059,298	1,059,298	1,059,298	1,058,640	1,058,640	1,058,640	1,046,480	1,046,480	1,046,480	963,336	963,336	963,336

Appendix C-2
Shock Case Scorecard results for 2020
for Dry Hydro, High Hydro, and $20/MMBtu Gas Prices

The scorecard results are a sample of results for 2020 and are based on a large spreadsheet with the list of results on the left-hand side and the nine thematic scenarios across the top. Because all nine scenarios cannot fit on an 8 1/2" x 11" sheet, the scenarios print out in two parts: the first includes the first five scenarios and all related results; the second includes the last four scenarios with the list of results repeated. The results include load, generation, production costs, capital costs, import energy,

The full spreadsheet of results is available at:
http://www.energy.ca.gov/2007publications/CEC-200-2007-010/appendices/appendixC-2_excel-1.xls

Source: Global Energy Decisions

CEC IEPR - Draft Score Card	Case 1			Case 1b			Case 2			Case 3a			Case 3b		
	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas
YEAR 2020 2020	2020			2020			2020			2020			2020		
	Case 1			Case 1b			Case 2			Case 3a			Case 3b		
1															
2 **Total WECC System Cost ($000)**	46,414,425	43,044,790	83,339,274	45,125,104	41,771,646	76,095,033	49,634,303	44,654,619	68,849,413	44,255,187	40,918,477	73,625,256	41,708,932	38,865,627	65,236,403
3 **California**															
4 **CA System Cost ($000)**	16,875,608	16,164,681	36,167,167	16,507,640	15,945,868	31,112,227	18,560,106	17,490,132	29,195,113	15,843,813	15,299,757	29,203,469	15,757,903	15,077,660	28,779,015
5 **CA Per Unit System Cost ($/MWh)**	50	47	106	53	52	101	62	59	98	54	52	99	53	51	97
6 **CA Peak Load (MW)**	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903
7 **CA Energy Load (GWh) Includes Losses and Pumping Load**	340,690	340,540	340,459	340,124	339,896	339,832	339,963	339,753	339,674	339,840	339,648	339,585	339,847	339,651	339,596
8 **CA "Energy Not Served" (GWh)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9 **CA (Excludes Remote*) Generation By Fuel (GWh)**															
10 ***Coal***	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,158	3,153	3,158
11 ***Fuel Oil***	33	27	2,176	30	47	2,041	55	54	1,954	27	7	2,010	14	33	1,722
12 ***Geothermal***	15,632	15,632	15,632	20,022	20,022	20,022	15,640	15,640	15,640	20,022	20,022	20,022	20,022	20,022	20,022
13 ***Hydro***	30,882	40,872	33,910	30,882	40,872	33,910	30,882	40,872	33,910	30,882	40,872	33,910	30,882	40,872	33,910
14 ***Natural Gas***	154,980	129,941	143,397	125,019	103,951	110,898	120,637	96,451	109,159	116,498	96,026	102,244	102,537	80,766	88,667
15 ***Nuclear***	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694	33,694
16 ***Other***	7,738	7,709	9,339	13,302	13,261	14,793	7,762	7,716	8,922	13,294	13,249	15,339	13,270	13,078	14,652
17 ***Pumped Storage Output***	2,976	2,847	2,805	2,587	2,405	2,372	2,478	2,308	2,261	2,381	2,228	2,194	2,392	2,237	2,208
18 ***Wind***	10,360	10,360	10,360	16,813	16,813	16,813	10,360	10,360	10,360	16,813	16,813	16,813	16,813	16,813	16,813
19 ***Total CA Generation***	259,452	244,240	254,470	245,506	234,222	237,700	224,666	210,253	219,058	236,769	226,068	229,384	222,782	210,667	214,846
20 **CA Distributed Generation (GWh)**															
21 ***Energy Efficiency***	0	0	0	29,638	29,638	29,638	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263	42,263
22 ***PV Solar***	0	0	0	1,629	1,629	1,629	0	0	0	1,629	1,629	1,629	1,629	1,629	1,629
23 ***Total Distributed Generation***	0	0	0	31,267	31,267	31,267	42,263	42,263	42,263	43,892	43,892	43,892	43,892	43,892	43,892
24 **CA (Excludes Remote*) O&M Costs**															
25 **CA Fuel Costs ($000)**	9,611,768	8,372,359	23,660,403	7,905,992	6,935,611	18,558,877	11,045,315	9,361,930	18,402,119	7,336,641	6,403,333	17,159,420	6,652,012	5,748,135	15,283,872
26 **CA VOM Costs ($000)**	505,120	456,539	490,682	473,912	433,146	452,234	432,150	384,949	413,937	456,629	416,496	433,890	430,183	387,955	406,526
27 **CA Start Costs ($000)**	61,565	74,745	146,895	65,067	77,449	92,508	93,214	106,540	150,270	57,875	67,572	63,685	70,808	74,932	95,737
28 **CA FOM Costs ($000)**	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892
29 ***Total CA Ot&M Costs***	11,332,345	10,057,536	25,451,872	9,598,864	8,600,099	20,257,511	12,724,571	11,007,312	20,120,217	9,005,037	8,041,294	18,810,887	8,306,895	7,364,914	16,940,026
30 **CA Other Costs**															
31 **CA Wheeling Costs ($000)**	29,700	60,196	37,401	26,791	50,713	34,523	31,717	78,474	44,100	26,619	50,384	33,240	36,023	83,543	55,283
32 **CA Energy Efficiency Costs ($000)**	0	0	0	1,100,203	1,100,203	1,100,203	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481
33 **CA PV Solar Costs ($000)**	0	0	0	633,822	633,822	633,822	0	0	0	633,822	633,822	633,822	633,822	633,822	633,822
34 **CA Variable Demand Response Costs ($000)**	3,240	2,863	204,027	135,622	135,598	350,309	214	186	146,942	230,029	230,027	520,471	230,029	230,027	417,618
35 **CA Transmission Capital Costs ($000)**	0	0	0	315,567	315,567	315,567	0	0	0	315,567	315,567	315,567	315,567	315,567	315,567
36 **CA Transmission Miles**	0	0	0	258	258	258	0	0	0	258	258	258	258	258	258
37 **CA Incremental Resource Capital Costs ($000)**	1,929,457	1,929,457	1,929,457	2,273,399	2,273,399	2,273,399	649,836	649,836	649,836	2,182,693	2,182,693	2,182,693	2,179,565	2,179,565	2,179,565
38 ***Total CA Other Costs***	1,962,397	1,992,516	2,170,885	4,485,404	4,509,302	4,707,823	1,953,248	1,999,976	2,112,359	4,660,210	4,683,973	4,957,274	4,666,486	4,714,004	4,873,336
39 **CA Renewable Generation**															
40 **CA Renewable Generation (GWh)**	32,299	32,299	32,299	45,586	45,584	45,587	32,317	32,315	32,317	45,586	45,583	45,586	48,740	48,700	48,738
41 **CA Renewable Energy (%)**	9%	9%	9%	15%	15%	15%	11%	11%	11%	15%	15%	15%	16%	16%	16%
42 **CA Renewable Generation (GWh) - with Hydro**	69,401	79,592	72,063	82,299	92,435	84,917	68,921	79,069	71,536	82,094	92,257	84,739	85,258	95,384	87,904
43 **CA Renewable Energy (%) - with Hydro**	20%	23%	21%	27%	30%	28%	23%	27%	24%	28%	31%	29%	29%	32%	30%
44 **CA (Excludes Remote*) Emissions**															
45 **CA CO2 Production (000 tons)**	79,968	69,142	76,617	67,441	58,866	62,886	63,982	54,438	60,912	63,401	55,124	58,921	57,804	49,691	53,251
46 **CA GHG 2020/1990 Ratio**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
47 **CA SO2 (000 tons)**	69	68	76	69	67	75	70	69	75	69	67	75	68	62	73
48 **CA NOx (000 tons)**	240	237	461	239	238	446	247	254	433	238	235	442	237	238	410
49 **CA HG (000 tons)**	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13
50 **CA Emission Costs SO2/NOx/HG ($000)**	100,340	96,745	103,543	99,220	96,063	103,576	94,819	91,705	96,776	97,907	94,573	102,126	96,082	89,027	99,344
51 **CA Remote* Generation**															
52 **CA Remote* Generation (GWh)**	39,099	38,726	38,498	38,946	38,420	37,711	38,805	37,958	37,640	38,897	38,286	37,474	38,210	36,976	37,081
53 **CA Remote* Generation Cost ($000)**	981,890	948,893	1,182,846	974,856	935,140	1,067,973	1,068,385	988,969	1,095,453	972,572	928,168	1,031,178	939,362	884,123	988,804
54 **CA Remote* CO2 (000 tons)**	27,344	27,043	27,177	27,282	26,874	26,826	27,211	26,577	26,784	27,261	26,798	26,720	26,932	25,717	26,491
55 **CA Remote* SO2 (000 tons)**	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
56 **CA Remote* NOx (000 tons)**	47	47	47	47	46	46	46	46	46	47	46	46	46	45	46
57 **CA Remote* HG (000 tons)**	222	222	222	222	221	222	222	221	222	222	221	222	222	219	221
58 **CA Imports**															
59 **CA Net Import ($000)**	2,498,636	3,068,992	7,258,021	1,349,295	1,805,264	4,975,344	2,719,084	3,402,171	5,770,307	1,108,086	1,551,749	4,302,005	1,749,078	2,025,592	5,877,504
60 **CA Net Import (GWh)**	42,139	57,574	47,490	24,405	35,987	33,155	34,229	49,280	40,714	20,282	31,403	28,835	34,964	48,115	43,778
61 **CA Import CO2 (000 tons)**	24,468	30,628	26,713	14,222	19,201	18,676	20,226	26,547	23,236	11,837	16,769	16,259	20,663	25,437	24,949
62 **CA Gas and Water Consumption**															
63 **CA Gas Consumption (Gbtu)**	1,227,073	1,033,371	1,110,200	985,986	833,549	874,132	942,773	782,183	863,046	921,761	773,352	815,300	817,143	670,637	718,698
64 **CA Water Consumption**															

	CEC IEPR - Draft Score Card	Case 1			Case 1b			Case 2			Case 3a			Case 3b		
		Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas
YEAR	2020 2020	2020			2020			2020			2020			2020		
		Case 1			Case 1b			Case 2			Case 3a			Case 3b		
65	**Rest of WECC (excluding California results)**															
66	**Rest of WECC System Cost ($000)**	29,538,817	26,880,109	47,172,107	28,617,464	25,825,778	44,982,806	31,074,196	27,164,487	39,654,301	28,411,374	25,618,720	44,421,787	25,951,029	23,787,967	36,457,389
67	**Rest of WECC Per Unit System Cost ($/MWh)**	39	35	62	38	34	59	43	38	55	38	34	59	38	35	54
68	**Rest of WECC Peak Load (MW)**	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514
69	**Rest of WECC Energy Load (GWh) Includes Losses and Pumpi**	757,767	757,787	757,760	757,754	757,771	757,743	757,729	757,747	757,721	757,760	757,779	757,751	757,675	757,682	757,670
70	**Rest of WECC "Energy Not Served" (GWh)**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
71	**Rest of WECC (Excludes Remote*) Generation by Fuel (GWh)**															
72	***Coal***	275,626	274,705	276,067	271,786	270,429	272,164	279,206	276,509	279,037	271,732	270,116	272,111	264,197	254,369	264,469
73	***Fuel Oil***	63	50	2,380	73	130	2,292	538	383	2,193	119	122	2,263	95	148	1,978
74	***Geothermal***	9,337	9,337	9,337	16,408	16,408	16,408	11,269	11,268	11,269	16,408	16,408	16,408	16,408	16,406	16,408
75	***Hydro***	177,110	253,317	207,385	177,110	253,317	207,385	177,110	253,317	207,384	177,110	253,317	207,385	177,110	253,317	207,385
76	***Natural Gas***	209,859	150,672	182,736	190,140	127,771	167,687	159,118	102,449	135,308	186,095	123,791	163,972	127,075	77,336	105,494
77	***Nuclear***	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,209	9,251	9,251	9,251	9,251	9,251	9,031	9,251
78	***Other***	11,869	11,796	11,949	19,329	19,200	19,396	11,746	11,541	11,776	19,330	19,173	19,395	19,228	18,004	19,257
79	***Pumped Storage Output***	464	478	459	455	467	448	438	450	432	459	472	453	400	405	397
80	***Wind***	43,538	43,538	43,538	34,609	34,609	34,609	43,538	43,538	43,538	34,609	34,609	34,609	34,609	34,609	34,609
81	***Total Rest of WECC Generation***	737,117	753,143	743,102	719,162	731,583	729,639	692,214	708,664	700,188	715,112	727,259	725,848	648,374	663,626	659,246
82	***Total Rest of WECC Exports***	42,139	57,574	47,490	24,405	35,987	33,155	34,229	49,280	40,714	20,282	31,403	28,835	34,964	48,115	43,778
83	***Total Excluding Remote* Generation and Exports***	694,978	695,569	695,612	694,757	695,596	696,484	657,985	659,385	659,474	694,831	695,856	697,012	613,410	615,511	615,469
84	**Rest of WECC Distributed Generation (GWh)**															
85	***Energy Efficiency***	0	0	0	0	0	0	37,463	37,463	37,463	0	0	0	82,408	82,327	82,408
86	***PV Solar***	0	0	0	527	527	527	0	0	0	527	527	527	527	527	527
87	***Total Distributed Generation***	0	0	0	527	527	527	37,463	37,463	37,463	527	527	527	82,935	82,854	82,935
88	**Rest of WECC (Excludes Remote*) O&M Costs**															
89	**Rest of WECC Fuel Costs ($000)**	17,044,884	14,500,530	34,142,361	16,115,703	13,463,452	32,104,888	19,234,099	15,461,053	27,591,584	15,919,293	13,275,641	31,616,180	12,765,668	10,703,481	22,965,482
90	**Rest of WECC VOM Costs ($000)**	1,151,122	1,024,781	1,101,501	1,155,289	1,023,337	1,117,540	1,065,206	948,451	1,020,586	1,146,328	1,015,219	1,110,235	991,869	875,685	956,388
91	**Rest of WECC Start Costs ($000)**	60,065	67,074	110,426	70,130	80,447	141,790	83,300	111,554	139,048	72,816	84,827	159,173	73,920	92,362	188,303
92	**Rest of WECC FOM Costs ($000)**	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561
93	***Total Rest of WECC O&M Costs***	19,968,632	17,304,947	37,066,849	19,053,683	16,279,798	35,076,779	22,095,166	18,233,620	30,463,780	18,850,999	16,088,248	34,598,149	15,544,018	13,384,090	25,822,734
94	**Rest of WECC Other Costs**															
95	**Rest of WECC Wheeling Costs ($000)**	229,118	273,836	226,248	224,831	258,121	220,848	232,052	298,034	234,439	224,633	256,119	219,525	224,879	319,756	260,188
96	**Rest of WECC Energy Efficiency Costs ($000)**	0	0	0	0	0	0	1,150,849	1,150,849	1,150,849	0	0	0	2,531,869	2,531,869	2,531,869
97	**Rest of WECC PV Solar Costs ($000)**	0	0	0	208,108	208,108	208,108	0	0	0	208,108	208,108	208,108	208,108	208,108	208,108
98	**Rest of WECC Variable Demand Response Costs ($000)**	0	0	12,666	0	0	11,501	0	0	7,326	0	0	11,824	0	0	4,276
99	**Rest of WECC Transmission Capital Costs ($000)**	0	0	0	1,187,588	1,187,588	1,187,588	0	0	0	1,187,588	1,187,588	1,187,588	1,187,588	1,187,588	1,187,588
100	**Rest of WECC Transmission Miles**	0	0	0	4,535	4,535	4,535	0	0	0	4,535	4,535	4,535	4,535	4,535	4,535
101	**Rest of WECC Incremental Resource Capital Costs ($000)**	7,445,604	7,445,604	7,445,604	6,063,888	6,063,888	6,063,888	5,528,480	5,528,480	5,528,480	6,063,888	6,063,888	6,063,888	4,434,785	4,434,785	4,434,785
102	***Total Rest of WECC Other Costs***	7,674,722	7,719,441	7,684,518	7,684,415	7,717,705	7,691,933	6,911,381	6,977,364	6,921,094	7,684,216	7,715,703	7,690,932	8,587,229	8,682,106	8,626,813
103	**Rest of WECC (Excludes Remote*) Emissions**															
104	**Rest of WECC CO2 Production (000 tons)**	366,910	333,736	354,855	368,366	335,105	356,524	352,379	319,558	340,543	369,059	335,667	357,431	326,497	290,835	315,611
105	**Rest of WECC SO2 (000 tons)**	403	401	408	402	399	408	404	398	407	402	399	407	397	379	402
106	**Rest of WECC NOx (000 tons)**	461	452	461	466	456	466	456	446	456	465	455	466	452	431	454
107	**Rest of WECC HG (000 tons)**	2,767	2,761	2,768	2,725	2,716	2,727	2,804	2,785	2,803	2,725	2,714	2,726	2,650	2,578	2,650
108	**Rest of WECC Emission Costs SO2/NOx/HG ($000)**	232,810	231,362	236,094	231,671	229,868	234,819	233,846	229,833	235,368	231,634	229,441	234,713	227,364	214,549	229,970
109	**Rest of WECC Remote* Generation**															
110	**Rest of WECC Remote* Generation (GWh)**	62,789	62,218	62,148	62,470	61,648	60,732	62,281	60,899	60,784	62,402	61,396	60,212	61,331	59,317	59,266
111	**Rest of WECC Remote* Generation Cost ($000)**	1,662,653	1,624,360	2,184,646	1,647,695	1,598,407	1,979,274	1,833,803	1,723,670	2,034,059	1,644,525	1,585,329	1,897,993	1,592,418	1,507,222	1,777,871
112	**Rest of WECC Remote* CO2 (000 tons)**	36,621	36,283	36,417	36,500	36,033	35,810	36,423	35,660	35,833	36,472	35,911	35,582	36,017	34,565	35,152
113	**Rest of WECC Remote* SO2 (000 tons)**	27	27	27	27	27	27	27	26	27	27	27	27	27	25	27
114	**Rest of WECC Remote* NOx (000 tons)**	61	61	61	61	61	61	61	60	61	61	61	61	61	59	60
115	**Rest of WECC Remote* HG (000 tons)**	343	343	343	343	343	343	343	342	343	343	342	343	343	337	342
116	**Rest of WECC Gas Consumption**															
117	**Rest of WECC Gas Consumption (Gbtu)**	1,641,670	1,205,013	1,449,012	1,489,767	1,033,031	1,308,436	1,272,509	861,796	1,078,915	1,457,961	1,004,244	1,272,465	1,014,882	682,221	843,468

	CEC IEPR - Draft Score Card	Case 4a			Case 4b			Case 5a			Case 5b		
		Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas
YEAR	2020 2020	2020			2020			2020			2020		
		Case 4a			Case 4b			Case 5a			Case 5b		
1													
2	Total WECC System Cost ($000)	46,809,917	43,617,879	71,676,351	48,755,731	45,851,881	69,754,896	45,998,219	42,866,307	69,214,098	46,022,953	43,933,822	61,735,800
3	California												
4	CA System Cost ($000)	19,039,752	18,617,701	29,552,188	19,055,587	18,501,518	29,362,372	18,491,545	18,121,512	27,774,812	18,450,465	17,799,534	26,811,373
5	CA Per Unit System Cost ($/MWh)	63	62	98	63	61	97	64	63	96	64	62	93
6	CA Peak Load (MW)	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903	66,903
7	CA Energy Load (GWh) Includes Losses and Pumping Load	339,951	339,811	339,745	339,945	339,810	339,716	339,734	339,642	339,564	339,697	339,601	339,543
8	CA "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0	0	0	0
9	CA (Excludes Remote*) Generation By Fuel (GWh)												
10	*Coal*	3,158	3,151	3,157	3,157	3,131	3,155	3,157	3,147	3,157	3,145	3,046	3,122
11	*Fuel Oil*	22	9	1,855	31	19	1,498	18	5	1,785	21	14	725
12	*Geothermal*	33,178	33,178	33,178	33,178	33,178	33,178	33,178	33,178	33,178	33,178	33,178	33,178
13	*Hydro*	30,882	40,872	33,910	30,882	40,872	33,910	30,882	40,872	33,910	30,882	40,872	33,910
14	*Natural Gas*	102,128	83,410	91,573	91,493	72,647	80,341	94,895	76,812	83,877	72,781	55,774	60,344
15	*Nuclear*	33,694	33,694	33,694	33,694	33,692	33,694	33,694	33,694	33,694	33,694	33,323	33,687
16	*Other*	22,688	22,562	23,967	22,638	22,331	23,528	22,676	22,507	24,453	22,474	21,344	22,774
17	*Pumped Storage Output*	2,444	2,329	2,299	2,440	2,330	2,277	2,292	2,215	2,170	2,275	2,193	2,164
18	*Wind*	31,220	31,220	31,220	31,220	31,220	31,220	31,220	31,220	31,220	31,220	31,220	31,220
19	*Total CA Generation*	259,414	250,424	254,852	248,732	239,418	242,800	252,011	243,648	247,444	229,668	220,963	221,124
20	CA Distributed Generation (GWh)												
21	*Energy Efficiency*	29,638	29,638	29,638	29,638	29,638	29,638	42,263	42,263	42,263	42,263	42,263	42,263
22	*PV Solar*	8,036	8,036	8,036	8,036	8,036	8,036	8,036	8,036	8,036	8,036	8,036	8,036
23	*Total Distributed Generation*	37,674	37,674	37,674	37,674	37,674	37,674	50,299	50,299	50,299	50,299	50,299	50,299
24	CA (Excludes Remote*) O&M Costs												
25	CA Fuel Costs ($000)	7,042,265	6,207,039	16,141,812	6,536,614	5,745,252	14,609,587	6,558,962	5,769,707	14,872,658	5,551,308	4,857,050	11,768,914
26	CA VOM Costs ($000)	520,612	483,566	505,046	500,030	462,798	481,721	505,824	470,426	489,258	463,457	426,986	439,631
27	CA Start Costs ($000)	59,762	68,005	79,126	71,460	72,733	104,598	48,189	54,886	50,812	63,907	59,761	64,502
28	CA FOM Costs ($000)	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892	1,153,892
29	*Total CA Ot&M Costs*	8,776,531	7,912,502	17,879,876	8,261,995	7,434,676	16,349,798	8,266,867	7,448,910	16,566,621	7,232,563	6,497,689	13,426,939
30	CA Other Costs												
31	CA Wheeling Costs ($000)	26,435	47,723	32,200	24,414	43,989	30,572	25,718	47,368	31,352	29,876	66,710	44,177
32	CA Energy Efficiency Costs ($000)	1,100,203	1,100,203	1,100,203	1,100,203	1,100,203	1,100,203	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481	1,271,481
33	CA PV Solar Costs ($000)	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984	2,987,984
34	CA Variable Demand Response Costs ($000)	135,670	135,640	319,427	135,692	135,640	260,787	230,063	230,008	485,646	230,086	230,014	291,864
35	CA Transmission Capital Costs ($000)	365,982	365,982	365,982	365,982	365,982	365,982	365,982	365,982	365,982	365,982	365,982	365,982
36	CA Transmission Miles	618	618	618	618	618	618	618	618	618	618	618	618
37	CA Incremental Resource Capital Costs ($000)	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736	4,428,736
38	*Total CA Other Costs*	9,045,011	9,066,269	9,234,533	9,043,011	9,062,535	9,174,265	9,309,965	9,331,560	9,571,182	9,314,146	9,350,908	9,390,225
39	CA Renewable Generation												
40	CA Renewable Generation (GWh)	85,714	85,680	85,711	85,705	85,584	85,699	85,712	85,658	85,708	85,652	84,856	85,535
41	CA Renewable Energy (%)	28%	28%	28%	28%	28%	28%	30%	30%	30%	30%	29%	30%
42	CA Renewable Generation (GWh) - with Hydro	122,284	132,455	124,968	122,272	132,360	124,934	122,130	132,319	124,837	122,052	131,496	124,658
43	CA Renewable Energy (%) - with Hydro	40%	44%	41%	40%	44%	41%	42%	46%	43%	42%	45%	43%
44	CA (Excludes Remote*) Emissions												
45	CA CO2 Production (000 tons)	60,914	53,438	58,014	56,826	49,585	53,303	57,592	50,467	54,450	49,318	42,429	44,364
46	CA GHG 2020/1990 Ratio	0	0	0	0	0	0	0	0	0	0	0	0
47	CA SO2 (000 tons)	68	64	74	66	59	71	67	63	73	62	48	62
48	CA NOx (000 tons)	244	242	433	245	242	397	243	241	426	243	230	316
49	CA HG (000 tons)	13	12	13	13	12	13	13	12	13	12	12	12
50	CA Emission Costs SO2/NOx/HG ($000)	107,879	102,792	111,865	105,175	96,631	108,110	106,698	100,849	110,223	99,108	83,841	97,793
51	CA Remote* Generation												
52	CA Remote* Generation (GWh)	38,642	37,802	37,220	37,980	36,208	36,674	38,533	37,567	37,096	36,375	32,789	34,538
53	CA Remote* Generation Cost ($000)	962,290	913,803	1,005,664	936,033	867,533	970,308	957,356	905,439	989,888	873,782	772,551	851,643
54	CA Remote* CO2 (000 tons)	27,112	26,361	26,562	26,666	24,849	26,089	27,056	26,166	26,492	25,462	21,755	24,114
55	CA Remote* SO2 (000 tons)	14	14	14	14	13	14	14	14	14	14	12	13
56	CA Remote* NOx (000 tons)	46	46	46	46	43	46	46	45	46	44	38	43
57	CA Remote* HG (000 tons)	221	220	221	220	216	220	221	219	221	217	200	214
58	CA Imports												
59	CA Net Import ($000)	148,042	622,336	1,320,251	709,372	1,040,143	2,759,891	-149,341	334,754	536,898	930,865	1,094,545	3,044,773
60	CA Net Import (GWh)	4,221	13,911	9,999	15,559	26,510	22,568	-1,109	8,128	4,725	23,355	35,551	33,582
61	CA Import CO2 (000 tons)	2,477	7,426	5,669	8,414	12,757	11,761	-652	4,335	2,682	12,426	15,815	16,917
62	CA Gas and Water Consumption												
63	CA Gas Consumption (Gbtu)	819,428	686,368	743,239	742,616	616,871	663,635	767,866	638,355	686,732	614,510	507,486	527,478
64	CA Water Consumption												

2020 2020 2020

	CEC IEPR - Draft Score Card	Case 4a			Case 4b			Case 5a			Case 5b		
		Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas	Dry Hydro	High Hydro	20$ Gas
YEAR	2020 2020	2020			2020			2020			2020		
		Case 4a			Case 4b			Case 5a			Case 5b		
65	**Rest of WECC (excluding California results)**												
66	**Rest of WECC System Cost ($000)**	27,770,165	25,000,178	42,124,163	29,700,144	27,350,362	40,392,524	27,506,674	24,744,795	41,439,286	27,572,488	26,134,288	34,924,427
67	**Rest of WECC Per Unit System Cost ($/MWh)**	37	33	56	39	36	53	36	33	55	41	39	52
68	**Rest of WECC Peak Load (MW)**	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514	125,514
69	**Rest of WECC Energy Load (GWh) Includes Losses and Pumpi**	757,753	757,776	757,747	757,890	757,902	757,880	757,753	757,776	757,747	757,830	757,833	757,815
70	**Rest of WECC "Energy Not Served" (GWh)**	0	0	0	0	0	0	0	0	0	0	0	0
71	**Rest of WECC (Excludes Remote*) Generation by Fuel (GWh)**												
72	***Coal***	271,071	266,994	271,318	261,725	249,150	261,308	270,895	265,749	271,061	239,672	208,140	234,179
73	***Fuel Oil***	61	124	2,148	119	148	1,800	101	121	2,110	185	148	1,126
74	***Geothermal***	16,408	16,408	16,408	27,823	27,823	27,823	16,408	16,408	16,408	27,823	27,822	27,823
75	***Hydro***	177,110	253,317	207,385	177,110	253,317	207,385	177,110	253,317	207,385	177,110	253,317	207,385
76	***Natural Gas***	171,220	110,431	146,588	129,738	80,191	107,256	166,256	106,272	141,830	79,824	55,817	67,486
77	***Nuclear***	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	8,727	9,247
78	***Other***	19,309	18,983	19,358	25,180	24,405	25,167	19,305	18,894	19,354	24,725	22,113	24,396
79	***Pumped Storage Output***	454	471	451	547	555	540	454	471	451	506	508	496
80	***Wind***	34,609	34,609	34,609	79,670	79,670	79,670	34,609	34,609	34,609	79,670	79,670	79,670
81	***Total Rest of WECC Generation***	699,494	710,588	707,515	711,164	724,509	720,201	694,390	705,093	702,458	638,766	656,262	651,806
82	***Total Rest of WECC Exports***	4,221	13,911	9,999	15,559	26,510	22,568	-1,109	8,128	4,725	23,355	35,551	33,582
83	***Total Excluding Remote* Generation and Exports***	695,273	696,677	697,516	695,605	697,999	697,633	695,499	696,965	697,733	615,412	620,711	618,224
84	**Rest of WECC Distributed Generation (GWh)**												
85	***Energy Efficiency***	0	0	0	0	0	0	0	0	0	82,408	82,371	82,408
86	***PV Solar***	527	527	527	1,317	1,317	1,317	527	527	527	1,317	1,317	1,317
87	***Total Distributed Generation***	527	527	527	1,317	1,317	1,317	527	527	527	83,725	83,688	83,725
88	**Rest of WECC (Excludes Remote*) O&M Costs**												
89	**Rest of WECC Fuel Costs ($000)**	15,214,201	12,617,214	29,287,494	13,189,721	11,034,856	23,600,256	14,968,575	12,382,315	28,619,588	10,302,918	9,064,072	17,462,104
90	**Rest of WECC VOM Costs ($000)**	1,115,321	984,636	1,074,571	1,076,038	952,412	1,034,847	1,105,029	973,493	1,064,374	900,939	794,028	870,167
91	**Rest of WECC Start Costs ($000)**	88,683	97,339	190,216	97,157	104,367	234,808	90,733	101,708	210,073	112,267	131,027	287,321
92	**Rest of WECC FOM Costs ($000)**	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561	1,712,561
93	***Total Rest of WECC O&M Costs***	18,130,766	15,411,750	32,264,842	16,075,477	13,804,196	26,582,472	17,876,898	15,170,077	31,606,597	13,028,685	11,701,689	20,332,153
94	**Rest of WECC Other Costs**												
95	**Rest of WECC Wheeling Costs ($000)**	228,590	252,326	220,672	271,545	298,632	265,063	229,810	250,370	221,193	266,427	344,784	293,673
96	**Rest of WECC Energy Efficiency Costs ($000)**	0	0	0	0	0	0	0	0	0	2,531,869	2,531,869	2,531,869
97	**Rest of WECC PV Solar Costs ($000)**	208,108	208,108	208,108	451,623	451,623	451,623	208,108	208,108	208,108	451,623	451,623	451,623
98	**Rest of WECC Variable Demand Response Costs ($000)**	0	0	10,692	0	0	6,548	0	0	12,011	0	0	1,310
99	**Rest of WECC Transmission Capital Costs ($000)**	1,308,908	1,308,908	1,308,908	2,350,642	2,350,642	2,350,642	1,308,908	1,308,908	1,308,908	2,452,282	2,452,282	2,452,282
100	**Rest of WECC Transmission Miles**	4,535	4,535	4,535	8,126	8,126	8,126	4,535	4,535	4,535	8,536	8,536	8,536
101	**Rest of WECC Incremental Resource Capital Costs ($000)**	6,037,957	6,037,957	6,037,957	8,743,438	8,743,438	8,743,438	6,037,957	6,037,957	6,037,957	7,142,004	7,142,004	7,142,004
102	***Total Rest of WECC Other Costs***	7,783,562	7,807,298	7,786,336	11,817,248	11,844,335	11,817,314	7,784,783	7,805,343	7,788,177	12,844,205	12,922,561	12,872,760
103	**Rest of WECC (Excludes Remote*) Emissions**												
104	**Rest of WECC CO2 Production (000 tons)**	371,748	336,540	360,119	340,400	302,076	328,721	372,600	336,531	360,834	293,114	246,308	278,910
105	**Rest of WECC SO2 (000 tons)**	401	394	406	393	374	397	400	392	405	379	329	372
106	**Rest of WECC NOx (000 tons)**	463	449	463	454	429	454	462	447	462	430	373	421
107	**Rest of WECC HG (000 tons)**	2,720	2,687	2,720	2,627	2,515	2,621	2,718	2,676	2,718	2,405	2,117	2,351
108	**Rest of WECC Emission Costs SO2/NOx/HG ($000)**	230,648	225,675	233,599	224,198	209,679	225,994	230,468	224,159	233,221	211,246	174,420	205,869
109	**Rest of WECC Remote* Generation**												
110	**Rest of WECC Remote* Generation (GWh)**	61,953	60,572	59,704	60,968	58,585	58,930	61,727	60,284	59,487	58,693	53,434	55,866
111	**Rest of WECC Remote* Generation Cost ($000)**	1,625,189	1,555,455	1,839,386	1,583,221	1,492,152	1,766,744	1,614,525	1,545,216	1,811,292	1,488,352	1,335,618	1,513,645
112	**Rest of WECC Remote* CO2 (000 tons)**	36,266	35,372	35,334	35,750	33,804	34,831	36,167	35,170	35,226	34,306	29,813	32,520
113	**Rest of WECC Remote* SO2 (000 tons)**	27	26	27	27	25	27	27	26	27	26	22	25
114	**Rest of WECC Remote* NOx (000 tons)**	61	60	60	60	58	60	61	60	60	59	52	57
115	**Rest of WECC Remote* HG (000 tons)**	343	340	342	341	332	340	343	339	342	336	304	329
116	**Rest of WECC Gas Consumption**												
117	**Rest of WECC Gas Consumption (Gbtu)**	1,355,535	916,228	1,151,656	1,050,565	705,871	868,664	1,315,081	886,127	1,115,016	682,898	531,717	583,928

APPENDIX D

TRANS-AREA SCORECARD RESULTS

Prepared by Global Energy Decisions, Inc.

Appendix D-1
Trans-Area Scorecard for Base, High, and Low Gas Cases

The transmission area results are a sample for 2020 for the Base Gas case. The results include load, generation, production costs, import energy, export energy, and emissions data. The data items are listed on the left-hand column with the nine thematic scenarios across the top.

