Western Interconnection 2006 Congestion Assessment Study

Prepared by the

Western Congestion Analysis Task Force

May 08, 2006

Western Interconnection 2006 Congestion Study

- DOE Task 3 -

1. **2008 Modeling Study**
2. **2015 Modeling Study**
   – 2015 Planned Resource Development (IRPs and RPS)
3. **W.I. Historical Path Usage Studies** – 1999 thru 2005
   – Physical congestion
   – Commercial congestion

WCATF Modeling Studies

ABB Gridview Model

- Model uses WECC 2005 L&R load forecast, modified with NPCC data for the NW, RMATS load forecasts for the Rocky Mtn area and the latest CEC load forecast for California
- Hourly load shapes were developed using FERC 714
- Incremental transmission was added to a WECC 2008 case to represent 2015 network topology
- WECC path ratings were used, modified as necessary to more closely represent operating experience. Path nomograms were modeled.
- Gridview has the ability to model losses, wheeling rates and forced outages, however these were not modeled in the 2015 study. (this will be pursued in the future) – Losses were included in the load projections. Loss sensitivity was investigated in the 2008 study.
- Resources
  - Modeled unit commitment with actual data if known; generic data if unknown
  - Incremental resources reflect utility IRPs and state RPS standards
  - Unit forced outage rates are modeled, using EIA data
  - Modeled Startup costs, ramp rates and variable O&M costs, gas prices of $5, $7 and $9.
  - Hydro and Wind are hard wired into the model, using data obtained for the major western river systems and from the National Renewable Energy Lab.

WECC Transmission Paths Definition & Rating

- All WECC Cataloged Paths are modeled, representing potentially constrained W.I. Paths, including Unscheduled (Loop) Flow Qualified Paths and OTC Policy Group paths. They represent all the significant paths in the W.I.
- A Path may represent a single line or combination of parallel lines from one area or a combination of areas to another area or combination of areas
- A Path may be between Control Areas or internal to a Control Area.
- Paths are defined based upon extensive planning studies and operating experience. They are well documented through a formal process.

WECC Transmission Paths (Cont.)

- Ratings are established thru an open process described in the WECC “Procedures for Regional Planning Project Review and Rating Transmission Facilities” document.
- Ratings are documented in the WECC Path Rating Catalog
- Ratings include both non- simultaneous and simultaneous limits, including development of nomograms
- All ratings are established applying NERC/WECC reliability criteria; the path must be able to withstand an outage while operating at rated capacity
- Ratings in the West are determined by the more restrictive of applicable steady state or contingency limits. These include transient, voltage stability and thermal limits.
- 67 existing WECC paths are currently rated

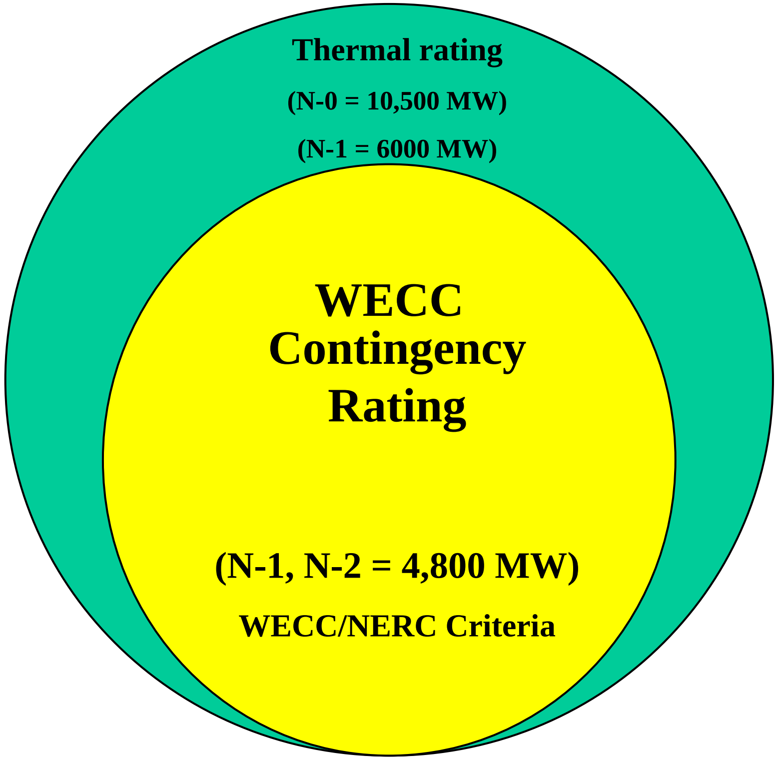
WECC Transmission Paths (Cont.)

- The WECC Operating Transfer Capability (OTC) Policy Committee reviews seasonal operating ratings for selected critical paths.
- Bottom Line:
  - TO MAINTAIN RELIABLE OPERATION, WESTERN PATH RATINGS ARE OFTEN BASED UPON STABILITY LIMITS WHICH MAY BE MORE LIMITING THAN THE THERMAL LIMITS THAT TYPICALLY LIMIT EASTERN PATHS. THIS IS PRIMARILY BECAUSE OF LONG TRANSMISSION DISTANCES IN THE WEST.
- All production cost modeling in the West (SSG-WI, RMATS, STEP & CDEAC studies) recognize OTC limits on all WECC paths and on all “internal” lines, but not the “day to day” operational limits that are based upon prevailing system conditions.

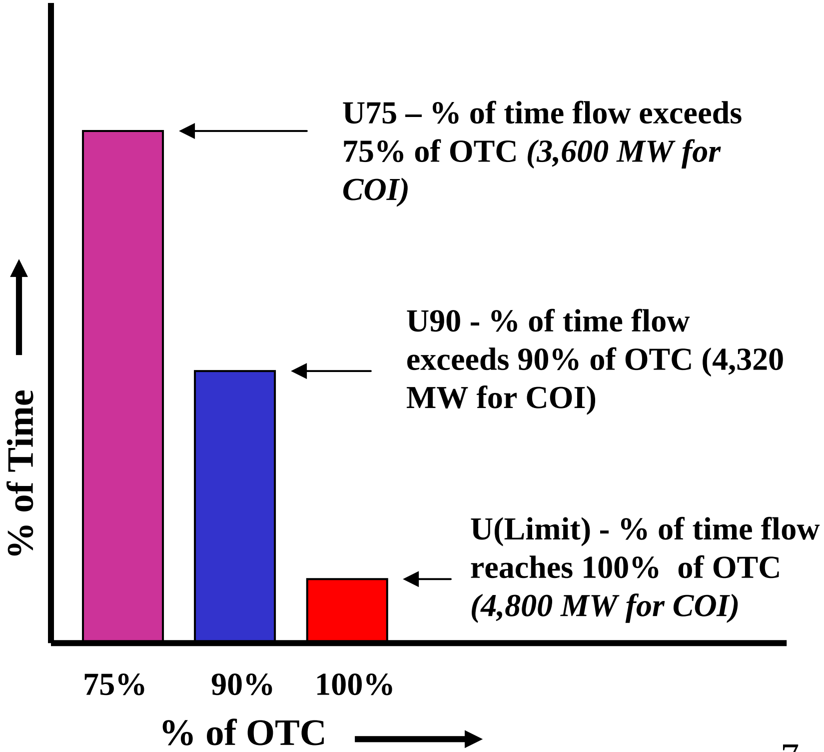
Understanding Western Path Flows

Measurement of Transfer Capacity
Example - California Oregon Intertie (COI)

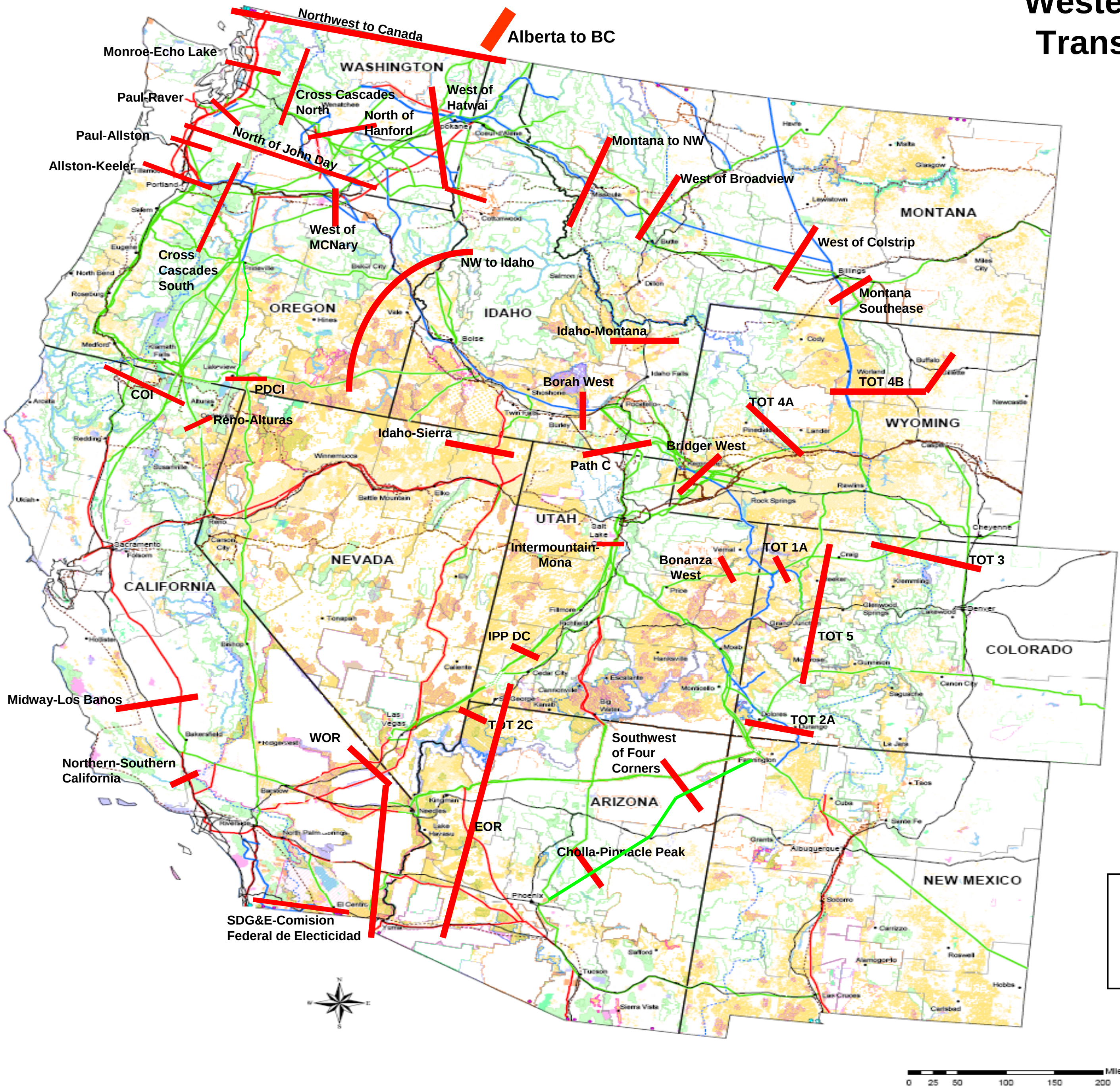
Path Ratings



U75, U90 and U(Limit)



Western Interconnect Transmission Paths



NOTE:
For clarity, not all WECC Rated Paths are shown.

WECC Paths
Refer to WECC Path Rating Catalog for Path Details

Path #	Path Name	Path #	Path Name
1	Alberta – British Columbia	39	TOT 5
2	Alberta - Saskatchewan	40	TOT 7
3	Northwest - Canada	41	Sylmar to SCE
4	West of Cascades - North	42	IID - SCE
5	West of Cascades - South	43	North of San Onofre
6	West of Hatwai	44	South of San Onofre
8	Montana to Northwest	45	SDG&E - CFE
9	West of Broadview	46	West of Colorado River
10	West of Colstrip	47	Southern New Mexico
11	West of Crossover	48	Northern New Mexico
14	Idaho to Northwest	49	East of Colorado River
15	Midway – Los Banos	50	Cholla – Pinnacle Peak
16	Idaho - Sierra	51	Southern Navajo
17	Borah - West	52	Silver Peak – Control 55kV
18	Idaho - Northwest	54	Coronado West
19	Bridger West	55	Brownlee East
20	Path C	58	Eldorado – Mead 230 kV
21	Arizona to California	59	WALC Blythe 161 kV Sub
22	SW of Four Corners	60	Inyo – Control 115 kV Tie
23	Four Corners 345/500 kV Tx.	61	Lugo – Victorville 500 kV line
24	PG&E - Sierra	62	Eldorado – McCullough 500 kV line
25	Pacificorp – PG&E 115 kV	63	Perkins-Mead-Marketplace 500 kV line
26	Northern – Southern California	64	Marketplace - Adelanto
27	IPP DC Line	65	Pacific DC Intertie
28	Intermountain – Mona 345 kV	66	COI
29	Intermountain – Gonder 230 kV	71	South of Allston
30	TOT 1A	73	North of John Day
31	TOT 2A	75	Midpoint – Summer Lake
32	Pavant – Gonder 230 kV	76	Alturas Project
33	Bonanza West	77	Crystal - Allen
35	TOT 2C	78	TOT 2B1
36	TOT 3	79	TOT 2B2
37	TOT 4A	80	Montana Southeast
38	TOT 4B		

NOTE: There are 67 WECC Rated Paths. Not all numbers are used.

Part 1

2008 Modeling Study

Incremental/Decremental Units in WECC, 2004-2008 SSG-WI Database Capacity in MWs									
			Fuel Type						
Region Name	**Area Name**	**Status**	**Bio**	**Coal**	**Gas**	**Hydro**	**Wind**	**Grand Total**
AZNMNV	ARIZONA	Add		430	1,974			2,404
	NEVADA	Add			1,126			1,126
	NEW MEXI	Add			614			614
		Retire			(149)			(149)
	WAPA L.C	Add			173			173
AZNMNV Total				**430**	**3,738**			**4,168**
CAISO	IMPERIAL	Add	275					275
	LADWP	Add			1,610			1,610
	PG&E_BAY	Add	100		923		50	1,073
		Retire			(497)			(497)
	PG&E_VLY	Add			1,047			1,047
		Retire			(294)			(294)
	SANDIEGO	Add			1,193			1,193
		Retire			(395)			(395)
	SOCALIF	Add			1,762			1,762
		Retire		(1,580)				(1,580)
CAISO Total			**375**	**(1,580)**	**5,349**		**50**	**4,194**
CANADA	ALBERTA	Add		450	354			804
		Retire		(134)	0			(134)
CANADA Total				**316**	**354**			**670**
NWPP	NW_EAST	Add			1,583		1,215	2,798
	NW_WEST	Add			434			434
NWPP Total					**2,017**		**1,215**	**3,232**
RMPP	COL E	Add			569			569
	IDAHO	Add					170	170
	KGB	Add					65	65
	MONTANA	Add	12	119	376	8	247	762
	UT N	Add			547			547
		Retire			(116)			(116)
	UT S	Add			503			503
RMPP Total			**12**	**119**	**1,879**	**8**	**482**	**2,500**
Total			**387**	**(715)**	**13,337**	**8**	**1,747**	**14,764**

2008 MODEL - - LOAD AND RESOURCES SUMMARY

				Resources (Capacity) MW by Fuel Type						2008 Load		
REGION	AREA	Nameplate Capacity MW	Discounted Capacity (per 2015 Case protocol)	Coal	Nat. Gas	Oil	Hydro + Pumped	Wind	Other	ANNUAL ENERGY MWh	SUMMER PEAK MW (Jul-Aug)	WINTER PEAK MW (Dec-Jan)
CALIF ("CAISO")	IMPERIAL	1,558	1,542	0	307	32	176	21	1,022	2,435,562	901	420
CALIF ("CAISO")	LADWP	6,022	5,932	0	4,899	0	1,003	120	0	27,608,019	5,736	4,644
CALIF ("CAISO")	MEXICO-C	3,313	3,313	0	2,175	439	0	0	699	8,941,612	2,229	1,662
CALIF ("CAISO")	PG&E_BAY	7,305	6,924	20	5,726	860	0	508	192	44,493,246	7,998	6,887
CALIF ("CAISO")	PG&E_VLY	24,568	23,633	50	11,723	174	8,579	1,247	2,796	88,948,052	17,240	13,103
CALIF ("CAISO")	SANDIEGO	4,609	4,609	0	4,561	48	0	0	0	19,113,488	4,631	3,582
CALIF ("CAISO")	SOCALIF	19,709	18,606	108	14,080	50	1,315	1,472	2,685	105,863,402	23,372	17,891
AZNMNV	ARIZONA	23,097	23,097	7,779	10,808	140	233	0	4,137	74,240,648	18,683	12,050
AZNMNV	NEVADA	7,582	7,582	605	6,800	177	0	0	0	20,863,359	6,008	3,115
AZNMNV	NEW MEXI	4,472	4,280	2,037	2,161	20	14	240	0	17,778,053	3,906	3,416
AZNMNV	WAPA L.C	5,939	5,939	0	2,197	0	3,742	0	0	2,357,343	208	201
CANADA	ALBERTA	11,944	11,859	5,380	4,904	0	1,493	106	62	59,916,102	8,217	8,570
CANADA	B.C.HYDR	11,995	11,995	0	1,639	0	10,356	0	0	56,876,741	7,199	9,187
NWPP	NW_EAST	34,274	29,984	0	3,628	24	27,639	1,693	1,290	72,335,959	10,955	12,017
NWPP	NW_WEST	11,574	10,965	1,966	4,148	74	5,067	89	230	104,868,308	15,508	17,378
RMPP	B HILL	1,020	1,020	522	317	42	139	0	0	5,669,651	851	835
RMPP	BHB	0	0	0	0	0	0	0	0	3,441,377	425	474
RMPP	BONZ	468	468	468	0	0	0	0	0	1,045,306	197	147
RMPP	COL E	8,866	8,688	3,517	4,287	120	744	198	0	52,116,113	8,878	7,920
RMPP	COL W	2,294	2,294	1,904	104	0	286	0	0	5,829,865	871	913
RMPP	IDAHO	2,393	2,035	0	135	0	2,088	170	0	15,010,623	3,025	2,311
RMPP	IPP	1,847	1,847	1,847	0	0	0	0	0	0	1	1
RMPP	JB	2,128	2,128	2,128	0	0	0	0	0	0	1	1
RMPP	KGB	324	272	15	0	0	244	65	0	6,118,633	1,275	965
RMPP	LRS	1,628	1,628	1,107	300	0	221	0	0	3,757,124	531	520
RMPP	MONTANA	3,911	3,714	2,511	376	0	700	247	77	8,992,483	1,611	1,620
RMPP	SIERRA	1,878	1,835	565	1,206	0	0	53	53	10,271,004	1,737	1,439
RMPP	SW WYO	264	181	0	0	0	160	104	0	3,401,463	481	400
RMPP	UT N	2,458	2,458	929	1,445	0	84	0	0	33,841,556	6,256	4,295
RMPP	UT S	2,911	2,911	2,274	613	0	0	0	24	4,993,398	967	672
RMPP	WYO	775	775	775	0	0	0	0	0	2,283,714	338	289
RMPP	YLW TL	288	288	0	0	0	288	0	0	8,784	1	1
	Total Capacity	211,411	202,799	36,506	88,538	2,200	64,569	6,331	13,267	863,420,989	160,237	136,926

Specific Capacity Credits (All other resources are counted at 100% of their noted capacity)

7.5%	Capacity Credit for BC Hydro Wind Resources
89.4%	Hydro Credit in NW (OR, WA, ID) (Based on Low Water availability being 4,000MW less than the 37,368MW average availability prior to adding 2015 incremental
20%	Capacity Credit for Wind - General
25%	Capacity Credit for California Wind Resources
10%	Capacity Credit for Colorado Wind Resources
10,356	BCHydro existing resource in Peace, Columbia and Coastal river systems are modeled at "dependable" capacity per Mary Johannis, so no "discount: is applied here.

2008 Modeling Study

Path Limits used in 2008 Study

Path Name	Limit in Pos. Dir. (MW)	Limit in Neg. Dir. (MW)		Path Name	Limit in Pos. Dir. (MW)	Limit in Neg. Dir. (MW)		Path Name	Limit in Pos. Dir. (MW)	Limit in Neg. Dir. (MW)
ALBERTA - BRITISH COLUMBIA	700	-720		PAVANT INTRMTN - GONDER 230 KV	440	-235		Z1-Imperial Valley - Ramona	1212	
ALBERTA - SASKATCHEWAN	150	-150		PERKINS - MEAD - MARKETPLACE 500	1400			Z1-Imperial Valley to Miguel	2200	
ALTURAS PROJECT	300	-300		PG&E - SPP	160	-150		Z1-Miguel Bank No. 1	1120	-1120
BILLINGS - YELLOWTAIL	400	-400		SILVER PEAK - CONTROL 55 KV	17	-17		Z1-Miguel Bank No. 2	1120	-1120
BONANZA WEST	785			SOUTH OF SAN ONOFRE	2500			Z1-North of Miguel	2000	
BORAH WEST	2557			SOUTHERN NEW MEXICO (NM1)	1048	-1048		Z1-PV to Devers	2280	
BRIDGER WEST	2200			SOUTHWEST OF FOUR CORNERS	2325			Z2- SDGE Import Limit	2850	
BROWNLEE EAST	1850			SYLMAR - SCE	1600	-1600		Z2: South of Lugo	6100	-6100
CHOLLA - PINNACLE PEAK	1200			TOT 1A	650			Z20-Imperial Valley - Miguel 2	2252	-2252
CORONADO - SILVER KING - KYRENE	1100			TOT 2A	690			Z2-EOR	7550	
EAGLE MTN 230_161 KV - BLYTHE 16	72	-218		Tot 2a 2b 2c Nomogram	1570	-1600		Z2-SCIT	16700	-16700
ELDORADO - MCCULLOUGH 500 KV	2598	-2598		TOT 2B	780	-850		Z2-WOR	10623	
ELDORADO - MEAD 230 KV LINES	1140	-1140		TOT 2B1	560	-600		Z3- Eldorado - Lugo	1386	-1386
FOUR CORNERS 345_500	840	-840		TOT 2B2	265	-300		Z3-Market Place - Adelanto	1636	-1636
IDAHO - MONTANA	337	-337		TOT 2C	300	-300		Z3-Mccullgh - Victorville	1385	-1385
IDAHO - NORTHWEST	2400	-1200		TOT 3	1450			Z3-Mohave - Lugo	1386	-1386
IDAHO - SIERRA	500	-360		TOT 4A	810			Z4- Jojoba - Kyrene	1732	-1732
IID - SCE	600			TOT 4B	680			Z4- Moenkopi - El Dorado	1645	-1645
INTERMOUNTAIN - GONDER 230 KV	220			TOT 5	1675			Z4-Navajo - Crystal	1411	-1411
INTERMOUNTAIN - MONA 345 KV	1400	-1200		TOT 7	890			Z4-Peacock - Mead	508	-508
INYO - CONTROL 115 KV TIE	56	-56		WEST OF BROADVIEW	2573			Z4-Perkins - Big Sandy	1238	-1238
IPP DC LINE	1920	-1400		WEST OF CASCADES - NORTH	10500	-10500		Z5-Navajo - Moenkopi	1411	
LUGO - VICTORVILLE 500 KV LINE	2400	-900		WEST OF CASCADES - SOUTH	7000	-7000		Z5-Navajo - Table Mesa	985	
MARKETPLACE - ADELANTO	1200	-1200		WEST OF COLSTRIP	2598			Z5-South of Navajo	2264	
MIDPOINT - SUMMER LAKE	1500	-600		WEST OF CROSSOVER	2598			Z6- Path 26	3700	-3000
MONTANA - NORTHWEST	2200	-1350		WEST OF HATWAI	4277			Z6-COI	4700	-3675
NORTH OF JOHN DAY	8600	-8600		WOR - IID230	600	-600		Z6-East of PV	6620	
NORTH OF SAN ONOFRE	2440			WOR - N.Gila	1861			Z6-MIDWAY - LOS BANOS	5400	
NORTHERN NEW MEXICO (NM2)	1800			WOR -n- El Dor to Lugo	2754			Z7- Miguel - Tijuana	912	-912
NORTHWEST - CANADA	2000	-3150		WOR -n- Mc-Vic	2592			Z7-Imperial Valley - La Rosita	797	-797
PACI vs PDCI	7300			Z1- Devers Bank No. 1	1120	-1120		Z7-Path 45	408	-800
PACIFIC DC INTERTIE (PDCI)	3000	-2100		Z1- El Centro Bank	225	-225				
PACIFICORP_PG&E 115 KV INTERCON.	80	-45		Z1- Hassayampa - N. Gila	1861					
PATH C	775	-850		Z1- N. Gila - Imperial Valley	1861					

Notes for Reviewing the 2008 Study Results

- Yellow Paths in the Tables are WECC Rated Paths
- White Paths in the Tables are other monitored lines, mostly located within WECC Rated Paths
- Study Metrics – U75, U90, U(Limit), Congestion Rent, Shadow Price averaged over 8760 hours, Shadow Price averaged over the “binding (or limit)” hours
- Metrics used to Identify Congestion Areas – Binding Hours Shadow Price, U75 and U90
- The following Paths may be considered by their owners to be “dedicated” facilities, planned and designed to integrate or deliver specified resources to load: (These were designed to be high usage paths and may not be considered congested)
  - Path 27 – Intermountain Power Project (IPP) DC Line
  - Path 19 – West of Bridger

Definitions

- U(Limit) = Annual Hours operating at the Path's Limit
- U75 & U90 = Hours of the year a path operates above 75% or 90% of the Path Limit. Note that in the historical path studies, U75 is sometimes the maximum seasonal value over the years studied.
- Congestion Rent = Average Hourly Shadow Price times Path Flow on that Hour, summed for the year
- Average Shadow Price = Average of the hourly Shadow Prices, averaged over 8760 Hours
- Binding Hour Average Shadow Price = Average Shadow Price, averaged over the number of hours the path is at its limit.

2008
Path Usage Study Results

$5, $7 (reference) and $9 Gas Price

2008 - Modeled Path Usage

U75, U90 and U(Limit) - - $5, $7 and $9 HH Gas Price - Med Hydro, Average Losses

Ordered by $7 U90 A dash in the table = 0 hours

Page 1 of 2	$5 Gas			$7 gas			$9 Gas		
Path Name	U(Limit) Congestion Hours (Hrs)	U90 Hours (Hrs)	U75 Hours (Hrs)	U(Limit) Congestion Hours (Hrs)	U90 Hours (Hrs)	U75 Hours (Hrs)	U(Limit) Congestion Hours (Hrs)	U90 Hours (Hrs)	U75 Hours (Hrs)
Nav - Crystl	7,428	8,231	8,760	6,997	8,091	8,680	6,461	7,815	8,382
Bonz - Mona	7,198	7,880	8,513	7,045	7,793	8,504	7,018	7,765	8,493
ALB BC	7,650	7,769	7,938	7,493	7,633	7,801	7,277	7,414	7,613
Cry - McC	7,180	7,494	7,916	7,366	7,601	7,882	7,069	7,310	7,577
Pea - Mead	7,006	7,109	7,338	7,072	7,152	7,411	6936	7054	7388
HA RB PS	7,460	7,581	7,728	6,912	7,046	7,216	6,546	6,673	6,873
TOT 2C	-	7,522	7,678	-	6,970	7,159	-	6,616	6,821
PAC PG&E	6,653	6,660	6,704	6,605	6,618	6,684	6,418	6,433	6,498
BR West	3,633	6,240	7,884	3,763	6,341	7,905	3,967	6,397	7,921
IID - SCE	2,620	4,666	6,905	3,725	5,734	7,390	4,861	6,585	7,735
MT NW	3,761	5,787	7,718	3,624	5,678	7,688	4,029	6,002	7,984
INT GOND	4,821	5,375	6,255	4,348	5,015	6,073	4,315	5,070	6,058
SW 4C	1,194	4,249	7,541	1,860	4,923	7,555	2,308	5,046	7,473
COR SK KY	1,383	5,244	7,030	1,234	4,610	7,009	1,130	4,218	6,979
EOR	1,395	5,868	8,192	949	4,593	8,058	356	2,835	7,639
Ship San J	2,945	4,571	6,804	3,018	4,572	6,652	2945	4510	6553
PDCI	3,585	4,090	4,612	3,592	4,097	4,696	3,608	4,172	4,814
INYO CONT	-	3,803	4,717	-	3,705	4,616	-	3,361	4,361
Malin - RM	2,645	3,806	5,258	2,389	3,550	5,072	2203	3275	4836
IPP DC LINE	2,164	3,600	5,486	2,365	3,539	5,285	2,519	3,678	5,316
COI	-	3,335	4,945	-	3,093	4,773	-	2,859	4,513
LUGO - VIC	-	3,468	6,104	-	3,006	5,509	-	2,526	4,935
ALTURAS	-	2,848	3,822	-	2,984	4,009	-	2,777	3,879
TOT 2A	841	1,722	3,330	1,925	2,851	4,144	2,530	3,375	4,631
W BROAD	92	3,158	7,710	7	2,807	7,486	86	3,101	7,847
El Dor Lugo	509	2,716	6,048	479	2,476	5,794	317	2,051	5,259
BONZ W	-	2,252	7,982	-	2,178	7,904	-	2,183	7,898
CH PPK	-	1,585	6,917	-	1,893	6,830	-	2,037	6,684
Hasy N Gila	1,190	2,975	6,547	588	1,862	5,195	177	945	3838
SDG&E to CFE	702	1,097	1,895	794	1,091	1,641	1,005	1,270	1,842
PVINTR GOND	-	1,063	5,157	-	974	4,778	-	815	4,848
Z2-WOR	-	1,125	5,091	-	968	4,725	-	587	4,093
PATH C	609	907	1,515	652	959	1,587	639	972	1,566
TOT 1A	707	873	4,234	709	904	4,296	700	877	4,251
MARKETPLACE - ADELANTO	80	839	4,154	82	808	3,964	44	664	3,516

page 2 of 2	$5 Gas			$7 gas			$9 Gas		
Path Name	U(Limit) Congestion Hours (Hrs)	U90 Hours (Hrs)	U75 Hours (Hrs)	U(Limit) Congestion Hours (Hrs)	U90 Hours (Hrs)	U75 Hours (Hrs)	U(Limit) Congestion Hours (Hrs)	U90 Hours (Hrs)	U75 Hours (Hrs)
IDAHO - SIERRA	338	908	2,046	286	690	1,679	342	802	1,804
FOUR CORNERS 345_500	624	626	2,710	624	624	3,175	624	624	3,224
BILLINGS - YELLOWTAIL	-	386	1,558	-	623	1,868	-	468	1,633
NORTH OF SAN ONOFRE	27	469	2,255	33	613	2,973	40	499	3,089
MIDPOINT - SUMMER LAKE	-	491	1,863	-	587	2,181	-	573	2,128
Moenkopi - El Dorado (EOR)	-	675	7,855	-	459	7,674	-	216	7,248
TOT 4B	38	385	1,517	58	459	1,817	40	429	1,530
WEST OF CROSSOVER	-	313	7,498	-	447	7,483	-	289	7,477
N. Gila - Imperial Valley WOR)	-	564	4,110	-	415	2,915	-	165	1,872
NORTHWEST - CANADA	87	320	689	169	399	775	221	461	906
SOUTHERN NEW MEXICO (NM1)	19	256	1,670	35	364	2,184	44	608	3,046
BORAH WEST	-	185	3,655	-	230	3,813	-	246	3,760
PG&E - SPP	42	303	4,365	21	215	4,160	26	187	4,294
PV to Devers (EOR)	-	194	2,419	-	98	2,034	-	31	1,567
INTERMOUNTAIN - MONA 345 KV	-	77	426	-	89	510	-	111	518
TOT 4A	6	62	258	5	66	258	8	97	285
BROWNLEE EAST	-	73	467	-	64	416	-	63	408
Mohave - Lugo (WOR)	-	15	4,106	-	19	3,833	-	4	3,187
TOT 2B2	-	-	359	-	7	752	-	5	1,030
IDAHO - NORTHWEST	1	6	520	-	6	596	-	7	586
TOT 3	3	26	318	-	3	219	-	-	200
WEST OF COLSTRIP	-	-	6,600	-	-	6,600	-	-	6,600
SILVER PEAK - CONTROL 55 KV	-	-	4,081	-	-	4,249	-	-	4,326
PERKINS - MEAD - MARKETPLACE 500	-	-	1,495	-	-	1,108	-	-	537
NORTHERN NEW MEXICO (NM2)	-	-	71	-	-	85	-	-	99
TOT 7	-	-	9	-	-	6	-	-	2
ALBERTA - SASKATCHEWAN	-	-	-	-	-	-	-	-	-
CENTENNIAL	-	-	-	-	-	-	-	-	-
EAGLE MTN 230_161 KV - BLYTHE 16	-	-	-	-	-	-	-	-	-
ELDORADO - MCCULLOUGH 500 KV	-	-	-	-	-	-	-	-	-
ELDORADO - MEAD 230 KV LINES	-	-	-	-	-	-	-	-	-
IDAHO - MONTANA	-	-	-	-	-	-	-	-	-
NORTH OF JOHN DAY	-	-	-	-	-	-	-	-	-
SOUTH OF SAN ONOFRE	-	-	-	-	-	-	-	-	-
SYLMAR - SCE	-	-	-	-	-	-	-	-	-
TOT 2B1	-	-	-	-	-	-	-	-	-
TOT 5	-	-	-	-	-	-	-	-	-
WEST OF CASCADES - NORTH	-	-	-	-	-	-	-	-	-
WEST OF CASCADES - SOUTH	-	-	-	-	-	-	-	-	-
WEST OF HATWAI	-	-	-	-	-	-	-	-	-

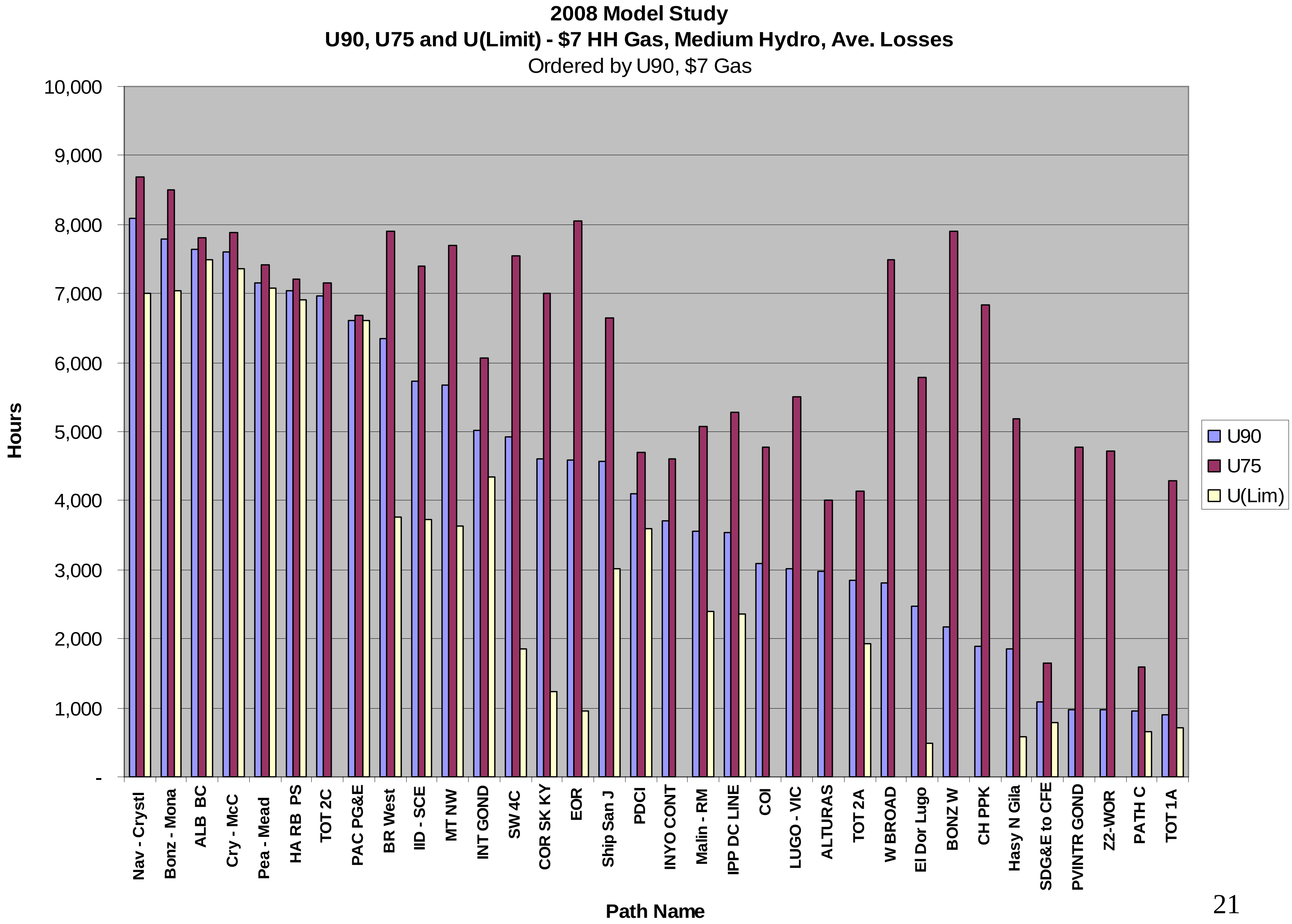
2008 - Modeled Path Usage Metric Ranking

U75, U90 and U(Limit) - - $5, $7 and $9 HH Gas Price - Med. Hydro, Average Losses

Ordered by $7 U90 A dash in the table indicates the path was unranked since the Hours = 0

Page 1 of 2	$5 Gas			$7 gas			$9 Gas		
Path Name	U(Limit) Congestion Hours Ranking	U90 Hours Ranking	U75 Hours Ranking	U(Limit) Congestion Hours Ranking	U90 Hours Ranking	U75 Hours Ranking	U(Limit) Congestion Hours Ranking	U90 Hours Ranking	U75 Hours Ranking
Navajo - Crystal (EOR)	3	1	1	5	1	1	6	1	2
Bonanza - Mona (Bonanza West)	4	2	2	4	2	2	3	2	1
ALBERTA - BRITISH COLUMBIA	1	3	5	1	3	7	1	3	9
Crystal - McCullough (EOR)	5	6	6	2	4	6	2	4	10
Peacock - Mead (EOR)	6	7	15	3	5	13	4	5	13
HA PS - Red Butte (TOT 2C)	2	4	9	6	6	15	5	6	16
TOT 2C	-	5	12	-	7	16	-	7	17
PACIFICORP_PG&E 115 KV INTERCON.	7	8	20	7	8	19	7	9	21
BRIDGER WEST	10	9	7	9	9	4	11	10	4
IID - SCE	15	14	18	10	10	14	8	8	7
MONTANA - NORTHWEST	9	11	10	11	11	8	10	11	3
INTERMOUNTAIN - GONDER 230 KV	8	12	24	8	12	23	9	12	22
SOUTHWEST OF FOUR CORNERS	19	17	13	18	13	10	16	13	12
CORONADO - SILVER KING - KYRENE	18	13	16	19	14	17	19	15	15
EOR	17	10	3	20	15	3	24	24	8
Shiprock - San Juan	12	15	19	13	16	20	13	14	20
PACIFIC DC INTERTIE (PDCI)	11	18	33	12	17	32	12	16	29
INYO - CONTROL 115 KV TIE	-	20	32	-	19	33	-	19	32
Malin - RM 1 & 2 (COI)	13	19	28	14	20	28	17	20	28
IPP DC LINE	16	21	27	15	21	26	15	17	24
COI	-	23	31	-	22	30	-	23	31
LUGO - VICTORVILLE 500 KV LINE	-	22	25	-	23	25	-	26	26
ALTURAS PROJECT	-	26	40	-	24	38	-	25	37
TOT 2A	21	29	42	17	25	37	14	18	30
WEST OF BROADVIEW	28	24	11	34	26	11	29	22	6
El Dor to Lugo (WOR)	26	27	26	26	27	24	26	28	25
BONANZA WEST	-	28	4	-	28	5	-	27	5
CHOLLA - PINNACLE PEAK	-	30	17	-	29	18	-	29	18
Hassy - N. Gila (EOR)	20	25	23	25	30	27	28	32	38
SDG&E to CFE	23	32	47	21	31	51	20	30	47
PAVANT INTRMTN - GONDER 230 KV	-	33	29	-	32	29	-	34	27
Z2-WOR	-	31	30	-	33	31	-	39	36
PATH C	25	35	52	23	34	52	22	31	51
TOT 1A	22	36	35	22	35	34	21	33	35
MARKETPLACE - ADELANTO	30	37	36	29	36	39	30	36	40

Page 2 of 2	$5 Gas			$7 gas			$9 Gas		
Path Name	U(Limit) Congestion Hours Ranking	U90 Hours Ranking	U75 Hours Ranking	U(Limit) Congestion Hours Ranking	U90 Hours Ranking	U75 Hours Ranking	U(Limit) Congestion Hours Ranking	U90 Hours Ranking	U75 Hours Ranking
IDAHO - SIERRA	27	34	46	27	37	50	25	35	48
FOUR CORNERS 345_500	24	39	43	24	38	42	23	37	41
BILLINGS - YELLOWTAIL	-	43	50	-	39	48	-	42	49
NORTH OF SAN ONOFRE	33	42	45	32	40	43	32	41	43
MIDPOINT - SUMMER LAKE	-	41	48	-	41	46	-	40	45
TOT 4B	32	44	51	30	42	49	33	44	52
Moenkopi - El Dorado (EOR)	-	38	8	-	43	9	-	47	14
WEST OF CROSSOVER	-	46	14	-	44	12	-	45	11
N. Gila - Imperial Valley WOR)	-	40	37	-	45	44	-	49	46
NORTHWEST - CANADA	29	45	54	28	46	54	27	43	54
SOUTHERN NEW MEXICO (NM1)	34	48	49	31	47	45	31	38	44
BORAH WEST	-	50	41	-	48	41	-	46	39
PG&E - SPP	31	47	34	33	49	36	34	48	34
PV to Devers (EOR)	-	49	44	-	50	47	-	53	50
INTERMOUNTAIN - MONA 345 KV	-	51	57	-	51	58	-	50	57
TOT 4A	35	53	60	35	52	60	35	51	59
BROWNLEE EAST	-	52	56	-	53	59	-	52	58
Mohave - Lugo (WOR)	-	55	38	-	54	40	-	56	42
TOT 2B2	-	-	58	-	55	56	-	55	53
IDAHO - NORTHWEST	37	56	55	-	56	57	-	54	55
TOT 3	36	54	59	-	57	61	-	-	60
WEST OF COLSTRIP	-	-	22	-	58	21	-	-	19
SILVER PEAK - CONTROL 55 KV	-	-	39	-	58	35	-	-	33
PERKINS - MEAD - MARKETPLACE 500	-	-	53	-	58	53	-	-	56
NORTHERN NEW MEXICO (NM2)	-	-	61	-	58	62	-	-	61
TOT 7	-	-	62	-	58	63	-	-	62
ALBERTA - SASKATCHEWAN	-	-	-	-	-	-	-	-	-
CENTENNIAL	-	-	-	-	-	-	-	-	-
EAGLE MTN 230_161 KV - BLYTHE 16	-	-	-	-	-	-	-	-	-
ELDORADO - MCCULLOUGH 500 KV	-	-	-	-	-	-	-	-	-
ELDORADO - MEAD 230 KV LINES	-	-	-	-	-	-	-	-	-
IDAHO - MONTANA	-	-	-	-	-	-	-	-	-
NORTH OF JOHN DAY	-	-	-	-	-	-	-	-	-
SOUTH OF SAN ONOFRE	-	-	-	-	-	-	-	-	-
SYLMAR - SCE	-	-	-	-	-	-	-	-	-
TOT 2B1	-	-	-	-	-	-	-	-	-
TOT 5	-	-	-	-	-	-	-	-	-
WEST OF CASCADES - NORTH	-	-	-	-	-	-	-	-	-
WEST OF CASCADES - SOUTH	-	-	-	-	-	-	-	-	-
WEST OF HATWAI	-	-	-	-	-	-	-	-	-



2008 Model Study
U90, U75 and U(Limit) - $7 HH Gas, Medium Hydro, Ave. Losses
Ordered by U90, $7 Gas
Hours
10,000
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8,000
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U90
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U(Lim)
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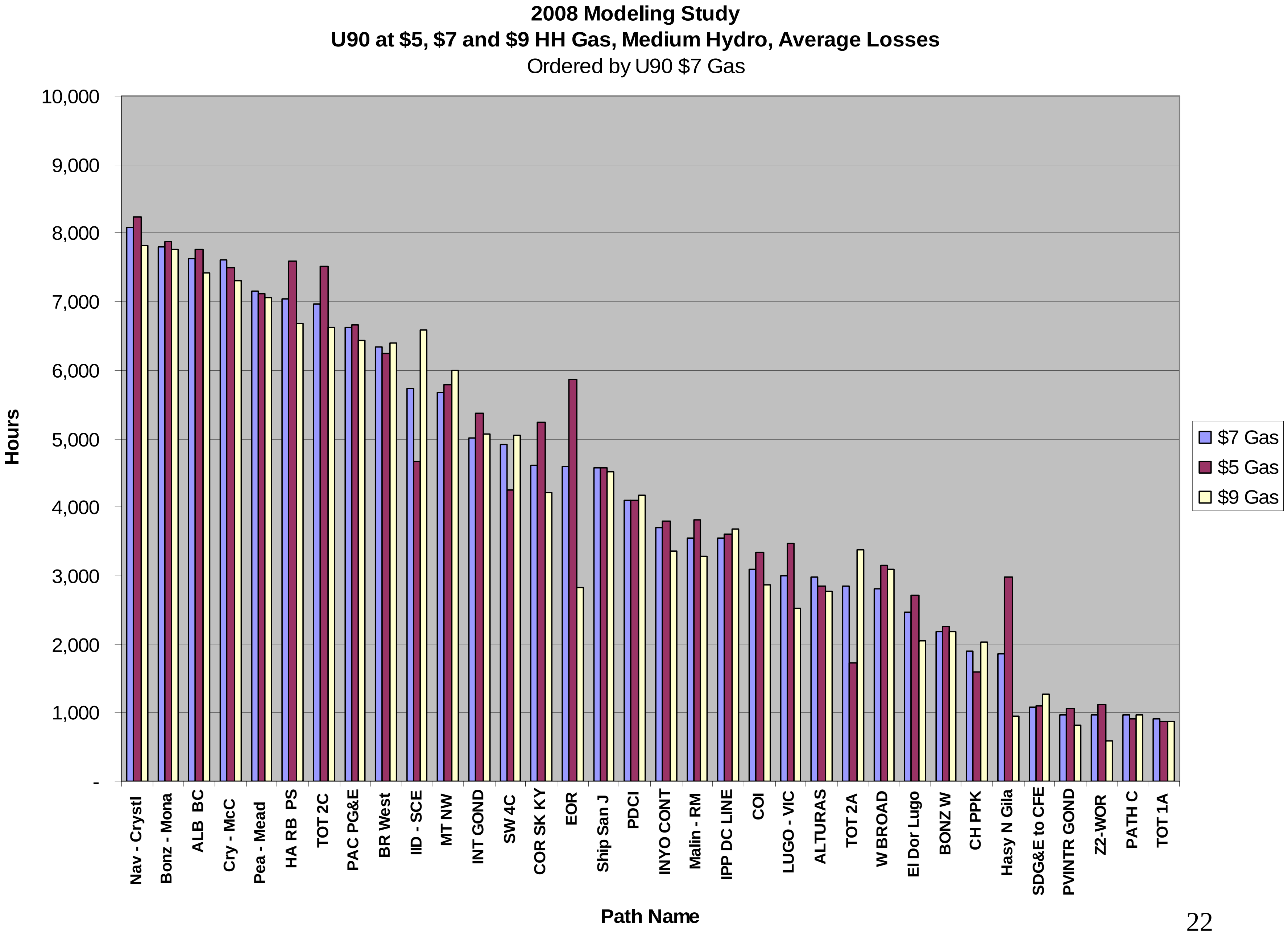
Bonz - Mona
ALB BC
Cry - McC
Pea - Mead
HA RB PS
TOT 2C
PAC PG&E
BR West
IID - SCE
MT NW
INT GOND
SW 4C
COR SK KY
EOR
Ship San J
PDCI
INYO CONT
Malin - RM
IPP DC LINE
COI
LUGO - VIC
ALTURAS
TOT 2A
W BROAD
El Dor Lugo
BONZ W
CH PPK
Hasy N Gila
SDG&E to CFE
PVINTR GOND
Z2-WOR
PATH C
TOT 1A
Path Name


2008 Modeling Study
U90 at $5, $7 and $9 HH Gas, Medium Hydro, Average Losses
Ordered by U90 $7 Gas
Hours
10,000
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$7 Gas
$5 Gas
$9 Gas
Nav - Crystl
Bonz - Mona
ALB BC
Cry - McC
Pea - Mead
HA RB PS
TOT 2C
PAC PG&E
BR West
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INT GOND
SW 4C
COR SK KY
EOR
Ship San J
PDCI
INYO CONT
Malin - RM
IPP DC LINE
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LUGO - VIC
ALTURAS
TOT 2A
W BROAD
El Dor Lugo
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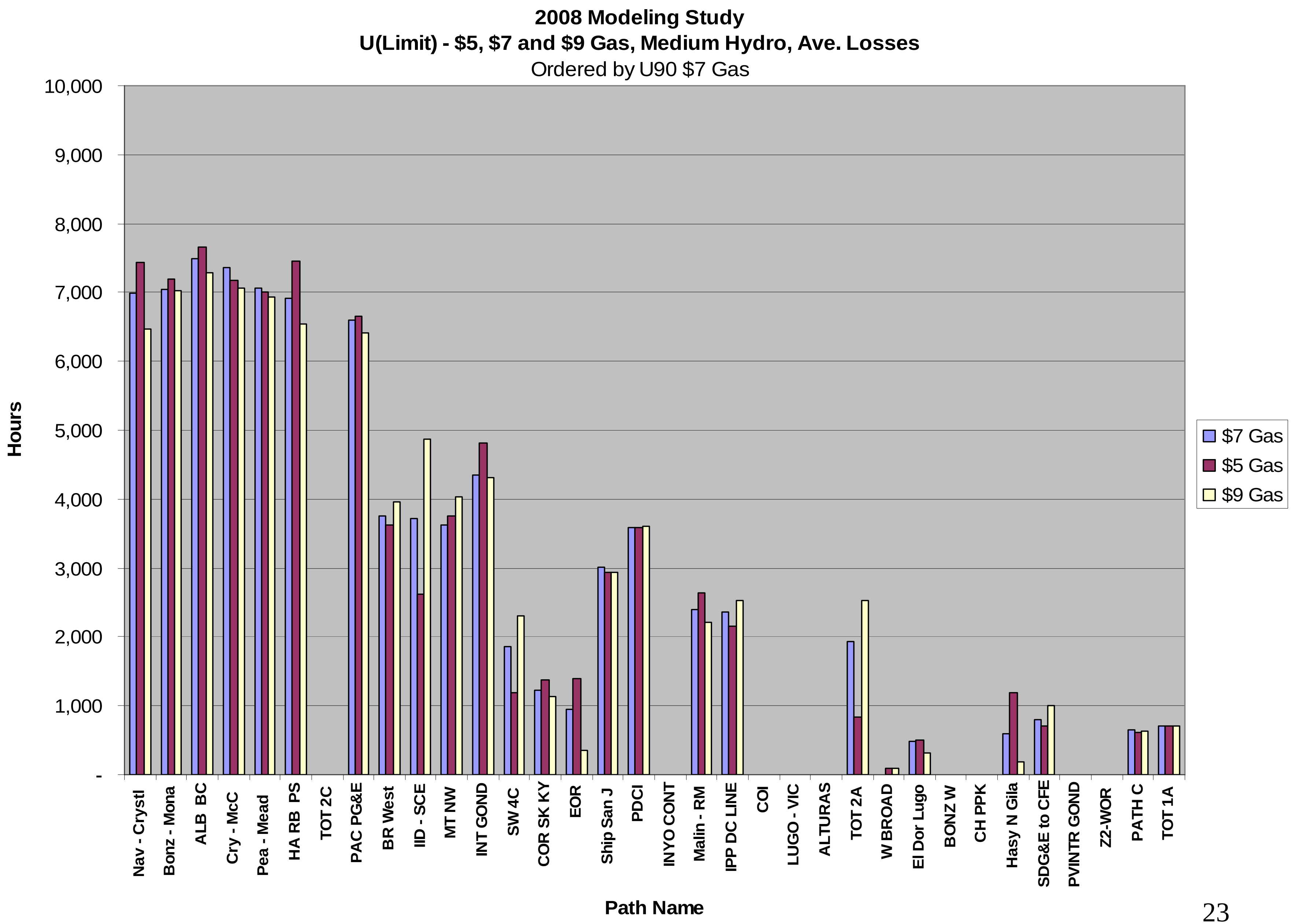
PATH C
TOT 1A
Path Name


2008 Modeling Study
U(Limit) - $5, $7 and $9 Gas, Medium Hydro, Ave. Losses
Ordered by U90 $7 Gas
Hours
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9,000
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$9 Gas
Nav - Crystl
Bonz - Mona
ALB BC
Cry - McC
Pea - Mead
HA RB PS
TOT 2C
PAC PG&E
BR West
IID - SCE
MT NW
INT GOND
SW 4C
COR SK KY
EOR
Ship San J
PDCI
INYO CONT
Malin - RM
IPP DC LINE
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LUGO - VIC
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El Dor Lugo
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Hasy N Gila
SDG&E to CFE
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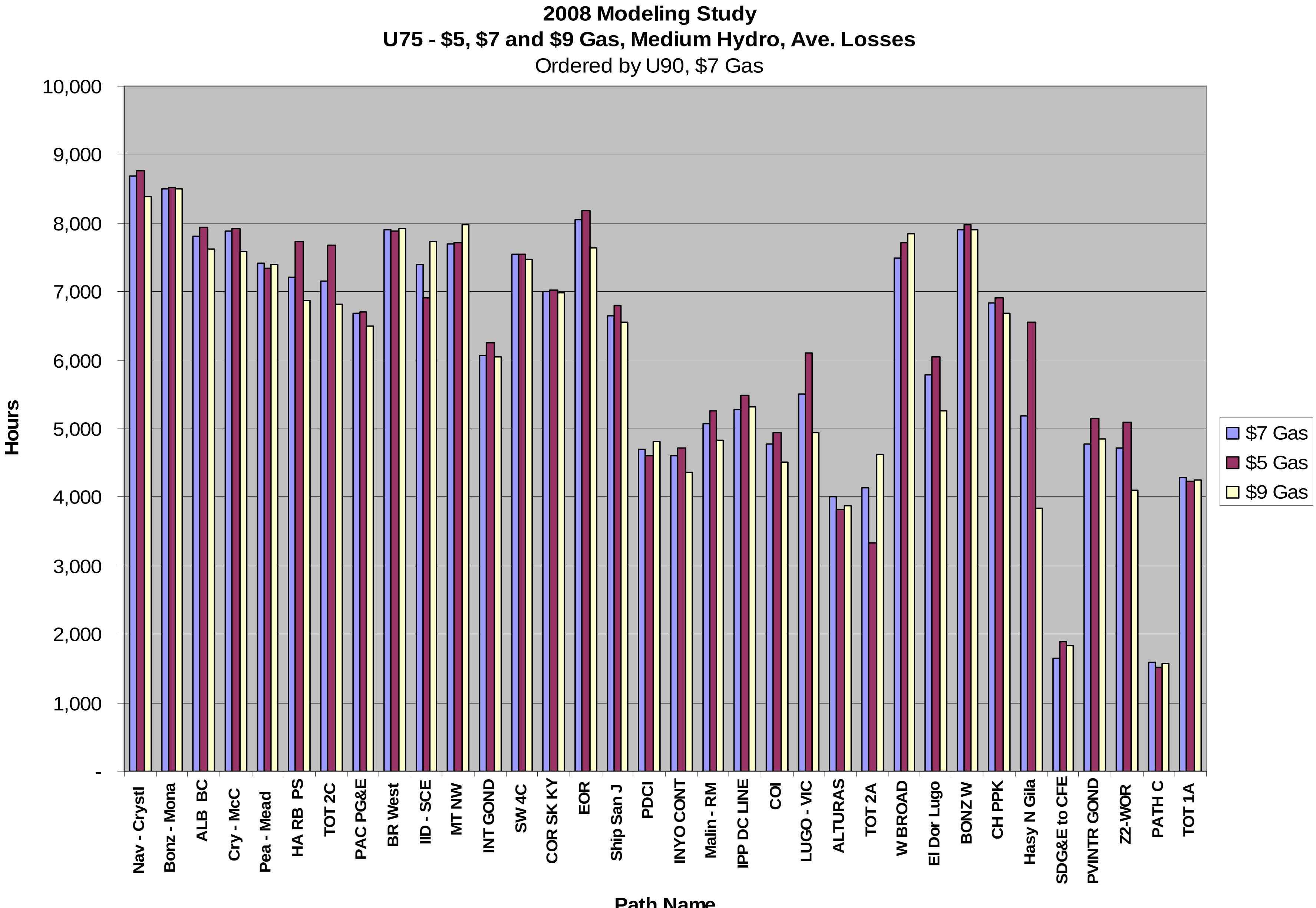
PATH C
TOT 1A
Path Name



2008 Modeling Study
U75 - $5, $7 and $9 Gas, Medium Hydro, Ave. Losses
Ordered by U90, $7 Gas
10,000
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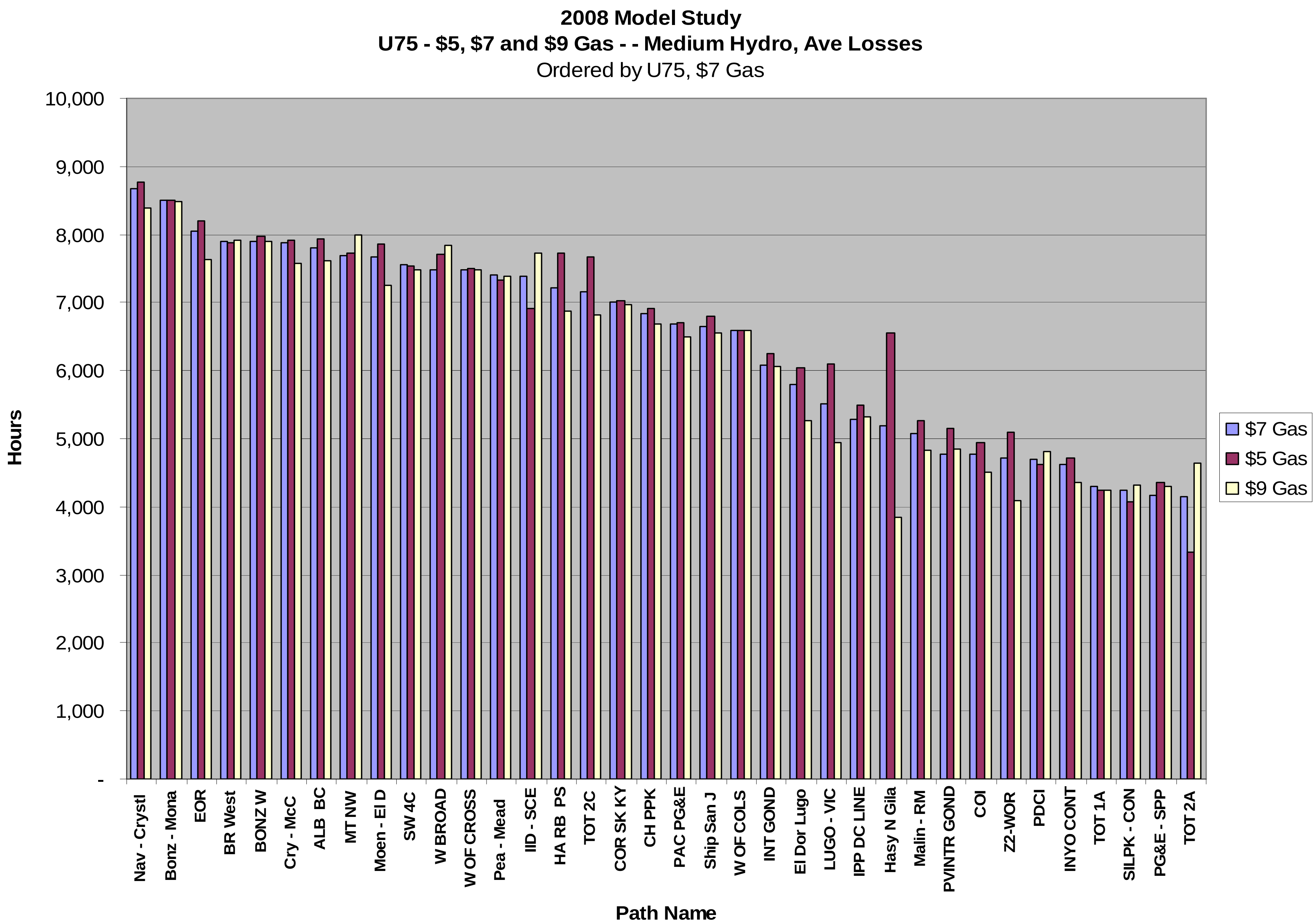
Hours
Nav - Crystl
Bonz - Mona
ALB BC
Cry - McC
Pea - Mead
HA RB PS
TOT 2C
PAC PG&E
BR West
IID - SCE
MT NW
INT GOND
SW 4C
COR SK KY
EOR
Ship San J
PDCI
INYO CONT
Malin - RM
IPP DC LINE
COI
LUGO - VIC
ALTURAS
TOT 2A
W BROAD
El Dor Lugo
BONZ W
CH PPK
Hasy N Gila
SDG&E to CFE
PVINTR GOND
Z2-WOR
PATH C
TOT 1A
Path Name
$7 Gas
$5 Gas
$9 Gas