The full spreadsheet of results is available at:
http://www.energy.ca.gov/2007publications/CEC-200-2007-010/appendices/appendixD-1_excel-1.xls

Source: Global Energy Decisions

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
1	AB_S									
2	Transarea Production Cost ($000)	621,169	578,331	465,793	583,652	385,868	566,543	514,764	567,864	319,036
3	Transarea Load (GWh)	34,656	34,656	34,656	34,656	34,656	34,656	34,656	34,656	34,656
4	Transarea Peak Load (MW) - December	4,924	4,924	4,924	4,924	4,924	4,924	4,924	4,924	4,924
5	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
6	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
7	Transarea Import Energy (GWh)	7,859	8,914	5,494	8,853	4,979	8,997	9,714	9,011	5,947
8	Transarea Export Energy (GWh)	1,536	2,001	1,958	1,957	4,419	1,770	1,398	1,721	3,839
9	Transarea Water Consumption (TCF?)									
10	Transarea Emissions (000 Tons)									
11	*CO2*	16,755	16,520	18,053	16,562	14,865	16,414	15,971	16,414	14,298
12	*SO2*	32	32	33	32	32	32	32	32	32
13	*NOX*	16	16	17	16	16	16	16	16	16
14	*HG*	144	144	185	144	144	144	144	144	144
15	Transarea Load/Generation (GWh)									
16	Load (GWh)									
17	Total Load Includes Losses and Pumping Load	34,656	34,656	34,656	34,656	34,656	34,656	34,656	34,656	34,656
18	EE	0	0	4,575	0	10,065	0	0	0	10,065
19	Rooftop Solar	0	0	0	0	0	0	0	0	0
20	Net Load	34,656	34,656	30,081	34,656	24,592	34,656	34,656	34,656	24,592
21	Generation (GWh)									
22	Nuclear	0	0	0	0	0	0	0	0	0
23	Hydro	1,237	1,237	1,237	1,237	1,237	1,237	1,237	1,237	1,237
24	Existing/Named Coal	5,745	5,745	5,736	5,745	5,745	5,745	5,745	5,745	5,743
25	Generic Coal	7,700	7,700	11,548	7,700	7,700	7,700	7,700	7,700	7,699
26	Existing/Named Gas-GT	622	519	442	516	341	491	431	481	329
27	Existing/Named Gas-CC	2,771	2,567	1,884	2,464	1,402	2,361	1,969	2,267	1,149
28	Existing/Named Gas-ST	134	133	131	133	131	133	132	133	131
29	Generic Gas - GT	1,692	1,254	633	1,392	179	1,276	1,096	1,384	243
30	Generic Gas - CC	3,498	3,496	0	3,480	2,204	3,394	2,938	3,326	862
31	Fuel Oil	0	0	0	0	0	0	0	0	0
32	Geothermal	0	0	0	0	0	0	0	0	0
33	Pumped Storage Output	0	0	0	0	0	0	0	0	0
34	Wind	4,934	4,886	4,934	4,886	4,886	4,886	4,886	4,886	4,886
35	Biomass/Other	0	0	0	0	0	0	0	0	0
36	*Biomass*	0	207	0	207	207	207	207	207	205
37	*DR*	0	0	0	0	0	0	0	0	0
38	*Jet Fuel*	0	0	0	0	0	0	0	0	0
39	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
40	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
41	*Refuse*	0	0	0	0	0	0	0	0	0
42	*Waste Heat*	0	0	0	0	0	0	0	0	0
43	*Wood*	0	0	0	0	0	0	0	0	0
44	*Other/Transaction*	0	0	0	0	0	0	0	0	0
45	Total	28,333	27,743	26,545	27,760	24,032	27,429	26,340	27,366	22,483
46	ABCN									
47	Transarea Production Cost ($000)	1,440,288	1,385,163	1,693,010	1,380,254	1,224,002	1,364,881	1,300,625	1,353,008	1,159,676
48	Transarea Load (GWh)	57,657	57,657	57,657	57,657	57,657	57,657	57,657	57,657	57,657
49	Transarea Peak Load (MW) - December	8,146	8,146	8,146	8,146	8,146	8,146	8,146	8,146	8,146
50	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
51	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
52	Transarea Import Energy (GWh)	86	219	329	244	1,046	273	505	306	1,993
53	Transarea Export Energy (GWh)	6,241	5,386	3,664	5,319	2,840	5,014	3,872	4,815	1,971
54	Transarea Water Consumption (TCF?)									
55	Transarea Emissions (000 Tons)									
56	*CO2*	53,358	52,950	51,962	52,907	51,537	52,771	52,205	52,666	50,851
57	*SO2*	92	93	91	93	93	93	93	93	92
58	*NOX*	79	79	78	79	78	79	78	79	78
59	*HG*	498	499	495	499	499	499	499	499	498
60	Transarea Load/Generation (GWh)									
61	Load (GWh)									
62	Total Load Includes Losses and Pumping Load	57,657	57,657	57,657	57,657	57,657	57,657	57,657	57,657	57,657
63	EE	0	0	0	0	0	0	0	0	0
64	Rooftop Solar	0	0	0	0	0	0	0	0	0
65	Net Load	57,657	57,657	57,657	57,657	57,657	57,657	57,657	57,657	57,657
66	Generation (GWh)			0						
67	Nuclear	0	0	0	0	0	0	0	0	0
68	Hydro	731	731	731	731	731	731	731	731	731
69	Existing/Named Coal	41,385	41,424	41,149	41,424	41,421	41,424	41,424	41,424	41,400
70	Generic Coal	3,850	3,850	3,850	3,850	3,850	3,850	3,850	3,850	3,850
71	Existing/Named Gas-GT	4,123	3,623	3,279	3,625	2,974	3,562	3,282	3,534	2,927
72	Existing/Named Gas-CC	10,722	10,073	9,199	10,012	7,687	9,770	8,747	9,645	6,288
73	Existing/Named Gas-ST	231	231	231	231	231	231	231	231	231
74	Generic Gas - GT	155	251	61	222	13	203	188	134	33
75	Generic Gas - CC	0	0	0	0	0	0	0	0	0
76	Fuel Oil	0	0	0	0	0	0	0	0	0
77	Geothermal	0	0	0	0	0	0	0	0	0
78	Pumped Storage Output	0	0	0	0	0	0	0	0	0
79	Wind	0	0	0	0	0	0	0	0	0
80	Biomass/Other	0	0	0	0	0	0	0	0	0
81	*Biomass*	290	290	287	290	290	290	290	290	282
82	*DR*	0	0	0	0	0	0	0	0	0
83	*Jet Fuel*	0	0	0	0	0	0	0	0	0
84	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
85	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
86	*Refuse*	0	0	0	0	0	0	0	0	0
87	*Waste Heat*	42	42	42	42	42	42	42	42	42
88	*Wood*	937	947	900	947	942	947	946	946	899
89	*Other/Transaction*	1,345	1,361	1,263	1,359	1,271	1,348	1,294	1,341	952
90	Total	63,811	62,824	60,992	62,733	59,451	62,398	61,025	62,167	57,635

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
91	**Arizona**									
92	Transarea Production Cost ($000)	3,238,225	3,035,637	3,560,291	2,974,849	2,509,321	2,838,743	2,534,840	2,801,905	2,237,790
93	Transarea Load (GWh)	108,086	108,076	108,068	108,082	108,046	108,081	108,077	108,081	108,038
94	Transarea Peak Load (MW) - July	24,360	24,360	24,360	24,360	24,360	24,360	24,360	24,360	24,360
95	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
96	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
97	Transarea Import Energy (GWh)	29,456	29,605	26,885	29,965	29,063	33,999	41,411	35,010	42,196
98	Transarea Export Energy (GWh)	10,430	5,799	6,208	4,993	7,161	5,836	13,353	6,042	17,988
99	Transarea Water Consumption (TCF?)									
100	Transarea Emissions (000 Tons)									
101	*CO2*	70,524	68,776	67,578	68,258	64,213	66,866	63,313	66,459	57,683
102	*SO2*	40	40	41	40	39	39	38	39	34
103	*NOX*	80	80	80	80	79	79	77	79	71
104	*HG*	494	494	494	493	492	492	484	491	453
105	Transarea Load/Generation (GWh)									
106	Load (GWh)									
107	Total Load Includes Losses and Pumping Load	108,086	108,076	108,068	108,082	108,046	108,081	108,077	108,081	108,038
108	EE	0	0	5,356	0	11,784	0	0	0	11,784
109	Rooftop Solar	0	73	0	73	73	73	468	73	468
110	Net Load	108,086	108,003	102,711	108,009	96,189	108,008	107,609	108,008	95,787
111	Generation (GWh)			0						
112	Nuclear	0	0	0	0	0	0	0	0	0
113	Hydro	4,859	4,859	4,859	4,859	4,859	4,859	4,859	4,859	4,859
114	Existing/Named Coal	46,810	46,737	46,824	46,711	46,420	46,408	45,355	46,293	41,841
115	Generic Coal	7,703	7,703	7,708	7,703	7,701	7,700	7,668	7,701	7,423
116	Existing/Named Gas-GT	475	452	712	588	769	673	980	717	1,260
117	Existing/Named Gas-CC	20,013	16,273	12,871	15,459	9,315	12,162	7,891	11,449	5,997
118	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
119	Generic Gas - GT	6,952	6,533	6,614	6,046	3,595	6,389	4,795	6,364	2,220
120	Generic Gas - CC	0	0	0	0	0	0	0	0	0
121	Fuel Oil	18	59	228	87	71	73	111	77	129
122	Geothermal	0	0	0	0	0	0	0	0	0
123	Pumped Storage Output	379	372	367	376	351	376	373	376	346
124	Wind	1,639	409	1,639	409	409	409	4,919	409	4,919
125	Biomass/Other	0	0	0	0	0	0	0	0	0
126	*Biomass*	38	38	38	38	38	38	38	38	38
127	*DR*	0	0	0	0	0	0	0	0	0
128	*Jet Fuel*	0	0	0	0	0	0	0	0	0
129	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
130	*CSP (Solar)*	22	610	22	610	610	610	2,421	610	2,421
131	*Refuse*	0	0	0	0	0	0	0	0	0
132	*Waste Heat*	0	0	0	0	0	0	0	0	0
133	*Wood*	152	152	152	152	151	150	143	149	127
134	*Other/Transaction*	0	0	0	0	0	0	0	0	0
135	Total	89,060	84,197	82,034	83,036	74,288	79,846	79,551	79,040	71,579
136	**BC**									
137	Transarea Production Cost ($000)	653,298	661,299	716,143	654,483	621,391	652,453	646,685	652,786	577,989
138	Transarea Load (GWh)	75,062	75,062	75,062	75,062	75,062	75,062	75,062	75,062	75,062
139	Transarea Peak Load (MW) - January	13,062	13,062	13,062	13,062	13,062	13,062	13,062	13,062	13,062
140	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
141	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
142	Transarea Import Energy (GWh)	8,645	9,535	5,960	9,636	3,374	9,697	10,109	9,721	4,355
143	Transarea Export Energy (GWh)	3,012	2,172	3,902	2,172	3,342	2,172	2,310	2,180	3,057
144	Transarea Water Consumption (TCF?)									
145	Transarea Emissions (000 Tons)									
146	*CO2*	4,218	4,380	4,172	4,317	3,826	4,277	4,088	4,267	2,877
147	*SO2*	1	1	1	1	1	1	1	1	0
148	*NOX*	5	5	5	5	5	5	5	5	4
149	*HG*	15	15	15	15	11	14	12	14	4
150	Transarea Load/Generation (GWh)									
151	Load (GWh)									
152	Total Load Includes Losses and Pumping Load	75,062	75,062	75,062	75,062	75,062	75,062	75,062	75,062	75,062
153	EE	0	0	3,720	0	8,184	0	0	0	8,184
154	Rooftop Solar	0	0	0	0	0	0	0	0	0
155	Net Load	75,062	75,062	71,343	75,062	66,879	75,062	75,062	75,062	66,879
156	Generation (GWh)			0						
157	Nuclear	0	0	0	0	0	0	0	0	0
158	Hydro	57,915	57,915	57,915	57,915	57,915	57,915	57,915	57,915	57,915
159	Existing/Named Coal	1,367	1,352	1,399	1,346	1,020	1,313	1,121	1,301	369
160	Generic Coal	0	0	0	0	0	0	0	0	0
161	Existing/Named Gas-GT	789	789	789	789	789	789	789	789	786
162	Existing/Named Gas-CC	1,783	1,740	1,623	1,732	1,408	1,697	1,536	1,682	1,130
163	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
164	Generic Gas - GT	19	116	0	34	0	55	172	70	0
165	Generic Gas - CC	0	0	0	0	0	0	0	0	0
166	Fuel Oil	0	0	0	0	0	0	0	0	0
167	Geothermal	0	0	0	0	0	0	0	0	0
168	Pumped Storage Output	0	0	0	0	0	0	0	0	0
169	Wind	4,922	2,951	4,922	2,951	2,951	2,951	2,951	2,951	2,951
170	Biomass/Other	0	0	0	0	0	0	0	0	0
171	*Biomass*	632	838	632	838	838	838	838	838	835
172	*DR*	0	0	0	0	0	0	0	0	0
173	*Jet Fuel*	0	0	0	0	0	0	0	0	0
174	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
175	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
176	*Refuse*	114	114	114	114	114	114	114	114	113
177	*Waste Heat*	90	90	90	90	89	90	90	90	89
178	*Wood*	1,798	1,794	1,801	1,791	1,722	1,776	1,738	1,772	1,393
179	*Other/Transaction*	0	0	0	0	0	0	0	0	0
180	Total	69,429	67,700	69,284	67,599	66,846	67,538	67,263	67,522	65,581

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
181	**CNP15**									
182	**Transarea Production Cost ($000)**	3,478,546	2,964,444	3,835,827	2,813,735	2,598,317	2,791,406	2,651,036	2,684,837	2,320,691
183	**Transarea Load (GWh)**	119,438	118,894	118,797	118,719	118,698	118,857	118,856	118,703	118,679
184	**Transarea Peak Load (MW) - July**	23,185	23,185	23,185	23,185	23,185	23,185	23,185	23,185	23,185
185	**Transarea "Energy Not Served" (GWh)**	0	0	0	0	0	0	0	0	0
186	**Transarea Dump Energy (GWh)**	0	0	0	0	0	0	0	0	0
187	**Transarea Import Energy (GWh)**	38,365	35,823	33,360	33,348	39,320	30,318	34,155	27,647	37,608
188	**Transarea Export Energy (GWh)**	9,709	8,760	9,399	8,487	9,889	10,705	11,111	10,888	11,916
189	**Transarea Water Consumption (TCF?)**									
190	**Transarea Emissions (000 Tons)**									
191	***CO2***	25,665	21,713	20,657	20,495	18,778	20,530	19,400	19,682	16,676
192	***SO2***	55	55	56	55	54	54	53	54	47
193	***NOX***	20	19	33	18	19	21	22	21	19
194	***HG***	4	4	4	4	4	4	4	4	4
195	**Transarea Load/Generation (GWh)**									
196	**Load (GWh)**									
197	**Total Load Includes Losses and Pumping Load**	119,438	118,894	118,797	118,719	118,698	118,857	118,856	118,703	118,679
198	**EE**	0	10,649	15,331	15,331	15,331	10,649	10,649	15,331	15,331
199	**Rooftop Solar**	0	481	0	481	481	2,883	2,883	2,883	2,883
200	**Net Load**	119,438	107,764	103,467	102,907	102,887	105,325	105,324	100,490	100,466
201	**Generation (GWh)**			0						
202	**Nuclear**	0	0	0	0	0	0	0	0	0
203	**Hydro**	25,761	25,761	25,761	25,761	25,761	25,761	25,761	25,761	25,761
204	**Existing/Named Coal**	858	858	858	858	858	858	858	858	858
205	**Generic Coal**	0	0	0	0	0	0	0	0	0
206	**Existing/Named Gas-GT**	4,843	3,979	3,816	3,676	3,574	3,326	3,458	3,015	3,263
207	**Existing/Named Gas-CC**	38,913	33,472	31,562	31,572	27,049	28,457	24,836	27,012	17,954
208	**Existing/Named Gas-ST**	1,213	496	307	194	245	85	180	0	130
209	**Generic Gas - GT**	1,840	0	202	0	0	0	0	0	0
210	**Generic Gas - CC**	0	0	0	0	0	0	0	0	0
211	**Fuel Oil**	11	31	46	4	22	26	42	6	40
212	**Geothermal**	7,457	7,457	7,465	7,457	7,457	12,441	12,441	12,441	12,441
213	**Pumped Storage Output**	1,859	1,490	1,443	1,369	1,358	1,456	1,455	1,350	1,341
214	**Wind**	3,287	2,148	3,287	2,148	2,148	5,230	5,230	5,230	5,230
215	**Biomass/Other**	0	0	0	0	0	0	0	0	0
216	*Biomass*	772	1,048	781	1,048	1,048	3,339	3,339	3,339	3,324
217	*DR*	0	0	0	0	0	0	0	0	0
218	*Jet Fuel*	0	0	0	0	0	0	0	0	0
219	*Petroleum Coke*	1,188	1,181	1,198	1,179	1,160	1,164	1,123	1,154	992
220	*CSP (Solar)*	0	0	0	0	0	795	795	795	795
221	*Refuse*	114	114	114	114	114	114	114	114	114
222	*Waste Heat*	0	0	0	0	0	0	0	0	0
223	*Wood*	2,666	2,666	2,666	2,665	2,662	2,661	2,646	2,657	2,530
224	*Other/Transaction*	0	0	0	0	0	0	0	0	0
225	**Total**	90,783	80,702	79,505	78,046	73,456	85,712	82,279	83,731	74,774
226	**CO_East**									
227	**Transarea Production Cost ($000)**	1,901,354	1,866,873	2,101,389	1,871,665	1,560,731	1,842,057	1,610,278	1,827,673	1,318,635
228	**Transarea Load (GWh)**	62,200	62,194	62,180	62,195	62,153	62,194	62,337	62,194	62,312
229	**Transarea Peak Load (MW) - July**	11,692	11,692	11,692	11,692	11,692	11,692	11,692	11,692	11,692
230	**Transarea "Energy Not Served" (GWh)**	0	0	0	0	0	0	0	0	0
231	**Transarea Dump Energy (GWh)**	0	0	0	0	0	0	0	0	0
232	**Transarea Import Energy (GWh)**	8,390	8,893	9,285	8,946	8,402	9,613	15,243	9,900	15,565
233	**Transarea Export Energy (GWh)**	713	500	891	496	650	373	88	348	69
234	**Transarea Water Consumption (TCF?)**									
235	**Transarea Emissions (000 Tons)**									
236	***CO2***	41,556	41,567	39,770	41,557	38,080	41,108	37,605	40,923	32,574
237	***SO2***	40	40	41	40	38	40	37	40	32
238	***NOX***	43	43	42	43	41	43	39	43	34
239	***HG***	207	207	207	207	203	206	199	206	182
240	**Transarea Load/Generation (GWh)**									
241	**Load (GWh)**									
242	**Total Load Includes Losses and Pumping Load**	62,200	62,194	62,180	62,195	62,153	62,194	62,337	62,194	62,312
243	**EE**	0	0	3,082	0	6,781	0	0	0	6,781
244	**Rooftop Solar**	0	0	0	0	0	0	0	0	0
245	**Net Load**	62,200	62,194	59,098	62,195	55,371	62,194	62,337	62,194	55,531
246	**Generation (GWh)**									
247	**Nuclear**	0	0	0	0	0	0	0	0	0
248	**Hydro**	783	783	783	783	783	783	783	783	783
249	**Existing/Named Coal**	27,423	27,469	27,338	27,420	26,497	27,236	25,802	27,169	23,090
250	**Generic Coal**	3,853	3,851	3,852	3,851	3,840	3,850	3,809	3,849	3,595
251	**Existing/Named Gas-GT**	1,231	1,133	912	1,308	953	1,324	856	1,235	579
252	**Existing/Named Gas-CC**	11,666	11,423	9,537	11,255	8,488	10,793	8,396	10,729	5,948
253	**Existing/Named Gas-ST**	0	0	0	0	0	0	0	0	0
254	**Generic Gas - GT**	3,209	2,709	1,825	2,674	649	2,542	1,730	2,444	236
255	**Generic Gas - CC**	0	0	0	0	0	0	0	0	0
256	**Fuel Oil**	34	17	151	37	22	12	5	18	20
257	**Geothermal**	0	158	0	158	158	158	96	158	96
258	**Pumped Storage Output**	80	76	63	76	47	76	173	76	156
259	**Wind**	6,244	5,567	6,244	5,567	5,567	5,567	4,949	5,567	4,949
260	**Biomass/Other**	0	0	0	0	0	0	0	0	0
261	*Biomass*	0	615	0	615	615	615	377	615	375
262	*DR*	0	0	0	0	0	0	0	0	0
263	*Jet Fuel*	0	0	0	0	0	0	0	0	0
264	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
265	*CSP (Solar)*	0	0	0	0	0	0	206	0	206
266	*Refuse*	0	0	0	0	0	0	0	0	0
267	*Waste Heat*	0	0	0	0	0	0	0	0	0
268	*Wood*	0	0	0	0	0	0	0	0	0
269	*Other/Transaction*	0	0	0	0	0	0	0	0	0
270	**Total**	54,523	53,801	50,704	53,744	47,619	52,955	47,182	52,643	40,035

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
271	**CO_West**									
272	Transarea Production Cost ($000)	418,676	416,731	434,860	415,917	410,522	413,991	402,102	413,179	379,283
273	Transarea Load (GWh)	8,216	8,216	8,216	8,216	8,216	8,216	8,216	8,216	8,216
274	Transarea Peak Load (MW) - July	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,473	1,473
275	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
276	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
277	Transarea Import Energy (GWh)	907	554	1,335	560	793	572	1,895	563	1,763
278	Transarea Export Energy (GWh)	7,862	7,474	8,606	7,467	8,430	7,413	8,289	7,378	8,101
279	Transarea Water Consumption (TCF?)									
280	Transarea Emissions (000 Tons)									
281	*CO2*	15,178	15,161	15,087	15,149	14,993	15,085	14,617	15,059	13,610
282	*SO2*	10	10	10	10	10	10	10	10	9
283	*NOX*	25	25	25	25	25	25	24	25	22
284	*HG*	104	104	103	104	103	103	100	103	94
285	Transarea Load/Generation (GWh)									
286	Load (GWh)									
287	Total Load Includes Losses and Pumping Load	8,216	8,216	8,216	8,216	8,216	8,216	8,216	8,216	8,216
288	EE	0	0	407	0	896	0	0	0	896
289	Rooftop Solar	0	0	0	0	0	0	0	0	0
290	Net Load	8,216	8,216	7,808	8,216	7,320	8,216	8,216	8,216	7,320
291	Generation (GWh)									
292	Nuclear	0	0	0	0	0	0	0	0	0
293	Hydro	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012	1,012
294	Existing/Named Coal	14,178	14,176	14,166	14,170	14,051	14,119	13,705	14,098	12,767
295	Generic Coal	0	0	0	0	0	0	0	0	0
296	Existing/Named Gas-GT	1	7	1	1	1	1	0	0	0
297	Existing/Named Gas-CC	104	66	25	64	19	51	18	46	4
298	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
299	Generic Gas - GT	0	0	0	0	0	0	0	0	0
300	Generic Gas - CC	0	0	0	0	0	0	0	0	0
301	Fuel Oil	0	0	0	0	0	0	0	0	0
302	Geothermal	0	0	0	0	0	0	0	0	0
303	Pumped Storage Output	0	0	0	0	0	0	0	0	0
304	Wind	0	0	0	0	0	0	0	0	0
305	Biomass/Other	0	0	0	0	0	0	0	0	0
306	*Biomass*	0	0	0	0	0	0	0	0	0
307	*DR*	0	0	0	0	0	0	0	0	0
308	*Jet Fuel*	0	0	0	0	0	0	0	0	0
309	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
310	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
311	*Refuse*	0	0	0	0	0	0	0	0	0
312	*Waste Heat*	0	0	0	0	0	0	0	0	0
313	*Wood*	0	0	0	0	0	0	0	0	0
314	*Other/Transaction*	-126	-126	-126	-126	-126	-126	-126	-126	-126
315	Total	15,171	15,135	15,079	15,122	14,957	15,057	14,610	15,031	13,658
316	**COB**									
317	Transarea Production Cost ($000)	205,403	168,979	204,982	161,105	161,671	136,986	116,199	132,107	100,815
318	Transarea Load (GWh)	1,981	1,981	1,981	1,981	1,981	1,981	1,981	1,981	1,981
319	Transarea Peak Load (MW) - January	342	342	342	342	342	342	342	342	342
320	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
321	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
322	Transarea Import Energy (GWh)	6,191	6,612	8,283	6,211	15,322	5,435	6,822	5,251	12,252
323	Transarea Export Energy (GWh)	7,504	7,234	8,437	6,703	15,203	5,483	6,551	5,215	11,258
324	Transarea Water Consumption (TCF?)									
325	Transarea Emissions (000 Tons)									
326	*CO2*	1,431	1,137	936	1,082	813	892	767	855	462
327	*SO2*	0	0	0	0	0	0	0	0	0
328	*NOX*	0	0	0	0	0	0	0	0	0
329	*HG*	0	0	0	0	0	0	0	0	0
330	Transarea Load/Generation (GWh)									
331	Load (GWh)									
332	Total Load Includes Losses and Pumping Load	1,981	1,981	1,981	1,981	1,981	1,981	1,981	1,981	1,981
333	EE	0	0	9	0	9	0	0	0	9
334	Rooftop Solar	0	0	0	0	0	0	0	0	0
335	Net Load	1,981	1,981	1,972	1,981	1,972	1,981	1,981	1,981	1,972
336	Generation (GWh)									
337	Nuclear	0	0	0	0	0	0	0	0	0
338	Hydro	0	0	0	0	0	0	0	0	0
339	Existing/Named Coal	0	0	0	0	0	0	0	0	0
340	Generic Coal	0	0	0	0	0	0	0	0	0
341	Existing/Named Gas-GT	1	0	0	1	1	0	1	1	1
342	Existing/Named Gas-CC	3,294	2,603	2,126	2,472	1,851	2,029	1,709	1,944	978
343	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
344	Generic Gas - GT	0	0	0	0	0	0	0	0	0
345	Generic Gas - CC	0	0	0	0	0	0	0	0	0
346	Fuel Oil	0	0	0	0	0	0	0	0	0
347	Geothermal	0	0	0	0	0	0	0	0	0
348	Pumped Storage Output	0	0	0	0	0	0	0	0	0
349	Wind	0	0	0	0	0	0	0	0	0
350	Biomass/Other	0	0	0	0	0	0	0	0	0
351	*Biomass*	0	0	0	0	0	0	0	0	0
352	*DR*	0	0	0	0	0	0	0	0	0
353	*Jet Fuel*	0	0	0	0	0	0	0	0	0
354	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
355	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
356	*Refuse*	0	0	0	0	0	0	0	0	0
357	*Waste Heat*	0	0	0	0	0	0	0	0	0
358	*Wood*	0	0	0	0	0	0	0	0	0
359	*Other/Transaction*	0	0	0	0	0	0	0	0	0
360	Total	3,295	2,603	2,126	2,473	1,852	2,029	1,710	1,945	979

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
361	CSCE									
362	Transarea Production Cost ($000)	3,214,092	2,756,508	3,656,321	2,649,638	2,472,770	2,496,721	2,332,641	2,361,576	2,056,860
363	Transarea Load (GWh)	127,680	127,608	127,569	127,555	127,584	127,567	127,561	127,537	127,536
364	Transarea Peak Load (MW) - August	27,720	27,720	27,720	27,720	27,720	27,720	27,720	27,720	27,720
365	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
366	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
367	Transarea Import Energy (GWh)	64,153	49,231	55,293	45,667	47,210	40,323	43,882	37,647	43,119
368	Transarea Export Energy (GWh)	13,280	9,988	12,000	9,869	7,803	11,351	11,620	11,562	11,023
369	Transarea Water Consumption (TCF?)	0	0	0	0	0	0	0	0	0
370	Transarea Emissions (000 Tons)									
371	*CO2*	21,784	18,281	17,956	17,401	15,975	16,359	15,068	15,290	12,880
372	*SO2*	11	10	11	10	10	10	9	10	7
373	*NOX*	16	15	15	15	15	17	17	17	16
374	*HG*	6	6	6	6	6	6	6	6	5
375	Transarea Load/Generation (GWh)									
376	Load (GWh)									
377	Total Load Includes Losses and Pumping Load	127,680	127,608	127,569	127,555	127,584	127,567	127,561	127,537	127,536
378	EE	0	10,629	15,935	15,935	15,935	10,629	10,629	15,935	15,935
379	Rooftop Solar	0	532	0	532	532	3,031	3,031	3,031	3,031
380	Net Load	127,680	116,447	111,634	111,088	111,117	113,908	113,901	108,571	108,570
381	Generation (GWh)									
382	Nuclear	16,828	16,828	16,828	16,828	16,828	16,828	16,828	16,828	16,823
383	Hydro	5,444	5,444	5,444	5,444	5,444	5,444	5,444	5,444	5,444
384	Existing/Named Coal	1,529	1,529	1,529	1,529	1,529	1,529	1,528	1,529	1,514
385	Generic Coal	0	0	0	0	0	0	0	0	0
386	Existing/Named Gas-GT	6,873	6,858	6,956	6,797	6,875	6,835	6,819	6,784	6,680
387	Existing/Named Gas-CC	30,609	25,309	24,897	23,806	20,172	19,223	15,931	16,886	11,083
388	Existing/Named Gas-ST	924	523	533	215	189	36	77	0	21
389	Generic Gas - GT	2,392	0	0	0	0	0	0	0	0
390	Generic Gas - CC	0	0	0	0	0	0	0	0	0
391	Fuel Oil	0	0	0	0	0	0	0	0	0
392	Geothermal	2,738	2,738	2,738	2,738	2,738	4,849	4,849	4,849	4,849
393	Pumped Storage Output	530	473	451	431	454	441	436	417	416
394	Wind	6,540	12,531	6,540	12,531	12,531	21,939	21,939	21,939	21,939
395	Biomass/Other	0	0	0	0	0	0	0	0	0
396	*Biomass*	1,001	1,395	1,001	1,395	1,395	2,858	2,858	2,858	2,842
397	*DR*	0	0	0	0	0	0	0	0	0
398	*Jet Fuel*	0	0	0	0	0	0	0	0	0
399	*Petroleum Coke*	211	203	237	200	181	189	165	186	102
400	*CSP (Solar)*	556	2,743	556	2,743	2,743	4,135	4,135	4,135	4,135
401	*Refuse*	258	258	258	258	258	258	258	258	253
402	*Waste Heat*	0	0	0	0	0	0	0	0	0
403	*Wood*	373	373	373	373	373	373	373	373	373
404	*Other/Transaction*	0	0	0	0	0	0	0	0	0
405	Total	76,806	77,205	68,342	75,289	71,710	84,935	81,639	82,486	76,474
406	CSDGE									
407	Transarea Production Cost ($000)	570,337	377,088	524,393	343,643	364,553	244,007	231,040	234,603	212,695
408	Transarea Load (GWh)	26,091	26,083	26,077	26,078	26,079	26,081	26,081	26,072	26,075
409	Transarea Peak Load (MW) - September	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334	5,334
410	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
411	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
412	Transarea Import Energy (GWh)	17,257	16,733	17,487	17,244	17,082	16,018	16,263	16,178	16,641
413	Transarea Export Energy (GWh)	31	20	1	2	1	18	2	3	0
414	Transarea Water Consumption (TCF?)									
415	Transarea Emissions (000 Tons)									
416	*CO2*	4,345	2,880	2,716	2,620	2,781	2,638	2,539	2,565	2,391
417	*SO2*	0	0	0	0	0	0	0	0	0
418	*NOX*	2	1	1	1	1	3	3	3	3
419	*HG*	0	0	0	0	0	0	0	0	0
420	Transarea Load/Generation (GWh)									
421	Load (GWh)									
422	Total Load Includes Losses and Pumping Load	26,091	26,083	26,077	26,078	26,079	26,081	26,081	26,072	26,075
423	EE	0	2,875	2,875	2,875	2,875	2,875	2,875	2,875	2,875
424	Rooftop Solar	0	208	0	208	208	607	607	607	607
425	Net Load	26,091	22,999	23,201	22,994	22,995	22,598	22,599	22,590	22,593
426	Generation (GWh)									
427	Nuclear	0	0	0	0	0	0	0	0	0
428	Hydro	9	9	9	9	9	9	9	9	9
429	Existing/Named Coal	0	0	0	0	0	0	0	0	0
430	Generic Coal	0	0	0	0	0	0	0	0	0
431	Existing/Named Gas-GT	105	79	173	69	122	139	169	134	187
432	Existing/Named Gas-CC	4,340	3,585	3,613	3,306	3,061	2,562	2,284	2,388	1,945
433	Existing/Named Gas-ST	158	81	143	44	66	255	239	256	194
434	Generic Gas - GT	3,974	1,752	1,508	1,548	1,878	0	0	0	0
435	Generic Gas - CC	0	0	0	0	0	0	0	0	0
436	Fuel Oil	0	0	0	0	0	0	0	0	0
437	Geothermal	0	0	0	0	0	0	0	0	0
438	Pumped Storage Output	58	52	45	48	48	49	50	43	45
439	Wind	137	488	137	488	488	1,508	1,508	1,508	1,508
440	Biomass/Other	0	0	0	0	0	0	0	0	0
441	*Biomass*	84	241	84	241	241	1,809	1,809	1,809	1,796
442	*DR*	0	0	0	0	0	0	0	0	0
443	*Jet Fuel*	1	0	3	0	0	1	3	2	1
444	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
445	*CSP (Solar)*	0	0	0	0	0	265	265	265	265
446	*Refuse*	0	0	0	0	0	0	0	0	0
447	*Waste Heat*	0	0	0	0	0	0	0	0	0
448	*Wood*	0	0	0	0	0	0	0	0	0
449	*Other/Transaction*	0	0	0	0	0	0	0	0	0
450	Total	8,865	6,286	5,715	5,753	5,914	6,598	6,337	6,414	5,951

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
451	CZP26									
452	Transarea Production Cost ($000)	1,545,557	1,392,373	1,705,370	1,318,083	1,216,517	1,245,815	1,192,754	1,185,649	1,092,318
453	Transarea Load (GWh)	10,454	10,454	10,454	10,454	10,454	10,454	10,454	10,454	10,454
454	Transarea Peak Load (MW) - August	1,751	1,751	1,751	1,751	1,751	1,751	1,751	1,751	1,751
455	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
456	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
457	Transarea Import Energy (GWh)	9,129	8,400	7,819	7,841	7,430	8,386	10,390	7,857	10,132
458	Transarea Export Energy (GWh)	33,851	31,782	29,269	30,284	27,927	29,066	29,983	27,826	28,082
459	Transarea Water Consumption (TCF?)									
460	Transarea Emissions (000 Tons)									
461	*CO2*	9,266	8,372	7,324	7,779	6,943	7,035	6,612	6,542	5,794
462	*SO2*	3	3	3	3	3	3	3	3	3
463	*NOX*	197	198	197	198	198	197	197	197	197
464	*HG*	3	3	3	3	3	3	3	3	3
465	Transarea Load/Generation (GWh)									
466	Load (GWh)									
467	Total Load Includes Losses and Pumping Load	10,454	10,454	10,454	10,454	10,454	10,454	10,454	10,454	10,454
468	EE	0	752	1,106	1,106	1,106	752	752	1,106	1,106
469	Rooftop Solar	0	43	0	43	43	249	249	249	249
470	Net Load	10,454	9,659	9,347	9,305	9,305	9,453	9,453	9,098	9,098
471	Generation (GWh)									
472	Nuclear	16,866	16,866	16,866	16,866	16,866	16,866	16,866	16,866	16,864
473	Hydro	32	32	32	32	32	32	32	32	32
474	Existing/Named Coal	771	771	771	771	770	770	769	770	748
475	Generic Coal	0	0	0	0	0	0	0	0	0
476	Existing/Named Gas-GT	5,877	5,873	5,894	5,863	5,870	5,867	5,868	5,852	5,844
477	Existing/Named Gas-CC	11,630	8,574	7,235	7,291	5,338	5,974	4,887	4,924	2,941
478	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
479	Generic Gas - GT	0	0	0	0	0	0	0	0	0
480	Generic Gas - CC	0	0	0	0	0	0	0	0	0
481	Fuel Oil	0	0	0	0	0	0	0	0	0
482	Geothermal	0	0	0	0	0	0	0	0	0
483	Pumped Storage Output	0	0	0	0	0	0	0	0	0
484	Wind	0	216	0	216	216	194	194	194	194
485	Biomass/Other	0	0	0	0	0	0	0	0	0
486	*Biomass*	0	710	0	710	710	429	429	429	426
487	*DR*	0	0	0	0	0	0	0	0	0
488	*Jet Fuel*	0	0	0	0	0	0	0	0	0
489	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
490	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
491	*Refuse*	0	0	0	0	0	0	0	0	0
492	*Waste Heat*	0	0	0	0	0	0	0	0	0
493	*Wood*	0	0	0	0	0	0	0	0	0
494	*Other/Transaction*	0	0	0	0	0	0	0	0	0
495	Total	35,176	33,041	30,798	31,748	29,802	30,133	29,045	29,068	27,049
496	ID_SW									
497	Transarea Production Cost ($000)	127,648	119,669	113,749	115,607	96,062	113,835	323,256	103,724	320,547
498	Transarea Load (GWh)	18,759	18,759	18,759	18,759	18,759	18,759	18,759	18,759	18,759
499	Transarea Peak Load (MW) - July	3,693	3,693	3,693	3,693	3,693	3,693	3,693	3,693	3,693
500	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
501	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
502	Transarea Import Energy (GWh)	17,165	17,430	16,060	17,453	13,130	17,860	13,229	17,890	6,963
503	Transarea Export Energy (GWh)	8,137	9,023	7,926	8,981	7,453	9,338	15,950	9,233	12,743
504	Transarea Water Consumption (TCF?)									
505	Transarea Emissions (000 Tons)									
506	*CO2*	475	406	212	374	162	355	3,850	277	3,763
507	*SO2*	0	0	0	0	0	0	0	0	0
508	*NOX*	0	0	0	0	0	0	9	0	9
509	*HG*	0	0	0	0	0	0	0	0	0
510	Transarea Load/Generation (GWh)									
511	Load (GWh)									
512	Total Load Includes Losses and Pumping Load	18,759	18,759	18,759	18,759	18,759	18,759	18,759	18,759	18,759
513	EE	0	0	1,458	0	3,207	0	0	0	3,207
514	Rooftop Solar	0	0	0	0	0	0	0	0	0
515	Net Load	18,759	18,759	17,301	18,759	15,551	18,759	18,759	18,759	15,551
516	Generation (GWh)									
517	Nuclear	0	0	0	0	0	0	0	0	0
518	Hydro	8,161	8,161	8,161	8,161	8,161	8,161	8,161	8,161	8,161
519	Existing/Named Coal	0	0	0	0	0	0	0	0	0
520	Generic Coal	0	0	0	0	0	0	0	0	0
521	Existing/Named Gas-GT	9	23	24	30	57	59	37	16	4
522	Existing/Named Gas-CC	150	147	144	146	138	144	136	143	124
523	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
524	Generic Gas - GT	750	615	178	543	111	467	66	375	1
525	Generic Gas - CC	0	0	0	0	0	0	0	0	0
526	Fuel Oil	0	0	0	0	0	0	0	0	0
527	Geothermal	309	309	309	309	309	309	6,371	309	6,371
528	Pumped Storage Output	0	0	0	0	0	0	0	0	0
529	Wind	352	1,098	352	1,098	1,098	1,098	982	1,098	982
530	Biomass/Other	0	0	0	0	0	0	0	0	0
531	*Biomass*	0	0	0	0	0	0	5,727	0	5,689
532	*DR*	0	0	0	0	0	0	0	0	0
533	*Jet Fuel*	0	0	0	0	0	0	0	0	0
534	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
535	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
536	*Refuse*	0	0	0	0	0	0	0	0	0
537	*Waste Heat*	0	0	0	0	0	0	0	0	0
538	*Wood*	0	0	0	0	0	0	0	0	0
539	*Other/Transaction*	0	0	0	0	0	0	0	0	0
540	Total	9,731	10,352	9,167	10,287	9,874	10,237	21,480	10,102	21,331