2008 Model Study
U75 - $5, $7 and $9 Gas - - Medium Hydro, Ave Losses
Ordered by U75, $7 Gas
Hours
Path Name
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$5 Gas
$9 Gas
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W OF CROSS
Pea - Mead
IID - SCE
HA RB PS
TOT 2C
COR SK KY
CH PPK
PAC PG&E
Ship San J
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INT GOND
El Dor Lugo
LUGO - VIC
IPP DC LINE
Hasy N Gila
Malin - RM
PVINTR GOND
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Z2-WOR
PDCI
INYO CONT
TOT 1A
SILPK - CON
PG&E - SPP
TOT 2A

2008
Path Shadow Prices
Results

2008 - Modeled Path Shadow Prices

Congestion Rent, Average Shadow Price and Binding Hours Average Shadow Price

for $5, $7 and $9 HH gas - Med. Hydro, Ave Losses - - Ordered by $7 Gas Binding Average Shadow Price - - A dash in the table = 0 value

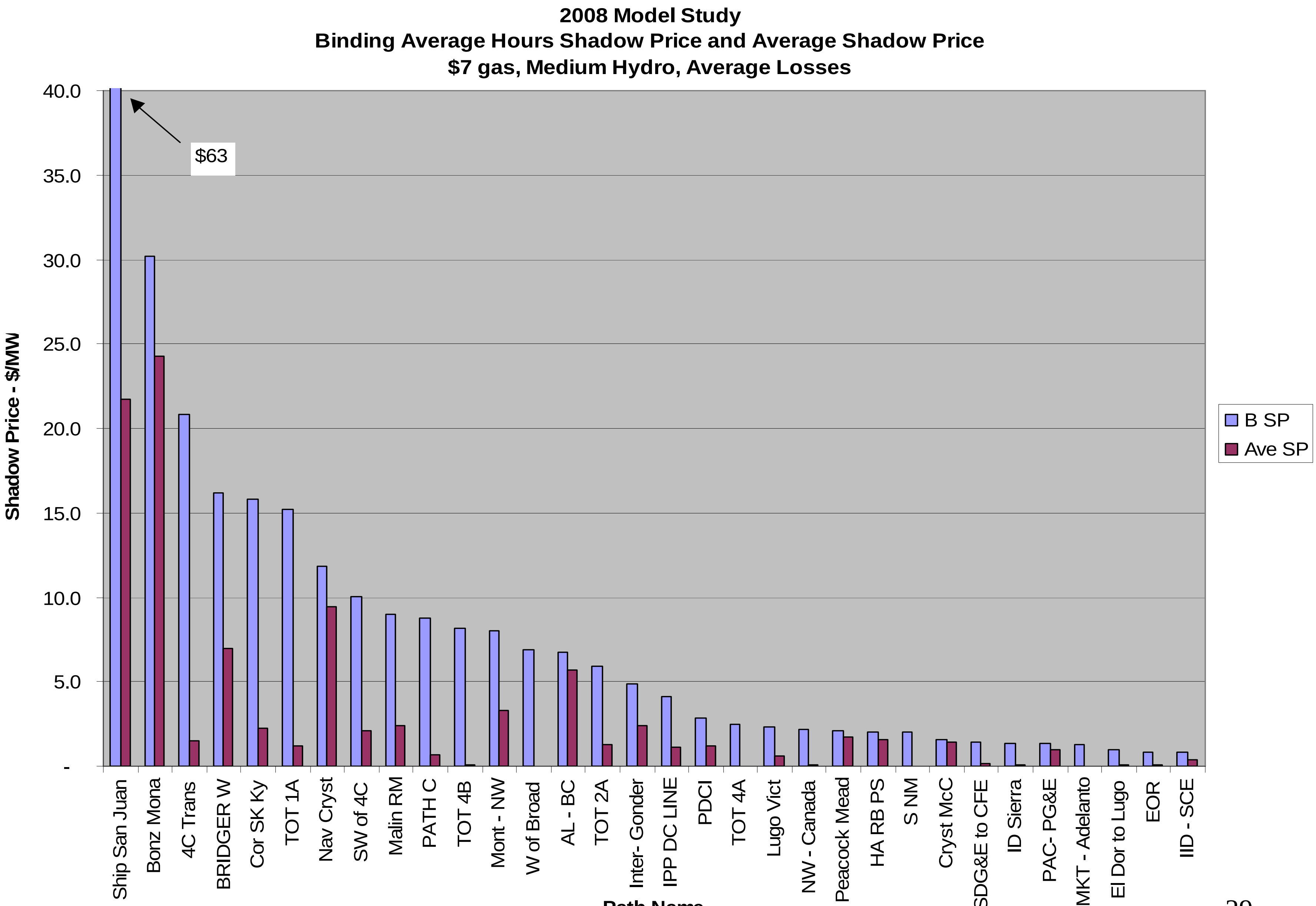
	$5 Gas			$7 Gas			$9 Gas		
Path Name	**Congestion Rent (k$/yr)**	**Average Shadow Price ($/MW)**	**Binding Average Shadow Price ($/MW)**	**Congestion Rent (k$/yr)**	**Average Shadow Price ($/MW)**	**Binding Average Shadow Price ($/MW)**	**Congestion Rent (k$/yr)**	**Average Shadow Price ($/MW)**	**Binding Average Shadow Price ($/MW)**
Shiprock - San Juan	76,189.97	12.7	38.0	129,963.36	21.7	63.2	175,350.41	29.3	87.4
Bonanze - Mona (Bonanza West)	107,145.85	19.8	24.1	131,555.28	24.3	30.2	159,709.73	29.4	36.9
4C Trans	9,064.17	1.2	17.3	10,898.85	1.5	20.8	11,105.78	1.5	21.2
BRIDGER WEST	96,626.08	5.0	12.1	134,152.81	6.9	16.2	156,967.43	8.1	18.0
Cor - Sking - Kyrene	13,949.27	1.4	9.2	21,445.63	2.2	15.8	31,425.74	3.3	25.3
TOT 1A	5,530.90	1.0	12.0	7,019.06	1.2	15.2	8,444.83	1.5	18.6
Navajo - Crystal (EOR)	140,908.70	11.4	13.4	116,844.42	9.4	11.8	89,182.88	7.2	9.8
SW of 4C	22,402.87	1.1	8.1	43,389.05	2.1	10.0	70,111.43	3.4	13.1
Malin - RM 1 & 2 (COI)	35,022.26	2.7	8.9	31,846.99	2.4	9.0	29,295.25	2.3	9.0
PATH C	3,324.91	0.5	6.9	4,518.17	0.6	8.8	5,074.11	0.7	10.0
TOT 4B	155.17	0.0	6.0	323.17	0.1	8.2	233.55	0.0	8.6
Mont - NW	53,230.99	2.8	6.4	63,815.86	3.3	8.0	89,353.26	4.6	10.1
W of Broad	1,095.70	0.0	4.6	123.56	0.0	6.9	2,030.99	0.1	9.2
AL - BC	34,070.17	5.5	6.4	35,227.22	5.7	6.7	36,591.23	6.0	7.2
TOT 2A	2,065.56	0.3	3.6	7,848.89	1.3	5.9	17,524.90	2.9	10.0
Inter- Gonder	4,083.24	2.1	3.8	4,676.19	2.4	4.9	5,369.55	2.8	5.7
IPP DC LINE	14,878.02	0.9	3.6	18,623.10	1.1	4.1	21,670.00	1.3	4.5
PDCI	29,356.02	1.1	2.7	30,951.55	1.2	2.9	33,589.62	1.3	3.1
TOT 4A	11.18	0.0	2.3	10.13	0.0	2.5	28.32	0.0	4.4
Lugo - Victorville (WOR)	12,364.42	0.6	2.1	12,160.90	0.6	2.3	10,465.25	0.5	2.4
NW - Canada	419.66	0.0	2.4	722.96	0.0	2.1	1,239.27	0.1	2.8
Peacock - Mead (EOR)	8,397.42	2.0	2.5	7,255.19	1.7	2.1	5,782.45	1.4	1.7
HA PS - Red Butte (TOT 2C)	3,332.36	1.3	1.6	4,002.12	1.6	2.0	4,554.29	1.8	2.4
S NM	26.99	0.0	1.4	72.86	0.0	2.0	122.17	0.0	2.6
Crystal - McCullough (EOR)	24,786.21	1.6	2.0	20,737.79	1.4	1.6	15,974.52	1.1	1.3
SDG&E to CFE	1,109.89	0.2	2.1	482.24	0.1	1.4	2,411.61	0.5	3.9
IDAHO - SIERRA	252.04	0.1	1.5	192.87	0.0	1.3	215.12	0.0	1.3
PAC- PG&E 115	760.87	1.1	1.4	701.47	1.0	1.3	664.51	0.9	1.3
MKT - Adelanto	110.59	0.0	1.2	126.78	0.0	1.3	56.71	0.0	1.1
El Dor to Lugo (WOR)	1,325.02	0.1	0.9	1,325.43	0.1	1.0	672.14	0.0	0.8
EOR	15,432.41	0.2	1.5	6,095.96	0.1	0.9	1,123.50	0.0	0.4
IID - SCE	1,297.60	0.2	0.8	1,809.29	0.3	0.8	2,812.40	0.5	1.0
Hassy - N. Gila (EOR)	2,232.26	0.1	1.0	637.24	-	0.6	141.51	-	0.4
N of San Ono	23.46	0.0	0.4	29.54	0.0	0.4	56.24	0.0	0.6
PG&E - SPP	2.52	0.0	0.4	0.84	0.0	0.2	1.03	0.0	0.2
ID - NW	3.73	0.0	3.1	-	-	-	-	-	-
TOT 3	2.03	0.0	0.5	-	-	-	-	-	-
ALBERTA - SASKATCHEWAN	-	-	-	-	-	-	-	-	-
ALTURAS PROJECT	-	-	-	-	-	-	-	-	-
BILLINGS - YELLOWTAIL	-	-	-	-	-	-	-	-	-
BONANZA WEST	-	-	-	-	-	-	-	-	-

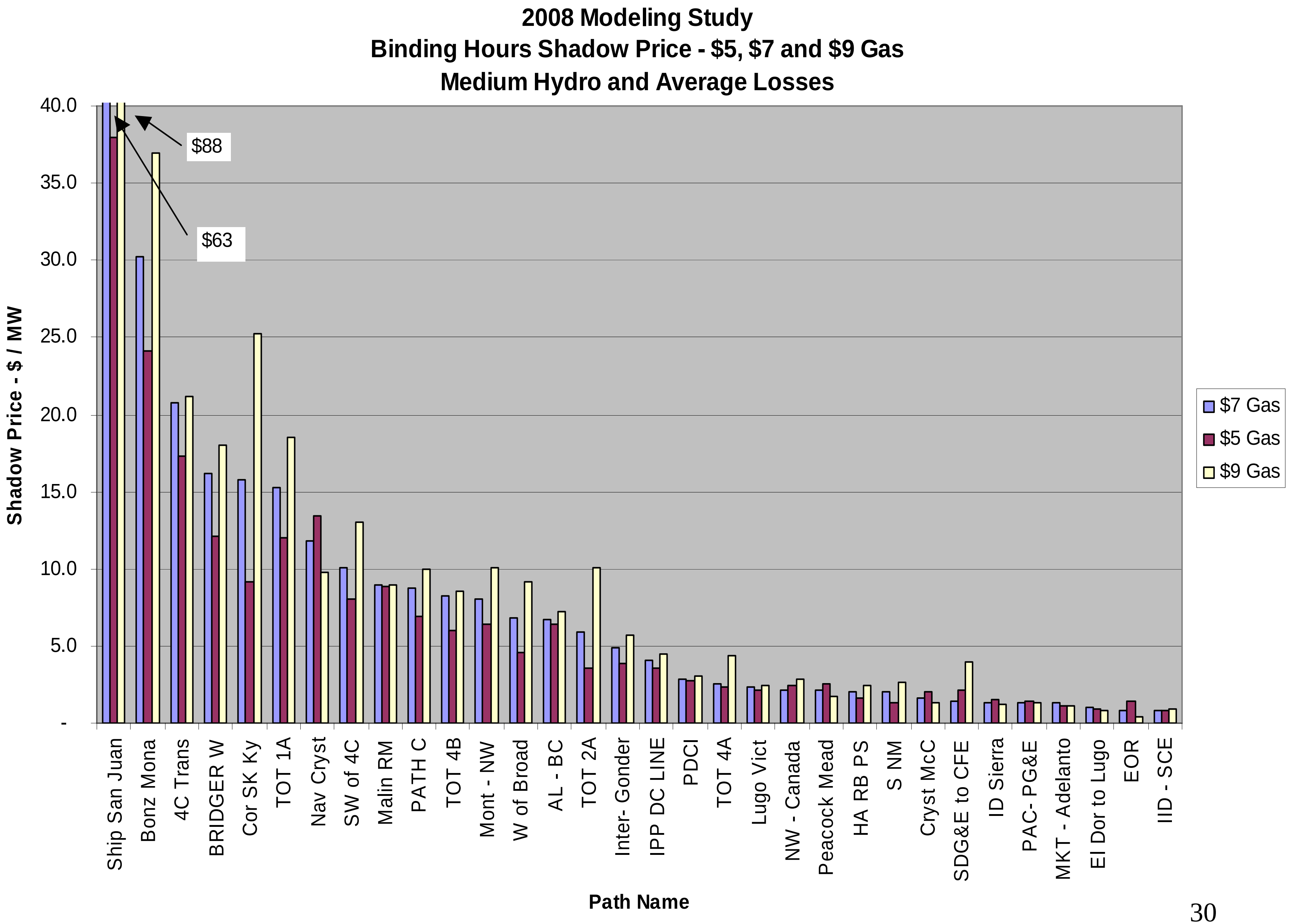
2008 - Modeled Shadow Price Metric Ranking

Congestion Rent, Average Shadow Price and Binding Hours Average Shadow Price

for $5, $7 and $9 HH gas - Med Hyrdo, Ave Losses - - Ordered by $7 Gas Binding Average Shadow Price

	$5 Gas			$7 Gas			$9 Gas		
Path Name	Congestion Rent Ranking	Average Shadow Price Ranking	Binding Average Shadow Price Ranking	Congestion Rent Ranking	Average Shadow Price Ranking	Binding Average Shadow Price Ranking	Congestion Rent Ranking	Average Shadow Price Ranking	Binding Average Shadow Price Ranking
Shiprock - San Juan	4	2	1	3	2	1	1	2	1
Bonanza - Mona (Bonanza West)	2	1	2	2	1	2	2	1	2
4C Trans	15	13	3	14	13	3	14	13	4
BRIDGER WEST	3	5	5	1	4	4	3	3	6
Cor - SKing - Kyrene	13	11	7	10	9	5	9	8	3
TOT 1A	17	17	6	17	16	6	16	14	5
Navajo - Crystal (EOR)	1	3	4	4	3	7	5	4	11
SW of 4C	10	15	9	6	10	8	6	7	7
Malin - RM 1 & 2 (COI)	6	7	8	8	8	9	10	11	13
PATH C	20	20	10	20	20	10	19	20	10
TOT 4B	30	29	13	28	26	11	28	26	14
Mont - NW	5	6	11	5	6	12	4	6	8
W of Broad	26	28	14	31	31	13	23	24	12
AL - BC	7	4	12	7	5	14	7	5	15
TOT 2A	22	21	17	15	15	15	12	9	9
Inter- Gonder	18	8	15	19	7	16	18	10	16
IPP DC LINE	12	18	16	12	18	17	11	16	17
PDCI	8	14	19	9	17	18	8	17	20
TOT 4A	34	33	22	34	31	19	34	26	18
Lugo - Victorville (WOR)	14	19	24	13	21	20	15	22	24
NW - Canada	28	30	21	24	28	21	24	25	21
Peacock - Mead (EOR)	16	9	20	16	11	22	17	15	25
HA PS - Red Butte (TOT 2C)	19	12	26	21	12	23	20	12	23
S NM	32	32	30	32	30	24	31	26	22
Crystal - McCullough (EOR)	9	10	25	11	14	25	13	18	26
SDG&E to CFE	25	24	23	27	23	26	22	23	19
IDAHO - SIERRA	29	26	27	29	27	27	29	26	28
PAC- PG&E 115	27	16	29	25	19	28	27	19	27
MKT - Adelanto	31	31	31	30	29	29	32	26	29
El Dor to Lugo (WOR)	23	27	33	23	25	30	26	26	31
EOR	11	23	28	18	24	31	25	26	33
IID - SCE	24	22	34	22	22	32	21	21	30
Hassy - N. Gila (EOR)	21	25	32	26	31	33	30	26	34
N of San Ono	33	33	37	33	31	34	33	26	32
PG&E - SPP	36	33	36	35	31	35	35	26	35
ID - NW	35	33	18	36	31	36	36	26	36
TOT 3	37	33	35	36	31	36	36	26	36
ALBERTA - SASKATCHEWAN									
ALTURAS PROJECT									
BILLINGS - YELLOWTAIL									
BONANZA WEST									
BORAH WEST									


2008 Model Study
Binding Average Hours Shadow Price and Average Shadow Price
$7 gas, Medium Hydro, Average Losses
Shadow Price - $/MW
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
-
$63
B SP
Ave SP
Ship San Juan
Bonz Mona
4C Trans
BRIDGER W
Cor SK Ky
TOT 1A
Nav Cryst
SW of 4C
Malin RM
PATH C
TOT 4B
Mont - NW
W of Broad
AL - BC
TOT 2A
Inter- Gonder
IPP DC LINE
PDCI
TOT 4A
Lugo Vict
NW - Canada
Peacock Mead
HA RB PS
S NM
Cryst McC
SDG&E to CFE
ID Sierra
PAC- PG&E
MKT - Adelanto
El Dor to Lugo
EOR
IID - SCE
Path Name


2008 Modeling Study
Binding Hours Shadow Price - $5, $7 and $9 Gas
Medium Hydro and Average Losses
Shadow Price - $ / MW
40.0
35.0
30.0
25.0
20.0
15.0
10.0
5.0
-
$88
$63
$7 Gas
$5 Gas
$9 Gas
Ship San Juan
Bonz Mona
4C Trans
BRIDGER W
Cor SK Ky
TOT 1A
Nav Cryst
SW of 4C
Malin RM
PATH C
TOT 4B
Mont - NW
W of Broad
AL - BC
TOT 2A
Inter- Gonder
IPP DC LINE
PDCI
TOT 4A
Lugo Vict
NW - Canada
Peacock Mead
HA RB PS
S NM
Cryst McC
SDG&E to CFE
ID Sierra
PAC- PG&E
MKT - Adelanto
El Dor to Lugo
EOR
IID - SCE
Path Name

2008
Alternative Ranking Methods

Congested Areas/Paths

Evaluation of Alternative Ranking Methodologies

- Five alternative Congestion Ranking Methods were applied to the W.I. 2008 Study results:
  - U90
  - U75
  - Shadow Price (binding hours)
  - Average of 9 metrics
  - Average of 9 metrics (modified method)
- Conclusion - - Ranking methodology results vary considerably, therefore identified W.I. Congestion Areas are grouped geographically and not ranked

Five Alternative Ranking Methods

1. U90
   - A usage based ranking
   - Paths were ranked using U90 at $7 gas
2. U75
   - A usage based ranking
   - Paths were ranked using U75 at $7 gas
3. Shadow Price
   - An economic based ranking
   - Paths were ranked using "binding hours shadow price" at $7 gas
4. Averaging Method
   - A combined usage and economic based ranking
   - Paths were ranked by (1) calculating the path's subranking for each of 9 categories (U90, U75, shadow price - - $5, $7, and $9 gas) and (2) calculating the average of these 9 subrankings. This value was then used to rank the paths.
5. Averaging Method (modified)
   - A combined usage and economic based ranking
   - Same as Method 4, however it was only applied to paths that ranked in the "top ten" in at least one of the 9 subranking categories.
   - This method defines a congestion grouping and assures that all paths that ranked high in at least one category are included.

Path Congestion Rankings for Five Alternative Ranking Methodologies Applied to the W.I. 2008 Modeling Study					
PATH	Usage		Economic	Usage plus Economic	
	U90 Ranking	U75 Ranking	Shadow Price Ranking	Average Ranking	Modified Average Ranking
Navajo - Crystal (EOR)	1	1	7	2	2
Bonanza - Mona (Bonanza West)	2	2	2	1	1
ALBERTA - BRITISH COLUMBIA	3	7	14	4	4
Crystal - McCullough (EOR)	4	6	25	9	9
Peacock - Mead (EOR)	5	13	22	10	10
Harry Allen PS - Red Butte (TOT 2C)	6	15	23	11	11
TOT 2C	7	16		18	17
PACIFICORP_PG&E 115 KV INTERCON.	8	19	28	16	15
BRIDGER WEST	9	4	4	3	3
IID - SCE	10	14	32	15	14
MONTANA - NORTHWEST	11	8	12	5	5
INTERMOUNTAIN - GONDER 230 KV	12	23	16	13	
SOUTHWEST OF FOUR CORNERS	13	10	8	6	6
CORONADO - SILVER KING - KYRENE	14	17	5	7	7
EOR	15	3	31	14	13
Shiprock - San Juan	16	20	1	8	8
PACIFIC DC INTERTIE (PDCI)	17	32	18	20	
INYO - CONTROL 115 KV TIE	19	33		28	
Malin Round Mountain 1 & 2	20	28	9	17	16
IPP DC LINE	21	26	17	19	
COI	22	30		30	
LUGO - VICTORVILLE 500 KV LINE	23	25	20	27	
ALTURAS PROJECT	24	38		34	
TOT 2A	25	37	15	22	19
WEST OF BROADVIEW	26	11	13	12	12
El Dorado to Lugo (WOR)	27	24	30	25	
BONANZA WEST	28	5		21	18
CHOLLA - PINNACLE PEAK	29	18		26	
Hassayampa - N. Gila (EOR)	30	27	33	31	
SDG&E to CFE	31	51	26	35	
PAVANT INTRMTN - GONDER 230 KV	32	29			
WOR	33	31		36	
Path C	34	52	10	33	23
TOT 1A	35	34	6	23	20
Four Corners Transformer	38	42	3	24	21
TOT 4B	42	49	11	38	
Moenkopi - El Dorado	43	9		29	22

1. U90 - Ranked by calculated U90 at $7 gas price
2. U75 - Ranked by calculated U75 at $7 gas price
3. Shadow Price - Ranked by "Binding Hours Average Shadow Price" at $7 gas
4. Average Ranking - Ranked according to the Average of the 9 individual rankings (U90, U75, and Shadow Price for $5, $7 and $9 gas price
5. Modified Average - Same as "Average" except that all paths must rank in the top 10 in at least one of the 9 categories

2008 Study - Summary of Results

Identified Congestion Areas using the "Modified Average" Method

Average of U75, U90 and Binding Average Shadow Price rankings for $5, $7 and $9 gas

Areas and Paths are grouped geographically and are not listed in rank order

Congestion Area		Congested Lines/Paths in Congestion Area		Impacted WECC Path	Path Number
Desert SW					
AZ to S. Cal and S. Nev		Navajo - Crystal		EOR	49
		EOR		EOR	49
		Crystal - McCullough		EOR	49
		Moenkopi - El Dorado		EOR	49
		Peacock - Mead		EOR	49
N and E Arizona		4 Corners Transformer		4 Corn TX	23
		Coronado - Silver King - Kyrene		Cor - SK - Ky	54
		SW of 4 Corners		SW of 4 C	22
Rock Mountain Area					
WY to Utah/Idaho		Bridger West		Bridger West	19
		Path C		Path C	20
Montana to NW		Montana to NW		MT to NW	8
		West of Broadview		W of Broad.	9
CO to Utah		Bonanza Mona		Bonanza W.	33
		Bonanza West		Bonanza W.	33
		TOT 1A		TOT 1A	30
CO to NM		TOT 2A		TOT 2A	31
		Ship Rock - San Juan		TOT 2A	31
Utah to S. Nevada		Red Butte - Harry Allen PS		TOT 2C	35
		TOT 2C		TOT 2C	35
Utah to Central Nevada		Intermountain - Gonder		Inter - Gondr	29
NW and Canada					
NW to California		PAC - PG&E 115 kV PS		PAC - PG&E	25
		Malin - Round Mtn. 1 & 2 (COI)		COI	66
Canada		Alberta to BC		ALB to BC	1
California					
Southern California		IID to SCE		IID to SCE	42

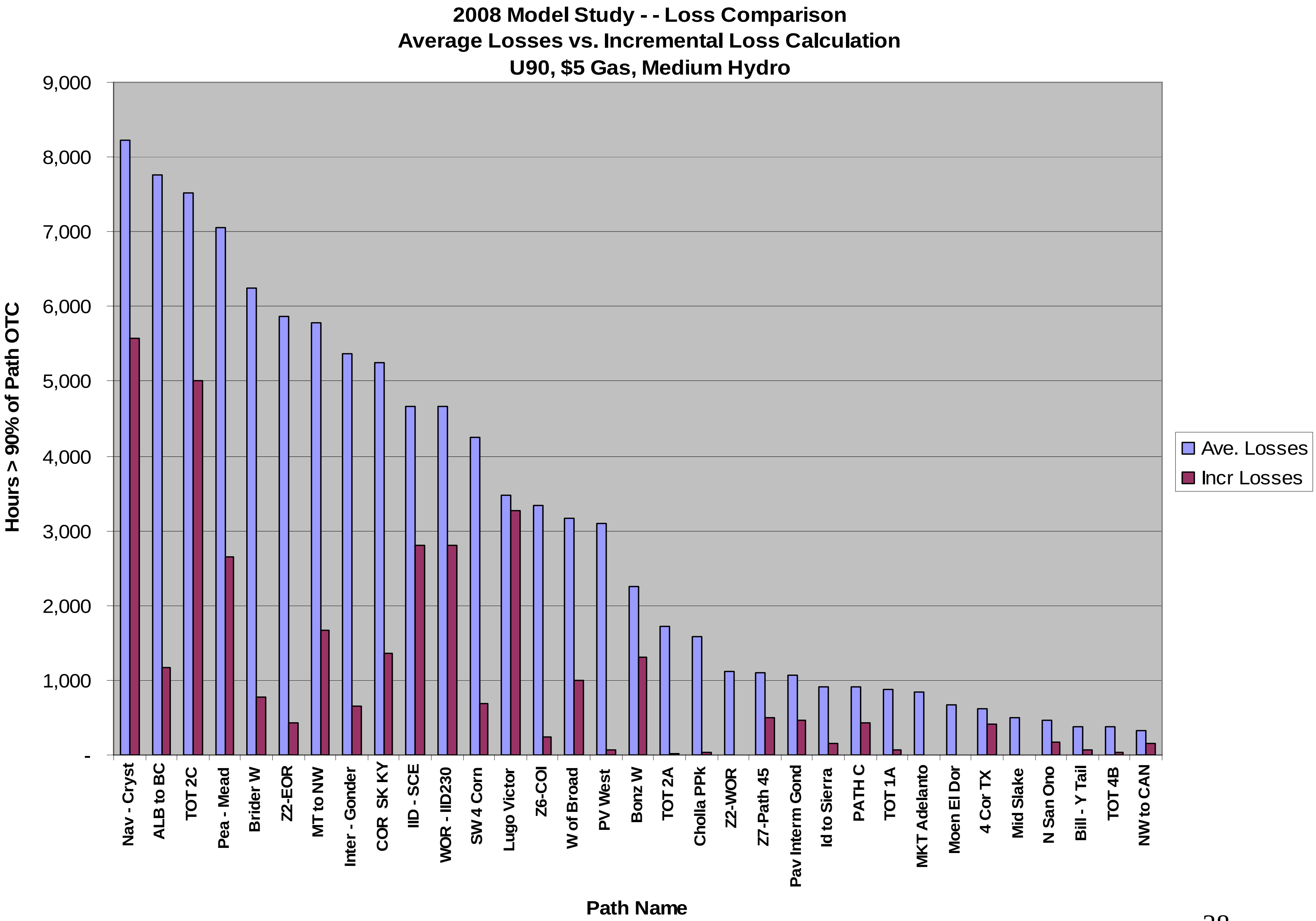
NOTE: In the "Modified Average" method, all paths must rank in the top 10 in at least one of the nine ranking categories (U75, U90, Binding Hrs Shadow Price, for $5, $7 and $9 gas.

2008
Loss Comparison Study

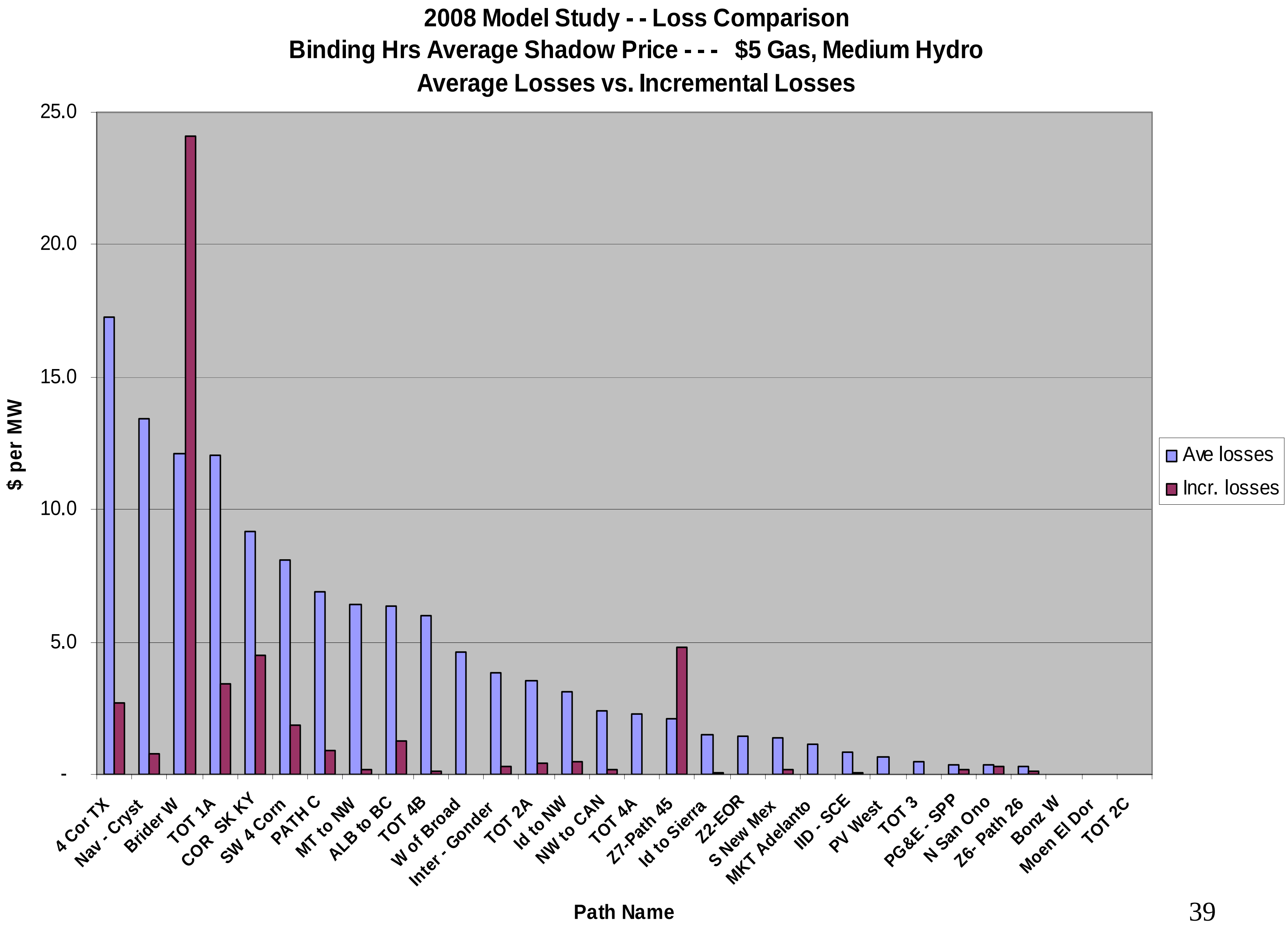
Average vs. Incremental Transmission Losses

2008 Study - Loss Comparison

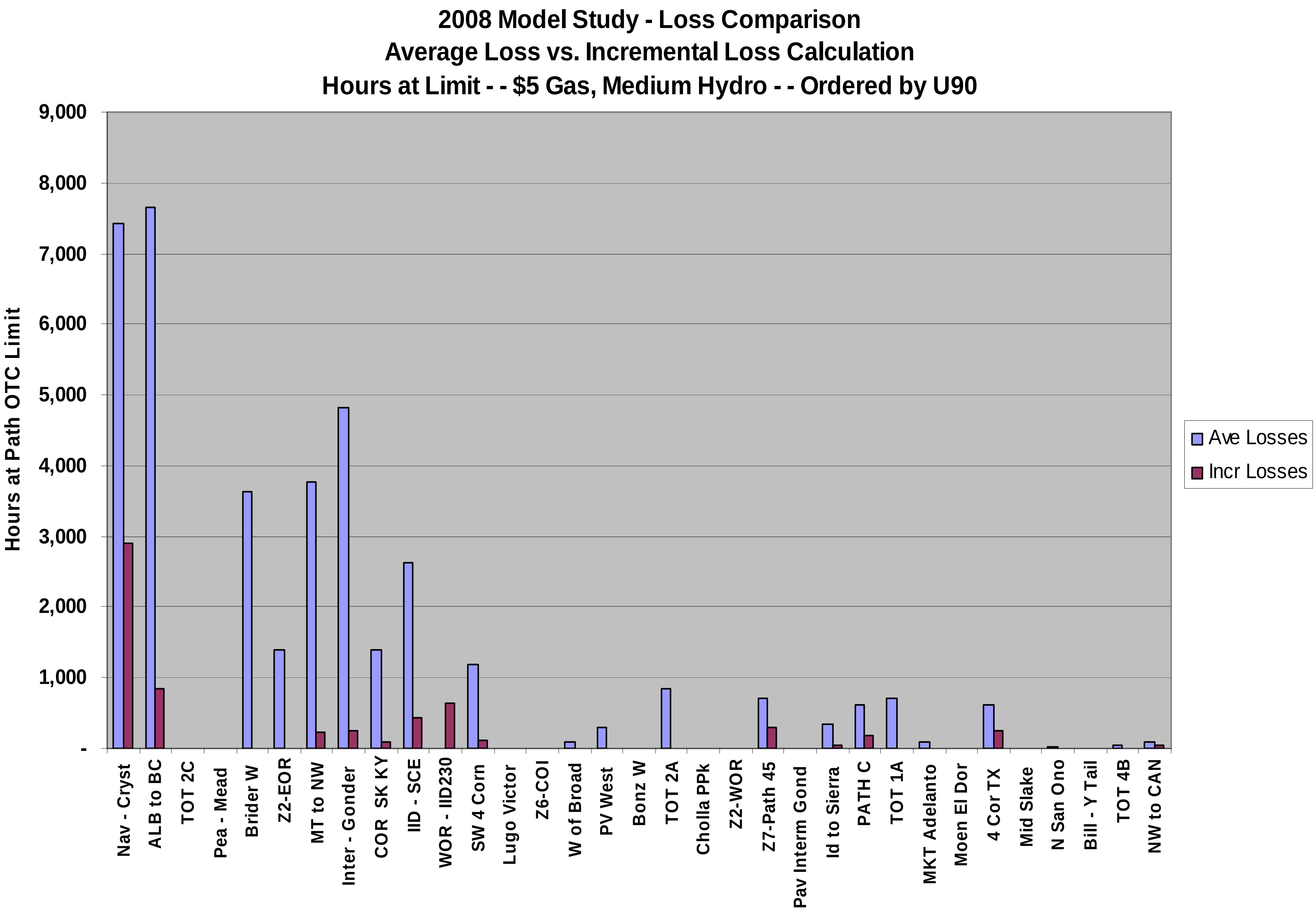
- Task 3 Studies used Average losses to be comparable to the Eastern Interconnection studies.
- A loss comparison study was run as part of the 2008 W.I. study. For comparison, transmission line losses were modeled as both Average Losses (included as a fixed amount in the load) and as Incremental Losses (line losses vary as the square of the line flow.
- Results are preliminary and need further analysis
- Preliminary results indicate the way line losses are modeled can have a significant impact on congestion.
- Modeling incremental line losses generally reduces congestion, often by a significant amount.
- A comparison is made between modeled path flows with average and incremental losses and observed historical flows

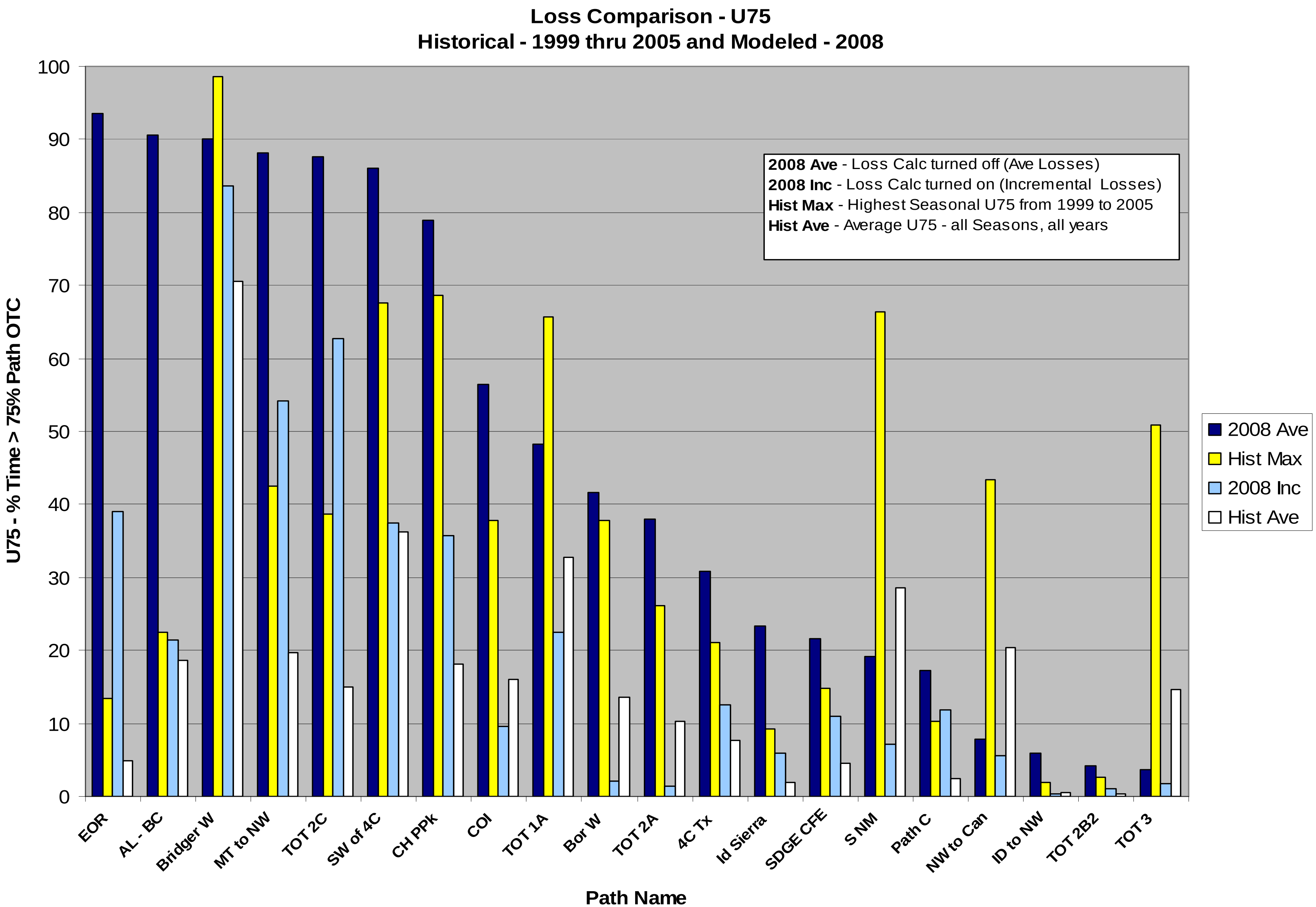


2008 Model Study - - Loss Comparison
Average Losses vs. Incremental Loss Calculation
U90, $5 Gas, Medium Hydro
Hours > 90% of Path OTC
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
Nav - Cryst
ALB to BC
TOT 2C
Pea - Mead
Brider W
Z2-EOR
MT to NW
Inter - Gonder
COR SK KY
IID - SCE
WOR - IID230
SW 4 Corn
Lugo Victor
Z6-COI
W of Broad
PV West
Bonz W
TOT 2A
Cholla PPk
Z2-WOR
Z7-Path 45
Pav Interm Gond
Id to Sierra
PATH C
TOT 1A
MKT Adelanto
Moen El Dor
4 Cor TX
Mid Slake
N San Ono
Bill - Y Tail
TOT 4B
NW to CAN
Path Name
Ave. Losses
Incr Losses



2008 Model Study - - Loss Comparison
Binding Hrs Average Shadow Price - - - $5 Gas, Medium Hydro
Average Losses vs. Incremental Losses
$ per MW
25.0
20.0
15.0
10.0
5.0
-
Ave losses
Incr. losses
4 Cor TX
Nav - Cryst
Brider W
TOT 1A
COR SK KY
SW 4 Corn
PATH C
MT to NW
ALB to BC
TOT 4B
W of Broad
Inter - Gonder
TOT 2A
Id to NW
NW to CAN
TOT 4A
Z7-Path 45
Id to Sierra
Z2-EOR
S New Mex
MKT Adelanto
IID - SCE
PV West
TOT 3
PG&E - SPP
N San Ono
Z6- Path 26
Bonz W
Moen El Dor
TOT 2C
Path Name


2008 Model Study - Loss Comparison
Average Loss vs. Incremental Loss Calculation
Hours at Limit - - $5 Gas, Medium Hydro - - Ordered by U90
Hours at Path OTC Limit
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
-
Ave Losses
Incr Losses
Nav - Cryst
ALB to BC
TOT 2C
Pea - Mead
Brider W
Z2-EOR
MT to NW
Inter - Gonder
COR SK KY
IID - SCE
WOR - IID230
SW 4 Corn
Lugo Victor
Z6-COI
W of Broad
PV West
Bonz W
TOT 2A
Cholla PPk
Z2-WOR
Z7-Path 45
Pav Interm Gond
Id to Sierra
PATH C
TOT 1A
MKT Adelanto
Moen El Dor
4 Cor TX
Mid Slake
N San Ono
Bill - Y Tail
TOT 4B
NW to CAN
Path Name



Loss Comparison - U75
Historical - 1999 thru 2005 and Modeled - 2008
2008 Ave - Loss Calc turned off (Ave Losses)
2008 Inc - Loss Calc turned on (Incremental Losses)
Hist Max - Highest Seasonal U75 from 1999 to 2005
Hist Ave - Average U75 - all Seasons, all years
2008 Ave
Hist Max
2008 Inc
Hist Ave
U75 - % Time > 75% Path OTC
100
90
80
70
60
50
40
30
20
10
0
EOR
AL - BC
Bridger W
MT to NW
TOT 2C
SW of 4C
CH PPk
COI
TOT 1A
Bor W
TOT 2A
4C Tx
Id Sierra
SDGE CFE
S NM
Path C
NW to Can
ID to NW
TOT 2B2
TOT 3
Path Name

Part 2

2015 Modeling Study

SSG-WI Path Limits

WECC Catalogue Operating Limits & Adjustments Made by SSG-WI

(xxx - Rating used in 2015 SSG-WI study, (xxx) – current WECC rating if different)

Interface Name	Forward Limit (MW)	Reverse Limit (MW)	Interface Name	Forward Limit (MW)	Reverse Limit (MW)	Interface Name	Forward Limit (MW)	Reverse Limit (MW)
ALBERTA - BRITISH COLUMBIA	700 (1000)	-720	Jojoba - Kyrene	1732	-1732	PV West	3600	
ALBERTA - SASKATCHEWAN	150	-150	LUGO - VICTORVILLE 500 KV LINE	2400	-900	SCIT	17700 (13700)	-17700
ALTURAS PROJECT	300	-300	Market Place - Adelanto	1636 (1200)	-1636	SDGE Import Limit	4000	
BONANZA WEST	785		Mccullgh - Victorville	1385	-1385	SILVER PEAK - CONTROL 55 KV	17	-17
BORAH WEST	2557 (2307)		MIDPOINT - SUMMER LAKE	1500	600 (400)	South of Alston	3050 (1620)	
BRIDGER WEST	2200		MIDWAY - LOS BANOS	5400 (3900)		South of Lugo	6100 (2264)	-6100
BROWNLEE EAST	1850 (1750)		Miguel - Tijuana	912	-912	South of Navajo	2264	
CHOLLA - PINNACLE PEAK	2700 (1200)		Miguel Bank No. 1	1120	-1120	SOUTH OF SAN ONOFRE	2500 (2200)	
COI	4700 (4800)	-3675	Miguel Bank No. 2	1120	-1120	SOUTHERN NEW MEXICO (NM1)	1048	-1048
Combined 4a 4b	1096		Moenkopi - El Dorado	1900	-1645	SOUTHWEST OF FOUR CORNERS	5325 (2325)	
CORONADO - SILVER KING - KYRENE	1600 (1100)		Mohave - Lugo	1386	-1386	SYLMAR - SCE	1600 (1200)	-1600
Crystal - H Allen 500 kV PS	1300		MONTANA - NORTHWEST	2950 (2200)	-1350	TOT 1A	800	-800
Crystal - H Allen230 kV PS	950		MONTANA SOUTHEAST	600	-600	TOT 2A	690	-690
Devers - San Bernardino 1(Post Outage)	317		N. Gila - Imperial Valley	1905		Tot 2a 2b 2c Nomogram	1570	-1600
Devers - San Bernardino 2 (Post Outage)	458		Navajo - Crystal	1900	-1900	TOT 2B	780	-850
Devers - Vista 1 (Post Outage)	458		Navajo - Moenkopi	1411		TOT 2B1	560	-600
Devers - Vista 2 (Post Outage)	494		NORTH OF JOHN DAY	8600 (8400)	-8600	TOT 2B2	265	-300
Devers Bank No. 1	1120	-1120	North of Miguel	2000		TOT 2C	300	-300
Devers Bank No. 1 (Post Outage)	1230		NORTH OF SAN ONOFRE	2440		TOT 3	1450 (1605)	-1800
EAGLE MTN 230_161 KV - BLYTHE 16	72	-218	NORTHERN NEW MEXICO (NM2)	1800		TOT 4A	810	-810
East of PV	6970		NORTHWEST - CANADA	2000	-3150	TOT 4B	680	-680
Eldorado - Lugo	1386	-1386	NW to Canada East BC	400	-400	TOT 5	1675	-1675
ELDORADO - MCCULLOUGH 500 KV	2598	-2598	NW to Canada West BC	2000	-2850	TOT 7	890	
ELDORADO - MEAD 230 KV LINES	1140	-1140	PACIFIC DC INTERTIE (PDCI)	2800 (3100)	-2100	WEST OF BROADVIEW	3323 (2573)	
EOR	10255 (7550)		PACIFICORP_PG&E 115 KV INTERCON.	100	-45	WEST OF CASCADES - NORTH	10500 (9800)	-10500
Hassayampa - N. Gila	1905		Path 26	4000 (3400)	-3000	WEST OF CASCADES - SOUTH	7000	-7000
IDAHO - MONTANA	337	-337	Path 45	408	-800	WEST OF COLSTRIP	3348 (2598)	
IDAHO - NORTHWEST	2400	-1200	PATH C	1075 (1000)	-850	WEST OF CROSSOVER	3348 (2598)	
IDAHO - SIERRA	500	-360	PAVANT INTRMTN - GONDER 230 KV	440	-235	WEST OF HATWAI	4277(2800)	
IID - SCE	1500		Peacock - Mead	508	-508	WOR	11823 (10118)	
Imperial Valley - La Rosita	797	-797	Perkins - Big Sandy	1238	-1238	WOR - IID230	600	-600
Imperial Valley to Miguel	2200		PERKINS - MEAD - MARKETPLACE 500	1400 (1300)		WOR - N.Gila	1861	
INTERMOUNTAIN - GONDER 230 KV	200		PG&E - SPP	160	-150	WOR -n- El Dor to Lugo	2754	
INTERMOUNTAIN - MONA 345 KV	1400	-1200	PGE-Bay	50000		WOR -n- Mc-Vic	2592	
INYO - CONTROL 115 KV TIE	56	-56	PV to Devers	4676		WYOMING TO UTAH	1700	
IPP DC LINE	1920	-1400						

2015

Resource Assumptions

Modeled Utility Integrated Resource Plans (IRP) and State Renewable Portfolio Standards (RPS)

Key Caveats

- Transmission congestion found in modeling is primarily driven by gas prices, hydro conditions and assumptions about location of generation resources in 2015
- Actual 2015 generation additions will evolve from those assumed in the study based on LSE preferences and state policies

2015 Resources By Area and Fuel Type

		2015 Resources		Resources (Capacity) MW by Fuel Type										
REGION	**AREA**	**Capacity (1) MW**	**Discounted Capacity (2) MW**	**Coal**	**Nat. Gas**	**Oil**	**Hydro**	**Wind**	**DR/DSM**	**Biomass (3) (thermal)**	**Solar**	**Geo**	**Nuclear**	**Other (4)**
CALIF ("CAISO")	IMPERIAL	2,108	2,092	0	357	32	176	21	0	405	0	1,117	0	0
CALIF ("CAISO")	LADWP **(5)**	8,983	8,121	0	6,645	0	1,003	1,150	0	0	185	0	0	0
CALIF ("CAISO")	MEXICO-C	4,717	4,717	0	3,793	139	0	0	0	0	0	785	0	0
CALIF ("CAISO")	PG&E_BAY	7,655	7,274	20	6,076	860	0	508	0	112	0	0	0	80
CALIF ("CAISO")	PG&E_VLY	28,680	27,722	50	14,055	174	8,592	1,278	0	611	280	1,286	2,190	165
CALIF ("CAISO")	SANDIEGO	4,923	4,801	0	4,372	48	40	163	0	0	300	0	0	0
CALIF ("CAISO")	SOCALIF	25,766	22,251	108	15,911	50	1,304	4,687	0	538	660	284	2,150	74
AZNMNV	ARIZONA	30,697	30,697	11,179	15,008	140	233	0	0	0	0	0	4,137	0
AZNMNV	NEVADA (5)	7,582	7,582	605	6,800	0	0	0			0	0	0	177
AZNMNV	NEW MEXI	5,619	5,427	2,037	3,264	0	14	240		64	0	0	0	0
AZNMNV	WAPA L.C	6,389	6,389	400	2,197	0	3,742	0	0	0	50	0	0	0
CANADA	ALBERTA	14,482	13,077	6,767	5,049	0	849	1,756	0	62	0	0	0	0
CANADA	B.C.HYDR	16,058	13,913	0	3,051	0	12,110	897	0	0	0	0	0	0
NWPP	NW_EAST	36,991	31,402	0	4,351	24	27,899	3,283	144	130	0	0	1,160	0
NWPP	NW_WEST	12,508	11,778	1,966	4,548	74	5,067	239	384	230	0	0	0	0
RMPP	B HILL	1,120	1,120	622	317	42	139	0	0	0	0	0	0	0
RMPP	BHB	0	0	0	0	0	0	0	0	0	0	0	0	0
RMPP	BONZ	468	468	468	0	0	0	0	0	0	0	0	0	0
RMPP	COL E	13,979	13,227	6,667	5,569	120	780	835	0	0	8	0	0	0
RMPP	COL W	2,294	2,294	1,904	104	0	286	0	0	0	0	0	0	0
RMPP	IDAHO	2,575	2,217	0	165	0	2,088	170	152	0	0	0	0	0
RMPP	IPP	1,847	1,847	1,847	0	0	0	0	0	0	0	0	0	0
RMPP	JB	2,628	2,628	2,628	0	0	0	0	0	0	0	0	0	0
RMPP	KGB	1,476	952	515	62	0	244	655	0	0	0	0	0	0
RMPP	LRS	1,628	1,628	1,107	300	0	221	0	0	0	0	0	0	0
RMPP	MONTANA	5,579	5,062	3,779	376	0	700	647	0	12	0	0	0	65
RMPP	SIERRA	4,137	3,656	1,268	1,720	0	0	601	0	23	0	524	0	0
RMPP	SW WYO	964	321	0	0	0	160	804	0	0	0	0	0	0
RMPP	UT N	2,438	2,438	929	1,381	0	84	0	44	0	0	0	0	0
RMPP	UT S	3,486	3,486	2,849	613	0	0	0	0	0	0	24	0	0
RMPP	WYO	775	775	775	0	0	0	0	0	0	0	0	0	0
RMPP	YLW TL	288	288	0	0	0	288	0	0	0	0	0	0	0
	Total Capacity	**258,838**	**239,648**	**48,490**	**106,084**	**1,703**	**66,017**	**17,933**	**724**	**2,187**	**1,483**	**4,021**	**9,637**	**561**

(1) Capacity represents installed capacity net of station service (capacity net to the grid).

(2) Discounted capacity reflects the the capacity contribution to peak load.

Assumed Discounts: BC Hydro (25% for hydro, 7.5% for wind), NW hydro credit 89.4%, California wind 25%, Colorado wind 10%, all other wind 20%

(3) Biomass (thermal): includes units using wood as fuel and "urban residuals".

(4) Other: Petroleum coke, waste heat

(5) LADWP includes 1,446MW of gas generation submitted by NV, but in the LADWP topology bubble because of dual allocation of the Crystal bus.
The 1,446MW was moved from the NV side of the substation to the LADWP side because of bus overloading on the NV side.

SSG-Wi 2015 IRP-RPS Reference Case

Difference with 2008 "Existing" Base Case

Includes submitted changes to the 2008 case, whether addition/subtraction of MW in pre-2008 years, or upgrades to older units

Sum of PSSEMaxCap(MW)			Fuel										
Region	**Area Name**	**Comment**	**Bio**	**Coal**	**DSM**	**Gas**	**Geothermal**	**Hydro**	**Oil**	**Solar**	**Wind**	**Nameplate Total**	**Discounted Total**
AZNMNV	ARIZONA	Added		3,400		2,700					1,500	7,600	6,400
	ARIZONA Total			3,400		2,700					1,500	7,600	6,400
	NEVADA	Added				1,446						1,446	1,446
	NEVADA Total					1,446						1,446	1,446
	NEW MEX	Added	64			1,406						1,470	1,470
		Retired				(149)			(20)			(169)	(169)
	NEW MEXI Total		64			1,257			(20)			1,301	1,301
	WAPA L.C	Added		400						50		450	450
	WAPA L.C Total			400						50		450	450
AZNMNV Total			**64**	**3,800**		**5,403**			**(20)**	**50**	**1,500**	**10,797**	**9,597**
CAISO	IMPERIAL	Added	75			50	425					550	550
	IMPERIAL Total		75			50	425					550	550
	LADWP	Added				300				185	1,030	1,515	743
	LADWP Total					300				185	1,030	1,515	743
	MEXICO-C	Added				1,619	86					1,704	1,704
		Retired							(300)			(300)	(300)
	MEXICO-C Total					1,619	86		(300)			1,404	1,404
	PG&E_BA	Added				565						565	565
		Retired				(215)						(215)	(215)
	PG&E_BAY Total					350						350	350
	PG&E_VL	Added	190			2,666	410			280	900	4,446	3,771
		Retired				(334)						(334)	(334)
	PG&E_VLY Total		190			2,332	410			280	900	4,112	3,437
	SANDIEGO	Added				500		40		300	163	1,003	881
		Retired				(689)						(689)	(689)
	SANDIEGO Total					(189)		40		300	163	314	192
	SOCALIF	Added	290			1,768				500	3,500	6,058	3,433
		Retired		(1,580)								(1,580)	(1,580)
	SOCALIF Total		290	(1,580)		1,768				500	3,500	4,478	1,853
CAISO Total			**555**	**(1,580)**		**6,229**	**921**	**40**	**(300)**	**1,265**	**5,593**	**12,723**	**8,528**

Sum of PSSEMaxCap(MW)			Fuel										
Region	**Area Name**	**Comment**	**Bio**	**Coal**	**DSM**	**Gas**	**Geothermal**	**Hydro**	**Oil**	**Solar**	**Wind**	**Nameplate Total**	**Discounted Total**
CANADA	ALBERTA	Added		1,420		1,164					1,670	4,254	2,918
		modified		(13)								(13)	(13)
		Retired		(434)		(359)		(317)				(1,110)	(1,110)
	ALBERTA Total			973		805		(317)			1,670	3,131	1,795
	B.C.HYDR	Added				1,173		1,754			897	3,823	2,994
	B.C.HYDR Total					1,173		1,754			897	3,823	2,994
CANADA Total				**973**		**1,978**		**1,437**			**2,567**	**6,954**	**4,788**
NWPP	NW_EAST	Added			144	723		260			1,590	2,717	1,445
	NW_EAST Total				144	723		260			1,590	2,717	1,445
	NW_WES	Added			384	790					150	1,324	1,204
	NW_WEST Total				384	790					150	1,324	1,204
NWPP Total					**528**	**1,513**		**260**			**1,740**	**4,041**	**2,649**
RMPP	B HILL	Added		100								100	100
	B HILL Total			100								100	100
	COL E	Added		3,150		1,282				8	835	5,275	4,524
	COL E Total			3,150		1,282				8	835	5,275	4,524
	IDAHO	Added			152	30						182	182
	IDAHO Total				152	30						182	182
	JB	Added		500								500	500
	JB Total			500								500	500
	KGB	Added		500		62					590	1,152	680
	KGB Total			500		62					590	1,152	680
	MONTANA	Added		1,268							400	1,668	1,348
	MONTANA Total			1,268							400	1,668	1,348
	SIERRA	Added		703		514	441				601	2,259	1,778
	SIERRA Total			703		514	441				601	2,259	1,778
	UT N	Added						44				44	44
		Retired				(128)						(128)	(128)
	UT N Total					(128)		44				(84)	(84)
	UT S	Added		575								575	575
	UT S Total			575								575	575
	SW Wyo	Added									700	700	140
RMPP Total				**6,796**	**152**	**1,760**	**441**	**44**		**8**	**3,126**	**12,327**	**9,723**
Total Net Change to 2008 Cas			**619**	**9,989**	**680**	**16,883**	**1,362**	**1,781**	**(320)**	**1,323**	**14,526**	**46,841**	**35,285**
Total Additions Only			**619**	**12,016**	**680**	**18,757**	**1,362**	**2,098**	**-**	**1,323**	**14,526**	**51,380**	**39,843**