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
541	IDE_WYSW									
542	Transarea Production Cost ($000)	426,948	421,863	446,090	422,693	424,289	424,535	416,361	422,780	393,169
543	Transarea Load (GWh)	10,661	10,661	10,661	10,661	10,661	10,661	10,661	10,661	10,661
544	Transarea Peak Load (MW) - July	1,766	1,766	1,766	1,766	1,766	1,766	1,766	1,766	1,766
545	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
546	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
547	Transarea Import Energy (GWh)	7,875	10,421	7,376	10,426	8,093	10,812	7,347	10,795	6,974
548	Transarea Export Energy (GWh)	18,433	17,733	17,831	17,750	15,402	18,151	14,507	18,108	13,135
549	Transarea Water Consumption (TCF?)									
550	Transarea Emissions (000 Tons)									
551	*CO2*	17,267	17,225	17,211	17,231	17,220	17,239	17,084	17,222	16,007
552	*SO2*	25	25	25	25	24	25	24	24	23
553	*NOX*	33	33	33	33	33	33	32	33	30
554	*HG*	281	281	281	281	280	281	279	280	261
555	Transarea Load/Generation (GWh)									
556	Load (GWh)									
557	Total Load Includes Losses and Pumping Load	10,661	10,661	10,661	10,661	10,661	10,661	10,661	10,661	10,661
558	EE	0	0	0	0	0	0	0	0	0
559	Rooftop Solar	0	0	0	0	0	0	0	0	0
560	Net Load	10,661	10,661	10,661	10,661	10,661	10,661	10,661	10,661	10,661
561	Generation (GWh)									
562	Nuclear	0	0	0	0	0	0	0	0	0
563	Hydro	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820	1,820
564	Existing/Named Coal	15,963	15,963	15,962	15,963	15,946	15,954	15,858	15,949	14,902
565	Generic Coal	0	0	0	0	0	0	0	0	0
566	Existing/Named Gas-GT	0	0	0	0	0	0	0	0	0
567	Existing/Named Gas-CC	0	0	0	0	0	0	0	0	0
568	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
569	Generic Gas - GT	153	77	52	89	92	113	31	92	0
570	Generic Gas - CC	0	0	0	0	0	0	0	0	0
571	Fuel Oil	0	0	0	0	0	0	0	0	0
572	Geothermal	0	0	0	0	0	0	0	0	0
573	Pumped Storage Output	0	0	0	0	0	0	0	0	0
574	Wind	3,170	0	3,170	0	0	0	0	0	0
575	Biomass/Other	0	0	0	0	0	0	0	0	0
576	*Biomass*	0	0	0	0	0	0	0	0	0
577	*DR*	0	0	0	0	0	0	0	0	0
578	*Jet Fuel*	0	0	0	0	0	0	0	0	0
579	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
580	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
581	*Refuse*	0	0	0	0	0	0	0	0	0
582	*Waste Heat*	0	0	0	0	0	0	0	0	0
583	*Wood*	0	0	0	0	0	0	0	0	0
584	*Other/Transaction*	113	113	113	113	113	113	112	113	101
585	Total	21,219	17,973	21,116	17,985	17,971	18,000	17,821	17,974	16,822
586	IID									
587	Transarea Production Cost ($000)	265,954	367,257	285,102	364,843	350,418	500,514	482,586	498,949	465,318
588	Transarea Load (GWh)	4,169	4,169	4,169	4,169	4,169	4,169	4,169	4,169	4,169
589	Transarea Peak Load (MW) - July	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041	1,041
590	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
591	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
592	Transarea Import Energy (GWh)	389	0	27	0	0	0	16	0	19
593	Transarea Export Energy (GWh)	3,337	7,866	3,145	7,903	7,630	14,715	14,398	14,770	14,172
594	Transarea Water Consumption (TCF?)									
595	Transarea Emissions (000 Tons)									
596	*CO2*	718	973	671	952	836	749	605	735	469
597	*SO2*	0	0	0	0	0	0	0	0	0
598	*NOX*	1	2	1	2	1	1	1	1	1
599	*HG*	0	0	0	0	0	0	0	0	0
600	Transarea Load/Generation (GWh)									
601	Load (GWh)									
602	Total Load Includes Losses and Pumping Load	4,169	4,169	4,169	4,169	4,169	4,169	4,169	4,169	4,169
603	EE	0	190	272	272	272	190	190	272	272
604	Rooftop Solar	0	1	0	1	1	3	3	3	3
605	Net Load	4,169	3,977	3,896	3,895	3,895	3,975	3,975	3,893	3,893
606	Generation (GWh)									
607	Nuclear	0	0	0	0	0	0	0	0	0
608	Hydro	293	293	293	293	293	293	293	293	293
609	Existing/Named Coal	0	0	0	0	0	0	0	0	0
610	Generic Coal	0	0	0	0	0	0	0	0	0
611	Existing/Named Gas-GT	29	68	15	59	27	58	23	46	4
612	Existing/Named Gas-CC	785	745	725	708	468	585	287	570	0
613	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
614	Generic Gas - GT	215	0	186	0	0	0	0	0	0
615	Generic Gas - CC	0	0	0	0	0	0	0	0	0
616	Fuel Oil	0	0	0	0	0	0	0	0	0
617	Geothermal	5,437	9,827	5,437	9,827	9,827	15,888	15,888	15,888	15,888
618	Pumped Storage Output	0	0	0	0	0	0	0	0	0
619	Wind	0	0	0	0	0	0	0	0	0
620	Biomass/Other	0	0	0	0	0	0	0	0	0
621	*Biomass*	0	552	0	552	552	315	315	315	312
622	*DR*	0	0	0	0	0	0	0	0	0
623	*Jet Fuel*	0	0	0	0	0	0	0	0	0
624	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
625	*CSP (Solar)*	0	0	0	0	0	1,193	1,193	1,193	1,193
626	*Refuse*	0	0	0	0	0	0	0	0	0
627	*Waste Heat*	0	0	0	0	0	0	0	0	0
628	*Wood*	357	357	357	357	357	357	357	357	357
629	*Other/Transaction*	0	0	0	0	0	0	0	0	0
630	Total	7,117	11,843	7,014	11,797	11,525	18,690	18,357	18,662	18,047

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
631	IV-NG									
632	Transarea Production Cost ($000)	235,486	158,617	167,001	116,411	71,448	77,876	64,591	55,516	47,917
633	Transarea Load (GWh)	0	0	0	0	0	0	0	0	0
634	Transarea Peak Load (MW) -	0	0	0	0	0	0	0	0	0
635	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
636	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
637	Transarea Import Energy (GWh)	5,640	8,904	7,892	9,825	10,207	9,194	11,126	9,480	11,950
638	Transarea Export Energy (GWh)	9,626	12,613	9,647	12,814	12,441	13,190	14,908	13,121	15,454
639	Transarea Water Consumption (TCF?)									
640	Transarea Emissions (000 Tons)									
641	*CO2*	1,772	1,150	841	822	489	524	429	356	300
642	*SO2*	0	0	0	0	0	0	0	0	0
643	*NOX*	1	0	0	0	0	0	0	0	0
644	*HG*	0	0	0	0	0	0	0	0	0
645	Transarea Load/Generation (GWh)									
646	Load (GWh)									
647	Total Load Includes Losses and Pumping Load	0	0	0	0	0	0	0	0	0
648	EE	0	0	0	0	0	0	0	0	0
649	Rooftop Solar	0	0	0	0	0	0	0	0	0
650	Net Load	0	0	0	0	0	0	0	0	0
651	Generation (GWh)									
652	Nuclear	0	0	0	0	0	0	0	0	0
653	Hydro	0	0	0	0	0	0	0	0	0
654	Existing/Named Coal	0	0	0	0	0	0	0	0	0
655	Generic Coal	0	0	0	0	0	0	0	0	0
656	Existing/Named Gas-GT	0	0	0	0	0	0	0	0	0
657	Existing/Named Gas-CC	3,986	2,511	1,755	1,790	1,036	1,119	904	763	627
658	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
659	Generic Gas - GT	0	0	0	0	0	0	0	0	0
660	Generic Gas - CC	0	0	0	0	0	0	0	0	0
661	Fuel Oil	0	0	0	0	0	0	0	0	0
662	Geothermal	0	0	0	0	0	0	0	0	0
663	Pumped Storage Output	0	0	0	0	0	0	0	0	0
664	Wind	0	323	0	323	323	1,553	1,553	1,553	1,553
665	Biomass/Other	0	0	0	0	0	0	0	0	0
666	*Biomass*	0	0	0	0	0	0	0	0	0
667	*DR*	0	0	0	0	0	0	0	0	0
668	*Jet Fuel*	0	0	0	0	0	0	0	0	0
669	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
670	*CSP (Solar)*	0	875	0	875	875	1,325	1,325	1,325	1,325
671	*Refuse*	0	0	0	0	0	0	0	0	0
672	*Waste Heat*	0	0	0	0	0	0	0	0	0
673	*Wood*	0	0	0	0	0	0	0	0	0
674	*Other/Transaction*	0	0	0	0	0	0	0	0	0
675	Total	3,986	3,709	1,755	2,988	2,234	3,996	3,782	3,641	3,504
676	La Rosita									
677	Transarea Production Cost ($000)	505,538	491,049	624,761	491,172	443,339	473,116	454,365	465,965	383,090
678	Transarea Load (GWh)	9,961	9,961	9,961	9,961	9,961	9,961	9,961	9,961	9,961
679	Transarea Peak Load (MW) - August	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786
680	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
681	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
682	Transarea Import Energy (GWh)	1,257	1,063	1,364	1,161	1,202	1,619	2,255	1,742	2,584
683	Transarea Export Energy (GWh)	2,636	2,145	2,864	2,223	2,430	2,250	2,407	2,232	2,397
684	Transarea Water Consumption (TCF?)									
685	Transarea Emissions (000 Tons)									
686	*CO2*	2,368	2,259	2,235	2,254	1,871	2,099	1,937	2,040	1,364
687	*SO2*	0	0	0	0	0	0	0	0	0
688	*NOX*	1	1	1	1	0	1	1	1	0
689	*HG*	0	0	0	0	0	0	0	0	0
690	Transarea Load/Generation (GWh)									
691	Load (GWh)									
692	Total Load Includes Losses and Pumping Load	9,961	9,961	9,961	9,961	9,961	9,961	9,961	9,961	9,961
693	EE	0	0	494	0	1,086	0	0	0	1,086
694	Rooftop Solar	0	0	0	0	0	0	0	0	0
695	Net Load	9,961	9,961	9,467	9,961	8,875	9,961	9,961	9,961	8,875
696	Generation (GWh)									
697	Nuclear	0	0	0	0	0	0	0	0	0
698	Hydro	0	0	0	0	0	0	0	0	0
699	Existing/Named Coal	0	0	0	0	0	0	0	0	0
700	Generic Coal	0	0	0	0	0	0	0	0	0
701	Existing/Named Gas-GT	0	0	0	0	0	0	0	0	0
702	Existing/Named Gas-CC	5,339	5,061	4,921	5,022	4,237	4,543	4,062	4,421	2,685
703	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
704	Generic Gas - GT	133	117	180	135	0	183	184	164	137
705	Generic Gas - CC	0	0	0	0	0	0	0	0	0
706	Fuel Oil	0	0	0	0	0	0	0	0	0
707	Geothermal	5,867	5,866	5,866	5,866	5,866	5,866	5,866	5,866	5,866
708	Pumped Storage Output	0	0	0	0	0	0	0	0	0
709	Wind	0	0	0	0	0	0	0	0	0
710	Biomass/Other	0	0	0	0	0	0	0	0	0
711	*Biomass*	0	0	0	0	0	0	0	0	0
712	*DR*	0	0	0	0	0	0	0	0	0
713	*Jet Fuel*	0	0	0	0	0	0	0	0	0
714	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
715	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
716	*Refuse*	0	0	0	0	0	0	0	0	0
717	*Waste Heat*	0	0	0	0	0	0	0	0	0
718	*Wood*	0	0	0	0	0	0	0	0	0
719	*Other/Transaction*	0	0	0	0	0	0	0	0	0
720	Total	11,339	11,043	10,967	11,023	10,103	10,592	10,112	10,451	8,688

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
721	**LADWP**									
722	Transarea Production Cost ($000)	818,824	673,234	960,655	633,711	598,191	681,706	639,217	639,142	544,040
723	Transarea Load (GWh)	30,810	30,806	30,805	30,807	30,807	30,807	30,807	30,806	30,806
724	Transarea Peak Load (MW) - July	6,497	6,497	6,497	6,497	6,497	6,497	6,497	6,497	6,497
725	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
726	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
727	Transarea Import Energy (GWh)	25,196	19,666	23,784	18,937	24,655	18,354	20,898	18,127	22,976
728	Transarea Export Energy (GWh)	8,427	3,769	7,649	3,399	8,136	2,532	4,267	2,601	5,274
729	Transarea Water Consumption (TCF?)									
730	Transarea Emissions (000 Tons)									
731	*CO2*	5,881	4,863	4,704	4,551	4,168	4,933	4,628	4,589	3,813
732	*SO2*	0	0	0	0	0	0	0	0	0
733	*NOX*	1	1	1	1	1	1	1	1	1
734	*HG*	0	0	0	0	0	0	0	0	0
735	Transarea Load/Generation (GWh)									
736	Load (GWh)									
737	Total Load Includes Losses and Pumping Load	30,810	30,806	30,805	30,807	30,807	30,807	30,807	30,806	30,806
738	EE	0	2,057	3,084	3,084	3,084	2,057	2,057	3,084	3,084
739	Rooftop Solar	0	308	0	308	308	960	960	960	960
740	Net Load	30,810	28,442	27,722	27,415	27,415	27,790	27,790	26,762	26,762
741	Generation (GWh)									
742	Nuclear	0	0	0	0	0	0	0	0	0
743	Hydro	619	619	619	619	619	619	619	619	619
744	Existing/Named Coal	0	0	0	0	0	0	0	0	0
745	Generic Coal	0	0	0	0	0	0	0	0	0
746	Existing/Named Gas-GT	33	10	59	18	39	220	211	220	176
747	Existing/Named Gas-CC	10,597	8,866	8,799	8,439	7,589	8,665	7,969	8,093	6,090
748	Existing/Named Gas-ST	51	0	0	0	26	1,106	1,003	948	818
749	Generic Gas - GT	2,005	1,345	1,376	1,095	917	0	0	0	0
750	Generic Gas - CC	0	0	0	0	0	0	0	0	0
751	Fuel Oil	0	0	0	0	0	0	0	0	0
752	Geothermal	0	0	0	0	0	0	0	0	0
753	Pumped Storage Output	358	355	355	356	356	356	356	355	355
754	Wind	329	932	329	932	932	658	658	658	658
755	Biomass/Other	0	0	0	0	0	0	0	0	0
756	*Biomass*	50	326	50	326	326	251	251	251	251
757	*DR*	0	0	0	0	0	0	0	0	0
758	*Jet Fuel*	0	0	0	0	0	0	0	0	0
759	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
760	*CSP (Solar)*	0	93	0	93	93	93	93	93	93
761	*Refuse*	0	0	0	0	0	0	0	0	0
762	*Waste Heat*	0	0	0	0	0	0	0	0	0
763	*Wood*	0	0	0	0	0	0	0	0	0
764	*Other/Transaction*	0	0	0	0	0	0	0	0	0
765	Total	14,041	12,545	11,587	11,877	10,897	11,968	11,159	11,237	9,060
766	**Miguel**									
767	Transarea Production Cost ($000)	212,332	199,327	298,985	195,235	187,336	187,902	174,283	183,899	149,679
768	Transarea Load (GWh)	0	0	0	0	0	0	0	0	0
769	Transarea Peak Load (MW)	0	0	0	0	0	0	0	0	0
770	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
771	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
772	Transarea Import Energy (GWh)	8,572	11,940	8,520	12,000	11,495	11,811	12,774	11,599	12,897
773	Transarea Export Energy (GWh)	12,349	15,437	12,070	15,429	14,673	15,046	15,655	14,756	15,122
774	Transarea Water Consumption (TCF?)									
775	Transarea Emissions (000 Tons)									
776	*CO2*	1,630	1,525	1,567	1,493	1,429	1,433	1,326	1,401	1,131
777	*SO2*	0	0	0	0	0	0	0	0	0
778	*NOX*	0	0	0	0	0	0	0	0	0
779	*HG*	0	0	0	0	0	0	0	0	0
780	Transarea Load/Generation (GWh)									
781	Load (GWh)									
782	Total Load Includes Losses and Pumping Load	0	0	0	0	0	0	0	0	0
783	EE	0	0	0	0	0	0	0	0	0
784	Rooftop Solar	0	0	0	0	0	0	0	0	0
785	Net Load	0	0	0	0	0	0	0	0	0
786	Generation (GWh)									
787	Nuclear	0	0	0	0	0	0	0	0	0
788	Hydro	0	0	0	0	0	0	0	0	0
789	Existing/Named Coal	0	0	0	0	0	0	0	0	0
790	Generic Coal	0	0	0	0	0	0	0	0	0
791	Existing/Named Gas-GT	34	51	82	26	78	43	43	26	60
792	Existing/Named Gas-CC	3,554	3,346	3,314	3,323	2,996	3,130	2,765	3,075	2,107
793	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
794	Generic Gas - GT	189	100	154	81	104	62	73	55	58
795	Generic Gas - CC	0	0	0	0	0	0	0	0	0
796	Fuel Oil	0	0	0	0	0	0	0	0	0
797	Geothermal	0	0	0	0	0	0	0	0	0
798	Pumped Storage Output	0	0	0	0	0	0	0	0	0
799	Wind	0	0	0	0	0	0	0	0	0
800	Biomass/Other	0	0	0	0	0	0	0	0	0
801	*Biomass*	0	0	0	0	0	0	0	0	0
802	*DR*	0	0	0	0	0	0	0	0	0
803	*Jet Fuel*	0	0	0	0	0	0	0	0	0
804	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
805	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
806	*Refuse*	0	0	0	0	0	0	0	0	0
807	*Waste Heat*	0	0	0	0	0	0	0	0	0
808	*Wood*	0	0	0	0	0	0	0	0	0
809	*Other/Transaction*	0	0	0	0	0	0	0	0	0
810	Total	3,777	3,497	3,550	3,429	3,178	3,234	2,881	3,157	2,225

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
811	**Montana**									
812	**Transarea Production Cost ($000)**	558,670	587,967	566,320	583,473	576,163	584,045	564,856	582,011	538,861
813	**Transarea Load (GWh)**	14,411	14,411	14,411	14,411	14,411	14,411	14,411	14,411	14,411
814	**Transarea Peak Load (MW) - July**	2,355	2,355	2,355	2,355	2,355	2,355	2,355	2,355	2,355
815	**Transarea "Energy Not Served" (GWh)**	0	0	0	0	0	0	0	0	0
816	**Transarea Dump Energy (GWh)**	0	0	0	0	0	0	0	0	0
817	**Transarea Import Energy (GWh)**	1,402	2,315	1,264	2,322	3,603	2,383	4,742	2,342	3,840
818	**Transarea Export Energy (GWh)**	14,206	15,992	14,643	15,932	18,599	15,981	19,986	15,903	19,815
819	**Transarea Water Consumption (TCF?)**									
820	**Transarea Emissions (000 Tons)**									
821	***CO2***	21,138	22,329	21,112	22,290	22,067	22,268	21,378	22,240	20,385
822	***SO2***	46	46	46	46	46	46	46	46	42
823	***NOX***	39	42	39	42	42	42	40	42	38
824	***HG***	40	40	40	40	40	40	40	40	38
825	**Transarea Load/Generation (GWh)**									
826	**Load (GWh)**									
827	**Total Load Includes Losses and Pumping Load**	14,411	14,411	14,411	14,411	14,411	14,411	14,411	14,411	14,411
828	**EE**	0	0	714	0	1,571	0	0	0	1,571
829	**Rooftop Solar**	0	0	0	0	0	0	0	0	0
830	**Net Load**	14,411	14,411	13,697	14,411	12,840	14,411	14,411	14,411	12,840
831	**Generation (GWh)**									
832	**Nuclear**	0	0	0	0	0	0	0	0	0
833	**Hydro**	4,966	4,966	4,966	4,966	4,966	4,966	4,966	4,966	4,966
834	**Existing/Named Coal**	17,641	17,649	17,608	17,647	17,492	17,626	17,490	17,612	16,701
835	**Generic Coal**	0	0	0	0	0	0	0	0	0
836	**Existing/Named Gas-GT**	8	2	1	1	1	1	1	2	0
837	**Existing/Named Gas-CC**	0	0	0	0	0	0	0	0	0
838	**Existing/Named Gas-ST**	0	0	0	0	0	0	0	0	0
839	**Generic Gas - GT**	100	97	0	33	6	43	12	19	0
840	**Generic Gas - CC**	0	0	0	0	0	0	0	0	0
841	**Fuel Oil**	0	0	0	0	0	0	0	0	0
842	**Geothermal**	0	0	0	0	0	0	0	0	0
843	**Pumped Storage Output**	0	0	0	0	0	0	0	0	0
844	**Wind**	3,325	2,378	3,325	2,378	2,378	2,378	5,250	2,378	5,250
845	**Biomass/Other**	0	0	0	0	0	0	0	0	0
846	*Biomass*	0	1,821	0	1,821	1,821	1,821	762	1,821	756
847	*DR*	0	0	0	0	0	0	0	0	0
848	*Jet Fuel*	0	0	0	0	0	0	0	0	0
849	*Petroleum Coke*	462	462	462	462	459	462	461	461	429
850	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
851	*Refuse*	0	0	0	0	0	0	0	0	0
852	*Waste Heat*	0	0	0	0	0	0	0	0	0
853	*Wood*	0	0	0	0	0	0	0	0	0
854	*Other/Transaction*	712	712	712	712	712	712	712	712	712
855	**Total**	27,215	28,088	27,075	28,021	27,836	28,010	29,655	27,972	28,815
856	**N Nevada**									
857	**Transarea Production Cost ($000)**	638,495	657,977	704,446	650,978	564,180	635,895	610,033	629,058	499,728
858	**Transarea Load (GWh)**	18,616	18,616	18,616	18,616	18,616	18,616	18,616	18,616	18,616
859	**Transarea Peak Load (MW) - July**	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135	3,135
860	**Transarea "Energy Not Served" (GWh)**	0	0	0	0	0	0	0	0	0
861	**Transarea Dump Energy (GWh)**	0	0	0	0	0	0	0	0	0
862	**Transarea Import Energy (GWh)**	1,904	1,203	1,959	1,233	1,179	1,360	853	1,424	1,441
863	**Transarea Export Energy (GWh)**	1,062	1,480	981	1,399	1,605	1,180	3,327	1,115	1,495
864	**Transarea Water Consumption (TCF?)**									
865	**Transarea Emissions (000 Tons)**									
866	***CO2***	11,436	11,064	11,012	11,006	10,211	10,836	9,553	10,759	5,290
867	***SO2***	8	8	8	8	8	8	7	8	6
868	***NOX***	14	13	13	13	13	13	13	13	10
869	***HG***	63	63	63	63	62	63	60	62	16
870	**Transarea Load/Generation (GWh)**									
871	**Load (GWh)**									
872	**Total Load Includes Losses and Pumping Load**	18,616	18,616	18,616	18,616	18,616	18,616	18,616	18,616	18,616
873	**EE**	0	0	923	0	2,030	0	0	0	2,030
874	**Rooftop Solar**	0	0	0	0	0	0	0	0	0
875	**Net Load**	18,616	18,616	17,693	18,616	16,586	18,616	18,616	18,616	16,586
876	**Generation (GWh)**									
877	**Nuclear**	0	0	0	0	0	0	0	0	0
878	**Hydro**	46	46	46	46	46	46	46	46	46
879	**Existing/Named Coal**	5,462	5,450	5,452	5,445	5,366	5,405	5,137	5,383	4,405
880	**Generic Coal**	3,845	3,844	3,846	3,843	3,823	3,834	3,713	3,823	0
881	**Existing/Named Gas-GT**	147	165	72	129	190	111	127	94	130
882	**Existing/Named Gas-CC**	3,359	2,488	2,417	2,421	710	2,143	78	2,071	73
883	**Existing/Named Gas-ST**	823	807	790	803	783	801	773	796	770
884	**Generic Gas - GT**	0	0	0	0	0	0	0	0	0
885	**Generic Gas - CC**	0	0	0	0	0	0	0	0	0
886	**Fuel Oil**	0	0	0	0	0	0	0	0	0
887	**Geothermal**	2,489	5,156	2,489	5,156	5,156	5,156	9,208	5,156	9,208
888	**Pumped Storage Output**	0	0	0	0	0	0	0	0	0
889	**Wind**	1,527	863	1,527	863	863	863	1,932	863	1,932
890	**Biomass/Other**	0	0	0	0	0	0	0	0	0
891	*Biomass*	0	0	0	0	0	0	0	0	0
892	*DR*	0	0	0	0	0	0	0	0	0
893	*Jet Fuel*	0	0	0	0	0	0	0	0	0
894	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
895	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
896	*Refuse*	0	0	0	0	0	0	0	0	0
897	*Waste Heat*	0	0	0	0	0	0	0	0	0
898	*Wood*	76	76	76	76	76	76	76	76	76
899	*Other/Transaction*	0	0	0	0	0	0	0	0	0
900	**Total**	17,774	18,893	16,715	18,782	17,012	18,436	21,090	18,307	16,640

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
901	NBAJA									
902	Transarea Production Cost ($000)	433,929	386,728	468,898	379,295	302,989	367,694	335,994	364,681	265,839
903	Transarea Load (GWh)	9,961	9,961	9,961	9,961	9,961	9,961	9,961	9,961	9,961
904	Transarea Peak Load (MW) - August	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786	1,786
905	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
906	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
907	Transarea Import Energy (GWh)	3,036	2,268	3,356	2,391	2,547	2,570	3,042	2,624	3,146
908	Transarea Export Energy (GWh)	207	390	105	347	255	241	122	221	26
909	Transarea Water Consumption (TCF?)									
910	Transarea Emissions (000 Tons)									
911	*CO2*	3,289	2,385	2,166	2,324	1,725	2,225	1,974	2,199	1,422
912	*SO2*	0	0	0	0	0	0	0	0	0
913	*NOX*	1	1	1	1	1	1	1	1	0
914	*HG*	0	0	0	0	0	0	0	0	0
915	Transarea Load/Generation (GWh)									
916	Load (GWh)									
917	Total Load Includes Losses and Pumping Load	9,961	9,961	9,961	9,961	9,961	9,961	9,961	9,961	9,961
918	EE	0	0	494	0	1,086	0	0	0	1,086
919	Rooftop Solar	0	0	0	0	0	0	0	0	0
920	Net Load	9,961	9,961	9,467	9,961	8,875	9,961	9,961	9,961	8,875
921	Generation (GWh)									
922	Nuclear	0	0	0	0	0	0	0	0	0
923	Hydro	0	0	0	0	0	0	0	0	0
924	Existing/Named Coal	0	0	0	0	0	0	0	0	0
925	Generic Coal	0	0	0	0	0	0	0	0	0
926	Existing/Named Gas-GT	96	28	94	58	104	79	111	49	58
927	Existing/Named Gas-CC	2,922	1,970	2,102	1,760	1,126	1,543	1,397	1,485	896
928	Existing/Named Gas-ST	15	10	16	19	12	9	10	9	0
929	Generic Gas - GT	2,344	1,556	2,034	1,565	920	1,526	1,224	1,569	870
930	Generic Gas - CC	1,754	1,702	0	1,699	1,602	1,659	1,483	1,628	1,116
931	Fuel Oil	2	4	39	4	6	4	4	7	5
932	Geothermal	0	2,811	1,932	2,811	2,811	2,811	2,811	2,811	2,811
933	Pumped Storage Output	0	0	0	0	0	0	0	0	0
934	Wind	0	0	0	0	0	0	0	0	0
935	Biomass/Other	0	0	0	0	0	0	0	0	0
936	*Biomass*	0	0	0	0	0	0	0	0	0
937	*DR*	0	0	0	0	0	0	0	0	0
938	*Jet Fuel*	0	0	0	0	0	0	0	0	0
939	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
940	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
941	*Refuse*	0	0	0	0	0	0	0	0	0
942	*Waste Heat*	0	0	0	0	0	0	0	0	0
943	*Wood*	0	0	0	0	0	0	0	0	0
944	*Other/Transaction*	0	0	0	0	0	0	0	0	0
945	Total	7,132	8,082	6,216	7,917	6,583	7,632	7,040	7,558	5,755
946	NewMexico									
947	Transarea Production Cost ($000)	1,306,255	1,247,133	1,424,941	1,225,997	1,075,074	1,194,866	1,052,613	1,191,500	971,552
948	Transarea Load (GWh)	34,111	34,111	34,111	34,111	34,111	34,111	34,111	34,111	34,111
949	Transarea Peak Load (MW) - July	5,767	5,767	5,767	5,767	5,767	5,767	5,767	5,767	5,767
950	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
951	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
952	Transarea Import Energy (GWh)	1,244	768	1,768	738	1,895	580	1,309	539	1,850
953	Transarea Export Energy (GWh)	9,927	9,022	10,116	8,597	8,346	7,810	23,334	7,665	25,523
954	Transarea Water Consumption (TCF?)									
955	Transarea Emissions (000 Tons)									
956	*CO2*	37,580	36,972	36,750	36,810	32,570	36,494	32,256	36,449	30,882
957	*SO2*	24	24	24	24	23	24	23	24	22
958	*NOX*	66	66	66	66	64	66	63	65	61
959	*HG*	581	581	581	581	538	579	533	579	516
960	Transarea Load/Generation (GWh)									
961	Load (GWh)									
962	Total Load Includes Losses and Pumping Load	34,111	34,111	34,111	34,111	34,111	34,111	34,111	34,111	34,111
963	EE	0	0	1,690	0	3,719	0	0	0	3,719
964	Rooftop Solar	0	0	0	0	0	0	0	0	0
965	Net Load	34,111	34,111	32,420	34,111	30,392	34,111	34,111	34,111	30,392
966	Generation (GWh)									
967	Nuclear	0	0	0	0	0	0	0	0	0
968	Hydro	367	367	367	367	367	367	367	367	367
969	Existing/Named Coal	29,862	29,850	29,848	29,846	29,803	29,798	29,605	29,784	28,839
970	Generic Coal	3,853	3,851	3,852	3,848	0	3,827	0	3,820	0
971	Existing/Named Gas-GT	631	645	701	646	703	628	746	650	664
972	Existing/Named Gas-CC	5,646	4,286	3,727	3,919	2,746	3,387	2,595	3,262	1,399
973	Existing/Named Gas-ST	779	777	778	777	777	777	778	777	777
974	Generic Gas - GT	305	265	145	243	125	236	0	257	0
975	Generic Gas - CC	0	0	0	0	0	0	0	0	0
976	Fuel Oil	0	0	0	0	0	0	0	0	0
977	Geothermal	0	591	0	591	591	591	438	591	438
978	Pumped Storage Output	0	0	0	0	0	0	0	0	0
979	Wind	996	996	996	996	996	996	20,598	996	20,598
980	Biomass/Other	0	0	0	0	0	0	0	0	0
981	*Biomass*	0	0	0	0	0	0	0	0	0
982	*DR*	0	0	0	0	0	0	0	0	0
983	*Jet Fuel*	0	0	0	0	0	0	0	0	0
984	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
985	*CSP (Solar)*	0	384	0	384	384	384	673	384	673
986	*Refuse*	0	0	0	0	0	0	0	0	0
987	*Waste Heat*	0	0	0	0	0	0	0	0	0
988	*Wood*	266	266	266	266	263	263	250	262	223
989	*Other/Transaction*	87	87	87	87	87	87	87	87	87
990	Total	42,793	42,365	40,768	41,971	36,843	41,341	56,137	41,237	54,065

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
991	**Northwest**									
992	Transarea Production Cost ($000)	3,029,558	2,955,049	3,199,589	2,937,242	2,257,728	2,836,267	2,510,994	2,820,345	2,027,530
993	Transarea Load (GWh)	185,191	185,191	185,191	185,191	185,191	185,191	185,191	185,191	185,191
994	Transarea Peak Load (MW) - January	32,359	32,359	32,359	32,359	32,359	32,359	32,359	32,359	32,359
995	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
996	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
997	Transarea Import Energy (GWh)	17,850	17,723	16,634	17,978	16,754	19,303	26,868	19,521	18,781
998	Transarea Export Energy (GWh)	21,108	22,028	21,452	21,872	26,995	20,999	20,667	20,828	22,295
999	Transarea Water Consumption (TCF?)									
1000	Transarea Emissions (000 Tons)									
1001	*CO2*	30,430	31,211	27,214	31,042	25,297	30,112	26,727	29,960	21,799
1002	*SO2*	21	21	21	21	20	21	20	21	19
1003	*NOX*	32	36	31	36	34	36	33	36	31
1004	*HG*	46	46	46	46	46	46	46	46	44
1005	Transarea Load/Generation (GWh)									
1006	Load (GWh)									
1007	Total Load Includes Losses and Pumping Load	185,191	185,191	185,191	185,191	185,191	185,191	185,191	185,191	185,191
1008	EE	0	0	9,177	0	20,190	0	0	0	20,190
1009	Rooftop Solar	0	0	0	0	0	0	0	0	0
1010	Net Load	185,191	185,191	176,013	185,191	165,000	185,191	185,191	185,191	165,000
1011	Generation (GWh)									
1012	Nuclear	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,251	9,246
1013	Hydro	122,837	122,837	122,837	122,837	122,837	122,837	122,837	122,837	122,837
1014	Existing/Named Coal	14,300	14,287	14,250	14,278	14,151	14,251	14,206	14,238	13,136
1015	Generic Coal	0	0	0	0	0	0	0	0	0
1016	Existing/Named Gas-GT	33	22	8	26	28	16	13	39	22
1017	Existing/Named Gas-CC	28,465	26,259	21,092	25,843	12,165	23,708	17,305	23,305	8,003
1018	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
1019	Generic Gas - GT	170	17	0	27	0	4	19	9	0
1020	Generic Gas - CC	0	0	0	0	0	0	0	0	0
1021	Fuel Oil	0	0	0	0	0	0	0	0	0
1022	Geothermal	257	257	257	257	257	257	257	257	257
1023	Pumped Storage Output	0	0	0	0	0	0	0	0	0
1024	Wind	10,854	11,526	10,854	11,526	11,526	11,526	11,256	11,526	11,256
1025	Biomass/Other	0	0	0	0	0	0	0	0	0
1026	*Biomass*	30	2,789	30	2,789	2,789	2,789	1,606	2,789	1,583
1027	*DR*	0	0	0	0	0	0	0	0	0
1028	*Jet Fuel*	0	0	0	0	0	0	0	0	0
1029	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
1030	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
1031	*Refuse*	260	260	260	260	260	260	260	260	260
1032	*Waste Heat*	435	435	435	435	435	435	435	435	434
1033	*Wood*	1,373	1,372	1,374	1,372	1,360	1,370	1,361	1,369	1,295
1034	*Other/Transaction*	183	183	183	183	183	183	183	183	183
1035	Total	188,448	189,495	180,831	189,085	175,241	186,887	178,989	186,498	168,514
1036	**PV**									
1037	Transarea Production Cost ($000)	1,997,156	1,895,468	2,306,870	1,867,659	1,593,646	1,684,102	1,447,197	1,629,688	1,209,829
1038	Transarea Load (GWh)	0	0	0	0	0	0	0	0	0
1039	Transarea Peak Load (MW)	0	0	0	0	0	0	0	0	0
1040	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
1041	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
1042	Transarea Import Energy (GWh)	0	0	0	0	0	18	6	44	12
1043	Transarea Export Energy (GWh)	55,961	54,204	50,551	53,649	48,214	50,037	45,164	49,009	40,074
1044	Transarea Water Consumption (TCF?)									
1045	Transarea Emissions (000 Tons)									
1046	*CO2*	10,667	9,774	8,854	9,562	7,408	8,133	6,198	7,707	4,293
1047	*SO2*	0	0	0	0	0	0	0	0	0
1048	*NOX*	1	1	1	1	1	1	0	1	0
1049	*HG*	0	0	0	0	0	0	0	0	0
1050	Transarea Load/Generation (GWh)									
1051	Load (GWh)									
1052	Total Load Includes Losses and Pumping Load	0	0	0	0	0	0	0	0	0
1053	EE	0	0	0	0	0	0	0	0	0
1054	Rooftop Solar	0	0	0	0	0	0	0	0	0
1055	Net Load	0	0	0	0	0	0	0	0	0
1056	Generation (GWh)									
1057	Nuclear	30,672	30,672	30,672	30,672	30,672	30,672	30,672	30,672	30,651
1058	Hydro	0	0	0	0	0	0	0	0	0
1059	Existing/Named Coal	0	0	0	0	0	0	0	0	0
1060	Generic Coal	0	0	0	0	0	0	0	0	0
1061	Existing/Named Gas-GT	0	0	0	0	0	0	0	0	0
1062	Existing/Named Gas-CC	25,290	23,003	19,880	22,448	17,013	18,818	13,958	17,765	8,881
1063	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
1064	Generic Gas - GT	0	0	0	0	0	0	0	0	0
1065	Generic Gas - CC	0	0	0	0	0	0	0	0	0
1066	Fuel Oil	0	0	0	0	0	0	0	0	0
1067	Geothermal	0	529	0	529	529	529	529	529	529
1068	Pumped Storage Output	0	0	0	0	0	0	0	0	0
1069	Wind	0	0	0	0	0	0	0	0	0
1070	Biomass/Other	0	0	0	0	0	0	0	0	0
1071	*Biomass*	0	0	0	0	0	0	0	0	0
1072	*DR*	0	0	0	0	0	0	0	0	0
1073	*Jet Fuel*	0	0	0	0	0	0	0	0	0
1074	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
1075	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
1076	*Refuse*	0	0	0	0	0	0	0	0	0
1077	*Waste Heat*	0	0	0	0	0	0	0	0	0
1078	*Wood*	0	0	0	0	0	0	0	0	0
1079	*Other/Transaction*	0	0	0	0	0	0	0	0	0
1080	Total	55,961	54,204	50,551	53,649	48,214	50,019	45,159	48,965	40,061

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
1081	**S Nevada**									
1082	Transarea Production Cost ($000)	2,186,164	1,915,643	2,457,103	1,870,047	1,401,952	1,721,497	1,301,122	1,652,760	941,069
1083	Transarea Load (GWh)	41,402	41,402	41,402	41,402	41,402	41,402	41,402	41,402	41,402
1084	Transarea Peak Load (MW) - July	10,051	10,051	10,051	10,051	10,051	10,051	10,051	10,051	10,051
1085	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
1086	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
1087	Transarea Import Energy (GWh)	6,275	1,666	1,874	891	3,326	1,953	9,665	2,537	15,135
1088	Transarea Export Energy (GWh)	18,700	6,007	8,575	4,363	2,045	2,163	3,291	1,331	3,335
1089	Transarea Water Consumption (TCF?)									
1090	Transarea Emissions (000 Tons)									
1091	*CO2*	27,149	21,998	23,721	21,619	17,652	20,258	16,533	19,648	10,059
1092	*SO2*	4	3	4	3	3	3	3	3	2
1093	*NOX*	16	14	15	13	13	13	12	13	8
1094	*HG*	137	95	137	95	94	94	90	94	42
1095	Transarea Load/Generation (GWh)									
1096	Load (GWh)									
1097	Total Load Includes Losses and Pumping Load	41,402	41,402	41,402	41,402	41,402	41,402	41,402	41,402	41,402
1098	EE	0	0	2,052	0	4,514	0	0	0	4,514
1099	Rooftop Solar	0	454	0	454	454	454	850	454	850
1100	Net Load	41,402	40,948	39,351	40,948	36,434	40,948	40,553	40,948	36,039
1101	Generation (GWh)									
1102	Nuclear	0	0	0	0	0	0	0	0	0
1103	Hydro	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377	6,377
1104	Existing/Named Coal	4,493	4,471	4,474	4,461	4,371	4,373	4,101	4,341	3,463
1105	Generic Coal	7,703	3,851	7,707	3,850	3,845	3,837	3,778	3,832	0
1106	Existing/Named Gas-GT	134	26	149	80	89	33	73	51	216
1107	Existing/Named Gas-CC	32,056	28,834	24,939	28,131	19,508	25,067	17,209	23,798	11,674
1108	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
1109	Generic Gas - GT	837	768	179	557	0	507	134	380	0
1110	Generic Gas - CC	0	0	0	0	0	0	0	0	0
1111	Fuel Oil	0	0	0	0	0	0	0	0	0
1112	Geothermal	0	0	0	0	0	0	0	0	0
1113	Pumped Storage Output	0	0	0	0	0	0	0	0	0
1114	Wind	2,110	527	2,110	527	527	527	1,302	527	1,302
1115	Biomass/Other	0	0	0	0	0	0	0	0	0
1116	*Biomass*	0	0	0	0	0	0	0	0	0
1117	*DR*	0	0	0	0	0	0	0	0	0
1118	*Jet Fuel*	0	0	0	0	0	0	0	0	0
1119	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
1120	*CSP (Solar)*	117	437	117	437	437	437	1,207	437	1,207
1121	*Refuse*	0	0	0	0	0	0	0	0	0
1122	*Waste Heat*	0	0	0	0	0	0	0	0	0
1123	*Wood*	0	0	0	0	0	0	0	0	0
1124	*Other/Transaction*	0	0	0	0	0	0	0	0	0
1125	Total	53,828	45,289	46,051	44,420	35,153	41,158	34,180	39,741	24,239
1126	**SF**									
1127	Transarea Production Cost ($000)	261,042	202,802	232,096	179,435	145,819	146,629	131,766	131,905	93,792
1128	Transarea Load (GWh)	6,134	6,134	6,134	6,134	6,134	6,134	6,134	6,134	6,134
1129	Transarea Peak Load (MW) - December	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030	1,030
1130	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
1131	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
1132	Transarea Import Energy (GWh)	1,659	2,223	2,708	2,421	3,019	2,690	2,951	2,729	3,307
1133	Transarea Export Energy (GWh)	60	100	98	127	62	152	95	189	25
1134	Transarea Water Consumption (TCF?)									
1135	Transarea Emissions (000 Tons)									
1136	*CO2*	1,967	1,485	1,179	1,295	1,026	1,337	1,219	1,219	924
1137	*SO2*	0	0	0	0	0	0	0	0	0
1138	*NOX*	1	0	0	0	0	1	1	1	1
1139	*HG*	0	0	0	0	0	0	0	0	0
1140	Transarea Load/Generation (GWh)									
1141	Load (GWh)									
1142	Total Load Includes Losses and Pumping Load	6,134	6,134	6,134	6,134	6,134	6,134	6,134	6,134	6,134
1143	EE	0	603	887	887	887	603	603	887	887
1144	Rooftop Solar	0	40	0	40	40	278	278	278	278
1145	Net Load	6,134	5,492	5,247	5,207	5,207	5,253	5,253	4,969	4,969
1146	Generation (GWh)									
1147	Nuclear	0	0	0	0	0	0	0	0	0
1148	Hydro	0	0	0	0	0	0	0	0	0
1149	Existing/Named Coal	0	0	0	0	0	0	0	0	0
1150	Generic Coal	0	0	0	0	0	0	0	0	0
1151	Existing/Named Gas-GT	194	115	134	119	124	83	100	69	99
1152	Existing/Named Gas-CC	4,342	3,254	2,503	2,794	2,126	2,044	1,710	1,773	1,004
1153	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
1154	Generic Gas - GT	0	0	0	0	0	0	0	0	0
1155	Generic Gas - CC	0	0	0	0	0	0	0	0	0
1156	Fuel Oil	0	0	0	0	0	0	0	0	0
1157	Geothermal	0	0	0	0	0	0	0	0	0
1158	Pumped Storage Output	0	0	0	0	0	0	0	0	0
1159	Wind	0	0	0	0	0	0	0	0	0
1160	Biomass/Other	0	0	0	0	0	0	0	0	0
1161	*Biomass*	0	0	0	0	0	587	587	587	583
1162	*DR*	0	0	0	0	0	0	0	0	0
1163	*Jet Fuel*	0	0	0	0	0	0	0	0	0
1164	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
1165	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
1166	*Refuse*	0	0	0	0	0	0	0	0	0
1167	*Waste Heat*	0	0	0	0	0	0	0	0	0
1168	*Wood*	0	0	0	0	0	0	0	0	0
1169	*Other/Transaction*	0	0	0	0	0	0	0	0	0
1170	Total	4,536	3,369	2,637	2,913	2,250	2,715	2,397	2,429	1,686

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
1171	SMUD									
1172	Transarea Production Cost ($000)	382,078	359,964	501,003	354,374	331,609	344,644	320,193	333,774	273,952
1173	Transarea Load (GWh)	15,682	15,682	15,682	15,682	15,682	15,682	15,682	15,682	15,682
1174	Transarea Peak Load (MW) - July	4,260	4,260	4,260	4,260	4,260	4,260	4,260	4,260	4,260
1175	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
1176	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
1177	Transarea Import Energy (GWh)	7,593	5,921	5,429	5,138	5,670	6,320	6,902	5,625	7,151
1178	Transarea Export Energy (GWh)	0	0	2	3	2	0	0	1	0
1179	Transarea Water Consumption (TCF?)									
1180	Transarea Emissions (000 Tons)									
1181	*CO2*	2,774	2,667	2,549	2,625	2,441	2,540	2,345	2,457	1,980
1182	*SO2*	0	0	0	0	0	0	0	0	0
1183	*NOX*	1	1	1	1	1	1	1	1	1
1184	*HG*	0	0	0	0	0	0	0	0	0
1185	Transarea Load/Generation (GWh)									
1186	Load (GWh)									
1187	Total Load Includes Losses and Pumping Load	15,682	15,682	15,682	15,682	15,682	15,682	15,682	15,682	15,682
1188	EE	0	1,883	2,771	2,771	2,771	1,883	1,883	2,771	2,771
1189	Rooftop Solar	0	17	0	17	17	24	24	24	24
1190	Net Load	15,682	13,782	12,911	12,894	12,894	13,775	13,775	12,886	12,886
1191	Generation (GWh)									
1192	Nuclear	0	0	0	0	0	0	0	0	0
1193	Hydro	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752	1,752
1194	Existing/Named Coal	0	0	0	0	0	0	0	0	0
1195	Generic Coal	0	0	0	0	0	0	0	0	0
1196	Existing/Named Gas-GT	216	108	111	81	92	83	79	28	72
1197	Existing/Named Gas-CC	5,957	5,671	5,475	5,595	5,053	5,326	4,748	5,190	3,619
1198	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
1199	Generic Gas - GT	0	0	0	0	0	0	0	0	0
1200	Generic Gas - CC	0	0	0	0	0	0	0	0	0
1201	Fuel Oil	0	0	0	0	0	0	0	0	0
1202	Geothermal	0	0	0	0	0	0	0	0	0
1203	Pumped Storage Output	0	0	0	0	0	0	0	0	0
1204	Wind	68	175	68	175	175	138	138	138	138
1205	Biomass/Other	0	0	0	0	0	0	0	0	0
1206	*Biomass*	76	154	76	154	154	154	154	154	154
1207	*DR*	20	1	1	0	0	1	1	0	0
1208	*Jet Fuel*	0	0	0	0	0	0	0	0	0
1209	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
1210	*CSP (Solar)*	0	0	0	0	0	0	0	0	0
1211	*Refuse*	0	0	0	0	0	0	0	0	0
1212	*Waste Heat*	0	0	0	0	0	0	0	0	0
1213	*Wood*	0	0	0	0	0	0	0	0	0
1214	*Other/Transaction*	0	0	0	0	0	0	0	0	0
1215	Total	8,089	7,861	7,483	7,758	7,226	7,455	6,873	7,263	5,736
1216	Utah									
1217	Transarea Production Cost ($000)	1,752,931	1,712,612	1,841,791	1,704,270	1,458,397	1,636,478	1,409,644	1,619,463	1,093,896
1218	Transarea Load (GWh)	48,400	48,400	48,400	48,400	48,400	48,400	48,400	48,400	48,400
1219	Transarea Peak Load (MW) - July	9,189	9,189	9,189	9,189	9,189	9,189	9,189	9,189	9,189
1220	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
1221	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
1222	Transarea Import Energy (GWh)	9,512	8,012	10,080	7,783	10,035	7,505	14,589	7,267	21,894
1223	Transarea Export Energy (GWh)	19,170	18,206	19,397	17,786	20,402	16,062	18,747	15,446	19,142
1224	Transarea Water Consumption (TCF?)									
1225	Transarea Emissions (000 Tons)									
1226	*CO2*	55,005	54,575	53,712	54,495	52,257	53,807	51,029	53,621	39,850
1227	*SO2*	61	61	61	61	61	61	60	61	54
1228	*NOX*	81	80	80	80	80	80	78	80	69
1229	*HG*	318	318	318	318	317	317	314	317	218
1230	Transarea Load/Generation (GWh)									
1231	Load (GWh)									
1232	Total Load Includes Losses and Pumping Load	48,400	48,400	48,400	48,400	48,400	48,400	48,400	48,400	48,400
1233	EE	0	0	2,399	0	5,277	0	0	0	5,277
1234	Rooftop Solar	0	0	0	0	0	0	0	0	0
1235	Net Load	48,400	48,400	46,001	48,400	43,123	48,400	48,400	48,400	43,123
1236	Generation (GWh)									
1237	Nuclear	0	0	0	0	0	0	0	0	0
1238	Hydro	608	608	608	608	608	608	608	608	608
1239	Existing/Named Coal	40,306	40,288	40,264	40,281	40,146	40,197	39,618	40,161	36,635
1240	Generic Coal	7,687	7,688	7,691	7,687	7,667	7,679	7,625	7,675	0
1241	Existing/Named Gas-GT	269	188	125	165	86	128	75	100	20
1242	Existing/Named Gas-CC	7,605	7,289	5,344	7,099	2,901	5,992	1,461	5,693	16
1243	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
1244	Generic Gas - GT	1,033	601	734	630	150	420	156	410	77
1245	Generic Gas - CC	0	0	0	0	0	0	0	0	0
1246	Fuel Oil	0	0	1	0	0	0	1	0	0
1247	Geothermal	415	730	415	730	730	730	2,246	730	2,246
1248	Pumped Storage Output	0	0	0	0	0	0	0	0	0
1249	Wind	134	1,072	134	1,072	1,072	1,072	725	1,072	725
1250	Biomass/Other	0	0	0	0	0	0	0	0	0
1251	*Biomass*	0	0	0	0	0	0	0	0	0
1252	*DR*	0	0	0	0	0	0	0	0	0
1253	*Jet Fuel*	0	0	0	0	0	0	0	0	0
1254	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
1255	*CSP (Solar)*	0	131	0	131	131	131	44	131	44
1256	*Refuse*	0	0	0	0	0	0	0	0	0
1257	*Waste Heat*	0	0	0	0	0	0	0	0	0
1258	*Wood*	0	0	0	0	0	0	0	0	0
1259	*Other/Transaction*	0	0	0	0	0	0	0	0	0
1260	Total	58,058	58,594	55,317	58,403	53,490	56,956	52,558	56,579	40,371

	CEC IEPR - Transarea Draft Score Card	Case1	Case1b	Case2	Case3a	Case3b	Case4a	Case4b	Case5a	Case5b
		Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas	Base Gas
	2020 2020			2020		2020			2020	
1261	WYCE									
1262	Transarea Production Cost ($000)	474,757	480,156	487,023	479,180	440,059	481,032	431,525	477,820	421,068
1263	Transarea Load (GWh)	18,430	18,430	18,430	18,430	18,430	18,430	18,430	18,430	18,430
1264	Transarea Peak Load (MW) - July	2,833	2,833	2,833	2,833	2,833	2,833	2,833	2,833	2,833
1265	Transarea "Energy Not Served" (GWh)	0	0	0	0	0	0	0	0	0
1266	Transarea Dump Energy (GWh)	0	0	0	0	0	0	0	0	0
1267	Transarea Import Energy (GWh)	1,701	1,790	1,915	1,810	2,350	1,731	2,653	1,748	3,971
1268	Transarea Export Energy (GWh)	11,195	10,700	12,184	10,700	10,826	10,644	26,215	10,613	29,128
1269	Transarea Water Consumption (TCF?)									
1270	Transarea Emissions (000 Tons)									
1271	*CO2*	24,238	24,429	24,188	24,416	22,121	24,428	21,783	24,393	21,325
1272	*SO2*	39	39	39	39	38	39	38	39	37
1273	*NOX*	33	34	33	34	33	34	32	34	31
1274	*HG*	403	403	402	402	377	402	373	402	365
1275	Transarea Load/Generation (GWh)									
1276	Load (GWh)									
1277	Total Load Includes Losses and Pumping Load	18,430	18,430	18,430	18,430	18,430	18,430	18,430	18,430	18,430
1278	EE	0	0	913	0	2,009	0	0	0	2,009
1279	Rooftop Solar	0	0	0	0	0	0	0	0	0
1280	Net Load	18,430	18,430	17,517	18,430	16,421	18,430	18,430	18,430	16,421
1281	Generation (GWh)									
1282	Nuclear	0	0	0	0	0	0	0	0	0
1283	Hydro	888	888	888	888	888	888	888	888	888
1284	Existing/Named Coal	18,720	18,720	18,665	18,718	18,686	18,710	18,543	18,704	18,183
1285	Generic Coal	2,312	2,312	2,312	2,312	0	2,312	0	2,311	0
1286	Existing/Named Gas-GT	260	269	176	251	172	282	132	240	79
1287	Existing/Named Gas-CC	0	0	0	0	0	0	0	0	0
1288	Existing/Named Gas-ST	0	0	0	0	0	0	0	0	0
1289	Generic Gas - GT	0	0	0	0	0	0	0	0	0
1290	Generic Gas - CC	0	0	0	0	0	0	0	0	0
1291	Fuel Oil	0	0	0	0	0	0	0	0	0
1292	Geothermal	0	0	0	0	0	0	0	0	0
1293	Pumped Storage Output	0	0	0	0	0	0	0	0	0
1294	Wind	3,331	2,337	3,331	2,337	2,337	2,337	19,918	2,337	19,918
1295	Biomass/Other	0	0	0	0	0	0	0	0	0
1296	*Biomass*	0	284	0	284	284	284	70	284	70
1297	*DR*	0	0	0	0	0	0	0	0	0
1298	*Jet Fuel*	0	0	0	0	0	0	0	0	0
1299	*Petroleum Coke*	0	0	0	0	0	0	0	0	0
1300	*CSP (Solar)*	0	117	0	117	117	117	28	117	28
1301	*Refuse*	0	0	0	0	0	0	0	0	0
1302	*Waste Heat*	0	0	0	0	0	0	0	0	0
1303	*Wood*	0	0	0	0	0	0	0	0	0
1304	*Other/Transaction*	2,414	2,414	2,414	2,414	2,414	2,414	2,414	2,414	2,414
1305	Total	27,924	27,340	27,785	27,320	24,897	27,343	41,992	27,295	41,578

Appendix D-2
Trans-Area Scorecard for Shock Sensitivities

The transarea scorecard for the shock sensitivities report results for the Dry Hydro, High Hydro, and $20/MMBtu Gas Price sensitivities. The results include load, generation, production costs, import energy, export energy, and emissions data. The data items are listed on the left-hand column with the nine thematic scenarios across the top.

The full spreadsheet of results is available at:
http://www.energy.ca.gov/2007publications/CEC-200-2007-010/appendices/appendixD-2_excel-1.xls

Source: Global Energy Decisions

APPENDIX E

RENEWABLE GENERATION PRODUCTION CHARACTERISTICS

Prepared by Global Energy Decisions, Inc.

E.1 Production Profiles

Hourly generation profiles were used in the modeling of renewable energy resources that typically have variable availability. In this study, wind, concentrated solar power (CSP), and photovoltaic solar resources were modeled using hourly generation profiles.

For modeling wind generation in California, Energy Commission staff provided historical hourly wind profiles for 2003 through 2005 for locations across California. Rather than averaging all three years and losing the inherent volatility present in the actual hourly wind profiles, a single year of hourly data was chosen for each location in California based on an analysis of annual capacity factors. The median capacity factor of the three years for each location determined which year to use. Thus, the 2003 wind profile was used in modeling wind resources at Altamont, San Gorgonio, and Solano, and the 2004 wind profile was used in modeling wind resources at Tehachapi. Table E-1 reports the capacity factors for each of the California wind locations by year.

Table E-1
Annual Capacity Factor by Wind Zone

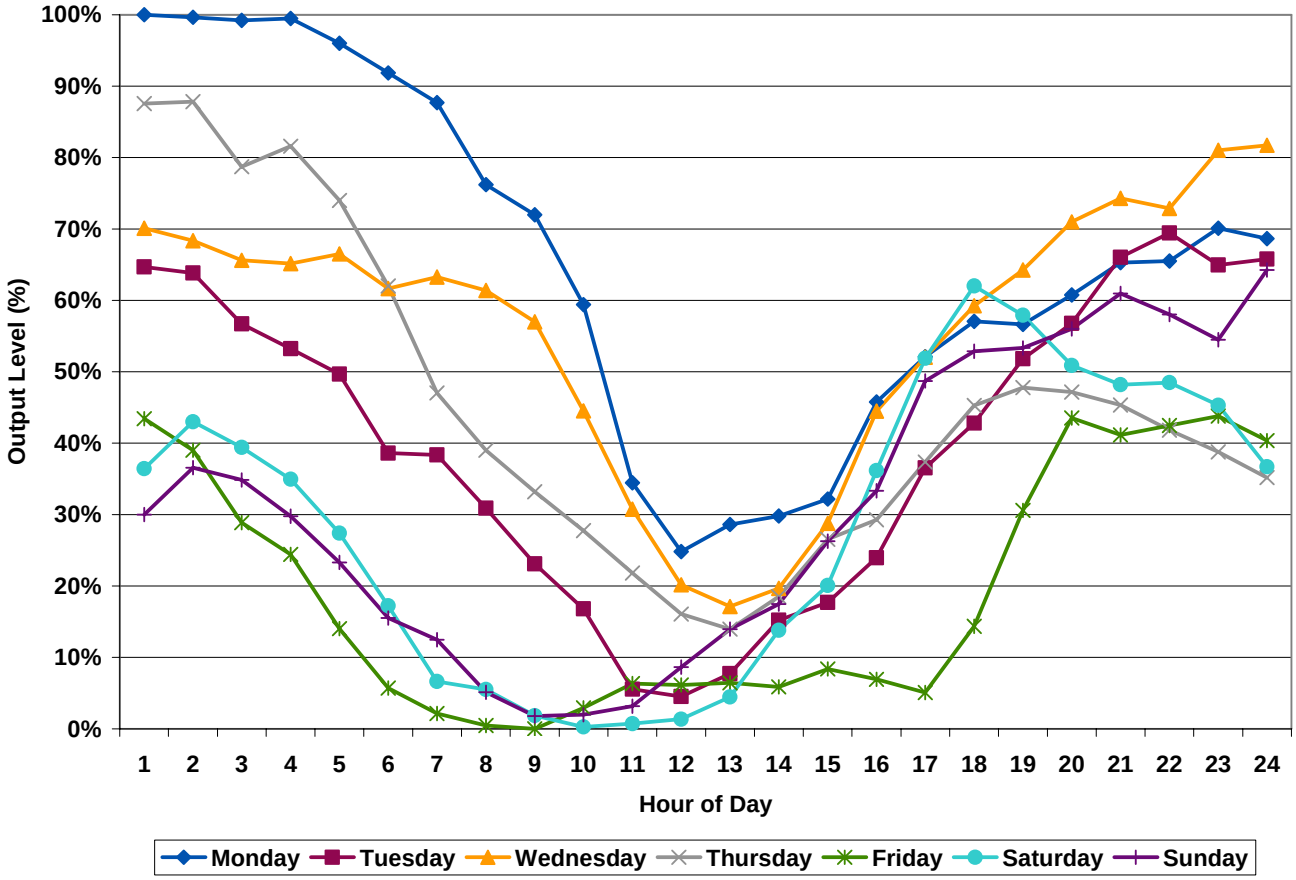
CA Wind Zone	Year	Annual
Altamont	2003	23.2%
	2004	26.2%
	2005	21.7%
San Gorgonio	2003	29.4%
	2004	28.4%
	2005	31.0%
Solano	2003	17.8%
	2004	20.5%
	2005	16.1%
Tehachapi	2003	31.4%
	2004	31.0%
	2005	30.3%

Source: California Energy Commission

For modeling wind generation outside of California, hourly wind shapes were obtained from the National Renewable Energy Laboratory (NREL) which were derived from historical hourly wind data. The wind data obtained from the two aforementioned sources were complete annual hourly series (8,760 data points

per year). However, under the simulation methodology of simulating only one week for each month, the wind profile during this week is simulated in the deterministic analysis. As an example, Figure E-1 illustrates the hourly profile used to model wind resource generation in the SP15 transarea for the typical week representing the month of July.

Figure E-1
Hourly Wind Generation Profile for SP15 for Month of July

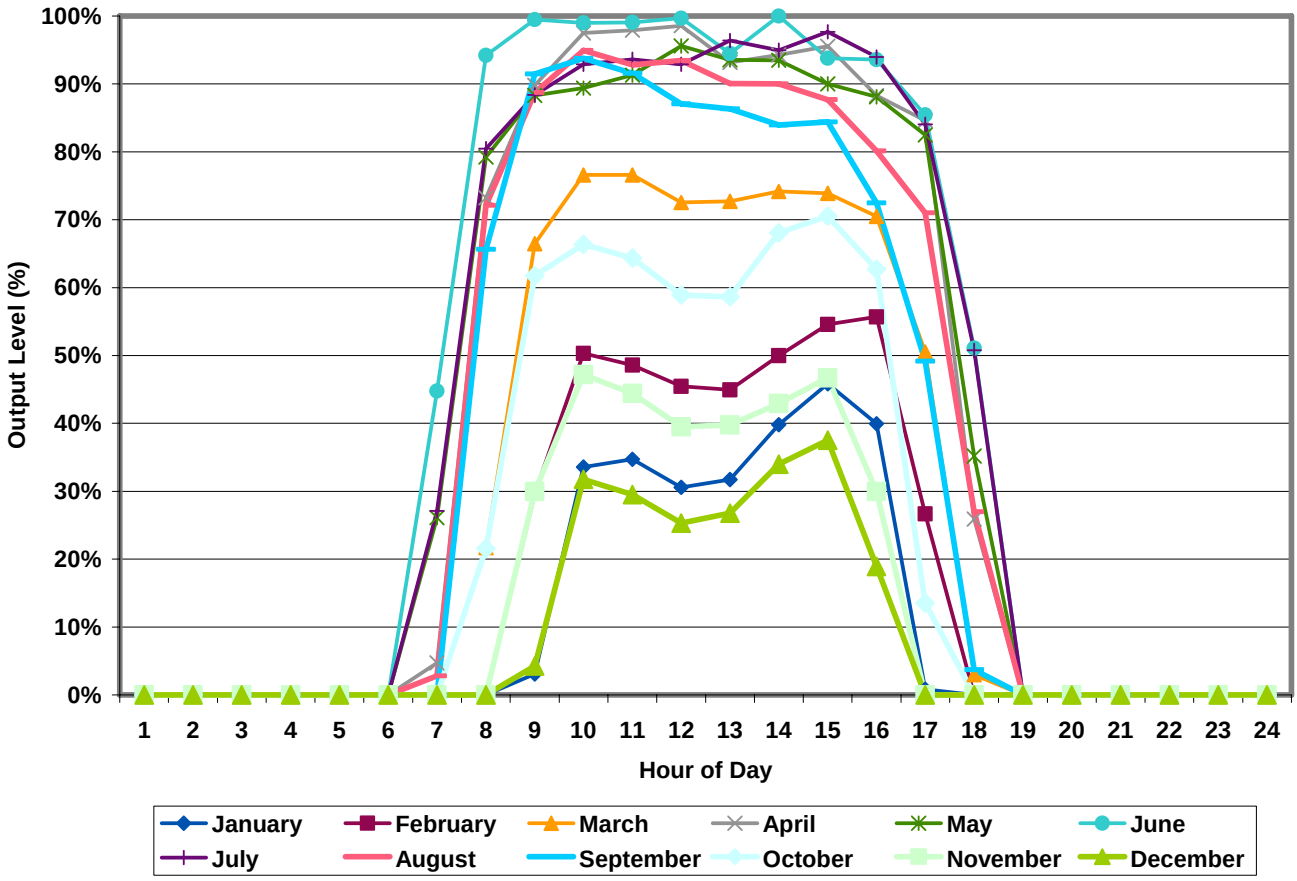


Source: US Department of Energy National Renewable Energy Laboratory

For modeling concentrated solar power (CSP), hourly data was obtained from NREL, however, only one twenty-four hour daily shape was provided for each month of the year. The twenty-four hour CSP shapes were duplicated for each day of the week to derive a typical week for each month of the year. As an

example, Figure E-2 illustrates the twenty-four hour CSP profile for each month used in modeling CSP resources in the SP15 transarea.

Figure E-2
Monthly CSP Generation Profiles for SP15



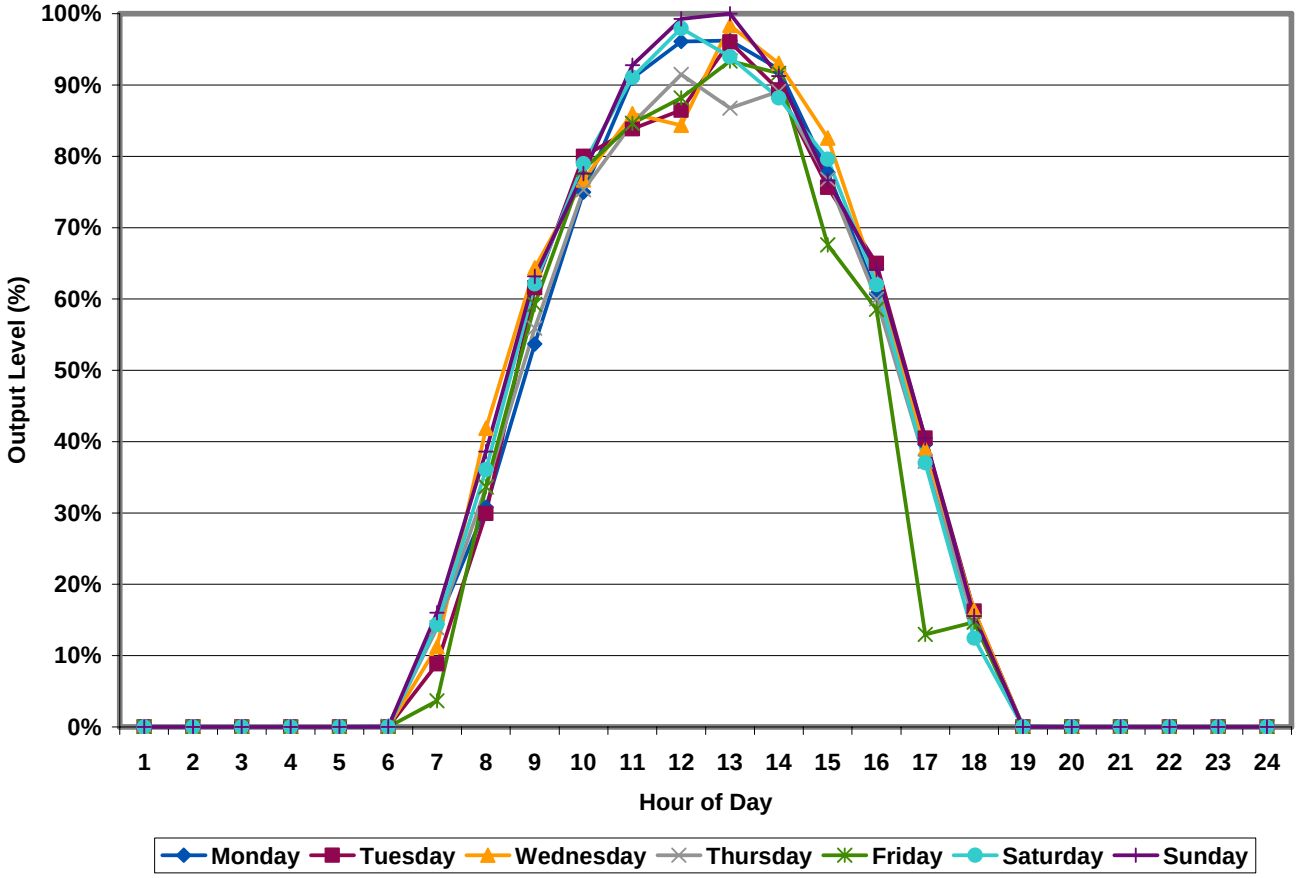
Source: US Department of Energy National Renewable Energy Laboratory

Rooftop PV production profiles were developed based on data compiled by the US Department of Energy's National Renewable Energy Laboratory (NREL) for various geographic locations. Appendix G-2 provides a detailed description of the data. These profiles were used in modeling PV solar generation profiles in each of the transmission areas where PV solar was modeled in the study. For modeling of PV solar outside of California such as Nevada and Arizona, California PV profiles were used as an approximation. As explained above, under the simulation methodology of simulating only one typical week for each

month, the PV solar profile during this typical week is simulated in the deterministic analysis.

As an example, Figure E-3 illustrates the hourly profile used to model photovoltaic solar generation in the SP15 transarea for the typical week representing the month of July.

Figure E-3
Hourly Photovoltaic Solar Generation Profile for SP15 for July



Source: US Department of Energy National Renewable Energy Laboratory

In the stochastic analysis, where of the renewable resource types, only wind and rooftop PV were treated stochastically. In the stochastic analysis, all 8,784 hours of the year 2020 were simulated, and the hourly profiles for wind and PV solar shown above facilitated the stochastic treatment of these resources. Daily-hourly

profiles were drawn for each day of each month for 100 iterations. For example, for Iteration 1 - January 1, any 24 hour daily shape of January would be used in the stochastic simulation. Following the example, Iteration 2 - January 1 could use the hourly generation profile from January 30. On Iteration 3 - January 1, the actual historic January 15 hourly daily profile might be used. This process continued until all 100 iterations were created for each day of the simulation for each transarea. Similarly, the 100 iterations for January 2 would also draw from the 30 daily profiles available for a January day. Global Energy used its Historical Wind Generation Tool to produce the iteration data input to the model.

E.2 Dependable Capacity for Resource Adequacy Purposes

For purposes of displacing generic fossil resources for an equivalent amount of renewable generation between cases, it was necessary to calculate the dependable capacity for renewable resources that exhibit variable availability. As previously discussed, the renewables that exhibit variable availability in this study are wind, CSP, and PV solar.

Dependable capacity from renewables was calculated from the hourly data described in the previous section using a similar approach as used by the California Public Utilities Commission. The calculation of dependable capacity is based on a two-step process. First, a derate factor is calculated for each type of resource to determine the capacity contribution from renewables. For summer peaking areas, derate factors were calculated from the months of May through September during the hours of 12 p.m. through 6 p.m. For winter peaking areas, derate factors were calculated from the months of November through February during the hours of 4 p.m. through 10 p.m. Secondly, the nameplate capacity of the resource is multiplied by this derate factor to determine the dependable capacity for this resource. Table E-2 reports the derate factors used in this study.

Table E-2
Derate Factor by Area – Wind, CSP, and Photovoltaic Solar

		Wind		CSP	PV***
TransArea	Peak	Summer Peak 12 PM - 6 PM	Winter Peak 4 PM - 10 PM	Summer Peak 12 PM - 6 PM	Summer Peak 12 PM - 6 PM
Alberta	Winter	-	46.7%	-	-
Arizona	Summer	45.9%	-	82.0%	42.0%
British Columbia	Winter	-	46.7%	-	-
CNP15	Summer	26.1%	-	-	48.0%
Colorado_East	Summer	33.1%	-	-	-
CSCE	Summer	31.8%	-	87.0%	45.0%
CSDGE	Summer	29.5%	-	-	42.0%

		Wind		CSP	PV***
TransArea	Peak	Summer Peak 12 PM - 6 PM	Winter Peak 4 PM - 10 PM	Summer Peak 12 PM - 6 PM	Summer Peak 12 PM - 6 PM
CZP26	Summer	26.1%	-	-	46.0%
Idaho East/Wyoming SW	Summer	35.3%	-	-	-
Idaho SW	Summer	52.5%	-	-	-
Imperial Valley	Summer	31.8%	-	87.0%	42.0%
LADWP	Summer	31.8%	-	87.0%	46.0%
Montana	Summer	36.4%	-	-	-
NewMexico	Summer	37.6%	-	70.0%	-
Northern Nevada	Summer	27.1%	-	-	-
Northwest	Winter	-	32.9%	-	-
SMUD	Summer	30.3%	-	-	48.0%
Southern Nevada	Summer	50.9%	-	80.0%	42.0%
Utah	Summer	38.6%	-	80.0%	-
Wyoming Central	Summer	39.3%	-	80.0%	-

*Derate factor for summer peaking areas were calculated using the months May through September

**Derate factor for winter peaking areas were calculated using the months November through February

***An additional credit of 15% is applied to PV Solar due to the fact that it is a demand-side resource that reduces load as well as operating reserves.

Source: Global Energy Decisions

PV Solar was modeled as a resource in this study though it is considered a demand-side resource or load modifier. Modeling PV Solar as a resource facilitated modeling the variability of the resource in the stochastic analysis. Since PV solar is a demand reducing resource, the treatment in the dependable calculation is slightly different compared to wind and CSP (both supply-side resources). For photovoltaic solar, once the dependable factor is applied to the nameplate capacity of the installed PV solar, an additional 15 percent credit is applied to the dependable calculation to capture the notion that this demand-

side load reducing resource will also decrease the amount of operating reserves necessary on the system

APPENDIX F

ENERGY EFFICIENCY AND DEMAND RESPONSE ANALYSES

Prepared by Navigant Consulting, Inc.

F-1 Energy Efficiency

Introduction

Energy efficiency (EE) resource estimates (including GWh, costs and load shapes) were developed by transmission planning area (transarea) for two bookend scenarios:

- **Current practices** – for California, the EE resources reflect the goals summarized in the investor-owned utility (IOU) 2006 procurement plans. For the rest-of-WECC, the current energy efficiency programs were assumed to be embedded in the load forecasts (i.e. the forecasts reflect sales net of reductions resulting from energy efficiency programs).
- **Aggressive development** – reflects aggressive expansion of EE programs. In California, this is equivalent to the economic potential (minus the portion of the economic potential attributable to emerging technologies)[1]. For the rest-of-WECC, the aggressive EE development scenario is based on the "Best Practices" scenario from the Western Governor's Association analysis [2](also referred to as CDEAC).

These scenarios were used in the cases as summarized below:

	Current Practices	Aggressive Development
California	Cases 1B, 2, 4A, 4B	Cases 3A, 3B, 5A, 5B
Rest-of-WECC	Cases 1, 1B, 3A, 4A, 4B	Cases 3B and 5B

For case 2, the rest-of-WECC EE was assumed to be equal to 5% of the rest-of-WECC sales (approximately half of the aggressive development scenario).

Approach

To evaluate EE as a resource option, annual forecasts of EE, hourly load shapes and costs are required. Annual estimates were developed by transmission planning area (transarea) for each scenario. The primary data sources and analysis that were used to develop each of these forecasts are briefly summarized below.

Annual GWh

The first step in the process was to develop annual forecasts of the EE resource base for each scenario. The major data sources and assumptions underlying the annual forecasted EE are summarized in table F.1.

Table F.1: Major Data Sources for EE Resource Forecasts

	California	Rest-of-WECC
Current Practices	**IOU Long-Term Procurement Plans**[3]	**Assumed to be embedded in the load forecasts**
Aggressive Development	**The economic potential (excluding the portion due to emerging technologies) from the Itron 2006 Potential Study net of utility accomplishment for 2004-2008.**	**"Best Practices" scenario potential minus the EE savings in the "Current Practices" scenario**[4]

First, a summary of the data sources used for each scenario is provided, followed by a more detailed description of the specific data and results for California and rest-of-WECC.

Current Practices

The California IOU long-term procurement filings include 10 year projections of uncommitted EE. PG&E and SCE presented alternative plans with projected EE resources less than the CPUC adopted goals in D.04-09-050. For SCE the "Best Estimate (SCE-Developed Load Scenario)" plan was used. This represents approximately 34% less EE than the CPUC goals for 2016[5]. Under this plan, the SCE EE programs would accomplish EE at the levels of SCE's 2004-2005 programs. For PG&E the "Current World" EE estimates were used. This "Current World" plan represents approximately 35% less EE than the CPUC goals for 2016. SDG&E's plan reflected the CPUC goals, but noted that the goals may not be attainable.

Since the procurement plans only included projections through 2016, EE accomplishments for 2017 through 2020 were assumed to grow at the same rate as the loads before EE. Procurement plans were not readily available for POUs, so it was assumed that the POUs could achieve between 50% and 100% of the IOU EE as a percentage of their loads.

For the rest-of-WECC, we assumed that the load forecasts included the current programs. Several utility Integrated Resource Plans (IRP) were reviewed, and it appeared that the sales forecasts being used for this modeling effort were consistent with sales net of the utility EE programs.

Aggressive Development

For California, the aggressive development scenario is drawn form the 2006 Itron Potential study. This study identified the economic potential (that is, all EE that is cost-effective), as well as achievable potential under several different scenarios. The IOU EE in the current practice scenario of 22,169 GWh in addition to the 11,023 GWh that the utilities project to accomplish between 2004 and 2008 (for a total of 33,192 GWh) substantially exceeds the "full incentives achievable potential," 23,974 GWh. But, the aggressive development scenario postulates that a significant portion of the economic potential can be developed by 2020. Emerging technology represents approximately 23% of the economic potential. Thus, the aggressive

development scenario assumes that 77% of the economic potential is achieved. Table F.2, summarizes the adjustments that were made to the Itron economic potential estimates to derive the additional 9,319 GWh of IOU EE for the aggressive development scenario. Since the EE in SDG&E's procurement plans already exceed the economic potential, SDG&E's EE resource is the same in both scenarios, and the incremental GWh were assigned to PG&E and SCE.

Table F.2: Derivation of CA IOU Aggressive Development EE Estimate

	Add/subtract	(GWh)	After Adjusted (GWh)
Economic potential in 2016		**53,150**	
Economic potential growth 2016 -20120	**+**	**1,892**	**54,992**
Emerging technology economic potential	**-**	**12,481**	**42,511**
Utility EE accomplishments 2004-2008	**-**	**11,023**	**31,488**
IOU current practices scenario for 2009	**-**	**22,169**	**9,319**
Aggressive Development Incremental IOU EE			**9,319**

Source: Navigant Consulting

Rest-of-WECC

The CDEAC analysis is the closest to the Itron study for the WECC. It included estimates of the EE resource for both a "Current Activities" and a "Best Practices" scenario. The report does not provide much detail and the reported numbers include 18 states including California, as well as states that are not in the WECC (e.g. Texas, Kansas, etc). The analysis results showed that the Best Practices scenario would reduce energy usage by 20% relative to the Reference forecast, with an incremental reduction of 11% over and above the "Current Activities" scenario as summarized in table F.3.

Table F.3: Percentage Savings from Reference Forecast for WGA States by Scenario

Scenario	2010	2015	2020
Current Activities	-4%	-7%	-9%
Best Practices	-7%	-14%	-20%

Source: Navigant Consulting

The "Current Activities" scenario includes existing building codes, appliance standards, public sector programs, and utility programs. The utility EE programs represent savings of 2.2% of load in 2010 and 5.5% by 2020. Based on the modest

level of utility DSM programs in the “Current Activities” scenario, the fact that the building codes are already in place, and the apparent consistency between the WECC load forecasts and the utility net of EE programs sales forecasts, it was assumed that the “Current Practices” was already embedded in the rest-of-WECC forecasts. Thus, the difference between the “Best Practices” and “Current Activities” scenarios was used for the aggressive development scenario.

The resulting 82,615 GWh of EE represents approximately 11% of rest-of-WECC 2020 loads.

California

For the California cases, the GWh estimates were first developed for each of the IOUs. The EE as a percent of each IOU’s sales was then calculated and applied to each California transarea. Each of the transareas was mapped to a particular IOU for the purposes of determining EE GWh, load shapes, and costs. For some of the transareas dominated by POUs, a discount factor was applied to account that less EE resource may be developed by the POU. Table F.4 summarizes the transareas, the mapped IOU, the discount factor, and the year 2020 EE as a percent of 2020 sales forecast.