2015

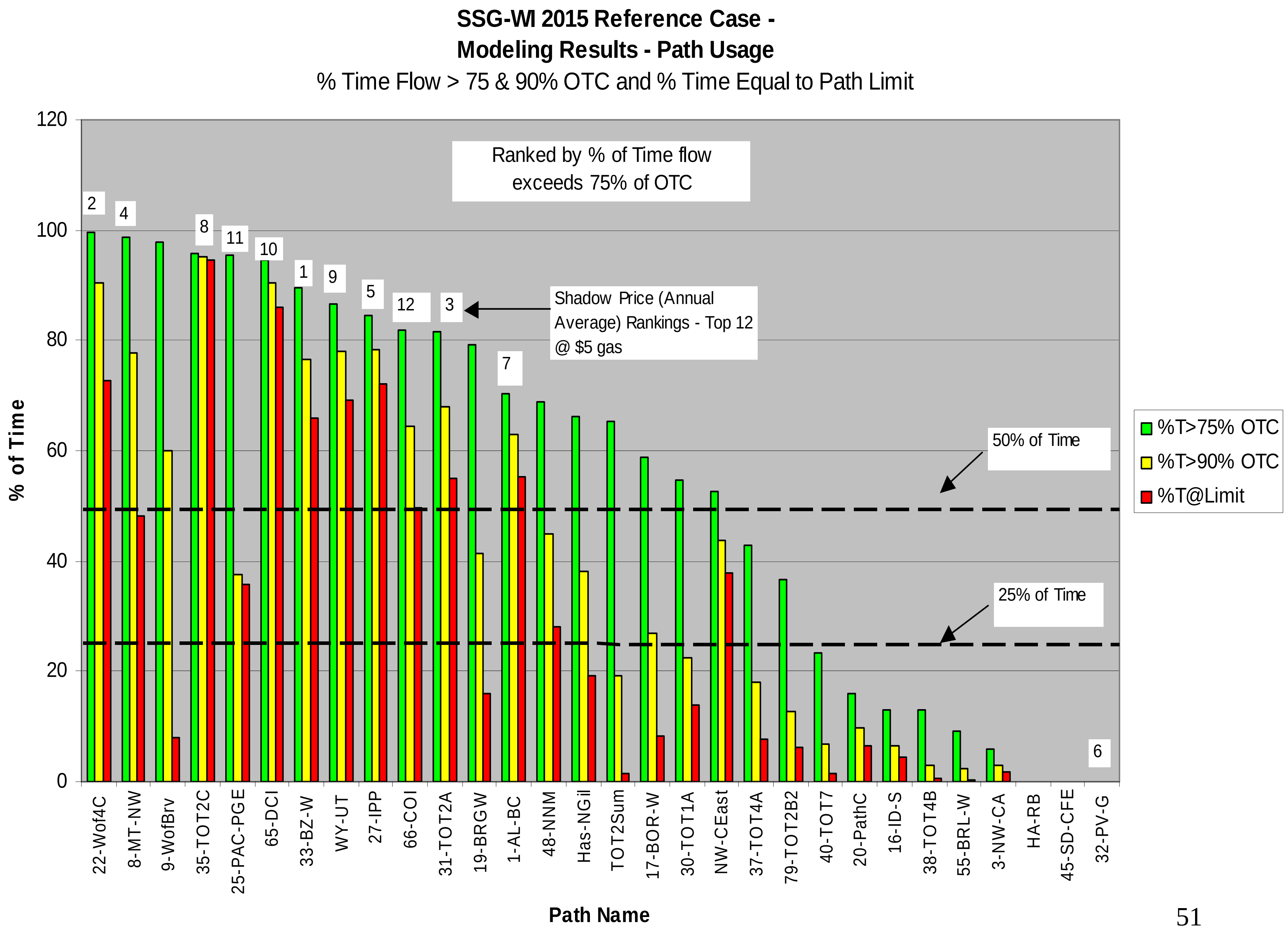
Study Results

Path Usage

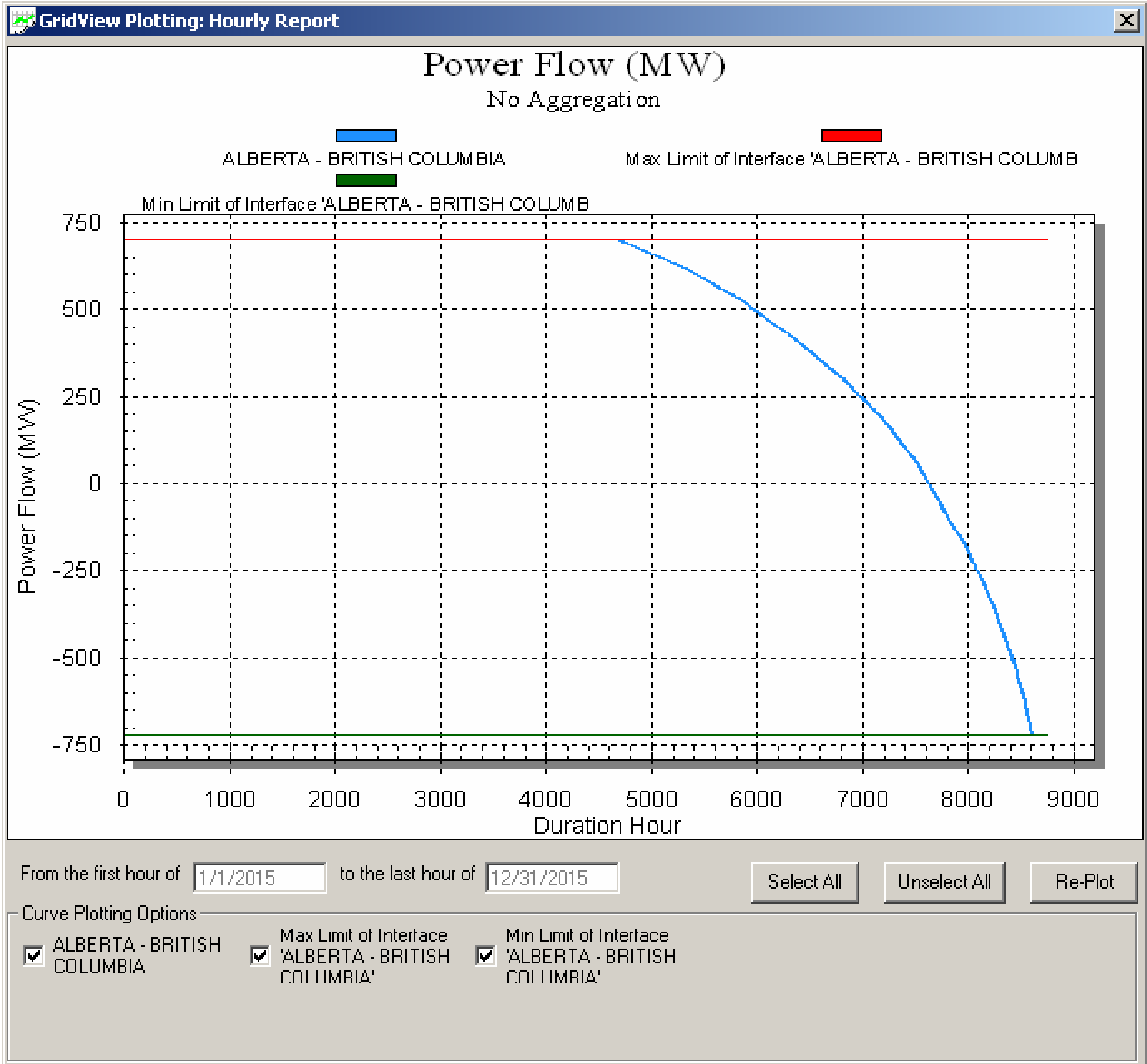
Path Economics

Key Caveats

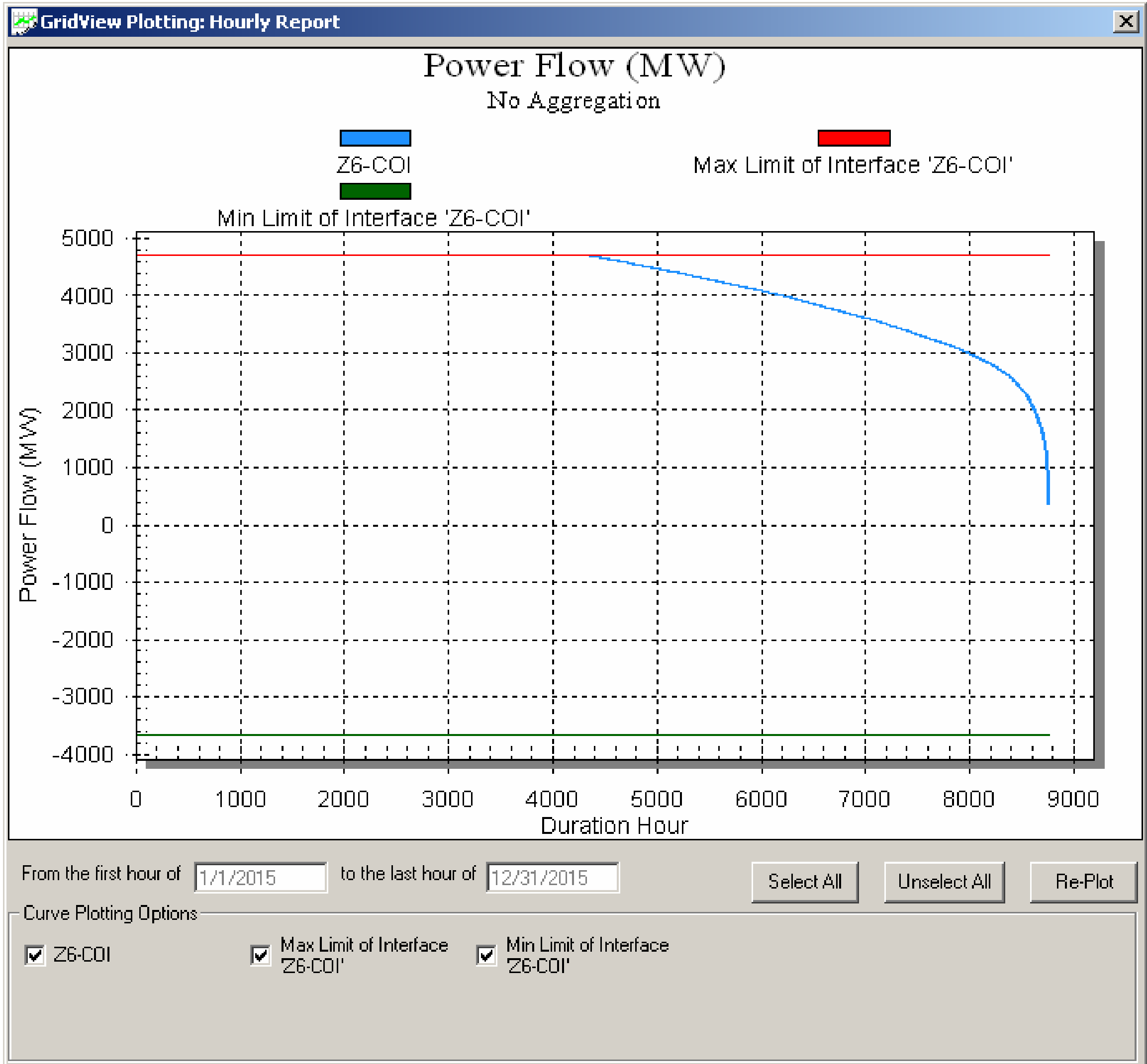
- High Flow Rankings do not necessarily imply Congested Paths. Some paths in the West have high flows because the path's primary function is to transmit generation to a specific load area. The IPP DC Line and Bridger West paths are typical examples.
- Results are highly dependent upon gas prices, hydro conditions and location of future resources.



SSG-WI 2015 Reference Case -
Modeling Results - Path Usage
% Time Flow > 75 & 90% OTC and % Time Equal to Path Limit
Ranked by % of Time flow exceeds 75% of OTC
Shadow Price (Annual Average) Rankings - Top 12 @ $5 gas
50% of Time
25% of Time
% of Time
Path Name
%T>75% OTC
%T>90% OTC
%T@Limit
22-Wof4C
8-MT-NW
9-WofBrv
35-TOT2C
25-PAC-PGE
65-DCI
33-BZ-W
WY-UT
27-IPP
66-COI
31-TOT2A
19-BRGW
1-AL-BC
48-NNM
Has-NGil
TOT2Sum
17-BOR-W
30-TOT1A
NW-CEast
37-TOT4A
79-TOT2B2
40-TOT7
20-PathC
16-ID-S
38-TOT4B
55-BRL-W
3-NW-CA
HA-RB
45-SD-CFE
32-PV-G



GridView Plotting: Hourly Report
Power Flow (MW)
No Aggregation
ALBERTA - BRITISH COLUMBIA
Max Limit of Interface 'ALBERTA - BRITISH COLUMB
Min Limit of Interface 'ALBERTA - BRITISH COLUMB
750
500
250
0
-250
-500
-750
Power Flow (MW)
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
Duration Hour
From the first hour of
1/1/2015
to the last hour of
12/31/2015
Select All
Unselect All
Re-Plot
Curve Plotting Options
ALBERTA - BRITISH COLUMBIA
Max Limit of Interface 'ALBERTA - BRITISH
Min Limit of Interface 'ALBERTA - BRITISH



GridView Plotting: Hourly Report
Power Flow (MW)
No Aggregation
Z6-COI
Max Limit of Interface 'Z6-COI'
Min Limit of Interface 'Z6-COI'
Power Flow (MW)
5000
4000
3000
2000
1000
0
-1000
-2000
-3000
-4000
0
1000
2000
3000
4000
5000
6000
7000
8000
9000
Duration Hour
From the first hour of
1/1/2015
to the last hour of
12/31/2015
Select All
Unselect All
Re-Plot
Curve Plotting Options
Z6-COI
Max Limit of Interface 'Z6-COI'
Min Limit of Interface 'Z6-COI'

Two Methods of Calculating Congestion Costs
(2015 Annual Summary)

Method I: Congestion Rent - - In the shadow price X MW flow columns, congestion cost for each congested path is defined as the hourly shadow price for each congested hour times the flow on the path for that hour, with the results summed for the year.

Method II: Annual Average Shadow Price - - The production cost decrease if 1 MW limit of the constraint is relaxed. It represents the average of the absolute value of the 8760 hourly shadow prices.

Interface Name	Method I (Shadow Price X MW Flow)						Method II Shadow Price ($/MW)					
	($000)			Rank			(Annual Average)			Rank		
	$5G	$7G	$9G	$5G	$7G	$9G	$5G	$7G	$9G	$5G	$7G	$9G
ALBERTA - BRITISH COLUMBIA	34,199	52,048	69,270	10	11	10	5.57	8.49	11.29	7	7	7
BONANZA WEST	128,592	193,862	260,621	3	3	3	18.93	28.19	37.90	1	1	1
BORAH WEST	32,490	53,503	79,154	11	10	8	1.43	2.39	3.53	18	16	14
BRIDGER WEST	36,955	56,449	73,984	9	9	9	1.93	2.93	3.84	16	12	12
BROWNLEE EAST	847	950	1,041	29	30	29	0.05	0.06	0.06	30	30	29
COI	93,035	77,532	68,445	5	8	11	2.25	1.88	1.66	12	19	21
HA-Red Butte PS	5,030	6,865	9,252	19	20	20	2.04	2.61	3.52	13	14	15
Hassayampa - N. Gila	4,988	3,371	812	20	25	30	0.45	0.20	0.05	25	28	30
IDAHO - SIERRA	1,976	4,049	6,136	25	23	22	0.62	1.28	1.95	22	21	19
IPP DC LINE	117,109	172,445	227,726	4	4	4	6.86	10.25	13.54	5	6	6
MONTANA - NORTHWEST	209,839	334,400	491,453	2	2	2	8.22	12.94	19.02	4	4	4
NORTHWEST - CANADA	1,060	1,525	2,224	28	29	26	0.06	0.09	0.13	29	29	28
NW to Canada East BC	7,110	9,461	12,600	17	17	19	1.98	2.69	3.59	15	13	13
PACIFIC DC INTERTIE (PDCI)	86,728	103,170	117,562	6	6	6	3.47	4.21	4.79	10	10	11
PACIFICORP_PG&E 115 KV INTERCON.	2,016	1,867	1,788	24	27	28	2.68	2.53	2.44	11	15	18
Path 45	3,914	5,725	5,905	23	22	23	0.78	0.82	0.86	21	23	24
PATH C	4,610	6,365	8,802	22	21	21	0.61	0.86	1.19	23	22	23
PAVANT INTRMTN - GONDER 230 KV	14,015	23,201	31,702	13	12	13	6.76	11.27	15.40	6	5	5
SOUTHERN NEW MEXICO (NM1)	9,462	18,665	28,457	16	15	14	1.02	2.03	3.10	19	18	17
SOUTHWEST OF FOUR CORNERS	717,209	1,117,571	1,504,644	1	1	1	15.60	23.96	32.26	2	2	2
TOT 1A	6,846	9,158	12,985	18	18	17	0.96	1.31	1.85	20	20	20
TOT 2A	76,727	129,341	177,936	7	5	5	12.25	21.40	29.44	3	3	3
Tot 2a 2b 2c Nomogram	1,357	3,414	4,815	27	24	24	0.09	0.25	0.35	28	27	26
TOT 2B2	4,929	9,095	12,684	21	19	18	2.01	3.92	5.46	14	11	10
TOT 2C	13,531	20,724	27,313	14	14	15	4.99	7.89	10.39	8	8	8
TOT 4A	10,252	15,543	24,952	15	16	16	1.57	2.19	3.52	17	17	16
TOT 4B	567	1,547	2,056	30	28	27	0.10	0.26	0.35	27	26	27
TOT 7	1,902	3,070	3,752	26	26	25	0.20	0.39	0.48	26	25	25
WEST OF BROADVIEW	14,280	21,085	39,050	12	13	12	0.52	0.72	1.34	24	24	22
WYOMING TO UTAH	57,250	81,758	107,017	8	7	7	3.87	5.49	7.19	9	9	9

Part 3

Historical Path Usage Study

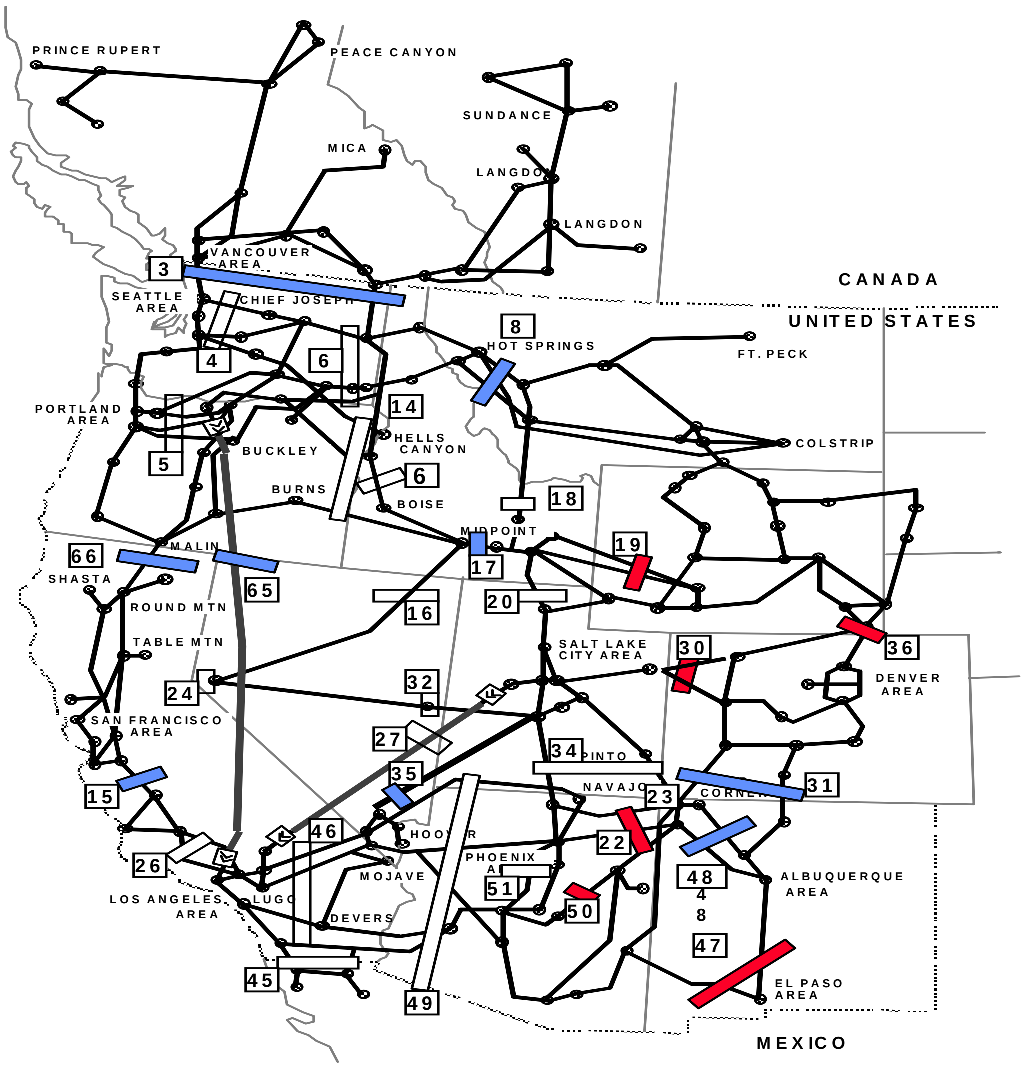
1999 thru 2005

Physical Usage

- Physical Usage analysis uses hourly data archived at WECC for actual hourly MW flow and hourly path limits (OTC)
  - OTC limits are often based on stability limits which may be more limiting than the thermal based transfer limits used in the East
  - Two measures
    - 1. Percent of time flows <u>exceeded 75%</u> of OTC based on the <u>maximum utilization in any season from 1999 to 2004</u>
    - 2. Percent of time flows <u>exceeded 90%</u> of OTC in the highest period from Spring 2004 through Summer 2005
  - Illustrative path
    - The duration of flows on SW of Four Corners Path
    - The maximum seasonal flows on SW of Four Corners Path

Physical Usage

- Seasons are defined in WECC as follows:
  - Spring: April and May
  - Summer: June thru October
  - Winter: November thru March

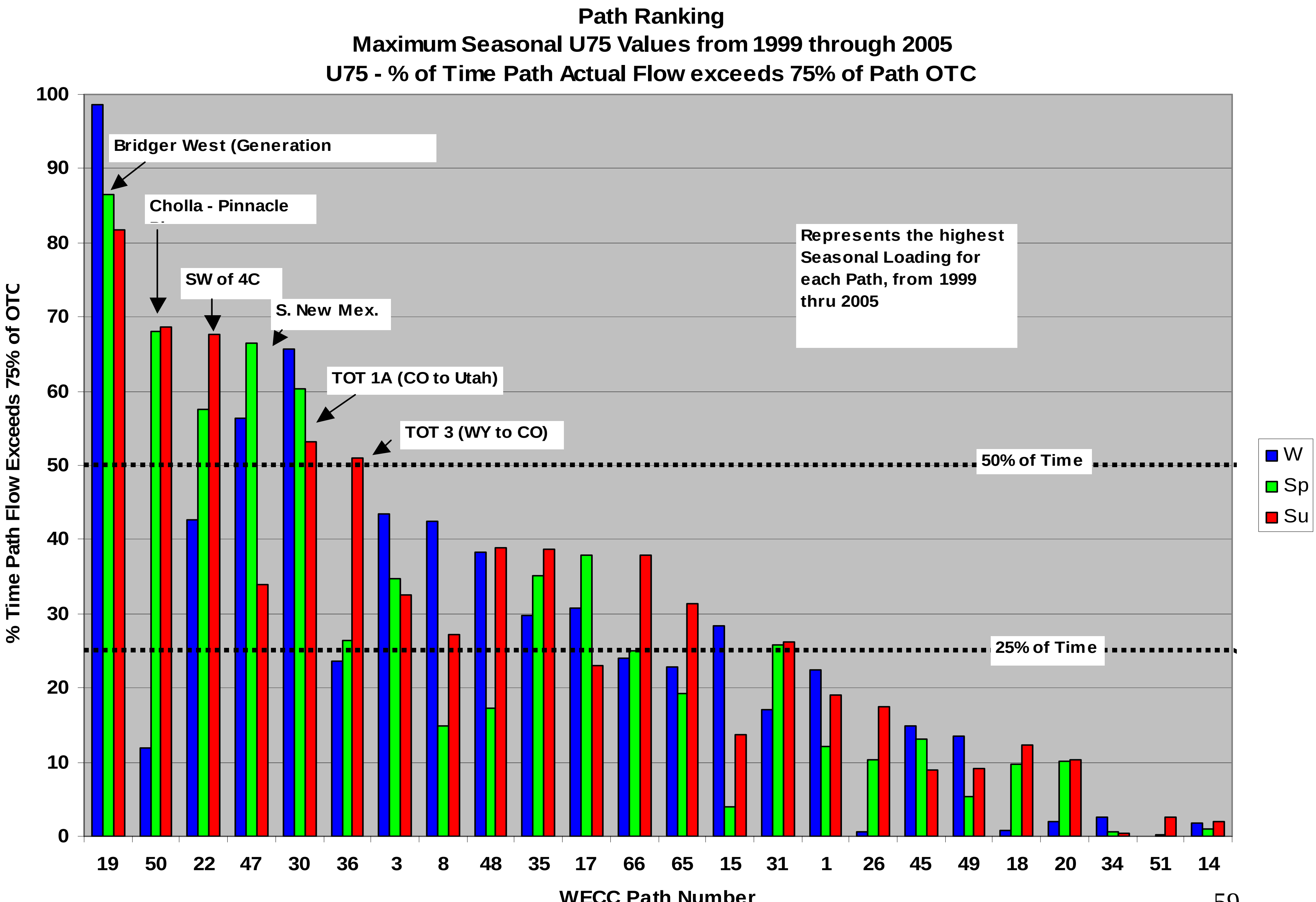


All Seasons 1999 thru 2005 (Based on Heaviest Loading Year)

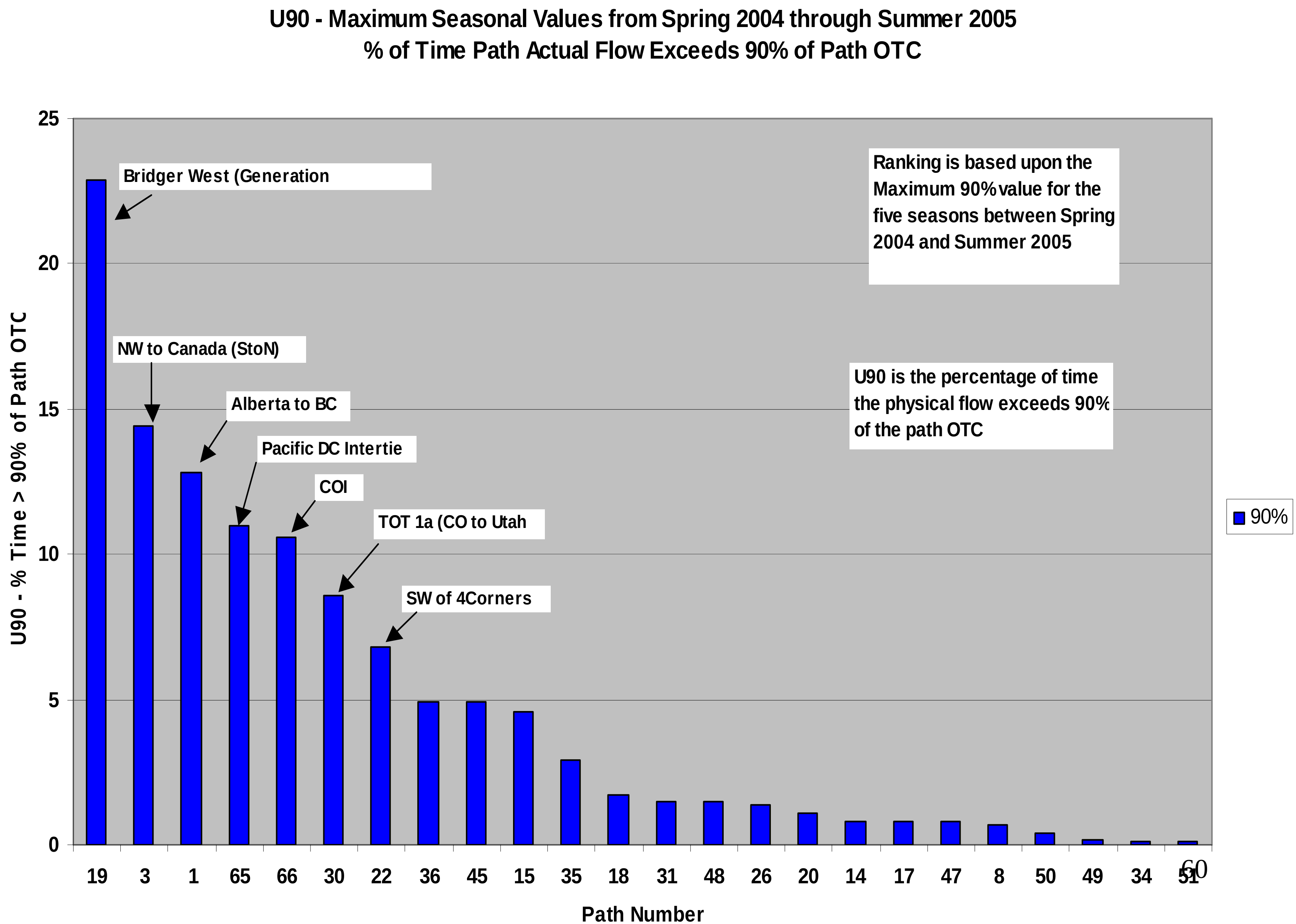
Actual Flow > 75% of OTC greater than 50% of time