Table F.4: – Transarea Percentage Savings

Transarea	Assigned IOU	Discount Factor	2020 Savings Percent	
			Current Practices	Aggressive Development
North of Path 15	PG&E		10.08%	14.84%
Zone Path 26	PG&E		10.08%	14.84%
SCE Area	SCE		8.93%	13.39%
SDG&E	SDG&E		11.35%	11.35%
SMUD	PG&E	25%	7.56%	11.13%
LADWP	SCE	25%	6.70%	10.04%
IID	SCE	50%	4.67%	6.70%
SF	PG&E		10.08%	14.84%

Source: Navigant Consulting

The GWh of EE by IOU and all POUs and year are summarized in table F.5.

Table F.5: California EE Resource Base by Scenario (GWh)

	Current Practices					Aggressive Development				
	PG&E	**SCE**	**SDG&E**	**POU**	**Total**	**PG&E**	**SCE**	**SDG&E**	**POU**	**Total**
2009	882	979	288	708	2,857	1,230	1,148	288	901	3,567
2010	1,715	1,889	530	1,369	5,503	2,460	2,296	530	1,800	7,086
2011	2,510	2,745	816	1,987	8,058	3,690	3,444	816	2,688	10,638
2012	3,294	3,555	1,044	2,584	10,477	4,920	4,592	1,044	3,580	14,136
2013	4,126	4,427	1,260	3,199	13,012	6,150	5,740	1,260	4,434	17,584
2014	4,960	5,264	1,500	3,879	15,603	7,380	6,888	1,500	5,406	21,174
2015	5,808	5,964	1,752	4,486	18,010	8,610	8,036	1,752	6,344	24,742
2016	6,652	6,609	1,992	5,069	20,322	9,840	9,184	1,992	7,277	28,293
2017	7,496	7,254	2,232	5,611	22,593	11,070	10,332	2,232	8,155	31,789
2018	8,340	7,899	2,472	6,129	24,840	12,300	11,480	2,472	8,995	35,247
2019	9,184	8,544	2,712	6,682	27,122	13,530	12,628	2,712	9,886	38,756
2020	10,028	9,189	2,952	7,235	29,404	14,760	13,776	2,952	10,775	42,263

Source: Navigant Consulting

Rest-of-WECC

The same percentage savings was applied to each non-California transarea. The resulting EE resource for selected years for each transarea is summarized in table F.6

Table F.6: Aggressive Development EE (GWh) by WECC Transarea

WECC transarea	2010	2015	2020
AB_S	641	2,228	3,778
ABCN	1,061	3,706	6,286
Arizona	1,816	6,647	11,784
BC	1,452	4,874	8,184
CNP15	2,548	8,964	15,331
CO East	1,141	3,981	6,781
CO West	149	523	896
COB	39	131	216
CSCE	2,653	9,302	15,935
CSDGE	514	1,707	2,875
CZP26	182	642	1,106
ID_SW	356	1,215	2,045
IDE_WYSW	206	695	1,162
IID	45	158	272
La Rosita	143	573	1,086
LADWP	564	1,886	3,084
Montana	265	924	1,571
N Nevada	313	1,143	2,030
NBAJA	143	573	1,086
New Mexico	582	2,110	3,719
Northwest	3,585	12,154	20,190
S Nevada	744	2,600	4,514

WECC transarea	2010	2015	2020
SF	147	515	887
SMUD	433	1,566	2,771
Utah	803	2,952	5,277
WYCE	332	1,163	2,009
Total	**20,855**	**72,934**	**124,877**
California Total	7,086	24,742	42,263
Balance of WECC Total	13,769	48,192	82,615

Source: Navigant Consulting

Load Shapes

The load shapes for EE were developed using a three step process for the California IOUs. These load shapes were applied to all of the other WECC transareas according to the IOU that is climatically the most similar to that transarea.

The first step in the process was to allocate the annual GWh to customer segments (i.e., new and existing, industrial, commercial, and residential). Next, the GWh for each customer segment were allocated to end-uses to obtain GWh by end-use, customer segment, IOU and year. Finally, these annual end-use EE savings were allocated to hours using hourly load shapes (typical day per month). The customer segment and end-use allocation factors were derived from the 2006 Itron Potential study. The load shapes were derived form the CEUS[6] and LSUI[7] databases.

Customer Segment Distribution

The annual savings were allocated to customer segments and end-uses using the distribution of savings from the full incentives achievable potential for the current practices scenario and the economic potential for the aggressive development scenario. The allocation factors by IOU and year are summarized in tables F.7 and F.8. These percentages apply to the cumulative EE installed.

Table F.7: Current Practice EE Customer Segment Allocation Factors

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SCE Residential												
Existing	50%	50%	51%	51%	52%	52%	52%	52%	52%	52%	52%	52%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
SCE Commercial												
Existing	25%	24%	24%	23%	23%	22%	22%	22%	22%	22%	22%	22%
New	7%	7%	7%	8%	8%	8%	9%	9%	9%	9%	9%	9%
SCE Industrial												
Existing	17%	17%	16%	16%	16%	16%	15%	15%	15%	15%	15%	15%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
SCE Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
PG&E Residential												
Existing	45%	46%	48%	49%	50%	50%	51%	51%	51%	51%	51%	51%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
PG&E Commercial												
Existing	25%	24%	23%	22%	22%	21%	21%	20%	20%	20%	20%	20%
New	6%	7%	7%	7%	8%	8%	8%	9%	9%	9%	9%	9%
PG&E Industrial												
Existing	21%	20%	19%	19%	18%	18%	17%	17%	17%	17%	17%	17%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
PG&E Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
SDG&E Residential												
Existing	58%	59%	59%	60%	60%	60%	60%	60%	60%	60%	60%	60%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
SDG&E Commercial												
Existing	25%	24%	23%	23%	22%	22%	22%	21%	21%	21%	21%	21%
New	7%	7%	7%	8%	8%	8%	9%	9%	9%	9%	9%	9%
SDG&E Industrial												
Existing	9%	9%	9%	9%	8%	8%	8%	8%	8%	8%	8%	8%
New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SDG&E Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: Navigant Consulting

Table F.8: Aggressive Development EE Customer Segment Allocation Factors

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SCE Residential												
Existing	45%	45%	45%	45%	45%	45%	44%	44%	44%	44%	44%	44%
New	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%
SCE Commercial												
Existing	32%	31%	31%	31%	30%	30%	30%	30%	30%	30%	30%	30%
New	7%	7%	8%	8%	8%	9%	9%	10%	10%	10%	10%	10%
SCE Industrial												
Existing	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%	14%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
SCE Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
PG&E Residential												
Existing	52%	52%	51%	51%	51%	50%	50%	50%	50%	50%	50%	50%
New	1%	1%	1%	1%	1%	1%	1%	2%	2%	2%	2%	2%
PG&E Commercial												
Existing	26%	26%	26%	26%	25%	25%	25%	25%	25%	25%	25%	25%
New	7%	7%	8%	9%	9%	9%	10%	10%	10%	10%	10%	10%
PG&E Industrial												
Existing	13%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%	12%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
PG&E Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
SDG&E Residential												
Existing	55%	54%	54%	53%	54%	53%	53%	53%	53%	53%	53%	53%
New	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
SDG&E Commercial												
Existing	30%	30%	29%	29%	29%	29%	28%	28%	28%	28%	28%	28%
New	7%	8%	8%	9%	9%	10%	10%	11%	11%	11%	11%	11%
SDG&E Industrial												
Existing	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%	7%
New	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
SDG&E Total	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Source: Navigant Consulting

End-Use Allocations

The customer segment specific savings were allocated to end-uses based upon the savings distribution in the economic potential. For example, if 5% of the economic potential GWh for residential existing construction came from air conditioning measures for a particular IOU, then it was assumed that 5% of the existing residential savings come from air-conditioning in all years. For existing commercial and industrial facilities, the same end-use allocations were used for all three IOUs. The residential miscellaneous end-use in the Itron study was split between whole facility and refrigeration end-uses. All new construction EE was assigned to the whole building load shape because most of the new construction results in the Itron analysis were only reported at the total building level, reflecting the fact that new construction strategies affect multiple end-uses. The end-use allocation factors are summarized in table F.9.

Table F.9: Percentage of Customer Segment Savings Allocated to Each End-Use

Customer Segment		Whole Facility	Lighting	HVAC	Refrigeration	Process
Residential Existing	PG&E	16%	64%	5%	15%	
	SCE	16%	61%	8%	15%	
	SDG&E	15%	67%	3%	15%	
Commercial, Existing			51%	36%	12%	1%
Industrial, Existing			25%	3%	2%	54%
New (Res., Com. & Ind.)		100%				

Source: Navigant Consulting

Typical Day Load Shapes

The result of the previous two allocation steps is the GWh of energy saved by year by customer class and end-use for each IOU. The last step was to allocate these annual loads to hours using typical day per month load shapes. It was assumed that the savings were proportional to the end-use load. For example, if a measure reduces annual loads by 5%, then it is assumed that the end-use load is reduced by 5% in all hours. While some measures save less energy on peak than on average, this was not reflected in the load shapes for several reasons:

- Most of the savings in the potential analysis are from measures where it is reasonable to assume that the hourly savings are proportional to annual savings. For example, nearly 80% of the savings are from lighting and refrigeration measures where hourly savings would be proportional to annual savings. Of the more 60% of savings that come from lighting measures, only a few percent come from lighting controls.
- There are only limited load shape data available for EE measures. Some measure specific load shapes were available, but some of them had anomalies and were not suitable to use for this analysis.

Thus, end-use load shapes were used to allocate the EE to hours. End-use load shapes were extracted from the CEUS database for commercial and industrial segments and from the savings from LSUI database for the residential sector for each IOU. Typical day per month shapes were developed. The shapes were then weighted by the customer segment and end-use allocations factors summarized above to develop aggregate load shapes for each IOU and year. The aggregate load shapes for each IOU for the aggressive development scenario for 2020 are provided in figures F.1 through F.3.

Figure F.1: PG&E 2020 Aggressive Development EE Load Shape (1,000 GWh)

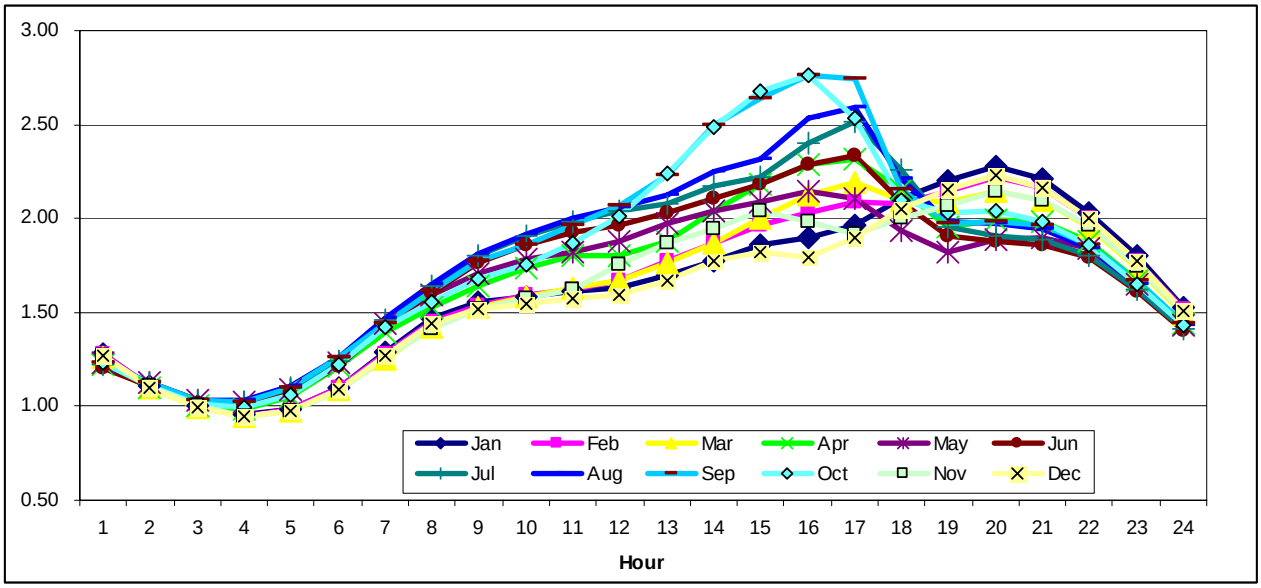


Figure F.2: SCE 2020 Aggressive Development EE Load Shape (1,000 GWh)

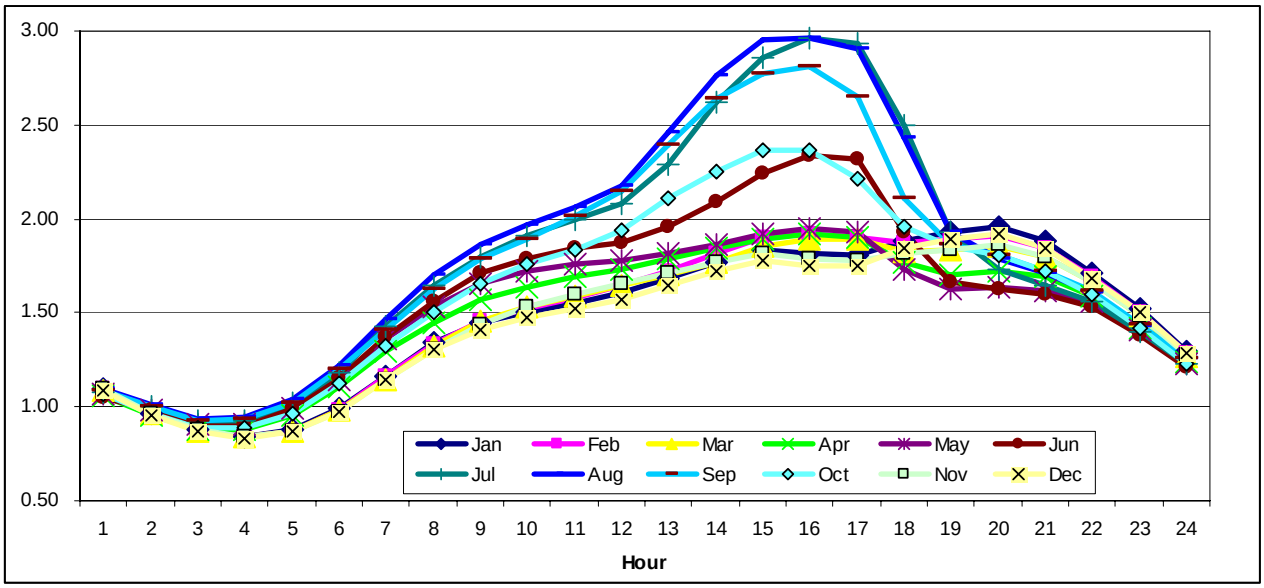
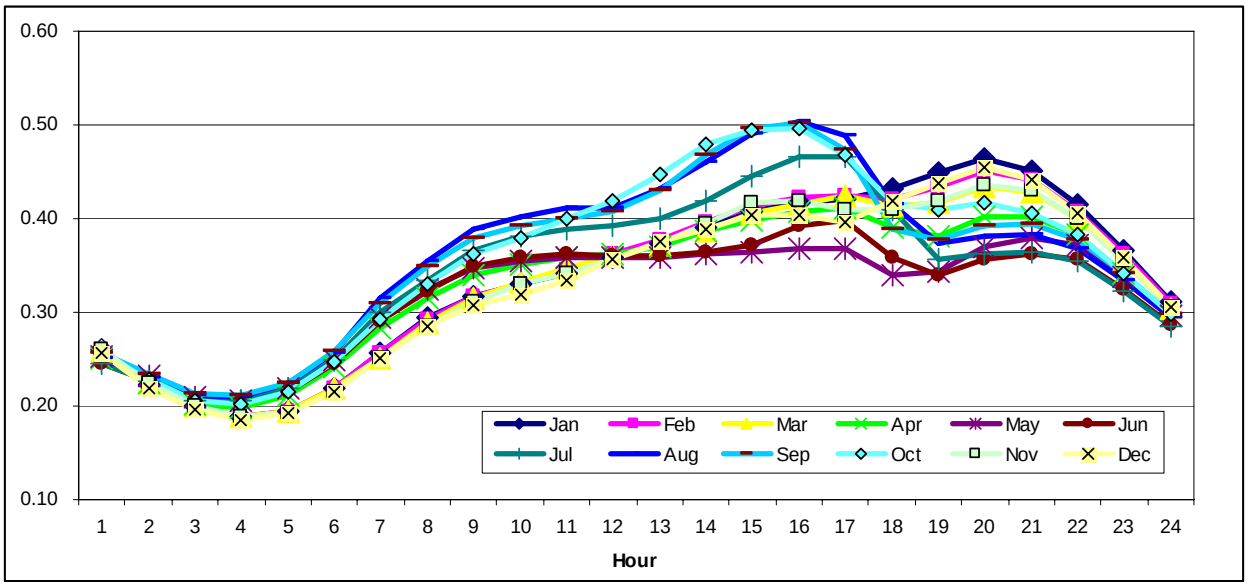


Figure F.3: SDG&E 2020 Aggressive Development EE Load Shape (1,000 GWh)



Source: Navigant Consulting, Inc.

Costs

Costs for developing the EE were estimated from the Itron potential study. Total resource costs, including utility program costs, were used. The measure costs per GWh saved were assumed to be the same for both the current practices and aggressive development scenarios. The Itron study indicated lower measure costs for the economic potential than for the achievable potential, because there were a few low cost measures that had very penetrations in the achievable potential. Since it seems unreasonable that additional EE would cost more, it was assumed that the measure costs were the same for both scenarios. The EE program administration costs were increased by 20% for the aggressive development scenario to reflect that more aggressive marketing will be required. The costs per kW saved are summarized by in table F.10.

Table F.10: Total Resource Costs Including Program Administration for EE ($/kW reduced)

		Current Practices			Aggressive Development		
		SCE	PG&E	SDG&E	SCE	PG&E	SDG&E
Residential	Existing	1,917	2,232	2,137	1,924	2,251	2,160
	New	2,431	2,560	2,830	2,523	2,639	2,897
Commercial	Existing	2,161	2,283	2,525	2,174	2,292	2,540
	New	1,554	1,350	1,188	1,569	1,376	1,199
Industrial	Existing	2,199	2,225	2,024	2,543	2,574	2,337
	New	937	952	1,000	958	990	1,020

Source: Itron Potential Study

F-2 Demand Response

Demand response (DR) estimates were developed from utility submittals to the Energy Commission as part of the 2007 IEPR proceeding. These data are summarized in table F.11 and compared to 5% of forecasted peak loads.

Table F.11: Summary of Utility reported DR Capability (Committed and Uncommitted) Compared to 5% of Peak Load

		2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
PG&E	Peak Demand	20,067	20,388	20,714	21,046	21,383	21,725	22,072	22,425	22,784	23,149
	5%	1,003	1,019	1,036	1,052	1,069	1,086	1,104	1,121	1,139	1,157
	Dispatchable	968	1,068	1,068	1,068	1,068	1,068	1,068	1,068	1,068	1,068
	Non-Dispatchable	177	245	270	277	280	284	291	292	294	297
	Subtotal	1,145	1,313	1,338	1,345	1,348	1,352	1,359	1,360	1,362	1,365
	Delta	-	-	-	-	-	-	-	-	-	-
SCE	Peak Demand	23,823	24,180	24,543	24,911	25,285	25,664	26,049	26,440	26,836	27,239
	5%	1,191	1,209	1,227	1,246	1,264	1,283	1,302	1,322	1,342	1,362
	Dispatchable	1,691	1,760	1,820	1,890	1,882	1,951	2,000	2,016	2,019	2,023
	Non-Dispatchable	25	81	142	185	200	203	204	208	211	213
	Subtotal	1,716	1,841	1,962	2,075	2,082	2,154	2,204	2,223	2,230	2,236
	Delta	-	-	-	-	-	-	-	-	-	-
SDG&E	Peak Demand	4,594	4,667	4,742	4,818	4,895	4,973	5,053	5,133	5,216	5,299
	5%	230	233	237	241	245	249	253	257	261	265
	Dispatchable	138	138	138	138	138	138	138	138	138	138
	Non-Dispatchable	126	126	126	126	126	126	126	126	126	126
	Subtotal	264	264	264	264	264	264	264	264	264	264
	Delta	-	-	-	-	-	-	-	-	-	1
SMUD	Peak Demand	3,213	3,297	3,382	3,470	3,560	3,653	3,748	3,845	3,945	4,048
	5%	161	165	169	174	178	183	187	192	197	202
	Dispatchable	115	115	115	115	115	115	115	115	115	115
	Non-Dispatchable	53	53	53	53	53	53	53	53	53	53
	Subtotal	168	168	168	168	168	168	168	168	168	168
	Delta	-	-	1	6	10	15	19	24	29	34
LADWP	Peak Demand	5,839	5,851	5,862	5,874	5,886	5,898	5,909	5,921	5,933	5,945
	5%	292	293	293	294	294	295	295	296	297	297
	Dispatchable	14	14	14	14	14	14	14	14	14	14
	Non-Dispatchable	20	20	30	30	40	40	50	50	50	50
	Subtotal	34	34	44	44	54	54	64	64	64	64
	Delta	258	259	249	250	240	241	231	232	233	233

Demands for IOUs from CEC-400-2006-008-SF, used 2007 demands and average annual growth rates

Demands for SMUD and LADWP from CEC-400-2005-034-ED2 for 2009 grown at annual average annual growth rates
DR Program MWs from Form 3-4 (2007), except SDG&E where the goals SDG&E presented at the March 27, 2007 workshop were used

Based on these data, dispatchable DR capabilities were developed for two cases:

- Cases 1a, 1b, 2, 4a, and 4b: include 3,357 MW of dispatchable DR capability by 2018 as reported by the utilities, reflecting the committed and uncommitted capability from their submittals.
- Case 3a, 3b, 5a, and 5b: increase the dispatchable DR capability by approximately 20% to 4,057 MW by 2018, with SCE and PG&E having DR capability of approximately 7.4% and 6% of their peak demands, exceeding the DR capability as a percent of load of any region in North America.

The MW by utility and case are summarized in table F.12.

Table F.12: Dispatchable DR Capability by Utility and Case

	Case 1b - Current Practices					Case 3b - Aggressive Development				
	PG&E	**SCE**	**SDG&E**	**SMUD**	**LADWP**	**PG&E**	**SCE**	**SDG&E**	**SMUD**	**LADWP**
2009	968	1,691	138	115	14	968	1,691	138	115	14
2010	1,068	1,760	138	115	14	1,068	1,760	152	125	32
2011	1,068	1,820	138	115	14	1,104	1,820	166	134	51
2012	1,068	1,890	138	115	14	1,139	1,890	180	144	69
2013	1,068	1,882	138	115	14	1,175	1,882	194	154	87
2014	1,068	1,951	138	115	14	1,211	1,951	208	164	105
2015	1,068	2,000	138	115	14	1,246	2,000	222	173	124
2016	1,068	2,016	138	115	14	1,282	2,016	237	183	142
2017	1,068	2,019	138	115	14	1,318	2,019	251	193	160
2018	1,068	2,023	138	115	14	1,389	2,023	265	202	178
2019	1,068	2,023	138	115	14	1,389	2,023	265	202	178
2020	1,068	2,023	138	115	14	1,389	2,023	265	202	178
% of 2018 Peak	4.6%	7.4%	2.6%	2.8%	0.2%	6.0%	7.4%	5.0%	5.0%	3.0%
Case 3a Incremental MW Added Relative to Case 1B						321	-	127	87	164

Source: Navigant Consulting

The DR capability for SCE was held the same in the aggressive cases (e.g. 3a) as in case1b, because their planned capability already substantially exceeded 5% of their peak loads. For the aggressive case DR capability was increased by approximately 20% to reflect more aggressive development of DR, by increasing DR capability to 6% of peak loads for PG&E, 5% of peak loads for SDG&E and SMUD, and to 3% of peak loads for LADWP.

The costs for the dispatchable DR were assumed to be $100/kW-year, except for SMUD where costs were assumed to be $360/kW-year. The data provided by the utilities showed tremendous range (SCE - $97/kW-year in 2009 declining to $66/kW-yr in 2018, PG&E - $25/kW-year; LADWP - $10/kW-year, and SMUD - between $348 and $368/kW-year). SCE's 2009 costs of $96/kW-year was rounded to

$100/kW-year and used for all of the utilities except SMUD. For SMUD, $360/kW-year was used as an average cost based on the costs that they provided.

Endnotes

1. Itron, KEMA, RLW, and AEC, May 2006, "*California Energy Efficiency Potential Study*"

2. Western Governor's Association, January 2006 "*Clean and Diversified Energy Initiative: Energy Efficiency Task Force Report*"

3. Pacific Gas & Electric, San Diego Gas & Electric, Southern California Edison, 2006 Procurement Plan, December 2006, R.06-002-013

4. Western Governor's Association, January 2006 "*Clean and Diversified Energy Initiative: Energy Efficiency Task Force Report*"

5. D.04-09-050 established goals through 2013. The 2016 goals are based on the assumption that the goals for 2014-2016 would be approximately the same as the goals for 2013.

6. ITRON, March 2006, "*Commercial End-Use Survey*," prepared for the California Energy Commission, CEC-400-2006-005

7. KEMA, JJ Hirsch Associates, November 17, 2006, "*Load Shape Update Initiative, Final Report*," prepared for the California Public Utilities Commission

APPENDIX G

SOLAR TECHNOLOGY ANALYSES

Prepared by Navigant Consulting , Inc.

Introduction

Rooftop photovoltaic (PV) and solar parabolic technologies were evaluated and used as power generation resources for the various cases used in this study. Customer-installed rooftop PV was estimated as a power supply, but then used to adjust net loads that would be served by existing and anticipated new central station generation resources, after reflecting load reductions achieved by energy efficiency measures. Unlike customer-installed PV, solar parabolic technology was assumed to be a central station generation source in some of the cases as part of the generation portfolio of the various cases studied.

In Case 1A, any existing or committed customer-installed PV was assumed to be reflected in the existing load forecast and no specific additional PV capacity additions were assumed. For Case 1B, penetration estimates provided by the investor-owned utilities in the December 2006 update filings for the utilities' Long Term Procurement Plans were used. For Case 4A, it was assumed that the CA Solar Initiative goals of 3000 MW of household and commercial PV installations are met by 2016. From 2017-2020, it was assumed that the rate of PV installations would grow at two percent annually. For Case 4B, 4A PV assumptions were assumed for California. For the rest of the WECC, an accelerated PV plan was implemented for Arizona and Nevada which is discussed later in this Appendix.

Solar parabolic central station generation additions were assumed as part of the generation portfolio for California in Case 4A, which featured high renewable resource levels in California to achieve the 33% RPS level by 2020, and in Case 5A, which assumes the Case 3A energy efficiency, plus meeting 33% RPS by 2020. Solar parabolic central station generation was also assumed as part of the generation portfolio in the rest of WECC outside of California in Case 4B, which featured high renewable resource additions in the rest of the US portion of the WECC and in Case 5B, which combines the high energy efficiency assumed in Case 3B for the rest of WECC, and the Case 4B high renewable resource additions in the rest of WECC.

The following describes the approach, assumptions, data sources and methods used to establish the levels of customer-installed PV and levels of central station solar parabolic generation resources included in the supply portfolio.

G.1: Rooftop PV Penetration Assessments

California PV Penetration

Customer-installed PV penetration estimates for California were derived from the *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential by County Report* Prepared for the Energy Commission PIER Renewables program, prepared by Navigant Consulting (NCI), completed in April 2007 (herein referred to as the "PIER PV Report")***.*** This report provided six levels of estimated PV penetration:

- Business as usual with no state PV incentives,
- with state PV incentives as proposed as part of implementation of the California Solar Initiative, and
- with state PV incentives and new business models which foster accelerated PV installed package cost advances and customer implementation.

For each of the above scenarios, a case with lower PV system module prices was assumed in combination with these incentive and business model assumptions. From these six alternative levels of PV penetration, two penetration scenarios were used in this Scenario Project Results Report:

- Scenario 1 – Business As Usual Pricing with California Solar Initiative and Federal Incentives (used for Case 1B);and
- Scenario 2 – Aggressive System Pricing, New Business Models, and California Solar Initiative and Federal Incentives (used as input, with some modification, for Case 2 – the high sustained natural gas and coal prices case, Case 4 – the high renewables in California only case and Case 5a – the high energy efficiency and renewables in California only case).

The assumptions supporting the levels of PV penetration are described in more detail in the above referenced PIER PV Report. This appendix provides excerpts from that report to provide context and explanation for purposes of this report. .

Table G-1 summarizes the key customer-installed PV system and financial assumptions used in the PIER PV Report.

For the scenarios 1 and 2 used in this Scenarios Project Report, Table G-2 summarizes the estimated costs per installed watt of PV used to estimate market penetration. While these PV costs were used in the PIER PV Report as part of the input to county-by-county penetration, described below, the Scenarios Project Report used a somewhat modified, but generally consistent estimate of installed PV costs starting at $10 per Watt ($10,000/kW) in 2006, ramping down to $5/Watt in 2015 and maintaining that cost through 2020. The starting levels and the trend in reductions are similar between the penetration analysis and the portfolio resource plan cost analysis, but they do not track exactly. For purposes of the trend analysis in this Scenarios Project, the penetration numbers seem

reasonable. More detailed analysis isolated on PV contributions could refine the analysis further.

Table G-1: Key PV System and Financial Assumptions

Factor	Commercial	Residential
System Life (Years)	30	30
O&M Cost ($/kW/year)	$12 declining at 3.5% per year	$10 declining at 4% per year
REC Value ($/MWh)	$15 with no escalation	0
Federal Tax Credit	30% ITC through 2007, 10% after	$2,000 credit for 2006 and 2007.
System Size (kW)	250 kW	5 kW
Module Tilt (degrees)	5	15
Depreciation (yrs)	5 years MACRS (accelerated)	-
System Power Density (MWp/million sq. ft)	10 MW in 2006, increasing to 14 MW in 2016	10 MW in 2006, increasing to 14 MW in 2016

Source: Navigant Consulting

Table G-2; Installed PV System Price

		Retrofit Installed System Price *($2006/Wpac)*			New Construction Installed System Price *($2006/Wpac)*		
System Price Scenario	Market Segment	2006	2010	2016	2006	2010	2016
Scenario 1	Residential	$9.60	$8.00	$5.80	$9.60	$7.70	$5.40
	Commercial	$8.70	$7.50	$5.40	$8.70	$7.20	$5.00
Scenario 2	Residential	$9.60	$6.00	$3.10	$9.60	$5.70	$2.90
	Commercial	$8.70	$5.10	$2.70	$8.70	$5.00	$2.50

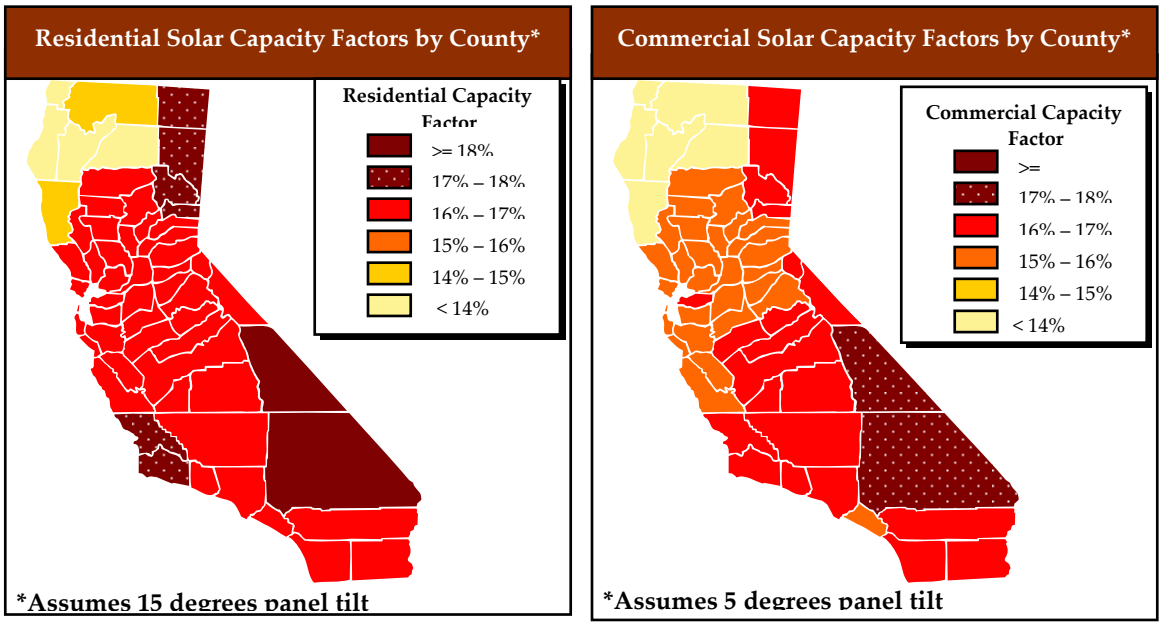
Source: Navigant Consulting

Estimates of PV penetration in the PIER PV report were developed for each county in California based on solar capacity factors, estimated future retail utility

rate levels, cost of PV systems, and resultant estimated pay-back levels. Separate estimates were prepared for residential and commercial customers. Residential and commercial solar capacity factors by county were developed using the Clean Power Estimator for California[1]. Navigant Consulting (NCI) used Energygauge software to develop monthly usage profiles for a typical home in each climate zone[2]. Standard utility residential rate classes were used for each utility for the relevant county and estimated rates for 2010 and 2016 were developed assuming annual escalation of three percent.

Figure G-1 shows the estimated solar capacity factor by California county for each of residential and commercial customer PV applications. This geographic distribution was a starting point for evaluating the distribution and penetration of rooftop PV in the PIER PV report.

Figure G-1 Residential and Commercial PV Capacity Factor by County



Source: Clean Power Estimator for California
(http://www.consumerenergycenter.org/renewables/estimator/index.html)

The estimated retail utility rates by county were used to determine avoided price factors by geographic area to assess PV penetration. For the commercial customer utility rates, time of use rates were assumed, which had a material effect on the level of commercial customer PV penetration in the PIER PV report findings. Figure G-2 and G-3 show the residential and commercial rate estimates, respectively, by county.

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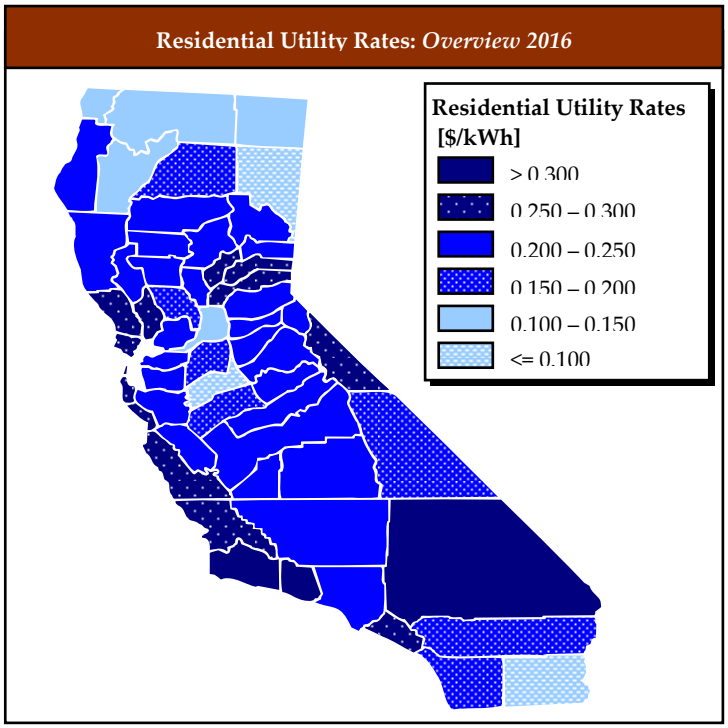
[1] http://www.consumerenergycenter.org/renewables/estimator/index.html

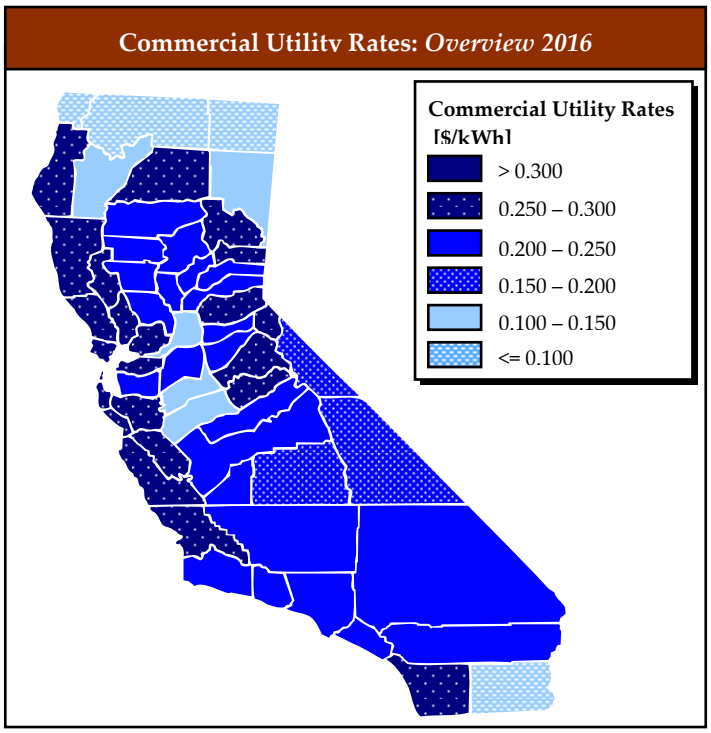
[2] Typical home statistics were taken from Residential New Construction Study Project Year #2 – 2002 by Regional Economic Research, Inc.

Figure G-2 Residential Utility Rate Assumptions



Sources: Baseline allowances, baseline service areas and rate structures for IOU's was taken from the CPUC at (http://www.cpuc.ca.gov/static/energy/electric/rates+and+tariffs/index.htm). Information for MUNI's was found from each MUNI's webpage.