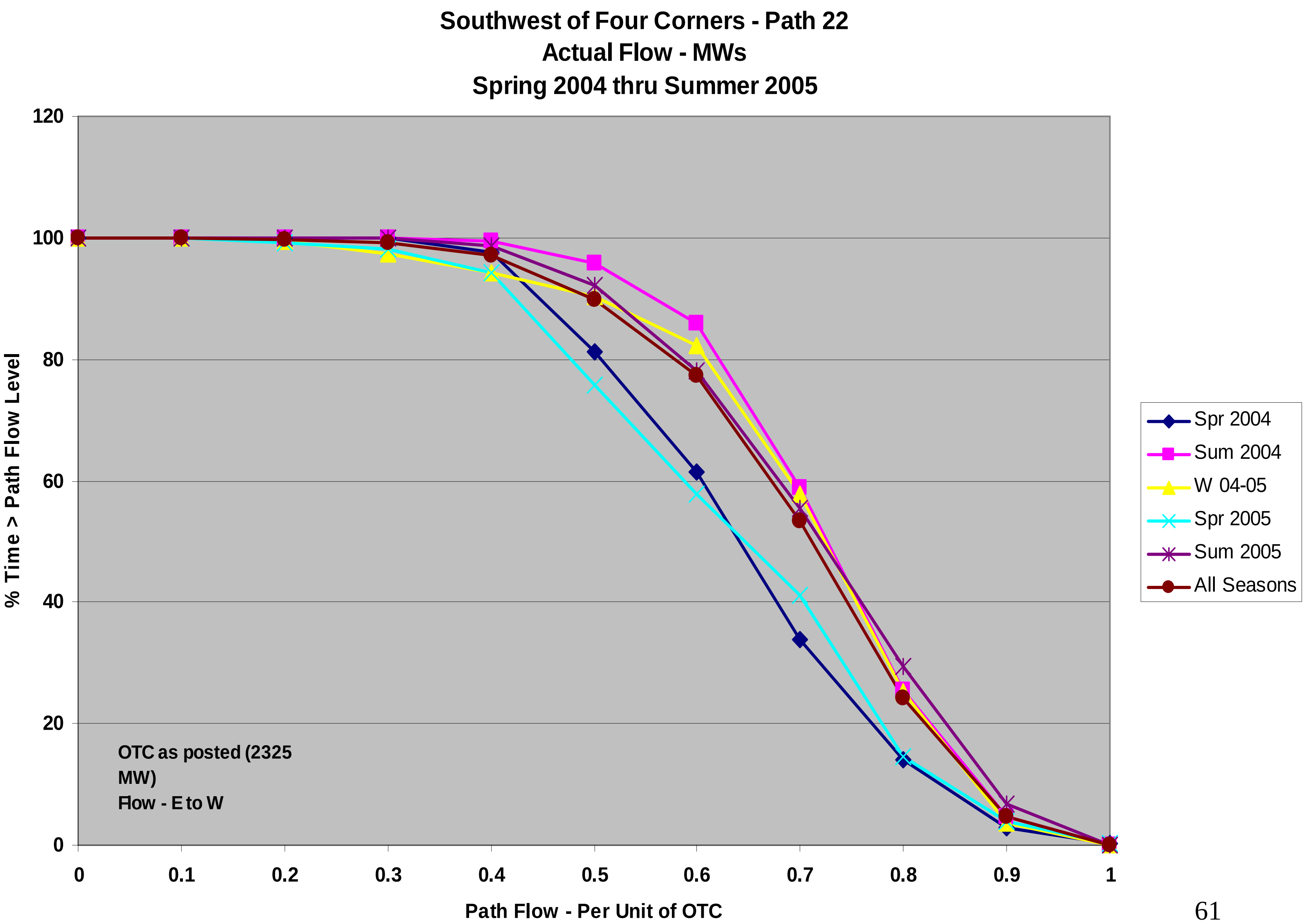
Actual Flow > 75% of OTC between 25% and 50 % of time

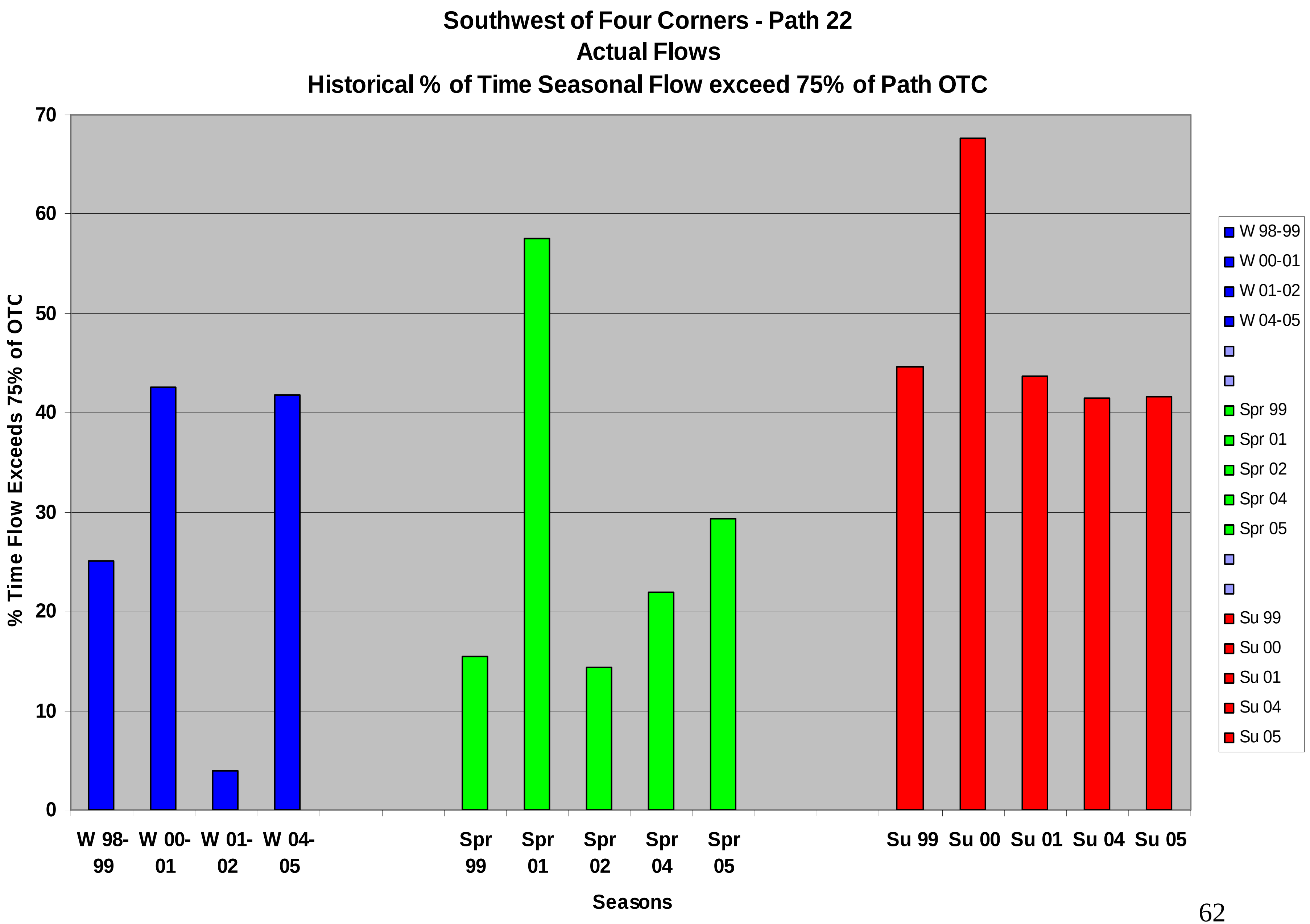
Actual Flow > 75% of OTC between 0% and 25% of time



Path Ranking
Maximum Seasonal U75 Values from 1999 through 2005
U75 - % of Time Path Actual Flow exceeds 75% of Path OTC
Bridger West (Generation
Cholla - Pinnacle
SW of 4C
S. New Mex.
TOT 1A (CO to Utah)
TOT 3 (WY to CO)
Represents the highest Seasonal Loading for each Path, from 1999 thru 2005
50% of Time
25% of Time
W
Sp
Su
% Time Path Flow Exceeds 75% of OTC
0
10
20
30
40
50
60
70
80
90
100
19
50
22
47
30
36
3
8
48
35
17
66
65
15
31
1
26
45
49
18
20
34
51
14
WECC Path Number


U90 - Maximum Seasonal Values from Spring 2004 through Summer 2005
% of Time Path Actual Flow Exceeds 90% of Path OTC
U90 - % Time > 90% of Path OTC
0
5
10
15
20
25
Bridger West (Generation
NW to Canada (StoN)
Alberta to BC
Pacific DC Intertie
COI
TOT 1a (CO to Utah
SW of 4Corners
Ranking is based upon the Maximum 90% value for the five seasons between Spring 2004 and Summer 2005
U90 is the percentage of time the physical flow exceeds 90% of the path OTC
90%
19
3
1
65
66
30
22
36
45
15
35
18
31
48
26
20
14
17
47
8
50
49
34
51
Path Number


Southwest of Four Corners - Path 22
Actual Flow - MWs
Spring 2004 thru Summer 2005
% Time > Path Flow Level
Path Flow - Per Unit of OTC
0
20
40
60
80
100
120
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
OTC as posted (2325 MW)
Flow - E to W
Spr 2004
Sum 2004
W 04-05
Spr 2005
Sum 2005
All Seasons


Southwest of Four Corners - Path 22
Actual Flows
Historical % of Time Seasonal Flow exceed 75% of Path OTC
% Time Flow Exceeds 75% of OTC
70
60
50
40
30
20
10
0
W 98-99
W 00-01
W 01-02
W 04-05
Spr 99
Spr 01
Spr 02
Spr 04
Spr 05
Su 99
Su 00
Su 01
Su 04
Su 05
Seasons
W 98-99
W 00-01
W 01-02
W 04-05
Spr 99
Spr 01
Spr 02
Spr 04
Spr 05
Su 99
Su 00
Su 01
Su 04
Su 05

Western Interconnect Congestion Areas

Summary Tables 1, 2 and 3 with Congestion Area Map

(Includes Explanation Table 4)

DOE Tasks 1, 3 and 4

Prepared by the Western Congestion Analysis Task Force

May 8, 2006

Executive Summary

- WCATF identified 14 Congestion Areas within the Western Interconnection in this 2006 Study. These areas are summarized in Table 3. An additional 6 Congestion Areas are identified from sub-regional planning studies.
- The WCATF study focused on the identification of transmission congestion; it did not specifically identify resource/load Constraint Areas (as defined by DOE).
- The WCATF Congestion Areas were not ranked due to the variability and inconsistency in the alternative metric ranking methods.
- Studies indicated that future Congestion Areas are highly dependent upon the location of future resources in the West.
- Proposed transmission additions have already been identified to alleviate the congestion in many identified Congestion Areas.
- Additional studies are required to determine if it is necessary or economical to add new or upgrade existing facilities to reduce congestion in the WCATF identified Congestion Areas.

Executive Summary (Cont.)

- The WECC plans to pursue modeling improvements in future congestion studies in areas such as hydro models and transmission losses in order to improve the accuracy of modeling studies.
- In addition to the constrained areas identified in Table 3, a number of studies performed in the Western Interconnection over the last several years (WGA, RMATS) have identified potential congestion in the Rocky Mountain Area and specifically Wyoming and Montana. This potential congestion is the result of the identification of abundant coal and wind resources in this area which can be developed and used to supply load growth along the West Coast and in the Southwest. Another resource rich area is the oil sands area in Northern Alberta. Transmission Projects proposed to facilitate resource development in these areas include the TransWest Express Project, the Frontier Project, and the Northern Lights Projects (Celilo and Inland Projects).
- The WCATF conducted an open congestion identification process involving all interested stakeholders. The WCATF encourages continued use of open public processes to identify congestion in the West.

Transmission facilities assumed in place prior to the 2015 study time frame

The following facilities are required to address existing constraints or constraints known to exist prior to the W.I. 2015 study time frame. In the 2015 studies, these facilities were assumed to be completed and were represented in the model study as being in service. They should be considered constraint areas until the facilities are operational. Most of these facilities are addressed in the WCATF Template Report.

- Palo Verde – Devers #2
- Tehachapi Wind transmission – 2 lines
- Navajo South System Upgrades
- Four Corners to Moenkopi and Moenkopi to Market Place
- Coronado to Silver King System Upgrades
- Four Corners to Phoenix
- West of Devers System Upgrades
- Capacity upgrade at North Gila
- Pinal Project
- Amps Phase Shifter (Mill Creek Phase Shifter)
- Transmission enhancements to increase Montana to NW transfer by 750 MWs
- New Wyoming to Utah transmission to integrate Bridger #5 and SW Wyoming wind
- San Francisco Bay area Project
- Imperial 500 kV (one to San Diego and one to LA)

Table 1

Studies/Reports of Western Interconnection Related to DOE Task 1

8-May-06

TABLE 1 - EXISTING STUDIES - DOE Task 1

SUMMARY OF WESTERN INTERCONNECTION CONGESTION AREAS

Congestion Area Path Number & Name	**Reference Study / Template** (See Template for additional details)	**Study Time Frame**	**Analytical Method** (Observed / Modeled)	**Criteria and Metrics Used**	**Status / Findings**
Northwest States and Canada					
Northwest to Canada Path 1 - Alberta to BC, Path 3 - NW to Canada	SSG-WI 2003 Path Utilization Study	1998 thru 2002	**Observed** - Analysis of hourly recorded data	Percentage of Time exceeding 75% of Operating Transfer Capability (OTC)	Actual Flow studies show flow on Path 3 has seasonally exceeded 75% of OTC 45% of time.
	Canada-NW-CA Transmission	2007 and later	**Modeled** - Power Flow Analysis. No production simulation studies have been run. However, without the transmission additions there would be substantial congestion if the modeled resources were developed.	WECC, NERC reliability criteria. The studies were designed to reliably increase the transfer on studied paths by approximately 1500 MW.	Study is providing information on transmission impacts, for developers of Canada resources for export to the US. Canada export increases of 1500 and 3000 MW were studied. As with all the future resource scenarios the extent of Congestion dependent upon actual future resource development.
	SSG-WI 2003 Study Program	2008	**Modeled** - Production Simulation Study with assumed generation additions	Flows exceeding path rating > 25% of time, Shadow Prices x Flow > $25,000 per MW per year (cutoff criteria).	SSG-WI "high level" studies showed congestion between Alberta and British Columbia which limit the flows between Canada and the U.S.
	Canada to Northwest Intertie Expansion - - This study is just underway and has not been completed.	2008 thru 2014	**Observed and Modeled -** The method of study will start with an analysis of recorded hourly data and then use a power flow based analysis to refine the initial conclusions.	The congestion metrics include the percent of time in excess of 75% OTC and 90% OTC and quantify the commercial value primarily with electricity price differentials between regions, seasons and between HLH and LLH's	This evaluation is just beginning. BCTC will look at utilizing the expected improvement in OTC on the AL to BC Intertie and expand the capacity on the BC to US intertie by up to 1,500 MW. Anticipate improvements to OTC from AL to occur in 2009 and 2015, from 500 to 1,500 MW. The AL tie is often zero rated. BCTC plans to develop a regional transmission strategy that selects one of 3 potential US intertie expansions and optimizes the capacity improvement and operational features with other expansions in the U.S.
	Project Development Status				*Currently in the study phase. No specific project proposals at this time.*
Desert Southwest					
Arizona to California Path 49 - East of River, Path 22 - SW of 4 Corners, Path 46 - WOR	SSG-WI 2003 Path Utilization Study	1998 thru 2002	**Observed** - Analysis of hourly recorded data	Percentage of Time exceeding 75% of Operating Transfer Capability (OTC)	Actual Flow studies show flow on Path 22 (SW of Four Corners) has sesaonally exceeded 75% of OTC, 70% of time; Path 49 has exceeded 75% OTC, 14% of the time.
	Path 49 (EOR) Transmission Upgrades	2006 to 2009	**Modeled** - Production Simulation Study, Power Flow and Transient Stability	Positive production cost savings	Purpose of study was to increase capacity between AZ and CA/NV regions. Identified proposed upgrades to Southern CA and to Nevada. Proposed additions result in total Western Interconnection annual production cost savings over $80M
	SSG-WI 2003 Study Program	2008 - 2013	**Modeled** - Production Simulation Study with assumed generation additions	Unconstrained flows exceeding path rating > 25% of time, Shadow Prices x Flow > $25,000 per MW per year (cutoff criteria).	SSG-WI studies showed congestion on Path 46 WOR for the gas, coal and Renewable resource scenarios. Specific projects were not identified

Congestion Area Path Number & Name or Map Reference Number	**Reference Study / Template** (See Template for additional details)	**Study Time Frame**	**Analytical Method** (Observed / Modeled)	**Criteria and Metrics Used**	**Status / Findings**
	California Energy Commission (CEC) Strategic Transmission Investment Plan (for PVD2)	2010	**Modeled** - CEC relied on modeling studies performed by others, such as the CAISO's TEAM lifecycle cost savings methodology and SCE's total benefit assessment.	Meet requirements for reliability, congestion relief and load growth as outlined in the Cal Public Resource Code Section 25324. Studies considered magnitude of CAISO Interzonal congestion revenues	Assessed 21 projects impacting CA reliability, markets, or renewables. Five were recommended for investment among which was the PVD2 project
	Project Development Status				*Short Term Upgrades now under construction. DPV2 Project under review by CPUC (CPCN initiated Apr 2005) and by the AZ Corp Commission (scheduled for Cert. of Env. Compatibiloity application in April 2006), Draft EIR/EIS sched for release in May 2006;EOR9000+ Project completed WECC path rating process for accepted rating.*
Arizona to southern New Mexico - Path 47 - Southern New Mexico	SSG-WI 2003 Path Utilization Study	1998 thru 2002	**Observed** - Analysis of hourly recorded data	Percentage of Time exceeding 75% of Operating Transfer Capability (OTC)	Actual Flow studies show flow on Path 47 has seasonally exceeded 75% of OTC, 65% of time.
	SSG-WI 2003 Study Program	2008 - 2013	**Modeled** - Production Simulation Study with assumed generation additions	Flows exceeding path rating > 25% of time, Shadow Prices x Flow > $25,000 per MW per year (cutoff criteria).	SSG-WI studies showed congestion between Arizona and Southern New Mexico, particularly for the coal resource scenario.
	Project Development Status				*No specific project proposals at this time.*
Rocky Mountain States					
Wyoming to Colorado - - Path 36 - TOT 3	SSG-WI 2003 Path Utilization Study	1998 thru 2002	**Observed** - Analysis of hourly recorded data	Percentage of Time exceeding 75% of Operating Transfer Capability (OTC)	Actual Flow studies show flow on TOT 3 exceeded 75% of operating capability 50% of time during a summer season.
	RMATS Study (Recommendation 1 & 2 - matches area load and generation and provides for export.)	2013	**Modeled - Production Simulation Study** with assumed generation additions to serve load growth in the region.	Positive annual production cost savings	Given the assumptions, study found capacity inceases are needed between WY and CO to match new regional resources with load growth in the region. Reinforcement also required for export of resources . Solution increases capacity by 750 MWs.
	Project Development Status				*Joint MOU signed by Trans-Elect, Wyoming Infrastructure Auth. and WAPA, now soliciting interest in feasibility study to upgrade TOT 3. Two Entitites (WAPA & BEPC) have Initiated WECC Regional Planning Process and Three Phase Path Rating Process on separate projects.*

Congestion Area Path Number & Name	**Reference Study / Template** (See Template for additional details)	**Study Time Frame**	**Analytical Method** (Observed / Modeled)	**Criteria and Metrics Used**	**Status / Findings**
Rocky Mountain States to West Coast, Nevada and Arizona					
The amount of Congestion in the following five areas is dependent upon the level of resource development in the Rocky Mountain area. The TransWest Express Project, the Frontier Project and the Northern Lights Inland Project have been proposed to address some of these congestion issues.					
A. Wyoming - Utah/Idaho Path 19 - Bridger West, Path 17 - Borah West, Path 20 - Path C	SSG-WI 2003 Path Utilization Study	1998 thru 2002	**Observed** - Analysis of hourly recorded data	Percentage of Time exceeding 75% of Operating Transfer Capability (OTC)	Actual Flow studies show Path 19 has seasonally exceeded 75% of OTC 98% of the time, Path 17- 38% of the time and Path 20 - 10% of the time..
	RMATS Study (Recommendations 1 and 2)	2013	**Modeled - Production Simulation Study** with assumed generation additions	Positive production cost savings	Study identified facilities needed to increase transfer capacity out of Wyoming to the West with added 3900 MW of generation in the Wyoming area. **Extent of Congestion dependent upon actual future resource development.**
	Project Development Status				The Wyoming Infrastructure Authority and NationalGrid have signed an MOU to look into the feasibility of a project line. APS, the Wyoming Infrastructure Authority and National Grid have signed an MOU to coordinate the feasibility analysis of the Wyoming - West and the TransWest Express Projects.
B. Montana - Idaho Path 18 - Idaho to Montana	RMATS Study (Recommendations 1 and 2)	2013	**Modeled - Production Simulation Study** with assumed generation additions	Positive production cost savings	Study identified facilities needed to increase transfer capacity out of Wyoming and Montana to the West with added 3900 MW of generation in the Wyoming area. **Extent of Congestion dependent upon actual future resource development.**
	Project Development Status				Northwestern Energy has initiated an open season process to solicit participation interest in new capacity associated with upgrading the capacity between Montana and Idaho
C. Montana to Northwest - - Path 8 - Montana to NW, Path 9 - West of Broadview	SSG-WI 2003 Path Utilization Study	1998 thru 2002	**Observed** - Analysis of hourly recorded data	Percentage of Time exceeding 75% of Operating Transfer Capability (OTC)	Actual Flow studies show Path 8 (between Montana and PNW) has seasonally exceeded 75% of operating capability 42% of the time.
	West of Hatwai System Upgrade Project	Existing issue - - studied 2005 and 2010	**Modeled** - Power Flow, Reactive Margin and Transient Stability Studies were run. **No production simulation studies were run.**	Meet WECC and NERC reliability criteria for firm transfer obligations. Increase firm transfer capacity across West of Hatwai cutplane	Study identified insufficient firm transfer capacity between Montana and the Northwest across the WofH cutplane. Study resulted in upgrading existing and construction of new facilities between Garrison Substation in Montana and Grand Coulee Substation in Washington.
	SSG-WI 2003 Study Program	2008 & 2013	**Modeled** - Production Simulation Study with assumed generation additions	Flows exceeding path rating > 25% of time, Shadow Prices x Flow > $25,000 per MW per year (cutoff criteria).	SSG-WI studies showed congestion between Montana and the PNW, particularly for the Renewable and Coal resource scenarios. **Extent of Congestion dependent upon actual future resource development.**
	RMATS Study (Recommendations 1 and 2)	2013	**Modeled - Production Simulation Study** with assumed generation additions	Positive production cost savings (assuming NW LSEs want to buy assumed generation)	Study identified facilities needed to increase transfer capacity from Colstrip to Taft by 500 MW. Study also evaluated a new 500 kv line as one of several options to support the export of 3900 MW of generation in MT and WY to the West Coast and Nevada area by 3900 MW. **Extent of Congestion dependent upon actual future resource development.**

Congestion Area Path Number & Name	**Reference Study / Template** (See Template for additional details)	**Study Time Frame**	**Analytical Method** (Observed / Modeled)	**Criteria and Metrics Used**	**Status / Findings**
	Montana Northwest Transmission Equal Angle Report	timing based on schedule for new resources in Montana	**Modeled** - Study added facilities to keep the power angle across the system constant when new resources were added. **No production simulation studies were run.**	Constant power angle across system with additions of new generation	Study identified facilities needed to upgrade Montana to NW capacity by 750 MW. This is the maximum path upgrade without building a new 500 kV line. **Extent of Congestion dependent upon actual future resource development.**
	Project Development Status				*WofH project was completed in 2005. Remainder of projects are in early study phase. Major additions for 750 MW increase, are series capacitor upgrades and some 230 and 500 kV construction in WA and OR. Major additions for 3900 MW upgrade include new 500kV transmission from Montana to WA, OR or Nevada.*
D. Colorado to Utah Path 30 - TOT 1a and Path 33 - Bonanza West	SSG-WI 2003 Path Utilization Study	1998 thru 2002	**Observed** - Analysis of hourly recorded data	Percentage of Time exceeding 75% of Operating Transfer Capability (OTC)	Actual Flow studies showed flow on Path 30 has seasonally exceeded 75% of OTC, 65% of time.
	RMATS Study (Recommendations 1 and 2)	2013	**Modeled - Production Simulation Study** with assumed generation additions	Positive production cost savings	Study identified facilities needed to increase transfer capacity out of Wyoming and Montana to the West with added 3900 MW of generation in the Wyoming area. Path 33 reached path limits 31% of the time for the resource assumptions in RMATS recommendation #2. **Extent of Congestion dependent upon actual future resource development.**
	Project Development Status				*No specific project proposals at this time.*
E. Utah - NV Path 35 - TOT2C	SSG-WI 2003 Path Utilization Study	1998 thru 2002	**Observed** - Analysis of hourly recorded data	Percentage of Time exceeding 75% of Operating Transfer Capability (OTC)	Actual Flow studies show Path 35 has seasonally exceeded 75% of operating capability 38% of the time.
	SSG-WI 2003 Study Program	2008 & 2013	**Modeled** - Production Simulation Study with assumed generation additions	Flows exceeding path rating > 25% of time, Shadow Prices x Flow > $25,000 per MW per year (cutoff criteria).	SSG-WI studies showed congestion between Utah and S. Nevada (TOT2C), particularly for the Renewable and Coal resource scenarios. **Extent of Congestion dependent upon actual future resource development.**

Congestion Area Path Number & Name	**Reference Study / Template** (See Template for additional details)	**Study Time Frame**	**Analytical Method** (Observed / Modeled)	**Criteria and Metrics Used**	**Status / Findings**
Subregional Areas					
California - San Francisco and Southern California Areas	California Energy Commission (CEC) Strategic Transmission Investment Plan	2010	**Modeled** - CEC relied on modeling studies performed by others, such as the CAISO's TEAM lifecycle cost savings methodology and SCE's total benefit assessment.	Meet requirements for reliability, congestion relief and load growth as outlined in the Cal Public Resource Code Section 25324. Studies considered magnitude of CAISO Interzonal congestion revenues	Assessed 21 projects impacting CA reliability, markets, or renewables. Five were recommended for investment. These are the following: 1) Sunrise Powerlink 500 kV Project, 2) Imperial Valley Transmission Upgrades, 3) Palo Verde - Devers #2 500 kV Project, 4) Tehachapi Transmission Projects, and 5) Trans-Bay DC Cable
	Tehachapi Wind Resource Study - California PUC Report	2010	**Modeled -** Power Flow and transient stability studies have been completed. Production Simulation studies will be report by the CPUC in Spring 2006	WECC and NERC reliabilty criteria and the CAISO Grid Planning Standards. Economic criteria will be described in later reports.	The study identified facilities required to integrate 4000 MW of wind generation in the Tehatchapi area. Phase I of the project is scheduled for completion by 2010.
	LEAPS & TE-VS Project		**Modeled -** Power Flow analysis	WECC and NERC reliability criteria and transfer capability	Studies have determined transmission required to integrate 500 MW of pumped storage generation into the SDG&E and SCE systems, plus increasing the import capability into the SDG&E system.
	Project Development Status				Phase I of the Tehachapi Wind Project is currently in the permitting and review stage. DPV2 Project under review by CPUC (CPCN initiated April 2005) and by the AZ Corp Commission (scheduled for Cert. of Env. Compatibility application April 2006), Draft EIR/EIS sched for release in May 2006. The LEAP Project is in the beginning phases of the WECC three phase rating process.
Nevada - S. Idaho Area (wind integration)	T4 Wind Project	2004-05 (Need date not defined)	**Modeled** - Power Flow and transient stability studies. **No production simulation studies were run.**	Move wind generation to markets while meeting WECC and NERC reliability criteria.	Identified facilities needing reinforcement to integrate over 2000 MW of wind resources
	Project Development Status				*Project is in the early study phase. Identified a tap to the Pacific DC intertie and a new Gonder to Harry Allen 500 kV line*
Colorado - Denver Area Ft. Morgan, CO to NE Denver area and Lamar, CO to SW Denver area	Colorado Long Range Transmission Planning Study	2014	**Modeled -** Power flow and transient stability studies. **No production simulation studies were run.**	WECC and NERC Reliability criteria	Study identified facilities necessary to develop a "back-bone" network in Colorado to benefit load service and transmission reliability.
	Project Development Status				*For heavy NE CO flows, need to add facilites between Ft. Morgan and NE Denver; for heavy SE CO flows, need to add facilities between Lamar and SE Denver. Several projects are under development to be in service between 2010 and 2014.*

Congestion Area Path Number & Name	**Reference Study / Template** (See Template for additional details)	**Study Time Frame**	**Analytical Method** (Observed / Modeled)	**Criteria and Metrics Used**	**Status / Findings**
Washington Puget Sound Area - - Transmission facilities serving and within the Puget Sound area. 500 kV facilities between Covington and Monroe Substations	Puget Sound Area Upgrade Study	2005 to 2012	**Modeled** - Power Flow Studies. The transfer capability between Canada and the United States is frequently decreased due to operational constraints. Local utilities have experienced frequent curtailments of firm transmission service.	Objective is to meet NERC and WECC reliability criteria, while providing reliable service to area loads and meeting U.S. - Canada Treaty obligations for return of Entitlement Power; and providing capacity for regional economic power sales.	Study identified operational congestion (and proposed solutions) to congestion currently experienced in the Puget Sound area associated with service to area load, importing from Canada, integrating local generation
	Project Development Status				*Project consists of reconductoring existing 230 kVlines, new 230 and 500 kV lines and substation mods. Projects will be completed by 2015.*
Washington / Oregon - - Internal NW system	Protecting and Managing an Increasingly Congested Transmission System	2005	Observed - Analysis of SCADA data	Number of flow excursions above path OTC requiring dispatcher action.	The study identified flow excursions above path OTC during August 2005 for the Paul - Allston, South of Allston (WECC Pth #71) and North of Hanford paths.
	Project Development Status				No projects have been proposed.
Arizona - - Phoenix and Tucson areas Path 50 - Cholla Pinnacle Pk, and lines serving Phoenix and Tucson areas	SSG-WI 2003 Path Utilization Study	1998 thru 2002	**Observed** - Analysis of hourly recorded data	Percentage of Time exceeding 75% of Operating Transfer Capability (OTC)	Actual Flow studies show flow on Path 50 (NE of Phoenix area on Cholla - PPk) has seasonally exceeded 75% of OTC, 70% of time.
	Central Arizona Transmission Study	Phase III - 2012 - - - Need dates vary from 2008 to 2015	**Modeled** - Power Flow Analysis. **No production simulation studies have been run.**	Objective was to meet WECC and NERC reliability criteria, while increasing power transfer capability into the Phoenix and Tucson areas, providing additional capacity to and from the Palo Verde Hub and providing capacity to integrate local generation.	Identified congestion and needed facility additions associated with overload of the Palo Verde East transmission System and import capability into Phoenix and Tucson areas.
	Project Development Status				*Solution consists of 7 major 500 kV transmission projects. Projects are currently in the design and land/row acquisition phase. Some elements have been constructed and energized.*

Table 2

Studies/Reports of Western Interconnection Related to DOE Task 3

8-May-06

TABLE 2

SUMMARY OF WESTERN INTERCONNECTION CONGESTION AREAS

As Identified in "New Studies" - DOE Task 3

Congestion Area Path Number/Name and Rating	Reference Study / Template (See Template for additional details)	Study Time Frame	Status / Findings See definitions of U75 and U90 in footnotes below	Are new studies validated by Task 1 Existing Studies (DOE Task 4 Question)
Northeast and Eastern Arizona Path 22 - SW of Four Corners, Path 50 - Cholla Pinnacle Peak, Path 54 - Coronado - Silver King - Kyrene **Path Rating** - Path 22 = 2325 MW E to W, Path 50 = 1200 MW NE to SW, Path 54 = 1100 MW E to W	SSG-WI 2006 Path Utilization Study	1998 thru 2005 **Usage Study**	**Observed flow -** Path 22 - Max. seasonal U75 = 68%, Path 50 = 69%	Yes, historical path usage studies, and both existing and new modeling studies show this area to be highly utilized today and potentially congested under future resource scenarios. Path 22 consistently exceeds a U75 of 40% in all summer seasons.
	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled Flow** - Path 22 U75 = 86% U90 = 56%, Path 50 U75 = 78% U90 = 22%, Path 54 U75 = 80% U90 = 53%	
		2008 **Economic Study**	**Modeled Economics** - Paths 22 and 54 had the 8th and 5th highest binding hours shadow price in the W.I.	
		2015 **Usage Study**	**Modeled flow -** Path 22 U75 = 100% U90 = 90%	
		2015 **Economic Study**	**Modeled Economics** - Path 22 had the 2nd highest shadow price of all W.I. paths	
Arizona to California Path 49 - East of River, Path 22 - SW of 4 Corners, Path 46 - WOR	SSG-WI 2006 Path Utilization Study	1998 thru 2005 **Usage Study**	**Observed flow -** Path 49 - Max seasonal flow U75 = 14%, Path 22 Max. seasonal flow U75 = 67%.	Yes, 2008 model studies show very high flows on East of River (Path 49) prior to the addition of Devers - Palo Verde #2 500 kV line. This finding is supported by existing studies showing the need for additional support on E of R path. See Table 1 for projects that are being pursued to relief path loading.
	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled flow -** Navajo-Crystal (EOR) U75 = 99% (highest ranking) U90 = 92%, EOR U75 = 92% U90 = 52%, Moen - El Dorado U75 = 88% U90 = 5%	
		2008 **Economic Study**	**Modeled Economics -** Navajo Crystal has the 7th highest ranked Shadow Price.	