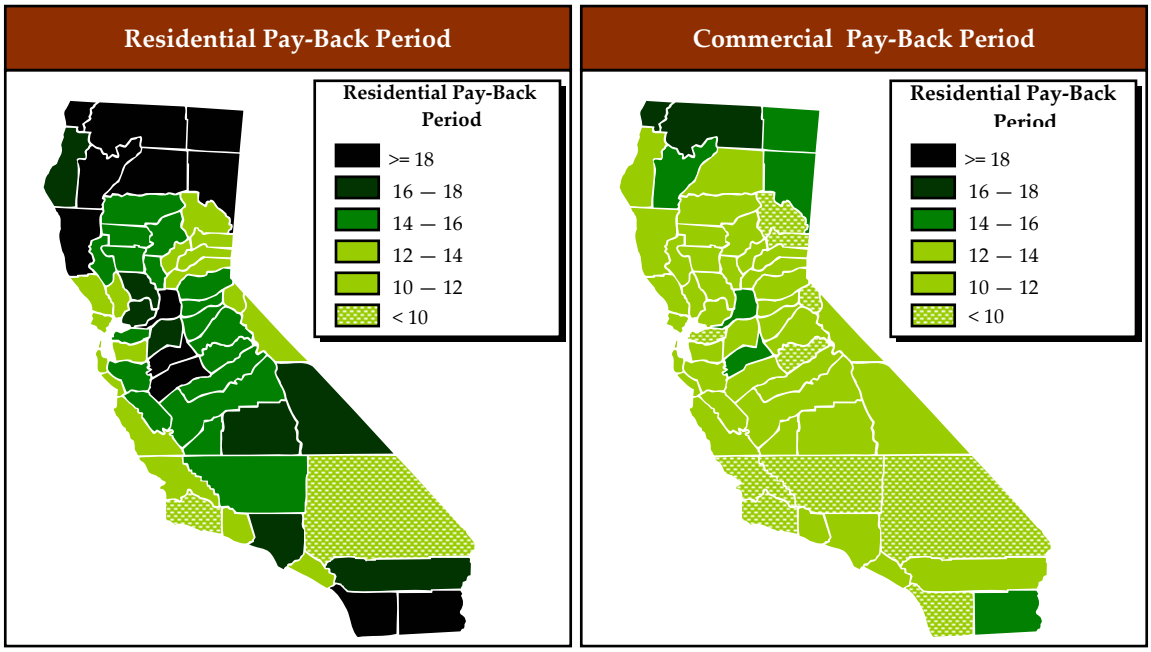
Figure G-3 Commercial Utility Rate Assumptions



Source: Time-Of-Use rate structures from the CPUC at (http://www.cpuc.ca.gov/static/energy/electric/rates+and+tariffs/index.htm) or utility websites.

Using the estimated costs for PV for existing and new construction for residential and commercial customers at the assumed utility rates by county, and PV capacity factors by county, payback estimates were developed for each of the PV scenarios. Figure G-4, below, shows an example of the county-by-county 2016 pay-back analysis results for both residential and commercial customers for the PV penetration scenario 1 – the case with business as usual PV system costs with California incentives. For scenario 1, pay-back periods varied from 10 to 30 years for systems installed in 2016, with lower pay-back periods for commercial customer installations. Similar pay-back analyses were performed for the other scenarios and are documented in the PIER PV report.

Figure G-4 PV Installation Pay-Backs with California Incentives



Source: Navigant Consulting

PV penetration was estimated by county considering the pay-back analysis by residential and commercial customer. Tables G-3 and G-4 show the assumed level of MW of PV installations by select years for PV penetration scenario 1 (California and federal incentives) and PV penetration scenario 2 – improved system pricing, California and federal incentives and new business models), respectively. Scenario 1 results in a total of over 800 MW of rooftop PV by 2016, and PV penetration scenario 2 results in an estimated total of over 4,300 MW by 2016.

Table G-3 MW of PV Penetration for PV Scenario 1

This 844 MWp does not include the ~180 MWp currently installed in California.

Scenario 1: Business-As-Usual System Pricing, CA CSI and Federal Incentives			
	Total Installations		
Cumulative Market Segment	2006	2010	2016
Residential	4	43	357
Total Installations due to New Construction	0	2	39
Commercial	58	141	487
Total Installations due to New Construction	*0*	*4*	*20*
Total	**62**	**184**	**844**
	Total Installations		
Annual Market Segment	2006	2010	2016
Residential Retrofits	4	16	108
Residential New Construction	0	1	14
Commercial Retrofits	58	29	147
Commercial New Construction	0	1	5

Source: Navigant Consulting

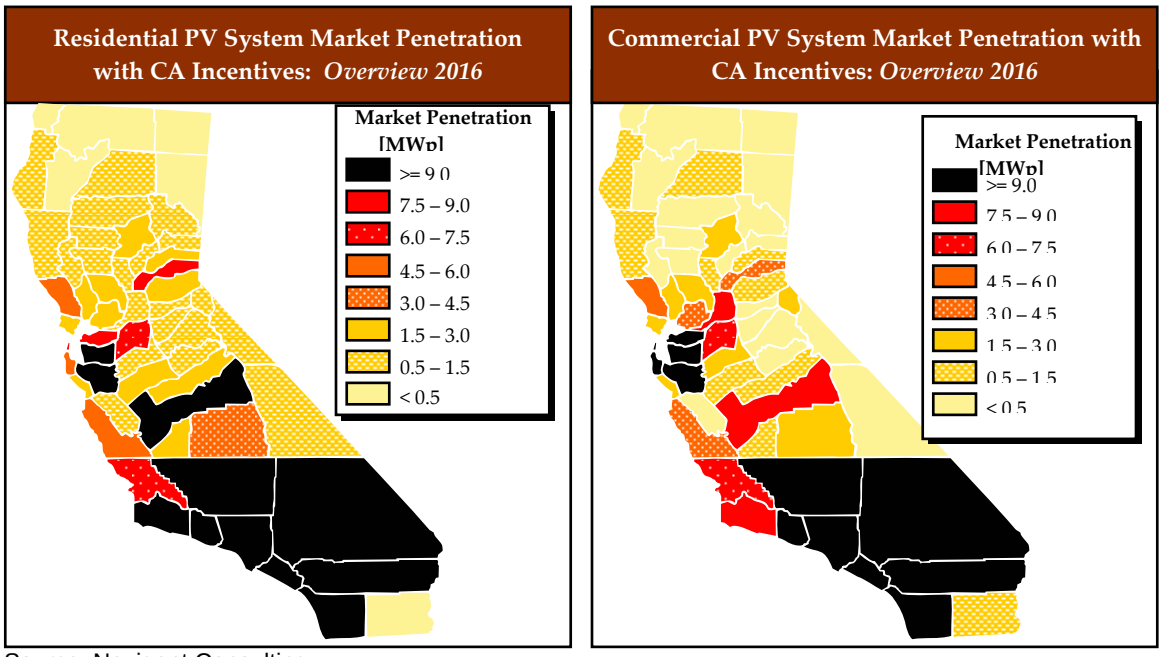
Table G-4 MW of PV Penetration for PV Scenario 2

Scenario 2: Aggressive System Pricing, New Business Models, CA CSI and Federal Incentives			
	Total Installations		
Cumulative Market Segment	2006	2010	2016
Residential	4	135	2,258
Total Installations due to New Construction	*0*	*5*	*178*
Commercial	58	267	2,126
Total Installations due to New Construction	*0*	*5*	*42*
Total	**62**	**402**	**4,384**
	Total Installations		
Annual Market Segment	2006	2010	2016
Residential Retrofits	4	63	1,154
Residential New Construction	0	4	81
Commercial Retrofits	58	132	771
Commercial New Construction	0	2	11

This 4384 MWp does not include the ~180 MWp currently installed in California.
Source: Navigant Consulting

As an indication of the distribution of rooftop PV, Figure G-5 shows county-by-county PV market penetration for PV scenario 1. For cases with more aggressive pricing of PV systems and new business models, the improved penetrations tend to follow the pattern on these figures, with greater penetration in the more darkly shaded counties, reflecting better solar resource availability, higher utility rates, and population density (roof availability).

Figure G-5 PV Market Penetration with Incentives



Source: Navigant Consulting

Beyond 2016, for purposes of the Scenarios Project report, customer-installed PV was assumed to grow at the rate of load growth.

Rest of WECC PV Penetration

For the rest of the US WECC region outside of California, estimates of customer-installed PV were prepared for Arizona and Nevada. These states were selected due to state-level support for PV installation, and due to combinations of available rooftops and solar incidence in those states compared to other non-California states in the WECC.

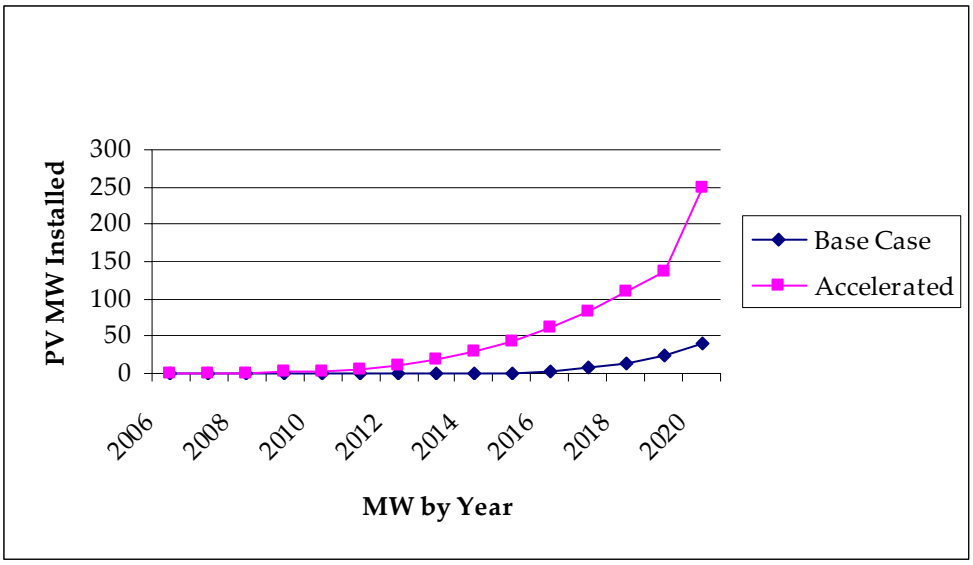
Estimated PV penetration for Arizona was based on analyses from the *Arizona Solar Electric Roadmap Study*, prepared by NCI for the Arizona Department of Commerce, published January 2007. This study evaluated the potential for both PV and central station solar generation as part of an economic development initiative by the State of Arizona. The base case for future PV and central station solar generation assumed the continuation of existing state-level incentives that presently are provided primarily through Arizona's electric utilities, no assumed breakthrough in solar generation cost pricing, and natural gas prices remaining in the $7 to $8/MMBtu range. An accelerated solar generation development case was developed assuming gas prices increase to an average in the $9 to $10/MMBtu range, greenhouse gas and other emissions add $5/MWh to typical combined cycle generation output costs, and transmission capability is developed by 2020 to support the export of an additional 200 MW of supply to markets outside of Arizona.

The accelerated solar development case also assumed that Arizona would undertake a broad program of solar generation development and output utilization through actions such as:

- Establishing a solar marketing and outreach program
- Establishing "solar zones" to foster solar generation development in certain geographic areas
- Creating a solar development center of excellence
- Forming community pilot efforts to accelerate solar generation implementation to stimulate market demand and build awareness

Figure G-6 presents the estimated rooftop PV installed capacity in Arizona under both cases.

Figure G-6 Arizona Rooftop PV Installation Projection

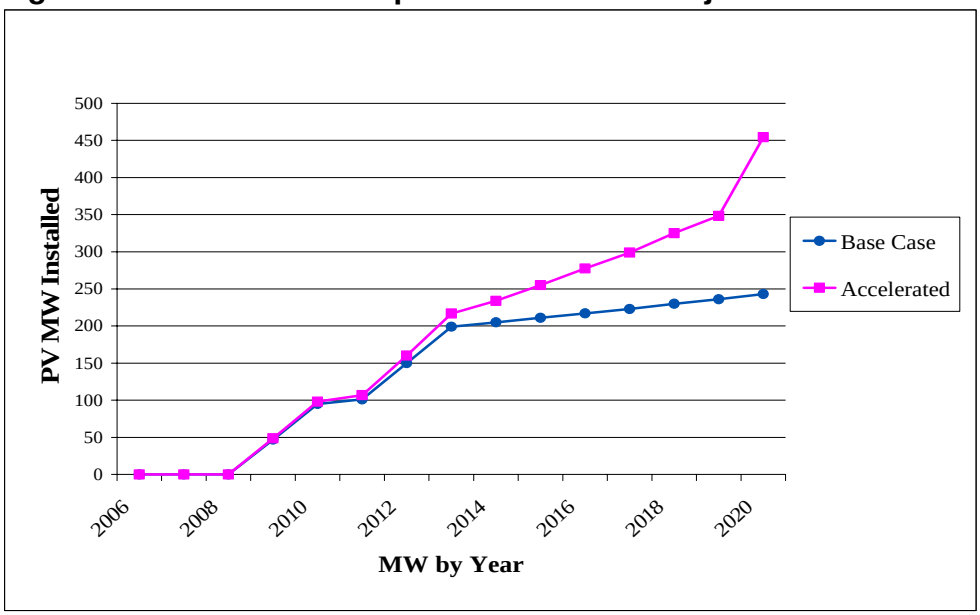


Source: Navigant Consulting

Due to lack of similar state or regional analysis of other subregions of the WECC outside of California and Arizona, the Arizona Solar Electric Roadmap Study PV installation estimates were applied to Nevada. Nevada has demonstrated similar interest as Arizona in fostering accelerated development of solar generation. Nevada, particularly the more highly populated southern part of the state, shares climate and solar resource characteristics of Arizona.

Nevada rooftop PV estimates for a base case (considered a Case 1B proxy) and an accelerate PV development case (used in Cases 2, 4B and 5B) were developed based on the estimates from the above described Arizona efforts. The base case for PV installation in Nevada was assumed to meet Nevada's RPS goals. For the accelerated PV installation scenario, the difference, expressed in MW of capacity, between the Arizona base case and the Arizona accelerated case was added to the Nevada base case. The Nevada customer-installed PV assumptions are shown on Figure G-7 for both cases.

Figure G-7 Nevada Rooftop PV Installation Projection



Source: Navigant Consulting

G-2: Rooftop PV Production Profiles

Rooftop PV production profiles were developed based on data compiled by the US Department of Energy's National Renewable Energy Laboratory (NREL) for various geographic locations. NREL publishes the PV Watts data base, comprised of insolation data by geographic location, and calculations of the hourly energy production per watt of installed PV capacity at that location. The PV Watts PV production profiles are an 8760 hr simulated year comprised of actual data for specific hours for specific months that were determined by NREL to comprise an average month from the history of collected data. Each such average month is then used for a "synthetic" year comprised of the twelve average months for each geographic location.

This daily and hourly information provides a typical hourly profile that can be used for typical daily profiles per month, or the hourly information can be used to perform statistical variance analysis of the intermittency of PV production for a given geographic location.

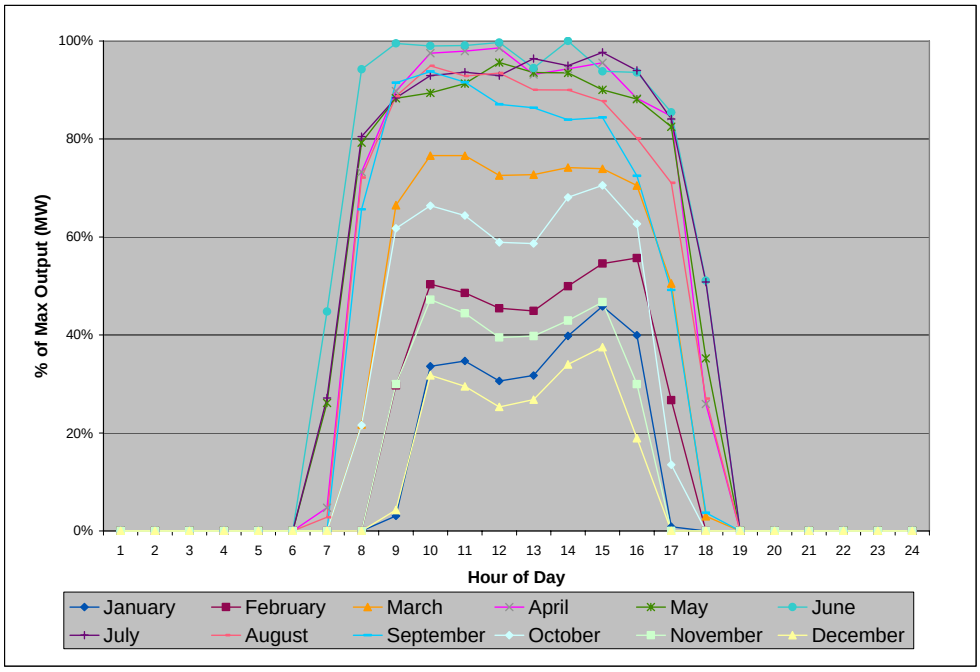
The most extensive analysis of PV penetration and associated contribution to net electric load reduction in this Scenarios Project was performed for California. For California, twelve PV Watts data sets were available to typify PV hourly production profiles across California. Data from these twelve sites were used to establish typical profiles for each county in California by Navigant Consulting. In turn, those counties were associated with individual transmission areas that are modeled by Global Energy in its generation production model. Those individual profiles were applied to the PV penetration estimates for the two scenarios described earlier in this Appendix to develop total hourly rooftop PV production on average and for the stochastic analyses performed by Global Energy to assess expected levels of variance in PV production, among other variables.

G-3: Solar Parabolic Production Profiles

Solar parabolic production profiles for use in modeling generation patterns of Concentrated Solar Power (CSP) units were obtained from the National Renewable Energy Laboratory (NREL) which were developed using their Parabolic Trough Performance Model. NREL provided one 24-hour profile per month for one year for each location in the model where CSP generation is modeled. The profiles are representative of a 100 MW single-axis solar trough system. While some of the CSP included in the resource mix is Solar Dish Stirling Engine technology, NREL does not have a model that develops profiles comparable to this technology. Balancing best available data and the time constraints associated with this project, NREL's single-axis solar trough profiles were used to model generation patterns for all central station concentrating solar generation technologies

As an example, Figure G-8 presents the NREL profile that was applied to CSP generation in the SP15 transmission area in southern California.

Figure G-8 Representative Concentrated Solar Power Hourly Profile (California SP 15 Transmission Area Example)



Source: US Department of Energy National Renewable Energy Laboratory

APPENDIX H

NATURAL GAS PRICE ASSESSMENTS

Prepared by Global Energy Decisions, Inc.

Appendix H-1: GPCM® – Product Description and Its Integration Into MARKETSYM®

Purpose

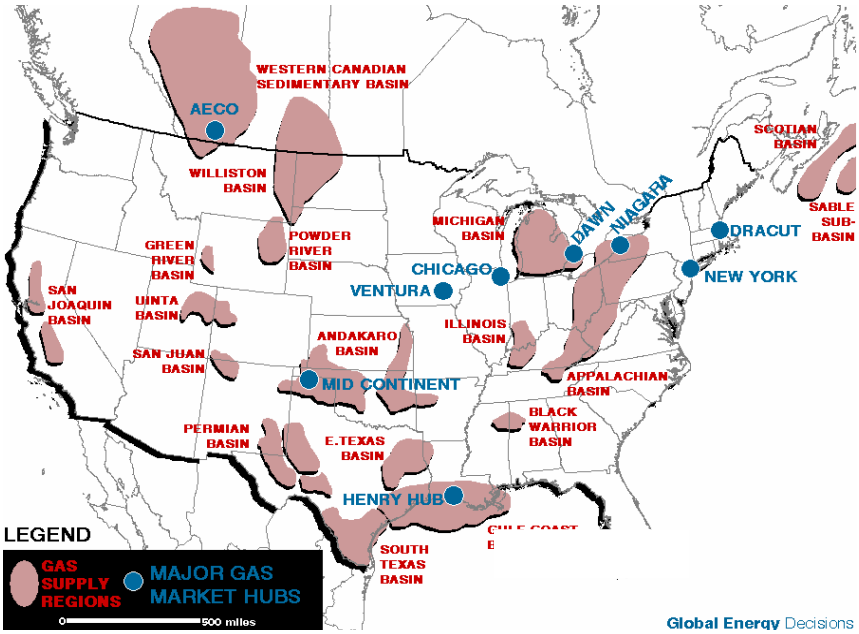
GPCM® is RBAC's[1] Natural Gas Market Forecasting System. Originally known as the Gas Pipeline Competition Model, GPCM is a combination software-database system, whose purpose is to enable its users to build models for analysis of natural gas economics, including the sectors of production, transportation, storage, marketing, and sales to distributors and other large customers. GPCM is the latest in a series of systems and models built by Dr. Robert Brooks from the mid-1970s through the present. Making use of the latest PC hardware, software technology and advanced computational algorithms, it enables analysts to do more at their desktop than has ever been possible in the past using mainframe computers with earlier, similar software tools.

Model Structure

Mathematically, GPCM® is a network model. It can be diagrammed as a set of "nodes" and "arcs". Nodes represent production regions, pipeline zones and interconnects, storage facilities, delivery points, and customers or customer groups. The connections between these nodes are called "arcs". They represent transactions and flows. Some of these are supplier deliveries to pipelines, transportation across zones and from one zone to another, transfers of gas by one pipeline to another, delivery of gas into storage, storage of gas from one period to another, withdrawal of gas from storage, and pipeline deliveries of gas to customers.

Figure H-1

Natural Gas Supply Basins and Major Market Hubs of the US and Canada

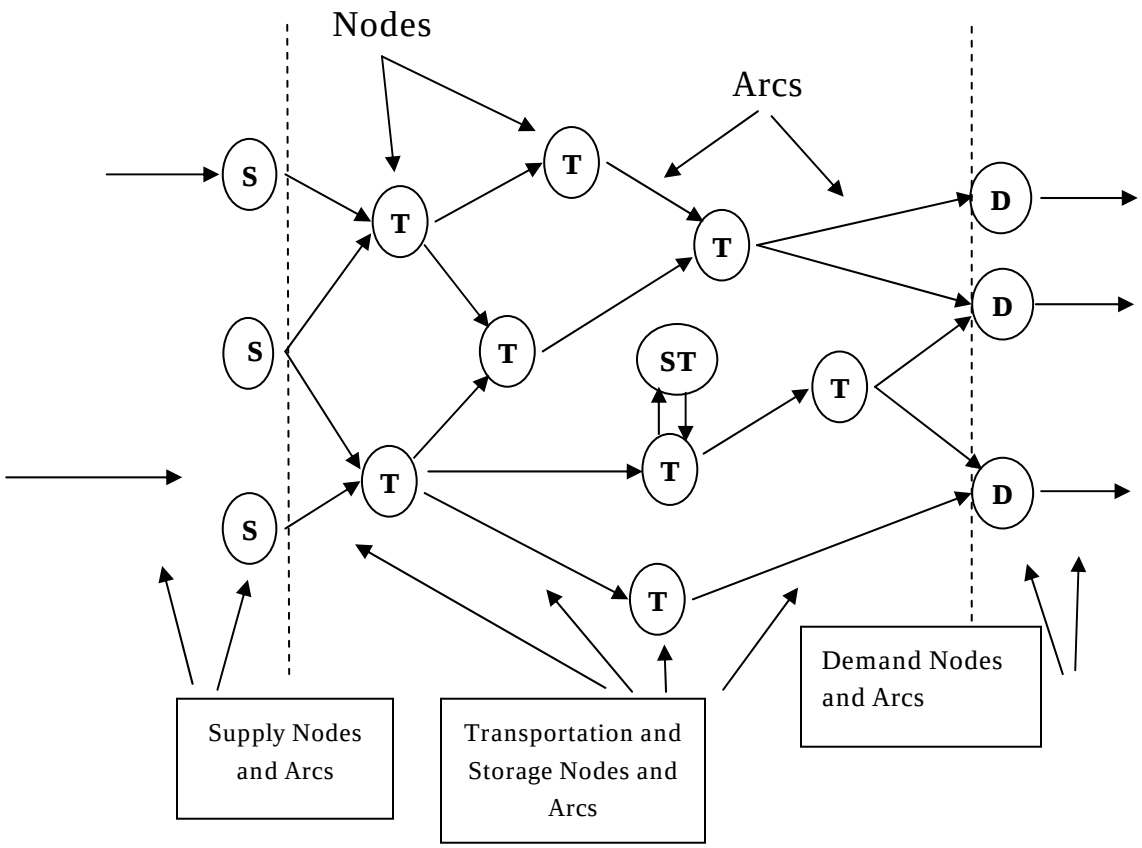


SOURCE: Global Velocity Suite

In general an arc has four input attributes and two output attributes. The inputs are cost (which may depend on transaction volume), a minimum, a maximum, and a loss factor (representing fuel use and miscellaneous losses). The outputs are the amount of the transaction (the flow) and the economic rent associated with the flow. The latter is defined mathematically as the economic value of a unit increase (decrease) in the upper (lower) bound. It generally applies to pipeline transportation and storage capacity and represents the marginal value of increased capacity. Figure H-2 outlines a simplified GPCM network model.

Figure H-2

Relatively Simple Representation of GPCM Network Model with Nodes and Arcs



SOURCE: RBAC, Inc.

The economic value of a solution to this problem is identified in economic theory to be the sum of producer and consumer surplus. These concepts are defined for price sensitive supplies and demands. We assume that each supply source and each customer has a well-defined supply or demand curve. The forms for these curves can be quite general. GPCM only requires the quantity to decrease with increasing price for demand curves and to increase with increasing price for supply curves.

The objective function for this "equilibrium" solution has been shown by Nobel Prize winning economist Paul Samuelson to consist of three terms: the integral of the demand price function over demand minus the integral of the supply price function over supply and minus the sum of the transportation and storage costs. By dividing the applicable range of possible prices into a number of small steps, we can approximate the integrals in the objective function by linear terms of the form p * delta q, where delta q is the additional demand (or supply) resulting from the small price change. Because of the form of the supply and demand functions and the objective function, each of these terms will be brought into the solution in an economically sensible order to produce an economically efficient. That is, the cheaper supplies will be used before more expensive ones and the customers willing to pay more will be served before those willing to pay less. Thus we are able to use a "linear programming" approach to solve a highly non-linear, complex model of market clearing behavior in the natural gas industry.

Transportation and Storage Tariff Structure

In general, each transportation and storage transaction cost is parameterized by five values: a unit demand charge, unit firm commodity charge, unit interruptible commodity charge, a "full discount quantity" (FDQ) and a "zero discount quantity" (ZDQ). The cost model for such transactions assumes that, for a price, some amount of the capacity could be reserved for certain customers. The cost of such capacity reservations will be the unit demand charge times the capacity reserved plus the unit firm commodity charge times the amount actually used. The cost for interruptible service (interruptible commodity charge) will be lower on average than the total cost for firm service, but higher than the firm commodity charge. The model says that if demand for the capacity is higher than the ZDQ, the pipeline will be able to charge the full interruptible rate for transportation. If not then it will have to discount. The amount of the discount in this model is maximal when demand falls to FDQ or lower: then the price of transportation is equal to the firm commodity charge. The discount declines linearly as demand increases from the FDQ up to the ZDQ. For all demand greater than or equal to ZDQ, the price is the full interruptible commodity charge, i.e. no discounting is required.

Storage (including LNG) transactions work the same way. There are three storage transactions: injection, storage, and withdrawal. Injection and withdrawal have the structure just defined. Storage has a simpler structure: a constant unit cost per period, which may be zero. The user may model a situation where gas is transported to a storage location on one rate schedule, injected and withdrawn under another, and delivered to another location under a third. The user may also model a "bundled" structure involving movement from one location to the storage location and then downstream to yet a third, all under the same rate structure. Figure H-3 and H-4 outline a generalized LNG supply source model and LNG import terminal model.

Figure H-3

LNG Supply Source Model

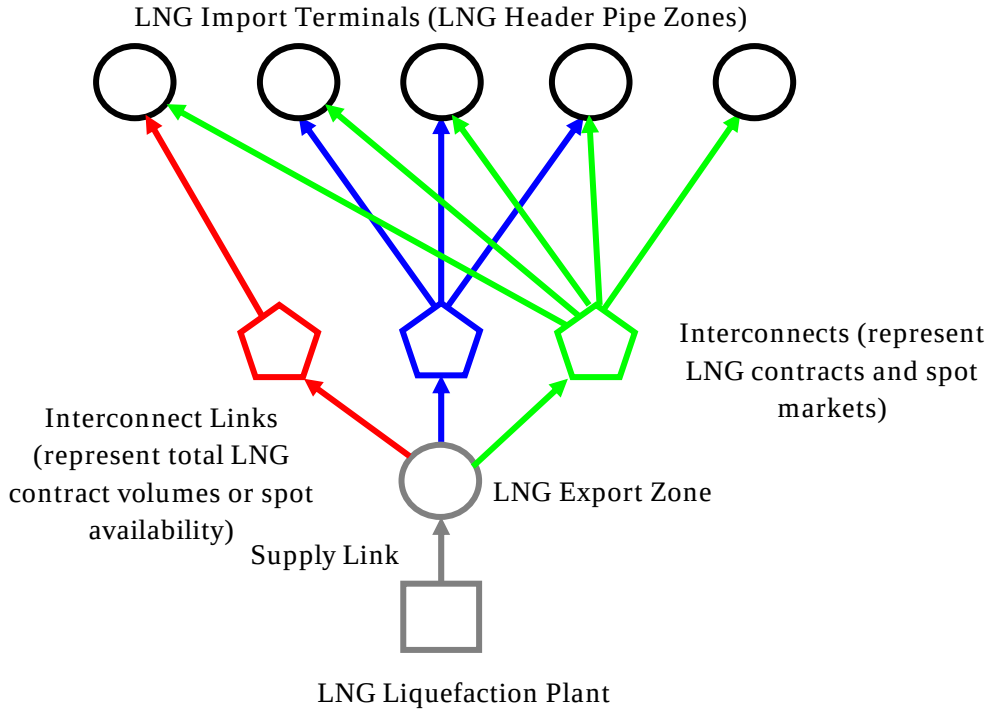
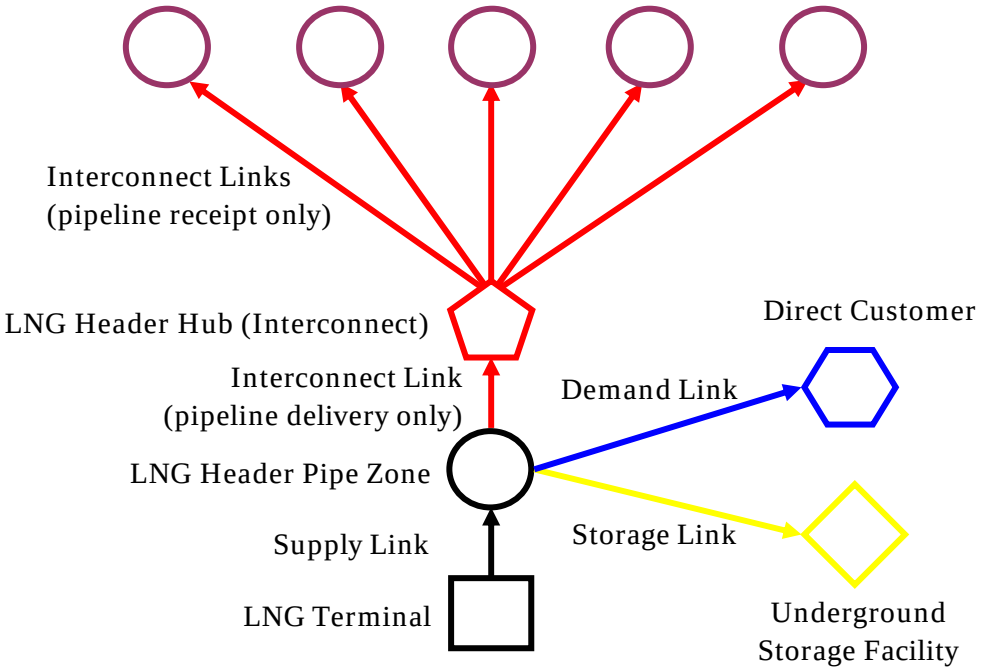


Figure H-4

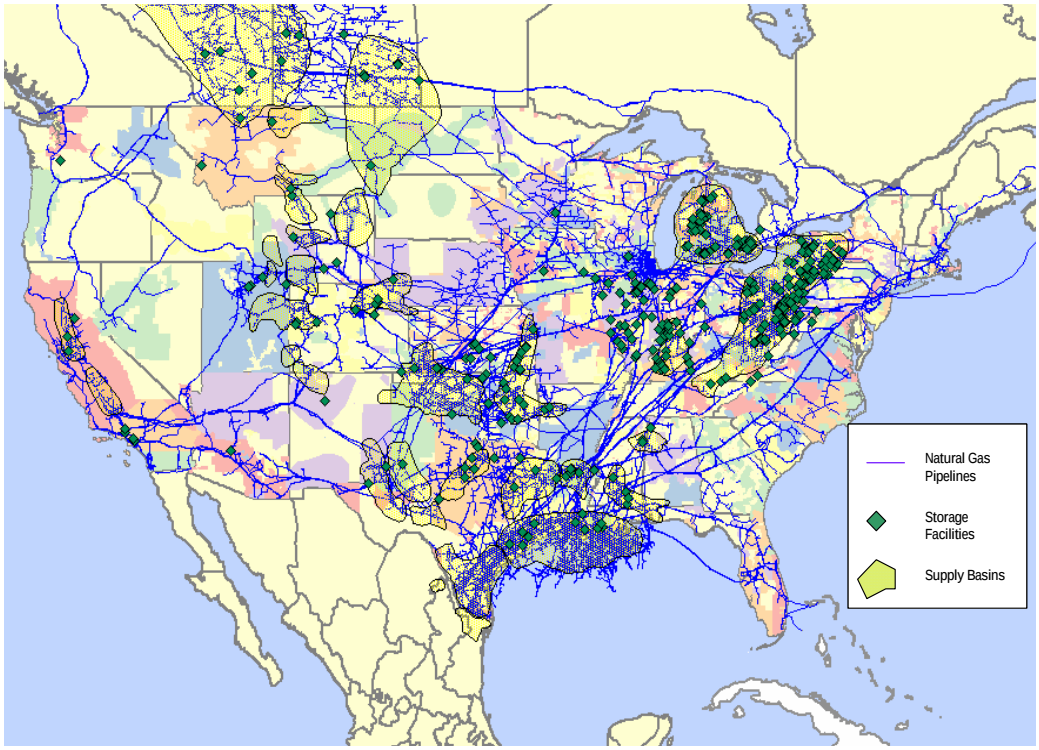
LNG Import Terminal Model



SOURCE: RBAC, Inc.

Marketers are modeled as a single undifferentiated sector in GPCM®. This sector is assumed to mediate all transactions in the model. It is the sector which makes the market by linking gas supply to gas demand through the pipeline and storage system.
The bulk of the economic rent due to capacity restrictions is generally distributed to the marketing sector. The assumption is basically that the marketers are able to buy at market conditions, sell at market conditions, and acquire transportation at prices fixed in the short term. Therefore, short term economic rents will not be acquired by the pipeline sector and will go to the marketing sector. Suppliers and customers owning Firm Transportation earn the remainder of these rents. Their rents may be earned by reselling their capacity to others or by using the F/T themselves. Figure H-5 gives an indication of the complexity of the U.S. interstate pipeline system including storage facilities.

Figure H-5
Natural Gas Infrastructure in North America



SOURCE: Global Energy Decisions, Inc.

User Interface

The user interface is the principal analysis tool contained in the GPCM system. It consists of a set of queries, macros, modules, forms, and reports contained in a Microsoft Access97 file. The user interacts with this interface through Access "Forms". Forms contain data from the database and controls such as button for causing actions to be done. The data displayed in forms is stored in database tables in a separate Access file. These tables are "attached" to the user interface so that they can be viewed and modified by the analyst.

Database

The database file consists of a number of data tables for input and output. The data inputs are primarily of three types: tables representing the basic entities of the model (suppliers, supply regions, customers, demand regions, pipeline zones, storage facilities), tables relating these entities representing the structural linkages in the model (the arcs), and the quantitative data representing supplies, demands, tariffs, capacities, fuel use, etc. The GPCM user typically populates the database via Windows clipboard copy-paste operations from Excel or other spreadsheets. Alternatively, the user can utilize GPCM's built-in data import routines.

EMNET Optimizer

EMNET is a program written by Professor Richard McBride of the University of Southern California Graduate School of Business. It is a specialized linear programming algorithm designed specifically to solve network models such as that used in GPCM. In benchmarking tests on a large variety of such problems, it has proven to be world class in speed and functionality. EMNET has been extended to handle the linearized approximations of non-linear supply, demand, and transportation cost functions required for the solution of the GPCM® model.

Outputs

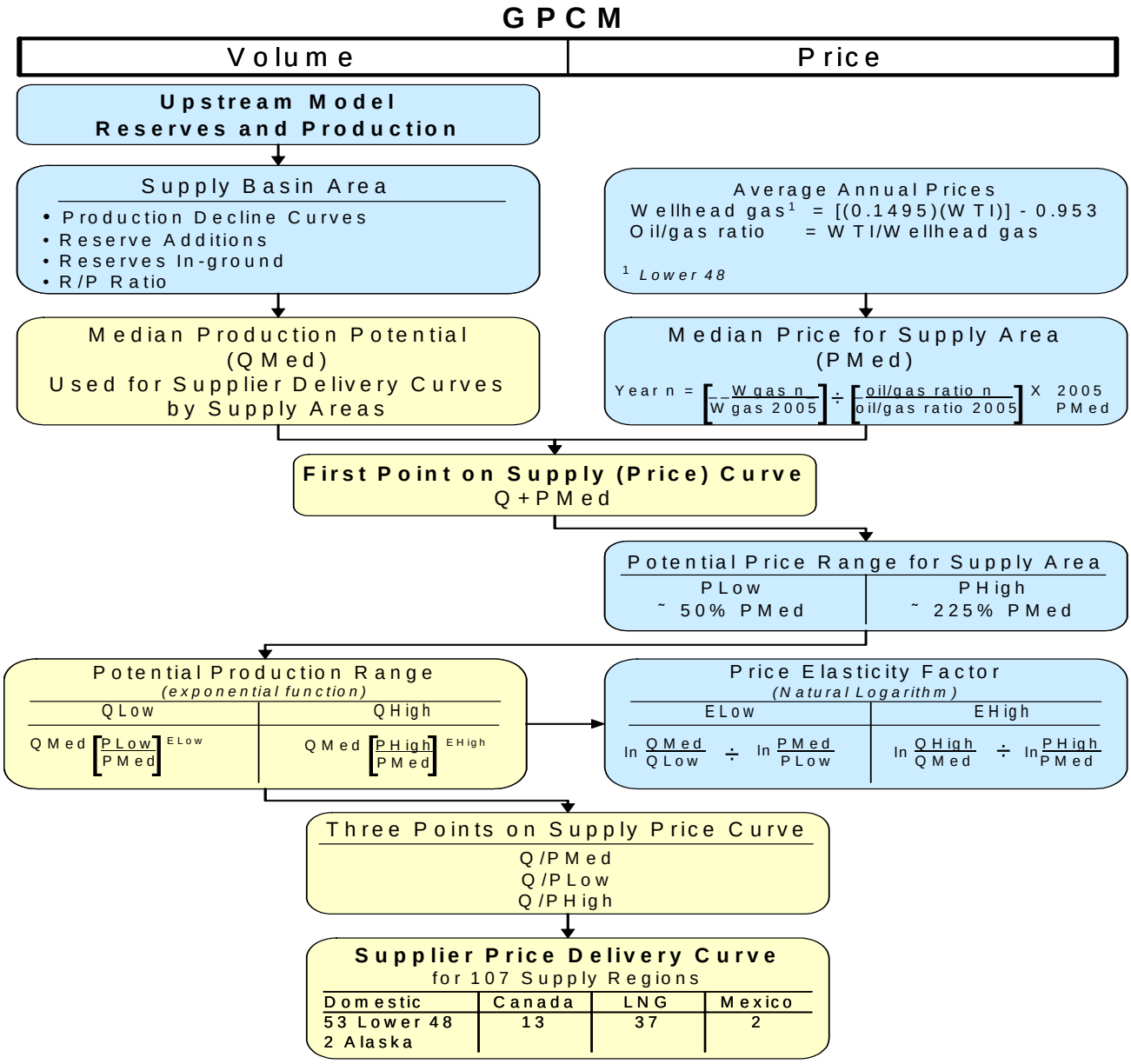
GPCM contains powerful and flexible tabular and graphical output capabilities. In addition the entire solution can be exported to an Excel spreadsheet for further analysis and reporting.