Congestion Area Path Number/Name and Rating	Reference Study / Template (See Template for additional details)	Study Time Frame	Status / Findings See definitions of U75 and U90 in footnotes below	Are new studies validated by Task 1 Existing Studies (DOE Task 4 Question)
Arizona to New Mexico - Path 47 - S. NM and Path 48 - N. NM **Path Ratings** - Path 47 = 1048 MW, Path 48 = 1947 MW (nonsimultaneous)	SSG-WI 2006 Path Utilization Study	1998 thru 2005 **Usage Study**	**Observed flow -** Path 47 - Max. seasonal U75 = 66%, Path 48 Max. seasonal U75 = 39%.	Yes, in historical path usage studies. Path 47 shows relatively high historical path usage with U75 typically around 30%, peaking at 66%. Path 48 has typically lower flows, with U75 hitting a high of 39% in 2004. The paths have not ranked high in 2008 or 2015 economic modeling studies, possibly due to renewable resource addition assumptions in New Mexico.
	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled Flow** - Paths 47 and 48 had relatively low flows. Path 47 U75 = 25% U90 = 4%, Path 48 = 1% U90 = 0%	
		2008 **Economic Study**	**Modeled Economics** - Paths 47 and 48 had relatively low binding hour shadow prices. (Path 47 ranked 24th)	
		2015 **Usage Study**	**Modeled flow -** Path 48 U75 = 68% U90 = 77%	
		2015 **Economic Study**	**Modeled Economics -** Path 47 had the 19th highest shadow price of all W.I. Paths. Path 48 was not in the top 30 rated paths	
Colorado to Utah Path 33 - Bonanza West, Path 30 - TOT1A **Path Rating** - Path 33 = 785 MW Max. E to W, Path 30 = 650 MW E to W.	SSG-WI 2006 Path Utilization Study	1998 thru 2005 **Usage Study**	**Observed flow** - Path 30 - Max. seasonal UCI (75) = 65%.	Yes, both existing studies and new 2008 and 2015 studies show this area to be highly utilized today and potentially congested under future resource scenarios. Flows on Path 30 typically have U75 in the summer from 30 to 40%. Path 33 has not been monitored for historical flows. Path 33 had the highest modeled shadow price of all the W.I. paths in the 2015 economic studies. Bonanza - Mona (feeding Path 33) had the 2nd highest shadow price in the 2008 study.
	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled Flow** - Bonanza Mona U75 = 97% U90 = 89%, Path 33 U75 = 90% U90 = 25%, Path 30 U75 = 49% U90 = 10%	
		2008 **Economic Study**	**Modeled Economics** - Bonanza - Mona had the 2nd highest shadow price, Path 30 had 6th highest shadow price, Path 33 was not ranked (above 32)	
		2015 **Usage Study**	**Modeled flow -** Path 33 U75 = 90% U90 = 77%	
		2015 **Economic Study**	**Modeled Economics** - Path 33 had the highest shadow price of all W.I. paths	

Congestion Area Path Number/Name and Rating	Reference Study / Template (See Template for additional details)	Study Time Frame	Status / Findings See definitions of U75 and U90 in footnotes below	Are new studies validated by Task 1 Existing Studies (DOE Task 4 Question)
Montana to Northwest Path 8 and Path 9 West of Broadview **Path Rating** (Path 8) = 2200 MW E to W	SSG-WI 2006 Path Utilization Study	1998 thru 2005 **Usage Study**	**Observed flow - Path 8 Max. seasonal U75 = 42%**	Yes. The Montana to Northwest path has consistently high utilization in observed and modeled path flow studies and in both existing and 2008 and 2015 economic modeling studies. Typical U75 for most seasons is 15 to 25% with a maximum of 42% during the winter of 2000-01.
	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled Flow** - Path 8 U75 = 88% U90 = 65%	
		2008 **Economic Study**	**Modeled Economics** - Path 8 had the 12th highest binding hour shadow price of all W.I. Paths.	
		2015 **Usage Study**	**Modeled flow -** Path 8 U75 = 98% U90 = 78%, Path 9 U75 = 98% U90 = 60%	
		2015 **Economic Study**	**Modeled Economics** - Path 8 had the 4th highest shadow price of all W.I. Paths.	
PNW to California Path 65 - DC Intertie and Path 66 - COI **Path Ratings**: Path 65 = 3100 MW, Path 66 = 4800 MW N to S, 3675 MW S to N	SSG-WI 2006 Path Utilization Study	1998 thru 2005 **Usage Study**	**Observed flow -** Path 65 Max. seasonal U75 = 32%; Path 66 Max. seasonal U75 = 38%	Yes. Historical usage shows the AC and DC intertie have U75 in the summer often in the 30 to 38% range depending upon hydro conditions. Heavy path use was apparent in the 2008 studies as shown in the 9th shadow price ranking for the Malin R. Mtn lines. Heavy use also occurred in the 2015 modeling studies. Usage is highest in the 2015 studies.
	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled flow** - Path 65 U75 = 54% U90 = 47%; Path 66 U75 = 54% U90 = 35%. Malin R. Mtn !&2 had U75 = 58%, U90 = 40% and U(Lim) = 27%.	
		2008 **Economic Study**	**Modeled Economics -** Path 65 had the 18th highest shadow price of all W.I. Paths; Path 66 was not ranked (above 32nd), Malin R. Mtn 1 & 2 had 9th highest shadow price	
		2015 **Usage Study**	**Modeled flow -** Path 65 U75 = 95% U90 = 90%; Path 66 U75 = 82% U90 = 64%	
		2015 **Economic**	**Modeled Economics** - Path 65 had the 10th highest shadow price of all W.I.	

Congestion Area Path Number/Name and Rating	Reference Study / Template (See Template for additional details)	Study Time Frame	Status / Findings See definitions of U75 and U90 in footnotes below	Are new studies validated by Task 1 Existing Studies (DOE Task 4 Question)
Wyoming to Colorado Path 36 - TOT3 **Path Rating** - Path 36 = 1509 MW N to S	SSG-WI 2006 Path Utilization Study	1998 thru 2005 **Usage Study**	**Observed flow** - Path 36 - Max. seasonal U75 = 51%.	Yes. Historical path usage studies show Path 36 typically has a U75 in the summer around 10 to 20%, with a maximum U75 of 51% during the summer of 1999. Path 36 does not rank high as a congested path in either the 2008 or 2015 modeling economic studies. Justification for Wyoming to Colorado being classified as a Constraint area is based primarily upon resource development in the RMATS studies and historical path flow studies.
	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Observed Flow -** Path 36 U75 = 2% U90 = 0%	
		2008 **Economic Study**	**Modeled Economics -** Path 36 is ranked above 35th.	
		2015 **Usage Study**		
		2015 **Economic Study**	**Modeled Economics** - Path 36 is not in the top 30 shadow price rated paths	
Utah to Central and Southern NV Path 35 - TOT 2C, Path 29 Intermountain to Gonder **Path Rating** = Path 35 = 300 MW, Path 29 = 200 MW	SSG-WI 2006 Path Utilization Study	1998 thru 2005 **Usage Study**	**Observed flow -** Path 35 Max. seasonal U75 = 38%	Yes. Historical path flow studies show Path 35 to be the 10th highest utilized path. However, Path 35 flows were high only one year, and are more recently in the 10 to 15 % range. This path was also identified as a congested path for the coal scenario in the 2003 SSG-WI Study Program. The path is also identified as one of the highly utilized paths in the 2015 SSG-WI studies. Path 29 (to Central Nevada) had high economic congestion in 2008 studies, however Path 35 (to Southern Nevada) was low and unranked.
	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled Flow** - Path 35 U75 = 82% U90 = 80%, Path 29 U75 = 69% U90 = 57%	
		2008 **Economic Study**	**Modeled Economics** - Path 29 had the 16th highest binding shadow price, Path 35 was not ranked.	
		2015 **Usage Study**	**Modeled flow -** Path 35 U75 = 96% U90 = 95%	
		2015 **Economic Study**	**Modeled Economics** - Path 35 had the 8th highest shadow price of all W.I. Paths.	

Congestion Area Path Number/Name and Rating	Reference Study / Template (See Template for additional details)	Study Time Frame	Status / Findings See definitions of U75 and U90 in footnotes below	Are new studies validated by Task 1 Existing Studies (DOE Task 4 Question)
Colorado to AZ/NM Path 31 - TOT 2A **Path Rating** = 690 MW Max. N to S	SSG-WI 2006 Path Utilization Study	1998 thru 2005 **Usage Study**	**Observed flow -** Path 31 - Max. seasonal U75 = 25%	This path shows up as a congested path in the 2008 and 2015 modeling studies. It is only marginally congested in Historical flow studies. It was not identified as a major area of congestion for the resource scenarios studied in the SSG-WI 2003 study program. Historical U75 values have varied from 7 to 26% during the summer seasons.
	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled Flow** - Path 31 U75 = 47% U90 = 33%.	
		2008 **Economic Study**	**Modeled Ecomonics** - Path 31 had the 15th highest shadow price of all W.I. Paths.	
		2015 **Usage Study**	**Modeled flow -** Path 31 U75 = 82% U90 = 68%.	
		2015 **Economic Study**	**Modeled Ecomonics** - Path 31 had the 3rd highest shadow price of all W.I. Paths.	
Wyoming to Utah Naughton (Southwest WY) to Ben Lomond (Northeast UT) **Not Currently Rated**, parallel paths - Path 19 = 2200 MW & Path 20 = 1000 MW	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled Flow** - Path 19 U75 = 90% U90 = 72%, Path 20 U75 = 18% U90 = 11%	Heavy usage of the Wyoming to Utah path appeared in the 2008 and the 2015 SSG-WI studies. The lines in this path (Naughton to Ben Lomond) were not specifically monitored in earlier SSG-WI usage or modeling studies. Heavy path usage has been observed in historical path flow studies on paths in parallel, particularly Path 19 - Bridger West which is the highest utilized path in the W.I. (U75= 98%) due to dedicated use of the path for Bridger integration.
		2008 **Economic Study**	**Modeled Economics** - Path 19 had the 4th highest binding shadow price, Path 20 was ranked 10th.	
		2015 **Usage**	**Modeled flow** - Naughton to Ben Lomond U75 = 87% U90 = 78%	
		2015 **Economic Study**	**Modeled Economics** - Wyoming to Utah had the 9th highest shadow price of all W.I. Paths.	
Southern California - Path 42 IID to SCE	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled Flow -** Path 42 U75 = 84% U90 = 65%	Path 42 was identified as a constrained path in the 2008 modeling studies. It was not reported in earlier studies as a constrained path. The path was not modeled in historical path usage studies and did not show up as a constrained path in the 2015 Studies. This is a new constrained path uncovered in the new 2008 studies.
		2008 **Economic Study**	**Modeled Economics -** Path 42 had the 32th ranked binding shadow price	

Congestion Area Path Number/Name and Rating	Reference Study / Template (See Template for additional details)	Study Time Frame	Status / Findings See definitions of U75 and U90 in footnotes below	Are new studies validated by Task 1 Existing Studies (DOE Task 4 Question)
PATHS INVOLVING CANADIAN SYSTEMS				
Northwest to Canada and Alberta to BC Path 3 and Path 1 **Path Rating** - Path 3 = 2800 MW and Path 1 = 1000 MW E to W. However Path 1 OTC is < 100 MW in E to W direction, 50% of time	SSG-WI 2006 Path Utilization Study	1998 thru 2005 **Usage Study**	**Observed flow** - Path 3 Max. seasonal U75 = 43%, Path 1 Max. seasonal U75 = 23%, U90 = 13%	Yes. Historical usage studies on Path 3 have shown typical U75 in the range of 30 to 40%. In modeling studies, the Alberta to BC path consistently shows up as a highly utilized path in both the 2003 studies for all resource scenarios and in the 2005 SSG-WI modeling studies for the 2015 IRP scenario. Path usage studies for 2004-05 show the capacity of the path in the Alberta to BC direction reaches 700 MW only 3% of the time (WECC rating = 1000 MW). The capacity limit is less than 100 MW 50% of the time. Both 2008 and 2015 modeling studies show high economic shadow prices for constraints on the Alberta to BC tie. The NW to Canada Path 3 tie does not show up as a highly congested path in the 2008 or 2015 studies, perhaps limited by the Alberta to BC
	SSG-WI/WECC 2005-06 Study Program (Modeling study)	2008 **Usage Study**	**Modeled Flow** - Path 1 U75 = 89% from Alberta to BC, U90 = 87%. Path 3 U75 = 9% U90 = 5%.	
		2008 **Economic Study**	**Modeled Economics** - Path 1 had the 14th highest shadow price of all W.I. Paths. Path 3 was ranked 21st.	
		2015 **Usage Study**	**Modeled flow -** Path 1 U75 = 70% U90 = 63% from Alberta to BC.	
		2015 **Economic Study**	**Modeled Economics** - Path 1 had the 7th highest shadow price of all W.I. Paths.	

Notes:

1. Modeling results are highly dependent upon resource assumptions. The 2005 SSG-WI studies modeled utility IRPs and state RPS standards.

2. The above Congestion Areas were identified and ranked based upon the following criteria:
   a. Historical Path Usage - paths with highest max and ave. Usage Congestion Index - U90 and U75
   b. Economic Studies (2008 study) - based upon calculated usage & binding hours shadow prices from 2008 modeling studies
   c. Economic Studies (2015 study) - based upon calculated usage and shadow prices from 2015 modeling studies

3. Actual historical MW flow is one indicator of usage. This should be combined with path schedule/reservation usage and ATC to obtain a more complete picture of path usage.

4. U75 or U90 - the % of time the flow exceeds 75% (U75) or 90% (U90) of the path operating transfer capability

5. Identification of a Congestion Area does not imply that it is economical or necessary to add facilities to relieve the congestion. Likewise, it may be economical to add facilities in areas not identified in this list of Congestion Areas.

Table 3

Summary of Identified Congestion Areas for the Western Interconnection

8-May-06

TABLE 3
COMPREHENSIVE SUMMARY LIST
WESTERN INTERCONNECTION IDENTIFIED CONGESTION AREAS

This Table 3 represents the sum of Congestion Areas identified by the Western Congestion Assessment Task Force
Merging the congestion areas identified from both existing studies (DOE Task 1) and from new SSG-WI/WECC studies (DOE Task 3)
See Tables 1 and 2 and Template Report for additional details

NOTE: This study did not identify resource or load "DOE Constraint Areas" within the Western Interconnect, only transmission Congestion Areas and Paths
NOTE: The paths in Table 3 are not intended to be listed in rank order.

Congestion Area	WECC Path Number	Path Name (See Table 2 for Path Ratings)	Identified in Task 1 Studies	Identified in Task 3 studies			Comments
				Historical	2008	2015	
WECC Paths							
Wyoming to Colorado	Path 36	TOT 3	x	x			Congestion identified in 2003 RMATS studies and Historical Path flow studies. Congestion not found in SSG-WI 2005 studies due to planned resource and transmission additions, including coal projects in southern Colorado (2009) and southwestern Kansas (2012) and associated transmission into southern, southeastern and eastern Colorado that could also accommodate wind resources.
Colorado to Utah	Path 33 Path 30	Bonanza West TOT1A	x	x	x	x	Congestion identified in all studies. Also a Qualified Path under the WECC USF procedures. Replacement of a Flaming Gorge transformer (2007) will help. Several queued transmission requests would result in additional capacity if constructed (date uncertain).
Colorado to NM	Path 31	TOT2A			x	x	A WECC Unscheduled Flow (USF) Qualified Path. No definite plans for expansion

Congestion Area	WECC Path Number	Path Name (See Table 2 for Path Ratings)	Identified in Task 1 Studies	Identified in Task 3 studies			Comments
				Historical	2008	2015	
Northeast Arizona	Path 22 Path 50 Path 54	SW of 4 Corners Cholla - PPeak Coronado - SK - Ky	x	x	x	x	Congestion identified in all studies. Path 22 is a Qualified Path under the WECC USF procedures
Arizona to California	Path 49 Path 46	East of CO River West of CO River	x		x		2015 studies modeled DPV2 line addition, which relieved congestion. In the 2008 Study, several individual lines in the path loaded to their limits
Arizona to S. New Mexico	Path 47 Path 48	S. New Mexico N. New Mexico	x	x			Congestion not found in 2008 and 2015 due to added resources in New Mexico
Montana to Northwest	Path 8 Path 9	MT to NW West of Broadview	x	x	x	x	Congestion identified in all studies
Montana to Idaho	Path 18	Idaho to MT	x	x			RMATS study showed congestion. Congestion not found in SSG_WI 2005 studies due to inclusion of a phase shifter in the model for Path 18
Utah to Nevada	Path 35 Path 29	TOT2C Intermtn. to Gonder	x	x	x	x	Congestion identified in all studies
Wyoming to Utah	 Path 19 Path 20	Naughton - Ben Lomond Bridger West Path C	x	x	x	x	Congestion identified in all studies. Frontier Project, TransWest Express are several projects that could bring Wyoming resources to the Wasatch Front and beyond (date uncertain).
Northwest to California	Path 65 Path 66	Pacific DC Intertie COI	x	x	x	x	COI, PDCI and Malin R Mtn lines had high congestion price rankings in 2008 and 2015.

Congestion Area	WECC Path Number	Path Name (See Table 2 for Path Ratings)	Identified in Task 1 Studies	Identified in Task 3 studies			Comments
				Historical	2008	2015	
Alberta to BC	Path 1	Alberta to BC	x	x	x	x	Congestion identified in all studies.
Northwest to Canada	Path 3	NW to Canada	x	x			Most congested in historical studies. Lower congestion levels in 2008 and 2015 are related in large part to the difficulty of modeling BC's hydro generation and Alberta to BC tie limitations.
Southern California	Path 42	IID - SCE		Not Monitored	x		Identified in 2008 studies. However these constraints may be alleviated by proposed transmission projects (e.g. Sunrise Power Link, Green Path, etc.) expected to come online after 2008.
Subregional Areas (See Templates for Details)		**Subregional Areas were not analyzed in the New SSG-WI or WECC Studies (Task 3) nor monitored in Historical Path studies.**					
Nevada - S. Idaho (wind)		Generation integration for new wind development in S. Idaho and N. Nevada	x	Not Monitored	Not Studied	Not Studied	Considering tapping the Pacific DC Intertie near Gerlach or integrating new wind generation into the Gonder (Robinson Summit) to Harry Allen 500 kV line.
Phoenix / Tucson Areas		Reinforcements in the Phoenix / Tucson areas	x	Not Monitored	Not Studied	Not Studied	Transmission Additions included (1) Palo Verde to Pinal West I and II 500 kV lines, (2) Pinal West to South East Valley/Browning 500 kV line, (3) Pinal West to Saguaro 500 kV line, (4) Saguaro to South 500 kV line, (5) SE Valley or Pinal South to Winchester 500 kV line, (6) Winchester to South 500 kV line and (7) Cholla/Saguaro 500 kV loop into Silver King.
Denver Area		Provide reinforcement to the Denver area	x	Not Monitored	Not Studied	Not Studied	See Template for detailed list of transmission additions. Future Public Service Company of Colorado responses to resource addition RFPs and associated transmission expansion will help (thru 2010).

Congestion Area	WECC Path Number	Path Name (See Table 2 for Path Ratings)	Identified in Task 1 Studies	Identified in Task 3 studies			Comments
				Historical	2008	2015	
Puget Sound Area		Provide reinforcement to the Seattle / Puget Sound area	x	Not Monitored	Not Studied	Not Studied	Congestion in Puget Sound Area (500 kV facilities between Covington and Monroe Substations) due mainly to planned maintenance outages
Pacific NW	71	South of Allston	x	Not Monitored	Not Studied	Not Studied	Transmission congestion noted on the following paths: (1) Paul - Allston, (2) North of Hanford and (3) South of Allston. Congestion does not occur in 2008 and 2015 studies due to assumed resource additions in Oregon.
Southern / Central California		Reinforcements in California, SF Bay area and S. California	x	Not Monitored	Not Studied	Not Studied	Projects identified include the following: (1) Sunrise Powerlink 500 kV Project, (2) Imperial Valley Transmission Upgrades, (3) Tehachapi Transmission Projects, (4) Trans-Bay DC Cable and (5) LEAPS pumped storage project and (6) the Talega-Escondido/Valley-Serrano 500kV Interconnect Project

Table 4

Criteria for Identifying Final Set of W.I. Congestion Areas

For use with Table 3 and Congestion Area Map

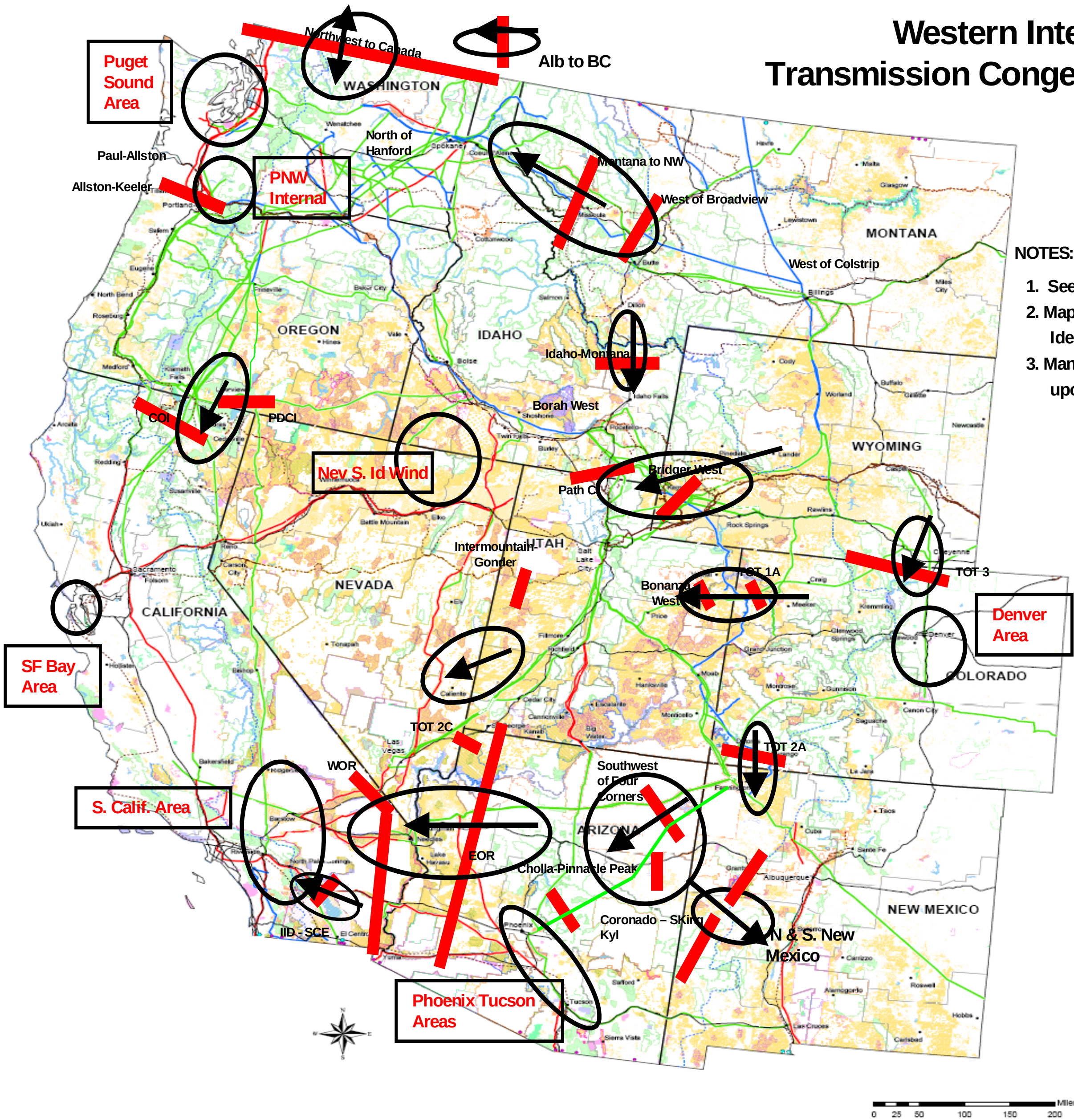
Table 4					
Criteria for Identifying Final Set of W. I. Congestion Areas					
(This table is a supplement to Table 3 defining how Table 3 and the Table 3 Map were derived.)					
Category (refer to Table 3)	**Criteria**	**Number of Identified WECC Paths or lines**	**Number of Identified Congestion Areas**	**Number of Identified Subregional Congestion Areas**	**Comments**
1. Task 1 - Existing Studies	Includes all congestion areas identified in Task 1 Template Reports	16	11	6	A common Congestion Area criteria was not developed by the WCATF for Task 1 studies. Rather, Task 1 relied upon the criteria used in each individual study.
2. Task 3 - Historical Path Flow	Includes all top 10 ranked WECC paths, based on maximum seasonal U75 or U90 for the period 1999 to 2005. Corresponds to a U75 > 40% of time or U90 > 5% of time	13	10	0	Historical Path Flow analysis was completed for the Western Interconnect. It is planned to analyze ATC data when data is available.
3. Task 3 - 2008 Model Study	Includes all WECC paths/critical lines ranked in the top 10 in at least 1 of the following 9 categories (for $5, $7 and $9 gas):	17	10	0	See Note 3
	U75 (>80% of time)				
	U90 (>50% of time)				
	Shadow Price (Binding Hours)				
4. Task 3 - 2015 Model Study	Includes all WECC paths ranked in the top 10 in at least 1 of the 5 following categories ($5 gas)	12	8	0	See Note 3
	U75 (>80% of time)				
	U90 (>60% of time)				
	Ulimit (>50% of time)				
	Shadow Price (Average)				
	Congestion Rent				
Table 3	**TOTAL WECC Paths**	**24**			See Note 2
	TOTAL Congestion Areas		**14**		See Note 2
	TOTAL Subregional Congestion Areas			**6**	See Note 2

Notes:

1. All of the final identified W.I. congestion areas shown in Table 3 met at least one of the above 4 criteria. Table 3 therefore includes all of the W.I. congestion areas, as identified in Tasks 1 and 3.
2. Many W.I. Congestion Areas met more than one of the above criteria. Therefore the TOTALs do not equal the sum of the 4 criteria subtotals.
3. The Congestion Area criteria for the 2008 and the 2015 studies used different congestion metrics. This resulted since the views on preferred metrics evolved during the study. Additional work is needed to define preferred Congestion Area criteria and metrics.