Following is a list of the pre-packaged screen and hardcopy reports available in GPCM®:

1) Results Summary / Detail
2) Pipeline Usage Summary
3) Supplier Deliveries Detail / Summary
4) Customer Receipts Detail / Summary
5) Supplier Revenue Report
6) Customer Cost Report
7) Transport Results Detail
8) Transport Zone Prices
9) Transport Zone Basis
10) Interconnect Basis
11) Transport Revenue
12) Storage Revenue
13) Transport Zone Utilization
14) Transport Link Utilization
15) Storage Utilization
16) Storage Balance

Figure H-6 summarizes the total flow of information, including volumes and prices, within the GPCM model.

Figure H-6
GPCM Flow Chart



SOURCE: RBAC, Inc.

Report 9 allows the user to find the basis (market price spread) between any two pipeline zones identified in the model in any period of the scenario. The report has a graphical capability which allows the user to produce a time series plot of the basis forecast over the forecast horizon of the case.

The Results Summary Report is an aggregate report of the gas and dollar flows among the various sectors of the gas industry. It shows the forecast aggregate average supply price, average unit return to the marketing sector, average transportation and storage cost per unit delivered, and average cost to customers represented in the model. There is also a graphical routine which allows the user to produce histograms comparing any of the elements of the case summary report for various cases.

Finally, GPCM® has a general purpose graphing capability the analyst can use to plot time series of inputs and / or outputs either one at a time or overlayed against each other. For example, the analyst could plot the time series of market clearing prices in two different regions in the same scenario or in multiple scenarios in order to get a visual perspective on their relative values. All of these on-screen reports can also be sent to the printer for hardcopy output.

Integration of GPCM Pricing Points into the MARKETSYM Data Model

This document outlines the general process that Global Energy Advisors use in integrating gas price results from the Gas Pipeline Competition Model (GPCM) into the MARKETSYM data model for use in electricity production cost forecasting.

Liquid Market Centers from GPCM

Global Energy Advisors' gas team creates a gas price forecast at 185 market pricing points across North America using the Gas Pipeline Competition Model (GPCM). Table H-1 lists the 185 market pricing points that are available from GPCM.

Table H-1

GPCM Liquid Market Centers

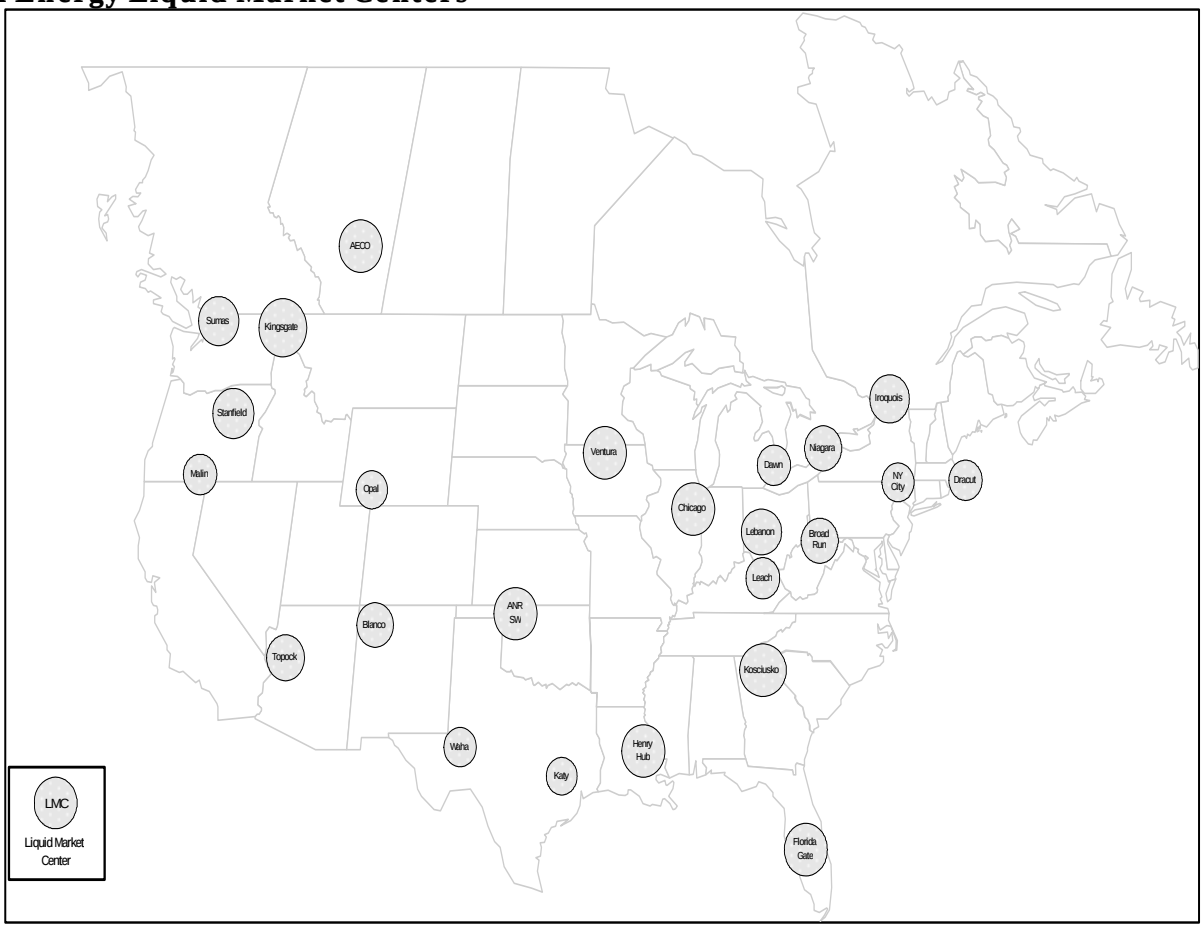
Number	GPCM Liquid Market Center	Number	GPCM Liquid Market Center	Number	GPCM Liquid Market Center	Number	GPCM Liquid Market Center
1	AECO-C Hub	47	EP Continental Connector Terminus	93	NATIONAL FUEL GAS	139	Stanfield, OR
2	AGUA DULCE HUB	48	Erath, LA	94	Needles, CA	140	SUMAS
3	Alberta Hub	49	FGT Z1	95	NGPL (LA.)	141	TENN Z6
4	Alberta Market Centre	50	FGT Z2	96	NGPL (MIDCONT.)	142	TENNESSEE (STX)
5	ALGONQUIN	51	FGT Z3	97	NGPL (PERMIAN)	143	TENNESSEE 800 LEG
6	ALGONQUIN CITYGATES	52	FGT, MOBILE BAY	98	NGPL (STX)	144	TENNESSEE ZONE 5
7	ALLIANCE (INTO INTERSTATES)	53	FLORIDA GAS	99	NGPL AMARILLO RECEIPT	145	TENNESSEE ZONE 6
8	ANR - OK	54	FLORIDA GATES VIA FGT	100	NGPL IOWA-ILL. RECEIPT	146	TENNESSEE ZONES 4-5 FT
9	ANR - SOUTH LA	55	Garden City	101	NGPL TEXOK (EAST)	147	TENNESSEE, 100 LEG
10	ANR ML7 (ENTIRE ZONE)	56	GULF SOUTH (ZONE 1)	102	NGPL TEXOK (WEST)	148	TENNESSEE, 500 LEG
11	Blanco, NM	57	GULF SOUTH (ZONES 1 & 2)	103	NIAGARA (NFG, TENN)	149	TEX INTRAS, WAHA AREA
12	Broad Run/Cornwell, WV	58	GULF SOUTH (ZONES 2 & 4)	104	Niagara, NY	150	TEXAS E. (ELA)
13	Brooklyn Union New York Hub	59	GULF SOUTH MOBILE BAY	105	NORTHERN (DEMARC)	151	TEXAS E. (WLA)
14	Buffalo Wallow	60	Harper, IA	106	NORTHERN (MID 10)	152	TEXAS E., M-1 (KOSI)
15	CAL BORDER KERN RIVER STATION	61	Haven, KS	107	NORTHERN (MID 11)	153	TEXAS E., M-3
16	CAL BORDER PG&E SMALL PKGS	62	Henry Hub	108	NORTHERN (MID 13)	154	TEXAS EASTERN (ETX)
17	CAL BORDER SOCAL SMALL PKGS	63	Holmesville, MS	109	NORTHERN (MIDS 1-6)	155	TEXAS EASTERN (STX)
18	Canada AECO - HH	64	Houston Hub	110	NORTHERN (VENTURA)	156	TEXAS GAS (ENTIRE Z 1)
19	CARTHAGE HUB TAILGATE	65	Houston Ship Channel	111	NORTHERN NATURAL TBS	157	TEXAS GAS SL
20	CHEYENNE	66	HPL	112	NORTHWEST (ALL GATES)	158	Thoreau
21	CHEYENNE HUB	67	IROQUOIS	113	NORTHWEST DOMESTIC	159	Topock, AZ
22	Chicago Hub	68	IROQUOIS , ZONE 2	114	NORTHWEST STANFIELD	160	Transco St 30
23	CHICAGO TO SMALL END-USERS	69	KATY HUB TAILGATE	115	NOVA (AECO-C, NIT)	161	Transco St 45
24	CHICAGO-LDCS, LARGE E-USERS	70	Katy/Teco Header	116	NW SOUTH OF GREEN RIVER	162	Transco St 65
25	CIG - N. SYSTEM	71	KERN RIVER	117	NW STANFIELD	163	TRANSCO Z5
26	Clarington	72	Kern River Station	118	NW WYOMING POOL	164	TRANSCO Z6 (NON-NY)
27	COLORADO CITYGATES	73	KERN RIVER/OPAL PLANT	119	OGT	165	TRANSCO Z6 (NY)
28	COLUMBIA	74	Kingsgate	120	ONEOK	166	TRANSCO, ST 85
29	COLUMBIA GAS (DELIVERED)	75	Kiowa Hub	121	Opal, WY	167	TRANSCO, ZONE 5
30	COLUMBIA, APP	76	Kosciusko, MS	122	PEPL - OK	168	TRANSCO-Z4
31	COLUMBIA, MAINLINE	77	Leach, KY	123	Permian Pool	169	TRANSOK
32	CrossAlta Market Center	78	Lebanon, OH	124	Perryville Hub	170	TRANSWESTERN - NTX
33	Daggett	79	Leidy Hub	125	PG&E CITYGATE	171	TRANSWESTERN - WTX
34	DAWN, ONT.	80	LONE STAR	126	PG&E LARGE PACKAGES	172	TRUNKLINE ELA
35	DJ BASIN	81	Malin	127	PG&E-GTNW (KINGSGATE)	173	TRUNKLINE SOUTH
36	DJ BASIN (INTO CIG)	82	Maumee Hub	128	PG&E-GTT (VALERO)	174	TRUNKLINE WLA
37	DOMINION (DELIVERED)	83	MICHCON TO SMALL END-USERS	129	Pittsburgh Terminal	175	TW (IGNACIO, PTS SOUTH)
38	DOMINION NORTH POINT	84	MICHIGAN CONS TO SMALL END-USERS	130	PSCo Citygates	176	TW SJ (BLANCO)
39	DOMINION SOUTH POINT	85	MICHIGAN-CONS ENERGY	131	QUESTAR	177	TW-PERMIAN
40	DRACUT (INTO TENNESSEE)	86	MICHIGAN-CONS POWER	132	Rayne, LA	178	Ventura, IA
41	Egan	87	MICHIGAN-MICH CON.	133	RELIANT (NORTH/SOUTH)	179	VIKING (EMERSON)
42	EL PASO BONDAD	88	MidContinent Market Center	134	RELIANT (WEST)	180	Waha / Teco Header
43	EL PASO NON-BONDAD	89	Moss Bluff	135	SOCAL EHRENBERG	181	Waha Permian Basin Hub
44	EL PASO PERMIAN	90	MRT MAINLINE	136	SOCAL GAS LARGE PKGS	182	WESTCOAST ST. 2
45	Ellisburg Hub	91	MRT WEST LEG	137	SONAT	183	Wharton Hub
46	Empress, AB	92	Muddy Creek, WY	138	SONAT Z2R	184	Wheeler Ridge, CA
						185	WILLIAMS

SOURCE: Global Energy Decisions, Inc.

Generally, Global Energy utilizes 24 of the 185 GPCM created market pricing points in the North American MARKETSYM data model. Figure H-7 illustrates the 24 liquid market centers from GPCM utilized in Global Energy's MARKETSYM NERC data model:

Figure H-7

Global Energy Liquid Market Centers



SOURCE: Global Energy Decisions, Inc.

Table H-2 reports the liquid market centers used in the MARKETSYM NERC data model and the corresponding GPCM market pricing point:

Table H-2

MARKETSYM LMC and Corresponding GPCM Market Pricing Point

	MARKETSYM LMC	GPCM MARKET POINT
1	AECO	AECO-C Hub
2	ANR SW	ANR - OK
3	Blanco	Blanco, NM
4	Broad Run	Broad Run/Cornwell, WV
5	Chicago	Chicago Hub
6	Dawn	DAWN, ONT.
7	Dracut	DRACUT (INTO TENNESSEE)
8	Florida Gate	FLORIDA GAS
9	Henry Hub	Henry Hub
10	Iroquois	IROQUOIS
11	Katy	KATY HUB TAILGATE
12	Kingsgate	Kingsgate
13	Kosciusko	Kosciusko, MS
14	Leach	Leach, KY
15	Lebanon	Lebanon, OH
16	Malin	Malin
17	Niagara	Niagara, NY
18	NY City	TRANSCO Z6 (NY)
19	Opal	Opal, WY
20	Stanfield	Stanfield, OR
21	Sumas	SUMAS
22	Topock	Topock, AZ
23	Ventura	Ventura, IA
24	Waha	Waha Permian Basin Hub

SOURCE: Global Energy Decisions, Inc.

Applying Liquid Market Center Prices to the MARKETSYM Data Model

Global Energy applies the GPCM LMC price forecasts to the MARKETSYM data model in two steps. First, the Henry Hub price is applied to the Fuel Basin table in the Base Data Editing form. Second, Global Energy calculates basis differentials from the Henry Hub price to each of the other 23 liquid market centers across North America. The calculated basis differentials at each liquid market center are input into the Named Annual Pattern table in the MARKETSYM Base Data Editing Form, which are linked to individual generator-used fuels. This two-step process creates the liquid market center pricing locations that are used in the MARKETSYM NERC data model. The next step is to create burner-tip prices that power generators will use in the production cost model.

Deriving Burner-Tip Gas Prices from Liquid Market Centers

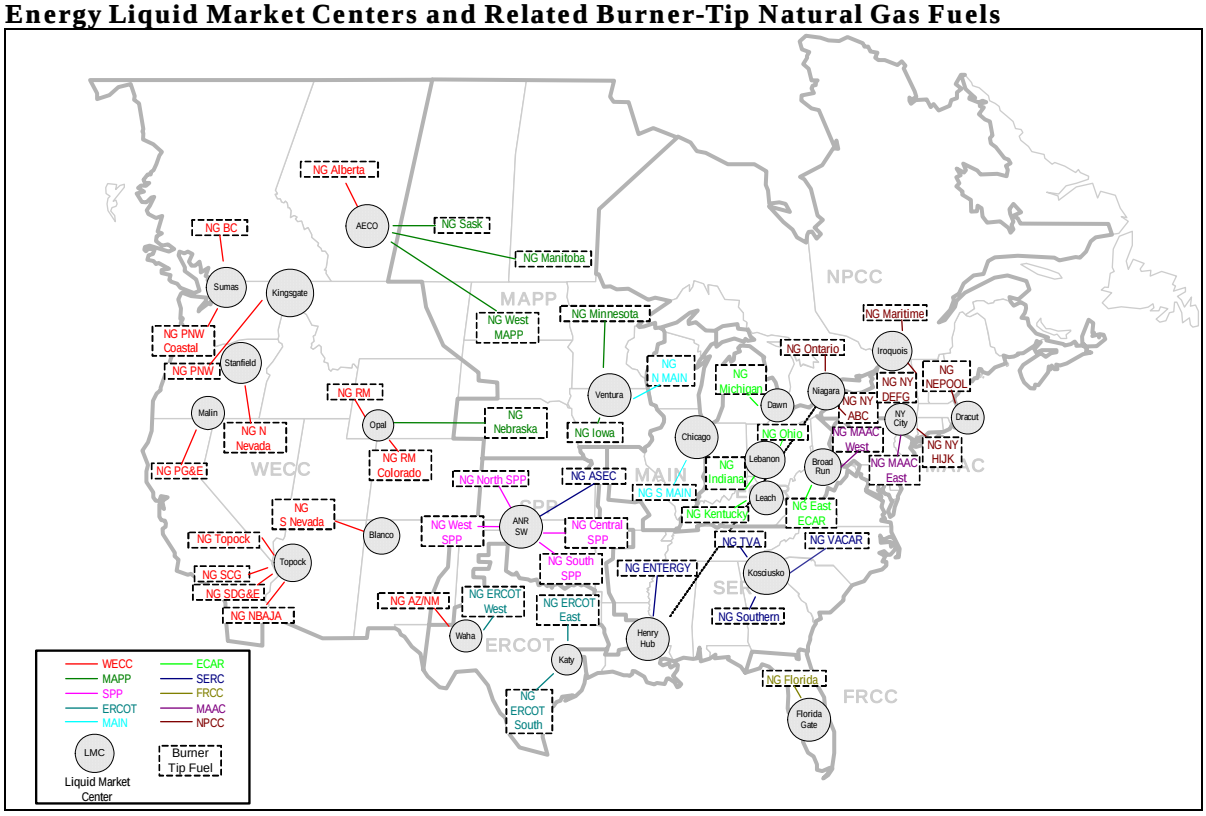
In Global Energy's MARKETSYM NERC data model, gas-fired generators are assigned to natural gas fuels that are modeled to capture burner-tip prices based on generator location. Global Energy has identified 48 burner-tip pricing points across North America subsequent to the 24 liquid market centers identified previously.

Each of the burner-tip natural gas fuels is assigned to the Henry Hub basin price, plus the corresponding liquid market center basis differential, plus a transportation adder that captures local distribution charges from the liquid market center to the power plant. Global Energy has estimated local distribution charges from the liquid market centers to each of the 48 natural gas fuels based on utility filings and other publicly available information. Some burner-tip natural gas fuels may not have an LDC since some plants do not incur these charges due to their proximity to the long-haul pipeline.

Figure H-8 illustrates the relationship between the liquid market centers discussed above and the burner-tip gas fuels. Liquid market centers are identified in the circles and burner-tip natural gas fuels are identified in the dotted squares.

Figure H-8

Global Energy Liquid Market Centers and Related Burner-Tip Natural Gas Fuels



SOURCE: Global Energy Decisions, Inc.

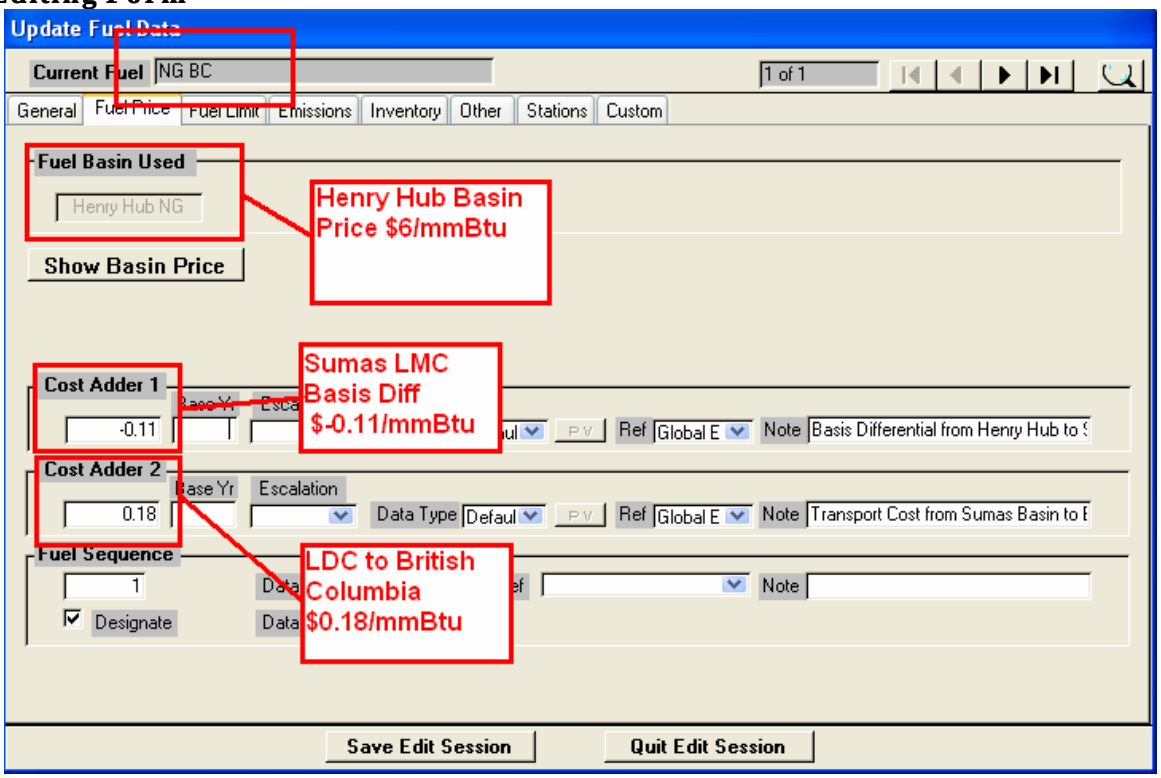
Applying the Henry Hub price, LMC Basis Differential, and Transportation Cost to a Fuel

Mechanically, Global Energy converts the 24 liquid market centers to the 48 burner-tip natural gas fuels through the MARKETSYM Base Data Editing form. For some liquid market centers, Global Energy has created two or more burner-tip natural gas fuel prices which reflect different pricing in surrounding locations due to differences in local distribution charges.

For example, as can be seen in the map in Figure H-8, from the Sumas liquid market center we have created the NG PNW Coastal and the NG BC (Natural Gas-British Columbia) burner-tip natural gas fuels. A gas-fired generator located in British Columbia is assigned to the NG BC fuel group while a generator in the coastal areas of the Washington is assigned to the NG PNW Coastal fuel group. Both fuels are assigned to the Henry Hub Basin price with the Sumas LMC basis differential; however, each fuel has a different estimated LDC assigned. The following screenshot in Figure H-9 illustrates the NG BC fuel and how it is linked to each of the three pricing aspects.

Figure H-9

NG BC – Hub Price, LMC Basis Differential, and LDC - MARKETSYM Basic Data Editing Form



SOURCE: Global Energy Decisions, Inc.

Following our example of NG BC and NG PNW Coastal, to obtain the NG BC burner-tip price for the month of January 2008, we would add the Henry Hub gas price ($6.00/mmBtu), plus the Sumas LMC Basis Differential ($-0.11/mmBtu), plus the LDC adder ($0.18/mmBtu) to get to BC. The burner-tip price for NG BC in January 2008 is therefore $6.07/mmBtu.

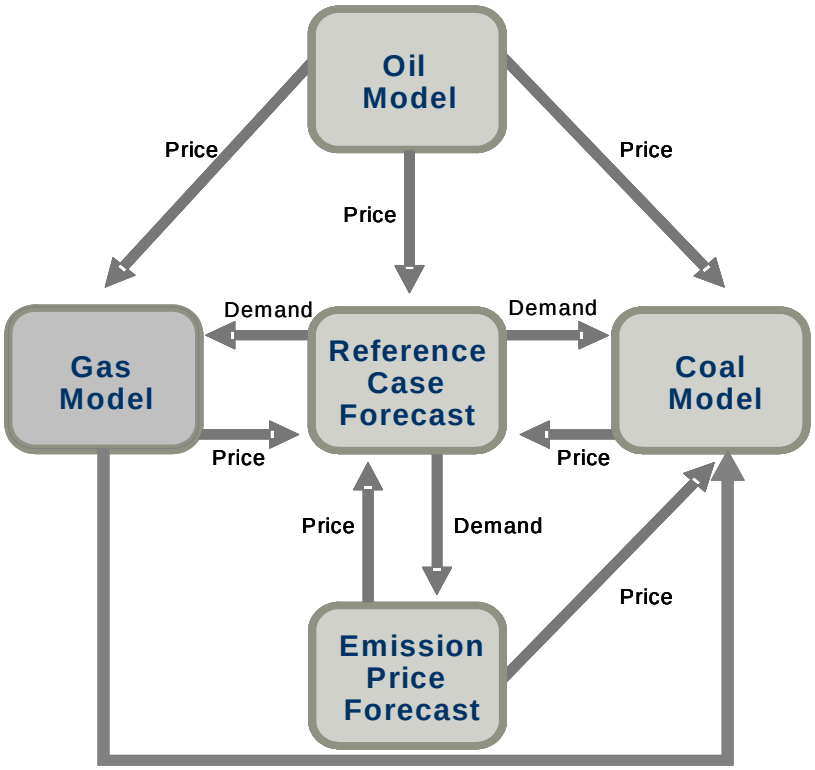
To obtain the NG PNW Coastal Price, we would add the Henry Hub price ($6.00/mmBtu), plus the Sumas LMC Basis Differential ($-0.11/mmBtu), plus the LDC adder ($0.25/mmBtu) to get to the coastal areas of Washington. The burner-tip price for NG PNW Coastal in January 2008 is therefore $6.14/mmBtu, $0.07/mmBtu higher than the price in BC.

In conclusion, Figure H-1- shows that combining the GPCM model with Global Energy's North American MARKETSYM data model, fundamentally based world oil, coal and emission models,

and Global's multidisciplinary energy expertise, provides a bottom up fundamental forecast of supply, demand, and market price trends.

Figure H-10

Generalized Equilibrium Solution Example



SOURCE: Global Energy Decisions, Inc.

APPENDIX H-2 – COMPARISON OF NATURAL GAS FORECASTS AND THEIR METHODOLOGIES – U.S. ENERGY INFORMATION ADMINISTRATION AND GLOBAL ENERGY DECISIONS – AND DEVELOPMENT OF THE BASE FORECAST FOR THE IEPR SCENARIOS[1]

Objective of Work

The objective of this report is to provide the Energy Commission staff and the IEPR Electricity Scenario Project group with a comparison of both prices and methodology between the publicly available EIA AEO Reference Case Forecast and the proprietary Global Energy Decisions Annual Gas Reference Case forecast in its revised Natural Gas Market Advisory Service 2006.

Natural Gas Forecasts

Table H-1 shows a comparison of five upstream natural gas forecasts (all in 2006$/MMBtu):

- EIA AEO 2007 Average Lower 48 U.S. Wellhead
- EIA AEO 2007 Henry Hub
- EIA AEO 2006 Average Lower 48 U.S. Wellhead[2]
- Global Energy 2006 (Revised) Henry Hub[3]
- Global Energy 2006 Henry Hub

1 Information in this Appendix is based on work performed in December 2006 and January 2007 and was written in that time period. This work developed the Base natural gas forecast for the IEPR scenarios, termed here the "Global Energy Using EIA WTI Proxy"

2 No EIA AEO 2006 Henry Hub price was forecast

3 Global Energy does not forecast an Average Lower 48 U.S. Wellhead price

Table H- 1
Natural Gas Price Projections

	A	B	C	D	E
	EIA AEO 2007 Early Release Avg U.S. Lower 48 Wellhead Nat. Gas GED Modified[(a)]	EIA AEO 2007 Early Release Henry Hub GED Modified[(a)]	EIA AEO 2006 Avg. U.S. Lower 48 Wellhead Nat. Gas GED Modified[(b)]	Global Energy 2006 (Revised) Henry Hub	Global Energy 2006 Henry Hub
	2006$/MMBtu	2006$/MMBtu	2006$/MMBtu	2006$/MMBtu	2006$/MMBtu
2007	6.65	7.45	6.23	7.22	9.08
2008	6.60	7.39	5.86	7.79	8.39
2009	6.06	6.80	5.43	7.17	7.22
2010	**5.76**	**6.47**	**5.10**	**5.61**	**5.32**
2011	5.33	6.00	4.85	4.62	4.59
2012	5.17	5.83	4.79	4.52	4.53
2013	5.02	5.65	4.87	4.69	4.93
2014	5.05	5.69	4.78	5.19	5.22
2015	**4.99**	**5.62**	**4.59**	**5.04**	**5.21**
2016	5.09	5.73	4.53	4.66	4.58
2017	5.29	5.95	4.60	4.84	4.81
2018	5.20	5.86	4.78	4.97	4.94
2019	5.14	5.79	4.92	5.24	5.11
2020	**5.23**	**5.89**	**4.97**	**5.59**	**4.85**

(a) Converted from 2005$ to 2006$
(b) Converted from 2004$ to 2006$ and from $/Mcf to $/MMBtu.

The 2006 price forecasts (Global Energy Henry Hub in column C and EIA AEO Average Lower 48 U.S. Wellhead in column E) are numerically very similar (recognizing that one is a Henry Hub forecast and the other an average wellhead forecast). In the initial four years of the forecast (2007-2010), Global Energy's incorporation of NYMEX futures prices creates a discrepancy with EIA, which does not make use of futures prices in its early years.

Subsequent to the influence of NYMEX prices, for 2011 through 2020, the two forecasts are within $0.50/MMBtu of each other, with Global Energy's being mainly higher (as would be expected for a Henry Hub price, as distinguished from an average U.S. wellhead price).

Prior to December, 2006, EIA performed a substantial revision of its annual forecast and in mid-December issued the early release of its AEO 2007 price forecasts (including Henry Hub and Average Lower 48 U.S. Wellhead in columns B and A, respectively). Global Energy has not performed a similar annual update to produce its 2007 Reference Case. Instead it made several minor revisions to its 2006 forecast. (The revised Global Energy forecast, column D, largely duplicates its 2006 Reference Case forecast. The revision consisted of adjusting demand data and updating the NYMEX futures forecast.

The only significant differences occur during 2007-2008 when different NYMEX futures are incorporated and in 2020 due to different gas demand assumptions).

In comparing EIA AEO 2007 Henry Hub to Global Energy 2006 (Revised) Henry Hub, for the 2009-2020 forecast period Global Energy's forecast is lower than the EIA 2007 price by $0.30-$1.00 per MMBtu (average of $0.75/MMBtu lower). The two forecasts start to converge by 2020 as Global Energy's gas demand for power generation steadily increases.

Table H-2 compares the gas price forecasts of Global Energy (2006 Revised) and EIA AEO 2006 for gas delivered to electricity generators in the Western U.S. Direct comparison is particularly difficult in the case of these regional prices because Global Energy's prices include a transportation adder into a specific gas utility, while EIA's prices are average delivered prices to an entire census region.

Geographically, Global Energy's 2006 (Revised) forecast area of WECC is roughly equivalent to EIA's Pacific and Mountain census regions for the EIA 2006 AEO.[4] This report compared EIA's Pacific region (column C) with the not-exactly comparable Global Energy Northern California (into PG&E) (column D) and Southern California (into SCE) (column E). The results showed Global Energy's forecasts for California are generally less than EIA's 2006 forecast for the Pacific region by $0.25 to $1.60 per MMBtu (averaging $0.80 less for Northern California, and $0.90 for Southern California).

For Global Energy's Rocky Mountain region (column B) and EIA's Mountain Census division (column A), Global Energy's gas prices delivered to electricity generators were generally less than EIA's by $0.30 to $1.40 per MMBtu (average of $0.70).

[4] Pacific Census Region of EIA: California, Oregon, and Washington, Alaska, Hawaii; Mountain Census Region of EIA: Montana, Idaho, Wyoming, Nevada, Utah, Colorado, Arizona, and Utah

Table H- 2
Gas Price Forecasts for Gas Delivered to Western U.S.
Electricity Generators
EIA AEO 2006 versus Global Energy 2006 (Revised)

	A	B	C	D	E
	EIA AEO 2006 Mountain Census Division GED Modified (1)	Global Energy 2006 (Revised) Rocky Mountain	EIA AEO 2006 Pacific Census Division GED Modified (1)	Global Energy 2006 (Revised) Northern CA (PG&E)	Global Energy 2006 (Revised) Southern CA (SCE)
	2006$/MMBtu	2006$/MMBtu	2006$/MMBtu	2006$/MMBtu	2006$/MMBtu
2007	7.35	6.62	7.74	7.07	6.96
2008	7.03	7.25	7.50	7.68	7.51
2009	6.45	6.70	6.88	7.22	7.10
2010	**6.07**	**5.18**	**6.52**	**5.62**	**5.54**
2011	5.91	4.62	6.35	5.03	4.89
2012	5.92	4.51	6.39	4.91	4.80
2013	6.02	4.69	6.51	5.11	5.02
2014	5.99	5.16	6.47	5.62	5.50
2015	**5.48**	**4.97**	**6.02**	**5.42**	**5.34**
2016	5.16	4.54	5.92	4.93	4.91
2017	5.24	4.70	5.90	5.11	5.10
2018	5.39	4.81	6.02	5.22	5.23
2019	5.67	5.06	6.23	5.50	5.50

(1) Converted from 2004$ to 2006$ and from $/Mcf to $/MMBtu.

Table H-3 shows Global Energy's delivered gas price forecast to electric generators by price component. Henry Hub and basis differentials are added to generate regional gas market prices, the latter plus a transport adder equal the projected delivered price. For the first four years of the forecast, NYMEX Henry Hub and NYMEX basis swap prices are incorporated. In 2011, basis differentials lessen when the forecast no longer has a NYMEX-based component and is a total supply-demand fundamentals forecast. Generally, the listed western U.S. gas market hubs (Opal, Malin, Topock) remain below Henry Hub in the price projections. California prices reflect the modeled addition of two California LNG plants between 2010 and 2015.

Table H- 3
Gas Price Forecasts for Gas Delivered to Western U.S. Electricity Generators By Price Component(1)
Global Energy 2006 (Revised) (2006$/MMBtu)

		Basis Differential			Regional Gas Market Prices			Transport Adder			Burner Tip Price		
Year	Henry Hub	Opal (2)	Malin (3)	Topock (4)	Opal (2)	Malin (3)	Topock (4)	Rocky Mountain	Northern CA (PG&E)	Southern CA (SCE)	Rocky Mountain	Northern CA (PG&E)	Southern CA (SCE)
2007	7.22	(0.74)	(0.55)	(0.55)	6.47	6.67	6.66	0.15	0.40	0.30	6.62	7.07	6.96
2008	7.79	0.69)	(0.51)	(0.58)	7.10	7.28	7.21	0.15	0.40	0.30	7.25	7.68	7.51
2009	7.17	(0.62)	(0.35)	(0.37)	6.55	6.82	6.80	0.15	0.40	0.30	6.70	7.22	7.10
2010	**5.61**	**(0.58)**	**(0.38)**	**(0.37)**	**5.03**	**5.22**	**5.24**	**0.15**	**0.40**	**0.30**	**5.18**	**5.62**	**5.54**
2011	4.62	(0.15)	0.01	(0.03)	4.47	4.63	4.59	0.15	0.40	0.30	4.62	5.03	4.89
2012	4.52	(0.16)	(0.00)	(0.02)	4.36	4.51	4.50	0.15	0.40	0.30	4.51	4.91	4.80
2013	4.69	(0.15)	0.02	0.02	4.54	4.71	4.72	0.15	0.40	0.30	4.69	5.11	5.02
2014	5.19	(0.18)	0.03	0.01	5.01	5.22	5.20	0.15	0.40	0.30	5.16	5.62	5.50
2015	**5.04**	**0.21)**	**(0.02)**	**0.00**	**4.82**	**5.02**	**5.04**	**0.15**	**0.40**	**0.30**	**4.97**	**5.42**	**5.34**
2016	4.66	(0.27)	(0.13)	(0.05)	4.39	4.53	4.61	0.15	0.40	0.30	4.54	4.93	4.91
2017	4.84	(0.29)	(0.13)	(0.04)	4.55	4.71	4.80	0.15	0.40	0.30	4.70	5.11	5.10
2018	4.97	(0.30)	(0.14)	(0.03)	4.66	4.82	4.93	0.15	0.40	0.30	4.81	5.22	5.23
2019	5.24	(0.33)	(0.14)	(0.04)	4.91	5.10	5.20	0.15	0.40	0.30	5.06	5.50	5.50
2020	**5.59**	**(0.34)**	**(0.14)**	**(0.04)**	**5.25**	**5.45**	**5.55**	**0.15**	**0.40**	**0.30**	**5.40**	**5.85**	**5.85**

2007-2010 Based on NYMEX Forecast (average of three days of settlement prices – December 19, 20, 21 of 2006) for 2007 and 2008
NYMEX forecast integrated with GPCM forecast (supply demand fundamentals) for 2009 and 2010 (see Table 2-1 of this report)
2011-2020 Total GPCM Forecast (supply demand fundamentals)

(1) Components include Henry Hub plus basis differential to calculate regional market prices, and then regional market prices plus transport adder to calculate delivered gas price to electric generators
(2) Regional gas market hub in southwestern Wyoming
(3) Regional gas market hub at northern California border with Oregon
(4) Regional gas market hub at southern California border with Arizona

Crude Oil Forecasts

Both EIA and Global Energy use their respective crude oil forecasts as important inputs to their gas models. **Table H-4** shows the crude oil forecasts for EIA (AEO 2006 and AEO 2007 Early Release) and for Global Energy (Revised 2006 forecast), noting that Global Energy forecasts a West Texas Intermediate (WTI) crude oil price, and EIA began forecasting a WTI Proxy referred to as "Imported Low-Sulfur Light Crude Oil" in its AEO 2006.

Table H- 4
"WTI" Crude Oil Price Projections of EIA AEO 2006, AEO 2007 Early Release and Global Energy 2006 (Revised)

	A	B	C
	EIA AEO 2007 Early Release WTI-Proxy(1) GED Modified(2)	EIA AEO 2006 WTI-Proxy(1) GED Modified(3)	Global Energy 2006 (Revised) WTI
	2006$/Bbl	2006$/Bbl	2006$/Bbl
2007	68.75	58.16	65.12
2008	66.06	54.69	63.56
2009	62.77	52.43	57.53
2010	**59.23**	**49.45**	**51.16**
2011	56.00	49.51	47.67
2012	53.30	49.82	44.26
2013	51.52	49.54	42.00
2014	51.16	49.04	42.14
2015	**51.40**	**49.97**	**42.25**
2016	51.27	50.40	42.25
2017	52.35	50.51	42.25
2018	52.85	51.49	42.36
2019	53.54	50.58	42.70
2020	**53.64**	**53.01**	**44.20**

(1) EIA WTI-Proxy is its Imported Low-Sulfur Light Crude Oil price projection
(2) Converted from 2005$ to 2006$
(3) Converted from 2004$ to 2006$

Global Energy's 2006 (Revised) WTI forecast (column C) is considerably higher than EIA's AEO 2006 oil forecast (column B) in the early years (2007-2010) because of Global Energy's use of NYMEX futures prices in the early part of the forecast. It is lower than EIA's by $6 to $9 per barrel in the later years (2011 to 2020).

EIA increased its WTI Proxy crude oil forecast in its AEO 2007 Early Release. EIA's AEO 2007 Early Release WTI proxy price is approximately $10 to $3.50 per barrel higher than its AEO 2006 forecast from 2009 to 2012. After 2012, the increase is slight, by $1.0-$2.0 per barrel in most years.

Global Energy has not yet performed the revision of its crude oil forecast for its 2007 Reference Case gas forecast. Global Energy's 2006 (Revised) WTI price forecast is generally lower than EIA's AEO 2007 Early Release forecast by $8 to $11 per barrel (during 2010 to 2020), equivalent to $1.40 to $1.90 per MMBtu.

Oil/Gas Price Ratios

In both Global Energy's and EIA's methodologies, gas prices and oil prices are related through the use of oil:gas price ratios as factors in the modeling. Higher ratios imply a higher relative value for oil in the energy marketplace, and lower ratios, the converse. In comparing Global Energy 2006 (Revised) and EIA AEO 2007 Early Release forecasts, Global Energy's lower Henry Hub gas price and WTI crude oil price are also reflected in generally lower oil/gas price ratios over the same period (see **Table H-5**).

Table H- 5
Crude Oil to Natural Gas Price Ratio Projections
EIA and Global Energy

	EIA AEO 2007 (Early Release) WTI Proxy ***Divided by:*** Henry Hub	EIA AEO 2006 Average U.S. Lower 48 Wellhead Crude Oil ***Divided by***: Average U.S. Lower 48 Wellhead Nat. Gas	Global Energy 2006 (Revised) WTI ***Divided by:*** Henry Hub
	MMBtu/Bbl	MMBtu/Bbl	MMBtu/Bbl
2007	9.23	7.87	9.02
2008	8.94	8.17	8.16
2009	9.23	8.47	8.02
2010	**9.15**	**8.91**	**9.12**
2011	9.33	9.46	10.32
2012	9.14	9.65	9.79
2013	9.11	9.39	8.96
2014	8.99	9.61	8.12
2015	**9.14**	**10.25**	**8.38**
2016	8.94	10.41	9.07
2017	8.79	10.41	8.73
2018	9.02	10.18	8.52
2019	9.24	9.93	8.15
2020	**9.11**	**9.99**	**7.91**

Supply and Demand Projections

Table H-6 compares gas supply and demand projections for EIA AEO 2006, EIA AEO 2007 Early Release and Global Energy 2006 (Revised).

Table H- 6
Gas Supply and Demand Comparisons
EIA and Global Energy

(TCF)	EIA AEO 2006			EIA AEO 2007 Early Release			Global Energy 2006 (Revised)		
	2010	2015	2020	2010	2015	2020	2010	2015	2020
Supply									
U.S. Production [1]	18.58	20.36	21.44	19.35	19.60	20.80	16.88	17.71	19.41
U.S. Net Imports via Pipeline[1]	2.28	2.05	1.32	2.74	2.63	1.65	3.01	2.84	1.82
U.S. Net LNG imports	2.07	3.05	3.70	1.81	2.99	3.69	3.81	5.09	6.89
Total	22.93	25.46	26.46	23.90	25.22	26.14	23.70	25.64	28.12
Demand	23.35	25.91	26.92	24.02	25.32	26.26	23.63	25.77	28.13
Discrepancy[2]	-0.42	-0.45	-0.46	-0.12	-0.10	-0.12	0.07	-0.13	-0.01
Discrepancy (% of Total Supply)[3]	1.83%	1.77%	1.74%	0.50%	0.40%	0.46%	0.30%	0.51%	0.04%

(1) EIA: Production consists of Lower 48 plus Alaska production (North Slope and non-North Slope) – No Alaska gas in imports category.
Global Energy: Production consists of Lower 48 only (Alaska production to U.S. markets included in imports category)
(2) Total Supply less Demand
(3) Discrepancy divided by Total Supply (absolute value)

Why the Gas Forecasts are Different

The fundamental reason the Global Energy Revised (2006) Henry Hub forecast is lower by an average of $0.75/MMBtu than the EIA AEO 2007 Early Release Henry Hub forecast is the difference in their respective crude oil price forecasts. Global Energy's Revised (2006) WTI forecast averages $9/bbl below the EIA AEO 2007 Early Release forecast, which equates to $1.55/MMBtu. (The impact on the gas price forecast is not 100%, i.e. not as high as $1.55/MMbtu, because of the different oil/gas ratios in the two forecasts and differences in the equations using oil/gas ratios in the two models.) Secondary reasons for gas price forecast differences include:

- Differences in the quantity and timing of indigenous North American pipeline gas. EIA projects higher volumes of indigenous North American gas.
- Differences in the volumes of imported LNG and how the two models structure its pricing
- Different "profitability" metrics used in the full-cycle cost recovery for incremental indigenous gas
- Different "price bidding" methodologies to derive market clearing prices

Modification of Global Energy 2006 (Revised) Gas Price Forecast with EIA AEO 2007 Early Release WTI Proxy Oil Price Forecast

As a final step in the forecast comparisons, we replaced Global Energy's 2006 (Revised) WTI crude oil forecast in the Global Energy 2006 (Revised) model with EIA's AEO 2007 Early Release WTI Proxy Oil Price Forecast. The result was a Henry Hub forecast significantly more similar to the EIA AEO 2007 Early Release Henry Hub gas forecast. **Figure H-1** shows this result (as does **Table H-7**).

After discussion and review by Commission staff and consultants, this forecast was chosen as the Base Forecast for the IEPR Scenarios.

Figure H- 1
Henry Hub Natural Gas Price Projections
EIA AEO 2007 Early Release vs. Global Energy 2006

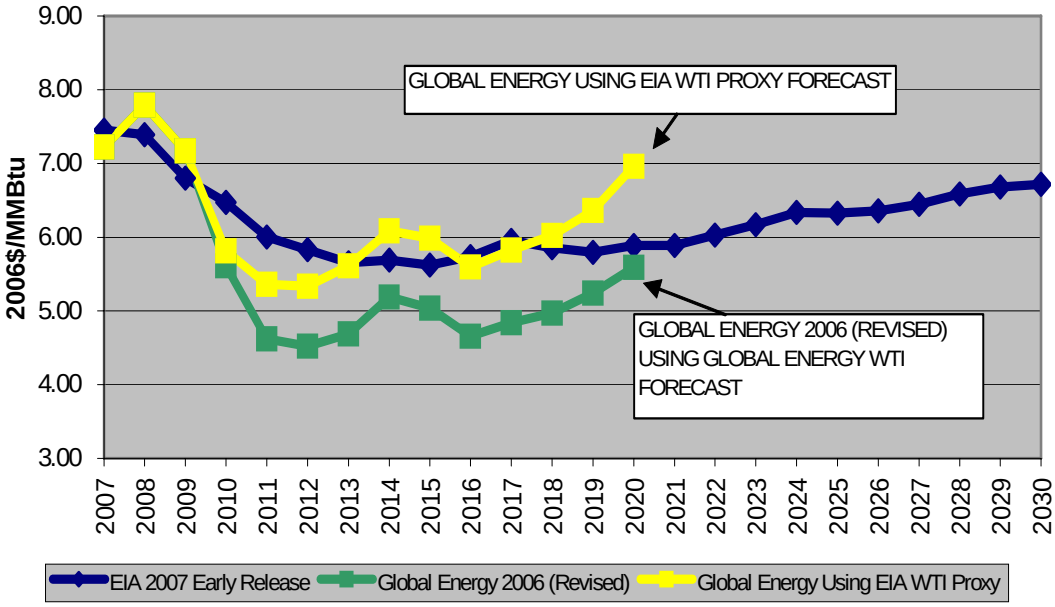


Table H- 7
Henry Hub Natural Gas Price Projections
EIA AEO 2007 Early Release vs. Global Energy 2006 (Revised) vs. Global Energy 2006 (Revised) with EIA AEO 2007 Early Release WTI Proxy

	EIA 2007 Early Release *GED Modified*(1)	Global Energy 2006 (Revised)	Global Energy Using EIA WTI Proxy
	2006$/MMBtu	2006$/MMBtu	2006$/MMBtu
2007	7.45	7.22	7.22
2008	7.39	7.79	7.79
2009	6.80	7.17	7.17
2010	**6.47**	**5.61**	**5.82**
2011	6.00	4.62	5.36
2012	5.83	4.52	5.34
2013	5.65	4.69	5.61
2014	5.69	5.19	6.09
2015	**5.62**	**5.04**	**5.99**
2016	5.73	4.66	5.60
2017	5.95	4.84	5.83
2018	5.86	4.97	6.02
2019	5.79	5.24	6.36
2020	**5.89**	**5.59**	**6.96**

(1) Converted from 2005$ to 2006$

APPENDIX H-3 – THE HIGH GAS FORECAST SCENARIO FOR SUSTAINED NATURAL GAS SCARCITY

Objective of Forecast

A natural gas High Forecast is required and appropriate for certain IEPR scenarios consistent with relatively high fuel prices caused by sustained natural gas scarcity.

The objective of this GPCM forecast was therefore to identify the high natural gas prices that would result from sustained scarcity of indigenous North American natural gas supply. Such an alternative scenario is important to consider because of the strong upward impact such natural gas prices would have on the cost of gas-fired electricity generation. Furthermore, fundamental market factors indeed exist that could make such a scenario possible, though currently not as likely as the Base Case.

Unless otherwise stated, all unit prices are in 2006 dollars.

Fundamental Market Characteristics

The following fundamental market characteristics could lead to a sustained scarcity of natural gas supply from various major North American sources:

- Indigenous USA production drops sharply, (declining to 13-17 Tcf/year by 2020, as compared to 19.2 Tcf in the Base Case).
- The ANS pipeline and the McKenzie Delta pipeline are not built during the forecast horizon of 2009-2020.
- With LNG providing the incremental supply, North America regasification facilities are utilized at a high regas capacity utilization percentage.
- Oil prices are very high ($75-$85) due to low global surplus production capacity and geopolitical factors.
- Oil:gas ratios are in the range of 7.5-8.5 to 1 (as compared to current and Base Case ratios of approximately 9:1), indicating an upward shift in the market valuation of natural gas, as compared to the value of crude oil. Such a shift will result if regulatory policies strongly favor natural gas fired generation over other fuels.

Results

Three iterations were run, with increasing rates of decline of U.S. indigenous production by 2020. An iterative process was used to identify accurately the scarcity point at which the resulting high prices would cut gas demand. The iterations and their declining U.S. production by 2020 are shown below.

Case	U.S. Indigenous Production Tcf in 2020
Base	19.3
Iteration #1	17.2
Iteration #2	15.0
Iteration #3	13.0

After reviewing the results, Global Energy and Commission analysts concluded that Iteration #3 provided a very good fit with the initial market parameters, for both the gas price and the oil/gas ratio, providing a maximum sustainable gas price range of approximately $9.00 - $11.00/MMBtu, with an approximate midpoint range of $10.00/MMBtu.

Iteration #3 was selected as the High Forecast. Additional background on the selection of this Iteration as the High Forecast is provided in "Results of Iteration No. 3." Table H-1 below shows the High Forecast and the Base Forecast.

Table H-1
High Forecast and Base Forecast (2006$)

Year	Base Forecast	High Forecast
2009	7.17	9.23
2010	5.82	8.78
2011	5.36	8.88
2012	5.34	8.94
2013	5.61	9.20
2014	6.09	9.78
2015	5.99	10.13
2016	5.60	10.66
2017	5.83	10.82
2018	6.02	10.84
2019	6.36	10.78
2020	6.96	10.55

Source: Global Energy Decisions, Inc.

The following sections provide detailed information as to the parameters and results of the three iterations.

Selection of Model Parameters for Scarcity High Gas Price Forecast

The parameters selected for the Scarcity High Gas Price forecasts were based on Global Energy's estimate of sustainable oil prices for its Base, High and Low case oil prices. The generalized ranges for Global Energy's oil price forecasts are:

High: $60-$70/bbl ($65/bbl midpoint)
Base: $45-$55/bbl ($50/bbl midpoint)
Low: $30-$40/bbl ($35/bbl midpoint)

These oil prices were generated by considering:

1. The full recovery of long-run marginal cost of incremental oil supply
2. Percentage of surplus capacity for wellhead oil production
3. The full recovery of capital cost for syngas and syncrude conversions.
4. Indigenous pipeline gas price parity/non-parity ratio
5. Availability of Arctic gas
6. Imported LNG price
    a. Global pricing formulae
    b. Liquefaction to regasification capacity ratio
    c. Utilization rate of North American regasification capacity.
    d. LNG as a price taker (infra-marginal price)
7. Estimated crude oil supply security and scarcity premiums related to geopolitical uncertainty and its affect on non-commercial (speculative) trading.
8. Estimated elasticity function for demand erosion.

For these Global Energy oil price forecasts, the "horizontal" range of price uncertainty within each scenario is $10/bbl and the "vertical" range of uncertainty between each scenario is $15/bbl. The EIA's WTI (2007) estimate is approximately equal to the midpoint price of the Base Case.

This same approximate range of uncertainty was added to Global Energy's High WTI Oil Scenario to establish CEC's Scarcity High Gas Price forecast and its three iterations. The initial parameters for the 2009 to 2020 period were $75 to $85/bbl oil with an 8.3 to 7.3 oil gas price ratio (OGPR) as shown on Table H-2.

Table H-2
Initial Parameters of the High Forecast Iterations 1-3 (2006$)

	WTI ($/bbl)	Oil to Gas Price Ratio
2009	75.00	8.33
2010	73.72	8.20
2011	72.46	8.10
2012	71.22	8.00
2013	70.00	8.00
2014	71.97	8.00
2015	73.99	8.00
2016	76.07	8.00
2017	78.21	8.00
2018	80.41	7.90
2019	82.67	7.8
2020	85.00	7.73

Source: Global Energy Decisions, Inc.

The initial oil price parameters included:

1. Full recovery of capital for incremental conventional crude.
2. Swing capacity for wellhead crude production of 1.0% or less.
3. Minor increase in refining capacity of lower-quality conventional crudes.

4. Minor substitution of unconventional crude (heavy gravity and high viscosity), and of syncrude (coal, bitumen, and gas) alternatives.
5. A moderate increase in expected rate of growth for China and India.

Non-fundamental oil parameters also included are OPEC's cartel pricing providing scarcity and security bid adders (premiums) of approximately $15/bbl, and related non-commercial (speculative) trading premium at approximately $5/bbl.

The initial oil/gas ratios included:

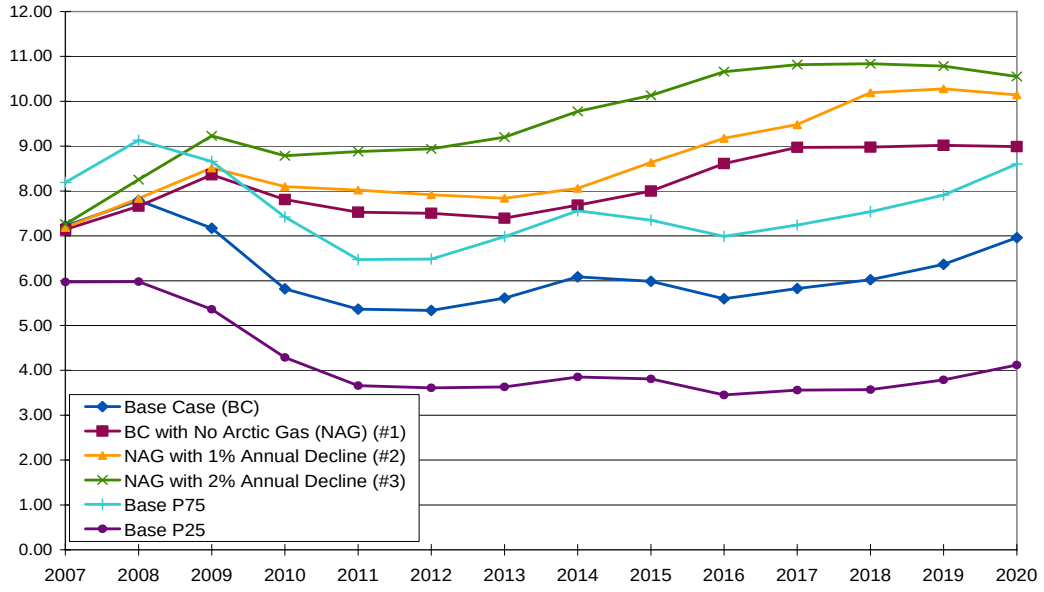
1. A projected price disparity between oil and gas, or the discount based on the Btu value of gas compared to oil, largely a vehicle fuel discount.
2. Cartel pricing by Gas Export Countries Forum (or other LNG cartel) based on limiting liquefaction and shipping capacity to provide LNG as an infra-marginal supply compared to the higher marginal cost of incremental indigenous gas.
3. Restricted incremental regasification capacity in North America, especially at market (downstream) locations.
4. A Green fuel premium for gas, based on continued growth of gas-fired generation, and a likely implementation of a carbon tax; reflected in a slightly declining ratio.

These initial parameters were then incorporated into GPCM®. The results are shown on Figures I-1 and I-2 and on Table H-3.

Figure H-1

Henry Hub Price Forecasts

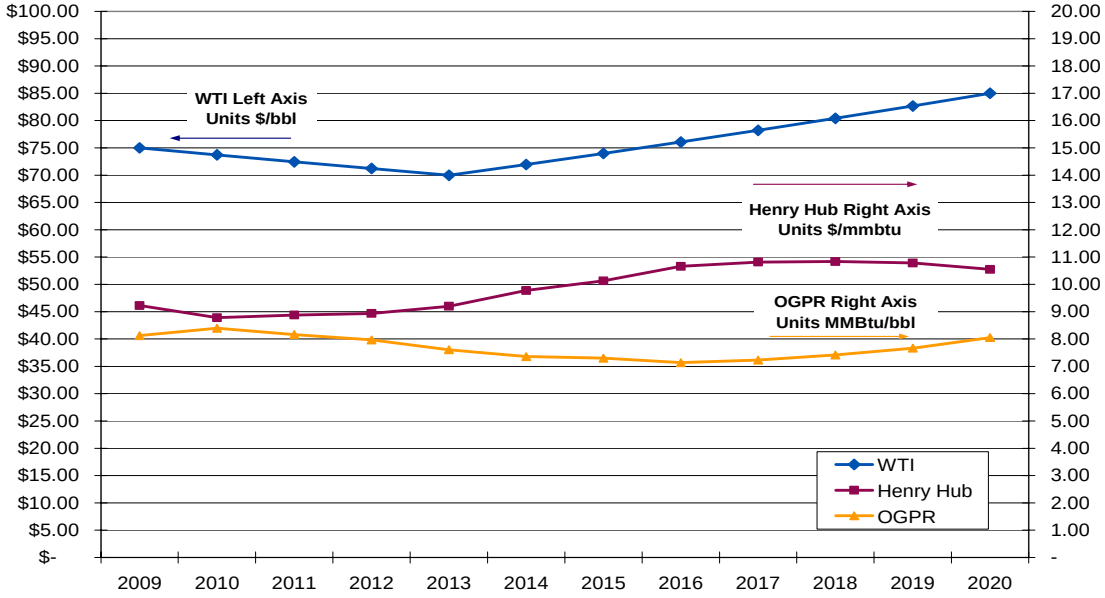
Base Case, BC25, BC75, High Iteration Nos. 1-3



Source: Global Energy Decisions

Figure H-2

Henry Hub Price Forecast and OGPR for Iteration No. 3



Source: Global Energy Decisions

Table H-3

Henry Hub Price Forecasts and Their OGPR

Henry Hub Forecasts

Data Period	Base Case P50	Base Case P75	Base Case P25	Iterations		
				No. 1	No. 2	No. 3
2007	7.22	8.19	5.97	7.14	7.18	7.26
2008	7.79	9.13	5.98	7.66	7.83	8.26
2009	7.17	8.66	5.36	8.36	8.51	9.23
2010	5.82	7.42	4.29	7.81	8.10	8.78
2011	5.36	6.47	3.66	7.53	8.02	8.88
2012	5.34	6.48	3.61	7.50	7.92	8.94
2013	5.61	6.98	3.63	7.39	7.84	9.20
2014	6.09	7.56	3.85	7.69	8.06	9.78
2015	5.99	7.35	3.81	8.00	8.64	10.13
2016	5.60	6.99	3.45	8.61	9.18	10.66
2017	5.83	7.24	3.56	8.97	9.48	10.82
2018	6.02	7.54	3.57	8.98	10.19	10.84
2019	6.36	7.91	3.79	9.02	10.28	10.78
2020	6.96	8.60	4.12	8.99	10.14	10.55

WTI-Henry Hub Oil Gas Price Ratio (OGPR)

	WTI	Base Case		WTI	No. 1		No. 2		No. 3	
	EIA	MMBtu/ Bbl	MMBtu/ MMBtu	Scarcity	MMBtu/ Bbl	MMBtu/ MMBtu	MMBtu/ Bbl	MMBtu/ MMBtu	MMBtu/ Bbl	MMBtu/ MMBtu
2009	62.77	8.75	1.51	75.00	8.97	1.55	8.81	1.52	8.13	1.40
2010	59.23	10.18	1.76	73.72	9.44	1.63	9.10	1.57	8.39	1.45
2011	56.00	10.44	1.80	72.46	9.63	1.66	9.03	1.56	8.16	1.41
2012	53.30	9.99	1.72	71.22	9.49	1.64	9.00	1.55	7.97	1.37
2013	51.52	9.18	1.58	70.00	9.47	1.63	8.93	1.54	7.61	1.31
2014	51.16	8.41	1.45	71.97	9.36	1.61	8.93	1.54	7.36	1.27
2015	51.40	8.58	1.48	73.99	9.25	1.60	8.57	1.48	7.30	1.26
2016	51.27	9.16	1.58	76.07	8.83	1.52	8.29	1.43	7.14	1.23
2017	52.35	8.98	1.55	78.21	8.72	1.50	8.25	1.42	7.23	1.25
2018	52.85	8.78	1.51	80.41	8.96	1.54	7.89	1.36	7.42	1.28
2019	53.54	8.42	1.45	82.67	9.17	1.58	8.04	1.39	7.67	1.32
2020	53.64	7.70	1.33	85.00	9.45	1.63	8.38	1.45	8.05	1.39

Source: Global Energy Decisions

Table H-4 summarizes the parameters used for the modeling of the three iterations and the Base Forecast.

Table H-4
Scarcity High Gas Price Forecast (Summary of Modeling Parameters)

Variable Component	Base Case	Three Iterations		
		No. 1	No. 2	No. 3
Oil Forecast	EIA	$75-$85/bbl	$75-$85/bbl	$75-$85/bbl
GPCM 3rd Q Arctic Gas	Yes	No	No	No
GPCM 3rd Q N.A. Production Decline	Yes 19.3 Tcf USA at 2020	Yes 17.2 Tcf USA at 2020	No 1%/year accelerated decline 15.0 Tcf USA at 2020 (approximate 12% reduction in No. 1 between 2009-2020)	No, 2%/year accelerated decline 13.0 Tcf USA at 2020 (approximate 25% reduction between 2009-2020)
Demand Erosion	No	Not Run	Not Run	Yes Between 2012 to 2020 increases from 1% to 10% by 2020, with a 20% decline in electric power consumption

Variable Component	Base Case	Three Iterations		
		No. 1	No. 2	No. 3
Canadian Pipeline Import Change	No	Not Run	Not Run	Yes Between 2012 to 2020 increases from 20% to 120%, with resultant erosion of approximately 50% of Canadian demand erosion
LNG Import Change	No	Not Run	Not Run	Yes Between 2010 to 2020 increases from 8% (6.8 Tcf) to 16% (7.9 Tcf) with capacity utilization rate increases from 40% to 80+%

Source: Global Energy Decisions

Results of Iteration #3

Results for Iteration No. 3 indicate a very good fit with the initial market parameters, for both the gas price and the oil/gas ratio, providing a maximum sustainable gas price range of approximately $9.00 to $11.00/MMBtu, with an approximate midpoint price of $10.00/MMBtu.

Iteration No. 3 is based on:

1. $75-$85/bbl WTI price
2. No Arctic pipeline gas
3. 2% per year accelerated decline in Lower 48 and Canadian indigenous pipeline gas, resulting in:
    a. 25% reduction in N.A. production or approximately 13.0 Tcf by 2020 compared to Iteration No. 1.
    b. 35% reduction in N.A. production by 2020 compared to Illustrative Base Case.

Global Energy believes that Iteration No. 3 provides a reasonable maximum price for a supply scarcity scenario that competitively links global oil, imported LNG, and N.A. indigenous pipeline gas supply. More adverse supply conditions create unreasonable conditions for long-term supply/demand equilibrium, and unreasonably aggressive:

1. Decreases in indigenous gas (particularly unconventional gas)
2. Increases in Canadian pipeline imports and in imported LNG, and
3. Increases in overall demand erosion (particularly in the electric power section).

Appendix H-4 – Results and Methodology of the Stochastic Forecasts on the Base Forecast

Objective of the Stochastic Forecasts

The stochastic forecasts on the Base Case are performed to obtain a simulation of the probabilistic results of a wide variety of shocks of various magnitudes impacting a given price scenario, in this case the Base Case scenario. Purely mathematical simulations, they do not represent different "world views" of commodity fundamentals, but rather the behavior of prices across a range of events that may occur within a given "world view." A hurricane with accompanying damage to pipeline and supply infrastructure would serve as one example. Price volatility and the accompanying periodic influence of hedgers and commodity speculators in raising prices above the range that would be calculated from supply demand fundamentals is another example.

Such probabilistic forecasts are appropriate to establish ranges of uncertainty around specific price trajectories.

Results

The stochastic analysis calculates all the probabilities from 1 to 99, of which P25 and P75 are tabulated below. The Base Case is the P50 forecast.

Table H-1
Base Case, P25 and P75 Stochastic Forecasts
(2006$/MMbtu)

Data Period	Base Case P50	Base Case P75	Base Case P25
2009	7.17	8.66	5.36
2010	5.82	7.42	4.29
2011	5.36	6.47	3.66
2012	5.34	6.48	3.61
2013	5.61	6.98	3.63
2014	6.09	7.56	3.85
2015	5.99	7.35	3.81
2016	5.60	6.99	3.45
2017	5.83	7.24	3.56
2018	6.02	7.54	3.57
2019	6.36	7.91	3.79
2020	6.96	8.60	4.12

SOURCE: Global Energy

Methodology

The methodology to determine the stochastic forecasts, of which the P25 and P75 have been selected for reporting, includes the following steps:

Step 1: Global Energy starts with GPCM Henry Hub price forecast (single price for each month).

Step 2: Daily stochastic (methodology explained below) draws are done based on daily volatilities and mean reversion parameters from historical data.

Step 3: At the end of each month, we average the daily prices for each of the 500 iterations.

Step 4: We then take all the iterations and their average prices for the each month and sort them from highest to lowest.

Step 5: We then take the iteration that is 25% from the top and the iteration that is 75% from the top and use those prices as the 25% and 75% price.

What Does Stochastic Mean?

In Ian Stewart's *Does God Play Dice?*, he states the etymology of *stochastic* in the statement, "The Greek word *stochastikos* means 'skillful in aiming' and thus conveys the idea of *using* the laws of chance for personal benefit."[1]

Generally, stochastic is used to indicate that a particular subject is seen from a point of view of randomness, as part of a probability theory it can predict *how likely* a particular outcome is. Stochastic is often used as a counterpart of the word "deterministic," which means that random phenomena are not involved. A single die roll is a probabilistic system—there is a one in six chance that the roll will end with the five facing up. We cannot predict the outcome of the die roll, but we can assign some probability to how often certain events will happen.

There are two "random" factors that affect fuel prices.

[1] Stewart, I., 1989, Does God Play Dice? The Mathematics of Chaos, Blackwell Publishers; Second Edition (February 2002).

Long Run

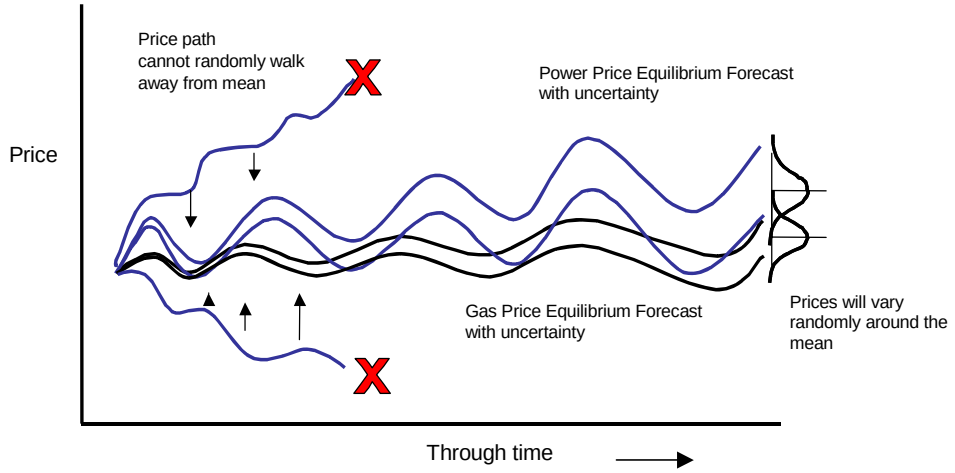
Long run (LR) factors such as technology, population changes, and GDP differences will result in a long run random effect on prices. Long-term volatility tends to be small compared to the short-term shocks and these random effects will have a limited effect on individual years particularly in the near term, but will have an increasingly important affect over the long term. The effect will be to show an increasing variance over time. We assume that LR volatility does not mean revert and follows a standard Brownian motion process.

Short Run with Mean Reversion

Random factors such as weather, outages, and short run liquidity effects will be captured in the short run volatility parameter. These short run "shocks" are assumed to be temporary deviations from the equilibrium. This process tends to be more significant in driving what is commonly perceived as price volatility and will capture the now infamous price spikes within the price process.

Figure H-1

Stylized Price Diffusion Process



SOURCE: Global Energy

Global Energy's analysis and many throughout the industry have concluded that the short run shocks are mean reverting. In other words, after some time they will revert to the equilibrium price.

The mean-reverting process can be likened to applying a piece of elastic between the observed price and the equilibrium price. A random factor continues to be applied to the price as it moves through time but as it moves further away from its equilibrium price a proportionately increasing force is applied to it to pull it back. The speed of mean reversion, a key input variable in this process, determines how quickly prices revert to equilibrium.

Once we have identified the short run and long run parameters, it is necessary to calculate the related correlations. In this analysis Global Energy is correlating all the fuel and electricity prices within a region for both the short and long run conditions.

Model Used

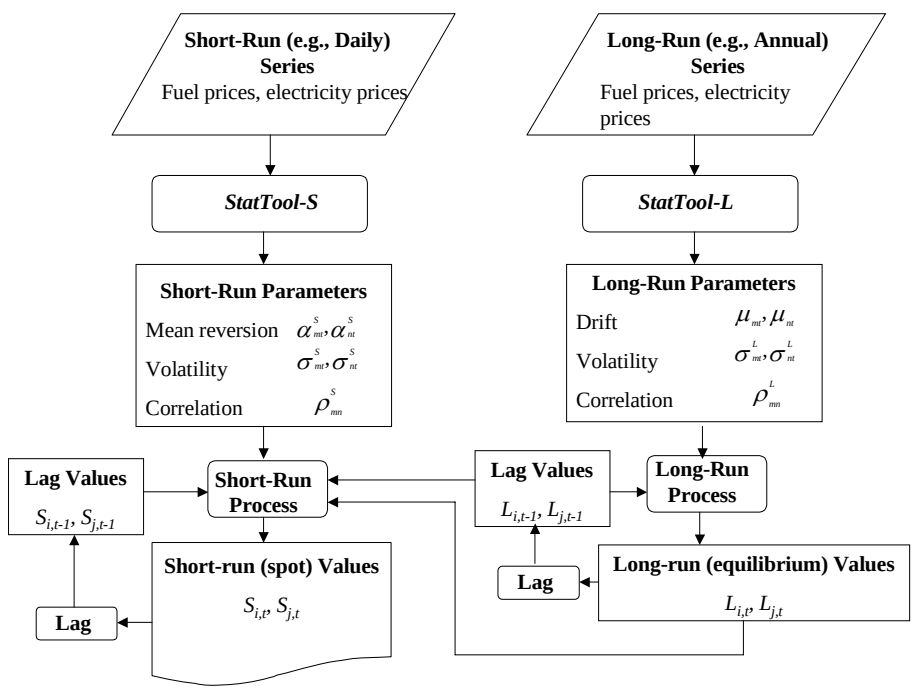
Global Energy's Enerprise™ Planning & Risk™ software was used to describe the stochastic properties of these variables, including their volatility and short-term mean reversion.

Historic price data was input for each price point for power, gas, and oil, which then estimated the mean reversion, volatility, and correlation parameters used in the simulation. This process is described in detail below.

The Planning & Risk™ basic stochastic model is a two-factor model in which one factor represents short-term or temporary deviations and the other factor represents long-term or cumulative deviations.

Some of the important features of the statistical estimation tools and their relation to the stochastic model are summarized in Figure H-2.

Figure H-2
Stochastic Model Process



SOURCE: Global Energy

Long- and short-term effects are combined in the two-factor model. First, the equilibrium price (to which the spot price reverts) receives periodic shocks that create a somewhat random or stochastic equilibrium level. Second, short-term factor shocks further cause spot prices to deviate from equilibrium prices.

The Planning & Risk™ stochastic model allows multiple entities to be jointly simulated with this two-factor stochastic process, accounting for correlation among the shocks impacting the set of stochastic processes. The entities simulated with this stochastic model in Planning & Risk™ included electricity energy, natural gas, oil, coal, and other fuel prices.

Detailed Stochastic Model Description

The discrete time mathematical representation of the two-factor (short-term and long-term) lognormal model is:

$$S_{n,t} = S_{n,t-1} + L_{n,t} - L_{n,t-1} + \alpha_{n,t}(L_{n,t-1} - S_{n,t-1}) + \sigma^S_{n,t}\varepsilon^S_{n,t} - \mathrm{Var}[S_{n,t} | S_{n,t-1}]/2 \quad (1)$$

$$L_{n,t} = L_{n,t-1} + \mu_{n,t} - (\sigma^L_{n,t})^2/2 + \sigma^L_{n,t}\varepsilon^L_{n,t} \quad (2)$$

$$\varepsilon^S_{n,t}\varepsilon^L_{n,t} = \rho^{S,L}_{n,t} = 0 \quad (3)$$

$$\varepsilon^S_{m,t}\varepsilon^S_{n,t} = \rho^S_{m,n,t} \quad (4)$$

$$\varepsilon^L_{m,t}\varepsilon^L_{n,t} = \rho^L_{m,n,t} \quad (5)$$

where:

n = entity (fuel price, or electricity price)

t = time period of observation (e.g., day, week, month)

S_n = logarithm of short run or spot value for commodity n

L_n = logarithm of long run or equilibrium value for commodity n

$\alpha_{n,t}$ = rate of mean-reversion in spot value for commodity n in period t

$\mu_{n,t}$ = expected rate of growth (drift) of equilibrium value for commodity n in period t

$\sigma^S_{n,t}$ = volatility of spot value "returns" for commodity n in period t

σ^L_n = volatility of equilibrium value growth rate for commodity n

ε^S = normally distributed random vector (mean = 0, s.d.= 1)

ε^L = normally distributed random vector (mean = 0, s.d.= 1)

$\rho^{S,L}$ = correlation of spot and long run value stochastic changes

$\rho^S_{m,n}$ = correlation of spot price stochastic changes for commodities m and n

$\rho^{L}_{m,n}$ = correlation of drift rate stochastic changes for commodities m and n

Var = variance.

The short-term or spot value for entity n, $S_{n,t}$, is modeled as following a mean-reverting process in which the "mean" is a time-varying, long run equilibrium level, $L_{n,t}$. This process, specified in equation (1), combines the stochastic shocks to the uncertain equilibrium value and short-term deviations around the equilibrium value. The long-term equilibrium value is an unobservable variable towards which the short-term observed spot value $S_{n,t}$ tends. The long-term value $L_{n,t}$ is generated by the long-term process specified in equation (2), which describes a random-walk around a time-varying trend rate, $\mu_{n,t}$.

In this analysis we have entered the Global Energy Retainer Forecasts as the equilibrium or expected value (mean) forecast, {exp($L_{n,1}$) ... exp($L_{n,T}$)}, for periods 1 through the horizon T. Then, a time series of drift rates is calculated by the software for this assumed trajectory of expected values.

Equation (3) says that short-term and long-term shocks are assumed to be uncorrelated. Equations (4) and (5) allow for a positive or negative correlation between the short-term and long-term shocks, respectively, for any two stochastic entities.

The application of the stochastic model summarized by equations (1) – (5) proceeds in two steps:

1. Statistical or judgmental estimation of the parameters, including the short-term mean reversion parameter(s) $\alpha_{n,t}$, short- and long-term volatilities $\sigma^{S}_{n,t}$ and $\sigma^{L}_{n,t}$, and short- and long-term correlation coefficients $\rho^{S}_{m,n,t}$ and $\rho^{L}_{m,n,t}$; and
2. The use of these parameters in conjunction with expected value forecasts in Monte Carlo simulations.

Appendix H-5:
Impacts on Natural Gas Market Prices of Low Demand for Gas as a Power Generation Fuel in the West

Section is forthcoming.

APPENDIX I

DEVELOPMENT OF POWER PLANT WATER CONSUMPTION FACTORS

This appendix will be forthcoming.

APPENDIX J

ASSESSMENT OF AGING POWER PLANT RETIREMENTS IN SOUTHERN CALIFORNIA

This appendix will be forthcoming