Western Interconnect
Transmission Congestion Areas/Paths

Identified by the WCATF
For Submission to US DOE
May 8, 2006



NOTES:

1. See Table 4 for Congestion Area Criteria
2. Map identifies all Congestion Areas Identified in DOE Tasks 1 and 3
3. Many Congestion Areas are dependent upon location of future W.I. resources

Congested WECC Path

Congestion Area (See Table 3)

Direction of Congestion

Low Northwest Hydro Sensitivity

- *Revisions to the 2008 SSG-Wi Base Case (starting point)*
- *Assumptions for low NW hydro sensitivity*
- *Results from low NW hydro sensitivity*

SSGwi

Seams Steering Group of the Western Interconnection

April 20, 2006

Revisions to 2008 SSG-Wi Base Case

- Starting point for low NW hydro sensitivity
- Prepared by ABB, Inc.
- Revision of load data

	2008 Base Case Load		Revised 2008 Base Case Load		% Difference	
	Peak (MW)	Energy (MWh)	Peak (MW)	Energy (MWh)	Peak	Energy
ALBERTA	8,570	59,916,102	8,570	59,916,102	0.0%	0.0%
B.C.HYDR	9,187	56,876,741	9,187	56,876,741	0.0%	0.0%
WAPA L.C	358	2,357,343	208	1,318,751	-42.0%	-44.1%
NEVADA	4,998	20,863,359	6,008	24,318,693	20.2%	16.6%
ARIZONA	15,204	74,240,648	18,683	86,829,384	22.9%	17.0%
NEW MEXI	3,290	19,912,565	3,906	22,587,539	18.7%	13.4%
LADWP	5,780	27,608,019	6,610	30,788,457	14.4%	11.5%
SOCALIF	20,106	105,863,402	24,544	124,703,912	22.1%	17.8%
SANDIEGO	3,571	19,113,488	4,631	21,221,435	29.7%	11.0%
IMPERIAL	740	2,971,386	901	3,490,536	21.7%	17.5%
MEXICO-C	1,645	8,941,612	2,229	10,896,392	35.5%	21.9%
PG&E_BAY	7,998	44,493,246	7,998	44,493,246	0.0%	0.0%
PG&E_VLY	17,869	88,948,051	17,869	88,948,051	0.0%	0.0%

- Revision of resource data
  - Inclusion of 390MW Port Westward generator (online 2006)

Updates to 2008 SSG-Wi Base Case

- **Revisions to Transmission System – path limits and ratings**

  - **Path 1:** Alberta-BC was decreased from 1,000 to 700 MW to reflect operational limits.
  - **Path 3:** The Canada-Northwest limit was not reduced from the 3,150 MW rating however a nomogram was included that decreased the Westside limit (2,850 MW) by 1 MW for each MW of Northern Puget Sound generation.
  - **Path 6:** West of Hatwai was increased from 4,000 to 4,277 MW to reflect the accepted rating that was recently obtained.
  - **Path 17:** The West of Borah path rating used was 2,557 MW to reflect a planned upgrade to increase this path by 250 MW by summer 2007.
  - **Path 36:** TOT3 was decreased from 1,605 to 1,450 MW to reflect seasonal de-rates.
  - **Path 44:** South of San Onofre was increased from 2,200 to 2,500 MW to reflect the actual capability on this path.
  - **Path 48**: Northern New Mexico (NM2) rating was changed to 1,800 MW to reflect a recent upgrade and match Path Rating Catalog.

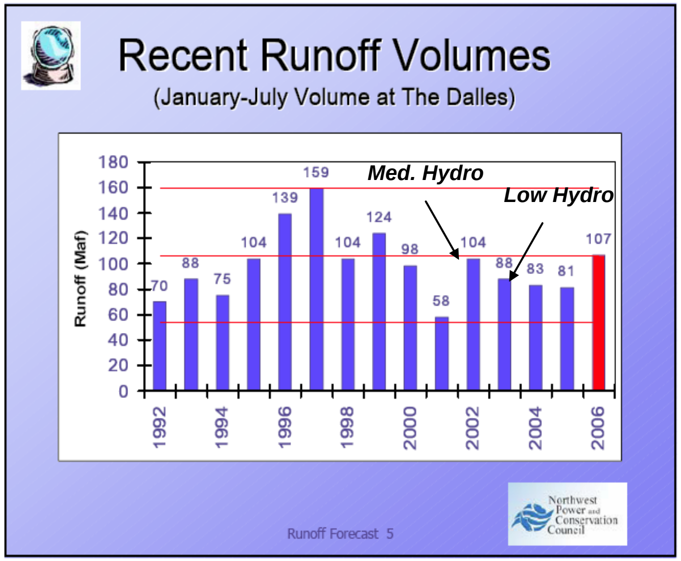
Updates to 2008 SSG-Wi Base Case

- **Revisions to Transmission System – path limits and ratings, cont'd.**
  - **Path 66**: COI rating was decreased from 4,800 to 4,700 MW due to seasonal de-rates. This is an increase from the number used in the 2003 study (4,500 MW) due to the impact of the addition of the Schultz-Wautoma line. There is also a COI/North of John Day/Midpoint-Summer Lake nomogram included.
  - **Path 76**: The rating of the Bordertown Phase Shifter (between busses 64017 and 64018) was changed to +/-300 MW so that the Alturas Path can be used to its full +/-300 MW rating.
  - **San Diego import limit** - Reversed direction of branch at San Onofre.
  - **Gregg to Hentap1** - Doubled line capacity by changing the impedance (previously, new generation had been added without transmission).

- **Omitted from Revised 2008 Base Case transmission system**
  - Path 66: Monitoring of COI lines not lifted, which limits path flow to the lowest rated line.
  - Path 64: Market Place-Adelanto was not increased from 1,200 to 1,636 MW. The increase would reflect this line's ability to carry more than its contractual allocation of 1,200 MW.
  - Path 65: The PDCI was only decreased from 3,100 to 3,000 MW instead of to 2,800 MW. The decrease to 2,800MW would be consistent with seasonal de-rates similar to the COI (-100 MW) and would reflect the lack of modeling losses in the program (-200 MW).

Creation of Low NW Hydro Sensitivity

- **NW hydro generation**
  - Reflects NWPPC's 2003 (low water year) generation data
  - 2003 represents a year with runoff in the lowest quartile
  - No change to Canada and Colorado hydro due to extensive storage capabilities
  - No change to Northern California hydro as 2003 was a medium hydro year in CA
  - No change to remaining hydro in the west – low hydro conditions may not be present due to geographical diversity



- **NW Loads – two sensitivities**
  1. Loads consistent with 2003 low hydro year
     - 2008 monthly energy and peak loads were adjusted by NWPCC to reflect 2003 temperatures (provides consistency in NW load and generation profiles)
     - These monthly energy and peaks were then converted to hourly using 2003 actual load as shapes
  2. Loads consistent with 2002 medium hydro yea
     - This sensitivity was done to isolate the effect of lower hydro conditions without the corresponding decrease in loads

- **$9/MMBtu Henry Hub reference gas price**
- **All else remains the same as Revised 2008 Base Case**

Observations

- **Low NW Hydro Sensitivity:**
  - No large impact on area production costs
  - No large impact on congestion – physical or congestion rent
- **Reasons:**
  - Temperature adjusted loads are lower and partially offset reduced hydro generation
  - Resource capacity is surplus (high planning margin) – ample relatively low-cost generation available to offset reduced hydro generation
- **Going forward:**
  - Low hydro case that includes low hydro conditions in CA and BC is warranted
  - This case should employ a more realistic planning margin for resource additions, i.e., 15 percent for non-hydro
  - WECC, through its new Transmission Expansion Planning committee (TEPPC) should give this priority

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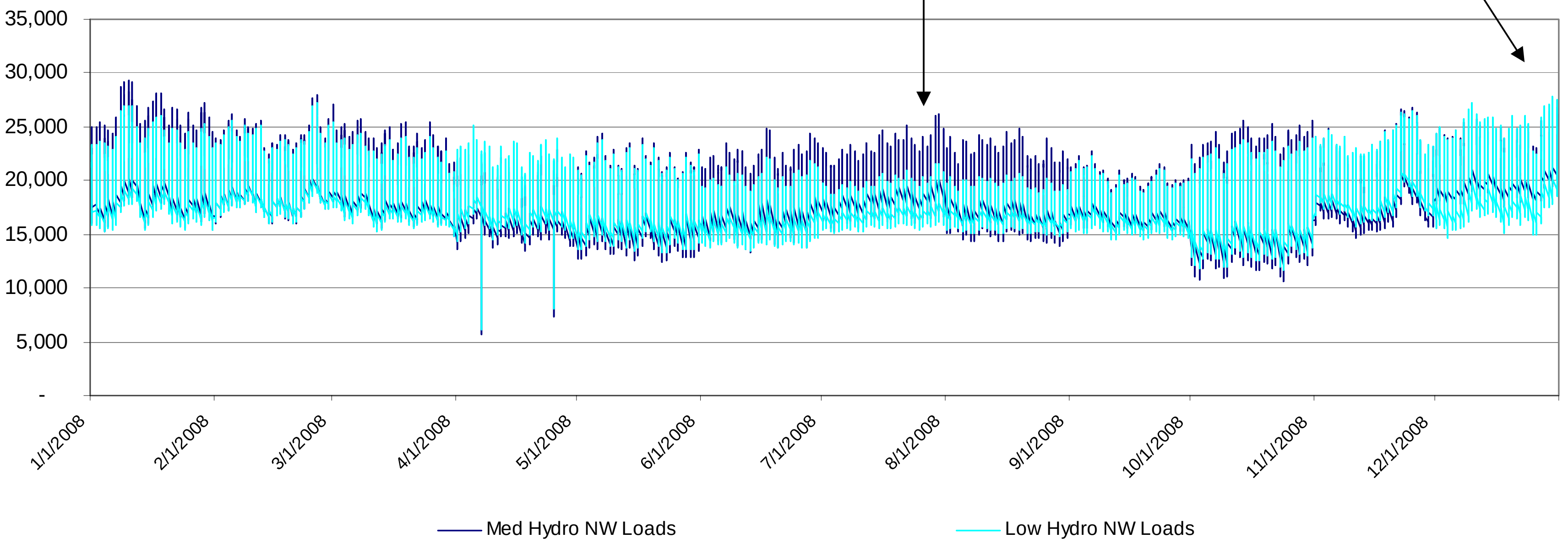
NW load profiles

low vs medium NW hydro year conditions

3% reduction in annual energy demand

3% reduction in winter peak hour

18% reduction in summer peak hour



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Revised Loads and Resources

Revised Base Case with Low NW Hydro Generation and Loads

				Resource (Capacity) MW by Fuel Type						As modeled in GridView for DOE Study Modified 2008 Base Case Low NW Hydro/Load Sensitivity				
REGION	AREA	Nameplate Capacity MW	Discounted Capacity (per 2015 Case protocol)	Coal	Nat. Gas	Oil	Hydro + Pumped	Wind	Other	ANNUAL ENERGY MWh	SUMMER PEAK MW (Jul-Aug)	WINTER PEAK MW (Dec-Jan)	NAMEPLATE MARGIN (Resource vs Load by Area)	DISCOUNTED MARGIN (Resource vs Load by Area)
CALIF ("CAISO")	IMPERIAL	1,558	1,542	0	307	32	176	21	1,022	2,435,562	901	420	73%	71%
CALIF ("CAISO")	LADWP	6,022	5,932	0	4,899	0	1,003	120	0	27,608,019	5,736	4,644	5%	3%
CALIF ("CAISO")	MEXICO-C	3,313	3,313	0	2,175	439	0	0	699	8,941,612	2,229	1,662	49%	49%
CALIF ("CAISO")	PG&E_BAY	7,305	6,924	20	5,726	860	0	508	192	44,493,246	7,998	6,887	-9%	-13%
CALIF ("CAISO")	PG&E_VLY	24,568	23,633	50	11,723	174	8,579	1,247	2,796	88,948,052	17,240	13,103	43%	37%
CALIF ("CAISO")	SANDIEGO	4,609	4,609	0	4,561	48	0	0	0	19,113,488	4,631	3,582	0%	0%
CALIF ("CAISO")	SOCALIF	19,709	18,606	108	14,080	50	1,315	1,472	2,685	105,863,402	23,372	17,891	-16%	-20%
AZNMNV	ARIZONA	23,097	23,097	7,779	10,808	140	233	0	4,137	74,240,648	18,683	12,050	24%	24%
AZNMNV	NEVADA	7,582	7,582	605	6,800	177	0	0	0	20,863,359	6,008	3,115	26%	26%
AZNMNV	NEW MEXI	4,472	4,280	2,037	2,161	20	14	240	0	17,778,053	3,906	3,416	14%	10%
AZNMNV	WAPA L.C	5,939	5,939	0	2,197	0	3,742	0	0	2,357,343	208	201	2755%	2755%
CANADA	ALBERTA	11,944	11,859	5,380	4,904	0	1,493	106	62	59,916,102	8,217	8,570	45%	44%
CANADA	B.C.HYDR	11,995	11,995	0	1,639	0	10,356	0	0	56,876,741	7,199	9,187	67%	67%
NWPP	NW_EAST	34,274	29,984	0	3,628	24	27,639	1,693	1,290	69,956,140	8,976	11,629	282%	234%
NWPP	NW_WEST	11,574	10,965	1,966	4,148	74	5,067	89	230	101,272,681	12,727	16,877	-9%	-14%
RMPP	B HILL	1,020	1,020	522	317	42	139	0	0	5,669,651	851	835	20%	20%
RMPP	BHB	0	0	0	0	0	0	0	0	3,441,377	425	474	-100%	-100%
RMPP	BONZ	468	468	468	0	0	0	0	0	1,045,306	197	147	137%	137%
RMPP	COL E	8,866	8,688	3,517	4,287	120	744	198	0	52,116,113	8,878	7,920	0%	-2%
RMPP	COL W	2,294	2,294	1,904	104	0	286	0	0	5,829,865	871	913	163%	163%
RMPP	IDAHO	2,393	2,035	0	135	0	2,088	170	0	15,010,623	3,025	2,311	-21%	-33%
RMPP	IPP	1,847	1,847	1,847	0	0	0	0	0	0	1	1	0%	0%
RMPP	JB	2,128	2,128	2,128	0	0	0	0	0	0	1	1	0%	0%
RMPP	KGB	324	272	15	0	0	244	65	0	6,118,633	1,275	965	-75%	-79%
RMPP	LRS	1,628	1,628	1,107	300	0	221	0	0	3,757,124	531	520	207%	207%
RMPP	MONTANA	3,911	3,714	2,511	376	0	700	247	77	8,992,483	1,611	1,620	143%	131%
RMPP	SIERRA	1,878	1,835	565	1,206	0	0	53	53	10,271,004	1,737	1,439	8%	6%
RMPP	SW WYO	264	181	0	0	0	160	104	0	3,401,463	481	400	-45%	-62%
RMPP	UT N	2,458	2,458	929	1,445	0	84	0	0	33,841,556	6,256	4,295	-61%	-61%
RMPP	UT S	2,911	2,911	2,274	613	0	0	0	24	4,993,398	967	672	201%	201%
RMPP	WYO	775	775	775	0	0	0	0	0	2,283,714	338	289	129%	129%
RMPP	YLW TL	288	288	0	0	0	288	0	0	8,784	1	1	28700%	28700%
	Total Capacity	211,411	202,799	36,506	88,538	2,200	64,569	6,331	13,267	857,445,542	155,477	136,037	36%	30%

2008 Base Case Sensitivity
April 2006

Effects of Low NW Hydro

Change in Westwide Generation and Generation Costs

Generation (MWh)		Med. Hydro		Low Hydro		Change in Generation		
						Change in Gas Price Only	Reduced NW Hydro Gen. & Loads	Reduced NW Hydro Gen. only
Sub-Region	Area	$5 HH	$9 HH	$9 HH	$9HH Medium Loads	Med. Hydro + $5HH vs $9 HH	$9HH	Low Hydro Gen vs Medium Hydro Gen
		A	B	C	D	(B-A)/A	(C-B)/B	(D-B)/B
AZNMNV	ARIZONA	135,667,344	131,107,099	**130,679,189**	**130,779,549**	-3%	0%	0%
	NEVADA	22,156,292	21,987,081	**22,129,012**	**22,296,262**	-1%	1%	1%
	NEW MEXI	20,089,660	19,219,910	**19,205,146**	**19,310,906**	-4%	0%	0%
	WAPA L.C	17,831,460	18,714,354	**18,662,897**	**18,788,028**	5%	0%	0%
AZNMNV Total		195,744,757	191,028,444	**190,676,244**	**191,174,745**	-2%	0%	0%
CALIF	IMPERIAL	6,191,841	6,707,466	**6,695,442**	**6,700,385**	8%	0%	0%
	LADWP	15,223,466	14,482,418	**14,459,222**	**14,860,619**	-5%	0%	3%
	MEXICO-C	8,718,961	10,704,598	**10,763,546**	**10,871,017**	23%	1%	2%
	PG&E_BAY	22,576,687	24,880,957	**24,865,126**	**25,518,527**	10%	0%	3%
	PG&E_VLY	80,022,877	80,939,223	**80,976,721**	**82,528,251**	1%	0%	2%
	SANDIEGO	8,953,071	9,308,602	**9,396,521**	**9,642,559**	4%	1%	4%
	SOCALIF	49,443,516	48,306,378	**48,371,923**	**49,684,348**	-2%	0%	3%
CALIF Total		191,130,419	195,329,643	**195,528,501**	**199,805,706**	2%	0%	2%
CANADA	ALBERTA	65,382,427	65,037,690	**65,232,394**	**65,525,682**	-1%	0%	1%
	B.C.HYDR	49,402,295	48,741,545	**48,788,499**	**48,917,663**	-1%	0%	0%
CANADA Total		114,784,722	113,779,235	**114,020,892**	**114,443,345**	-1%	0%	1%
NWPP	NW_EAST	139,193,831	138,964,676	**132,393,513**	**132,541,064**	0%	-5%	-5%
	NW_WEST	64,077,625	64,243,082	**64,494,651**	**64,678,255**	0%	0%	1%
NWPP Total		203,271,456	203,207,758	**196,888,164**	**197,219,318**	0%	-3%	-3%
RMPP	B HILL	5,240,783	5,226,108	**5,228,252**	**5,236,793**	0%	0%	0%
	BHB	0	0	**0**	**0**	0%	0%	0%
	BONZ	3,752,709	3,755,302	**3,752,483**	**3,760,244**	0%	0%	0%
	COL E	45,884,425	46,747,354	**46,875,863**	**46,991,790**	2%	0%	1%
	COL W	16,676,844	16,700,059	**16,691,267**	**16,699,612**	0%	0%	0%
	IDAHO	9,390,864	9,308,690	**9,310,560**	**9,332,994**	-1%	0%	0%
	IPP	14,928,582	14,928,582	**14,928,582**	**14,928,582**	0%	0%	0%
	JB	17,196,120	17,197,347	**17,198,833**	**17,197,345**	0%	0%	0%
	KGB	1,329,854	1,329,854	**1,329,854**	**1,329,854**	0%	0%	0%
	LRS	10,156,019	10,041,566	**10,045,569**	**10,051,603**	-1%	0%	0%
	MONTANA	27,486,698	27,590,636	**27,616,678**	**27,597,132**	0%	0%	0%
	SIERRA	5,454,198	5,937,386	**5,943,208**	**6,155,893**	9%	0%	4%
	SW WYO	878,448	878,448	**878,448**	**878,448**	0%	0%	0%
	UT N	14,598,911	14,881,027	**14,952,626**	**15,038,617**	2%	0%	1%
	UT S	22,591,458	22,629,828	**22,660,373**	**22,658,076**	0%	0%	0%
	WYO	6,270,265	6,270,265	**6,267,435**	**6,267,435**	0%	0%	0%
	YLW TL	1,209,589	1,209,589	**1,209,589**	**1,209,589**	0%	0%	0%
RMPP Total		203,045,765	204,632,041	**204,889,621**	**205,334,006**	1%	0%	0%
Total		907,977,119	907,977,121	**902,003,422**	**907,977,120**	0%	-1%	0%

Generation Cost (M$)		Med. Hydro		Low Hydro		Change in Generation Cost		
						Change in Gas Price Only	Reduced NW Hydro Gen. & Loads	Reduced NW Hydro Gen. only
Sub-Region	Area	$5 HH	$9 HH	$9 HH	$9HH Medium Loads	Med. Hydro + $5HH vs $9 HH	$9HH	Low Hydro Gen vs Medium Hydro Gen
		A	B	C	D	(B-A)/A	(C-B)/B	(D-B)/B
AZNMNV	ARIZONA	2,741	3,611	**3,578**	**3,588**	32%	-1%	-1%
	NEVADA	826	1,339	**1,349**	**1,364**	62%	1%	2%
	NEW MEXI	435	457	**456**	**465**	5%	0%	2%
	WAPA L.C	205	400	**396**	**406**	95%	-1%	2%
AZNMNV Total		4,206	5,808	**5,779**	**5,823**	38%	0%	0%
CALIF	IMPERIAL	110	164	**163**	**164**	50%	-1%	0%
	LADWP	622	994	**992**	**1,023**	60%	0%	3%
	MEXICO-C	305	591	**595**	**604**	94%	1%	2%
	PG&E_BAY	946	1,570	**1,568**	**1,618**	66%	0%	3%
	PG&E_VLY	1,430	2,367	**2,366**	**2,487**	66%	0%	5%
	SANDIEGO	413	709	**715**	**733**	72%	1%	4%
	SOCALIF	1,151	1,785	**1,792**	**1,899**	55%	0%	6%
CALIF Total		4,975	8,181	**8,192**	**8,528**	64%	0%	4%
CANADA	ALBERTA	1,505	1,984	**1,999**	**2,021**	32%	1%	2%
	B.C.HYDR	158	220	**224**	**234**	40%	1%	6%
CANADA Total		1,662	2,204	**2,222**	**2,255**	33%	1%	2%
NWPP	NW_EAST	920	1,636	**1,638**	**1,645**	78%	0%	1%
	NW_WEST	1,379	2,198	**2,193**	**2,210**	59%	0%	1%
NWPP Total		2,298	3,834	**3,832**	**3,854**	67%	0%	1%
RMPP	B HILL	78	91	**92**	**92**	17%	0%	1%
	BHB	0	0	**0**	**0**	0%	0%	0%
	BONZ	44	44	**44**	**44**	0%	0%	0%
	COL E	884	1,261	**1,273**	**1,280**	43%	1%	2%
	COL W	235	245	**245**	**245**	5%	0%	0%
	IDAHO	11	9	**9**	**11**	-18%	2%	23%
	IPP	216	216	**216**	**216**	0%	0%	0%
	JB	227	227	**227**	**227**	0%	0%	0%
	KGB	2	2	**2**	**2**	0%	0%	0%
	LRS	83	82	**83**	**83**	-1%	0%	1%
	MONTANA	309	390	**390**	**389**	26%	0%	0%
	SIERRA	116	176	**176**	**193**	51%	0%	10%
	SW WYO	0	0	**0**	**0**	0%	0%	0%
	UT N	379	579	**581**	**586**	53%	0%	1%
	UT S	407	520	**521**	**521**	28%	0%	0%
	WYO	48	48	**48**	**48**	0%	0%	0%
	YLW TL	0	0	**0**	**0**	0%	0%	0%
RMPP Total		3,038	3,890	**3,905**	**3,938**	28%	0%	1%
Total		16,180	23,917	**23,930**	**24,399**	48%	0%	2%

Impact of reduced NW Loads and NW Hydro Generation

				LOADS - MEDIUM HYDRO CASE			LOADS - LOW HYDRO CASE			LOAD DIFFERENCE					
REGION	AREA	Nameplate Capacity MW	Discounted Capacity (per 2015 Case protocol)	ANNUAL ENERGY MWh	SUMMER PEAK MW (Jul-Aug)	WINTER PEAK MW (Dec-Jan)	ANNUAL ENERGY MWh	SUMMER PEAK MW (Jul-Aug)	WINTER PEAK MW (Dec-Jan)	ANNUAL ENERGY MWh	SUMMER PEAK MW (Jul-Aug)	WINTER PEAK MW (Dec-Jan)	GENERATION - Medium Hydro Case	GENERATION Low Hydro Case	MWh Difference
CALIF ("CAISO")	IMPERIAL	1,558	1,542	2,435,562	901	420	2,435,562	901	420	0	0	0	6,707,466	6,695,442	-12,024
CALIF ("CAISO")	LADWP	6,022	5,932	27,608,019	5,736	4,644	27,608,019	5,736	4,644	0	0	0	14,482,418	14,459,222	-23,196
CALIF ("CAISO")	MEXICO-C	3,313	3,313	8,941,612	2,229	1,662	8,941,612	2,229	1,662	0	0	0	10,704,598	10,763,546	58,948
CALIF ("CAISO")	PG&E_BAY	7,305	6,924	44,493,246	7,998	6,887	44,493,246	7,998	6,887	0	0	0	24,880,957	24,865,126	-15,831
CALIF ("CAISO")	PG&E_VLY	24,568	23,633	88,948,052	17,240	13,103	88,948,052	17,240	13,103	0	0	0	80,939,223	80,976,721	37,498
CALIF ("CAISO")	SANDIEGO	4,609	4,609	19,113,488	4,631	3,582	19,113,488	4,631	3,582	0	0	0	9,308,602	9,396,521	87,919
CALIF ("CAISO")	SOCALIF	19,709	18,606	105,863,402	23,372	17,891	105,863,402	23,372	17,891	0	0	0	48,306,378	48,371,923	65,545
AZNMNV	ARIZONA	23,097	23,097	74,240,648	18,683	12,050	74,240,648	18,683	12,050	0	0	0	131,107,099	130,679,189	-427,909
AZNMNV	NEVADA	7,582	7,582	20,863,359	6,008	3,115	20,863,359	6,008	3,115	0	0	0	21,987,081	22,129,012	141,931
AZNMNV	NEW MEXI	4,472	4,280	17,778,053	3,906	3,416	17,778,053	3,906	3,416	0	0	0	19,219,910	19,205,146	-14,764
AZNMNV	WAPA L.C	5,939	5,939	2,357,343	208	201	2,357,343	208	201	0	0	0	18,714,354	18,662,897	-51,457
CANADA	ALBERTA	11,944	11,859	59,916,102	8,217	8,570	59,916,102	8,217	8,570	0	0	0	65,037,690	65,232,394	194,704
CANADA	B.C.HYDR	11,995	11,995	56,876,741	7,199	9,187	56,876,741	7,199	9,187	0	0	0	48,741,545	48,788,499	46,953
NWPP	NW_EAST	34,274	29,984	72,335,959	10,955	12,017	69,956,140	8,976	11,629	-2,379,819	-1,979	-388	138,964,676	132,393,513	-6,571,164
NWPP	NW_WEST	11,574	10,965	104,868,308	15,508	17,378	101,272,681	12,727	16,877	-3,595,628	-2,781	-501	64,243,082	64,494,651	251,569
RMPP	B HILL	1,020	1,020	5,669,651	851	835	5,669,651	851	835	0	0	0	5,226,108	5,228,252	2,144
RMPP	BHB	0	0	3,441,377	425	474	3,441,377	425	474	0	0	0	0	0	0
RMPP	BONZ	468	468	1,045,306	197	147	1,045,306	197	147	0	0	0	3,755,302	3,752,483	-2,818
RMPP	COL E	8,866	8,688	52,116,113	8,878	7,920	52,116,113	8,878	7,920	0	0	0	46,747,354	46,875,863	128,509
RMPP	COL W	2,294	2,294	5,829,865	871	913	5,829,865	871	913	0	0	0	16,700,059	16,691,267	-8,792
RMPP	IDAHO	2,393	2,035	15,010,623	3,025	2,311	15,010,623	3,025	2,311	0	0	0	9,308,690	9,310,560	1,871
RMPP	IPP	1,847	1,847	0	1	1	0	1	1	0	0	0	14,928,582	14,928,582	0
RMPP	JB	2,128	2,128	0	1	1	0	1	1	0	0	0	17,197,347	17,198,833	1,486
RMPP	KGB	324	272	6,118,633	1,275	965	6,118,633	1,275	965	0	0	0	1,329,854	1,329,854	0
RMPP	LRS	1,628	1,628	3,757,124	531	520	3,757,124	531	520	0	0	0	10,041,566	10,045,569	4,002
RMPP	MONTANA	3,911	3,714	8,992,483	1,611	1,620	8,992,483	1,611	1,620	0	0	0	27,590,636	27,616,678	26,042
RMPP	SIERRA	1,878	1,835	10,271,004	1,737	1,439	10,271,004	1,737	1,439	0	0	0	5,937,386	5,943,208	5,822
RMPP	SW WYO	264	181	3,401,463	481	400	3,401,463	481	400	0	0	0	878,448	878,448	0
RMPP	UT N	2,458	2,458	33,841,556	6,256	4,295	33,841,556	6,256	4,295	0	0	0	14,881,027	14,952,626	71,600
RMPP	UT S	2,911	2,911	4,993,398	967	672	4,993,398	967	672	0	0	0	22,629,828	22,660,373	30,545
RMPP	WYO	775	775	2,283,714	338	289	2,283,714	338	289	0	0	0	6,270,265	6,267,435	-2,830
RMPP	YLW TL	288	288	8,784	1	1	8,784	1	1	0	0	0	1,209,589	1,209,589	0
		211,411	202,799	863,420,989	160,237	136,926	857,445,542	155,477	136,037	(5,975,447)	(4,760)	(889)	907,977,121	902,003,422	(5,973,699)

Impact of reduced NW hydro generation in the Low NW Hydro Case is offset by temperature-adjusted (reduced) loads forecast for the same low hydro year.

Generation (MWh)			Hydro Scenario		
Region	Load Area	Fuel	Med.	Low	Difference
	NW_EAST	Hydro	100,219,385	93,658,588	(6,560,798)
	NW_WEST	Hydro	18,810,136	19,064,491	254,355
			119,029,522	112,723,079	(6,306,443)

Seams Steering Group of the Western Interconnection

Path Congestion Ranking

Low vs Medium NW Hydro

The rank is calculated based on congestion cost. The congestion rent of each congested path is defined as the hourly shadow price for each congested hour multiplied by the flow on the path for that hour. The results are summed to yield congestion cost.

Interfaces	Rank			
	Low NW Hydro		Medium NW Hydro	
	$9 G (no NW Load Reduction)	$9 G (NW Load Reduction)	$9 G	$5G
ALBERTA - BRITISH COLUMBIA	8	8	8	8
BONANZA - MONA	3	2	2	2
BRIDGER WEST	2	3	3	3
CHOLLA - PRECHCYN	9	9	10	14
COLGATE - RIO OSO	26	19	18	19
CORONADO - SILVER KING - KYRENE	10	11	11	15
CRYSTAL - MCCULLGH	15	15	15	10
EOR	33	33	34	12
FLAGSTAF - PINPKBRB	4	4	4	5
FOUR CORNERS 345_500	16	16	16	17
FOURCORN - MOENKOPI	20	20	21	20
HA PS - REDBUTTE	23	25	25	24
INTERMOUNTAIN - GONDER 230 KV	22	22	23	23
IPP DC LINE	13	14	13	13
LUGO - VICTORVL	17	17	17	16
MALIN - ROUND MT #2	12	12	12	7
MONTANA - NORTHWEST	5	6	5	6
Navajo - Crystal	6	5	6	1
PACIFIC DC INTERTIE (PDCI)	11	10	9	9
PATH C	27	23	24	25
PEACOCK - MEAD	19	21	22	18
SHIPROCK - SAN-JUAN	1	1	1	4
SOUTHWEST OF FOUR CORNERS	7	7	7	11
TBL MT D - RIO OSO	18	24	19	21
TOT 1A	14	18	20	22
TOT 2A	28	13	14	29

Rank of 1 indicates highest congestion

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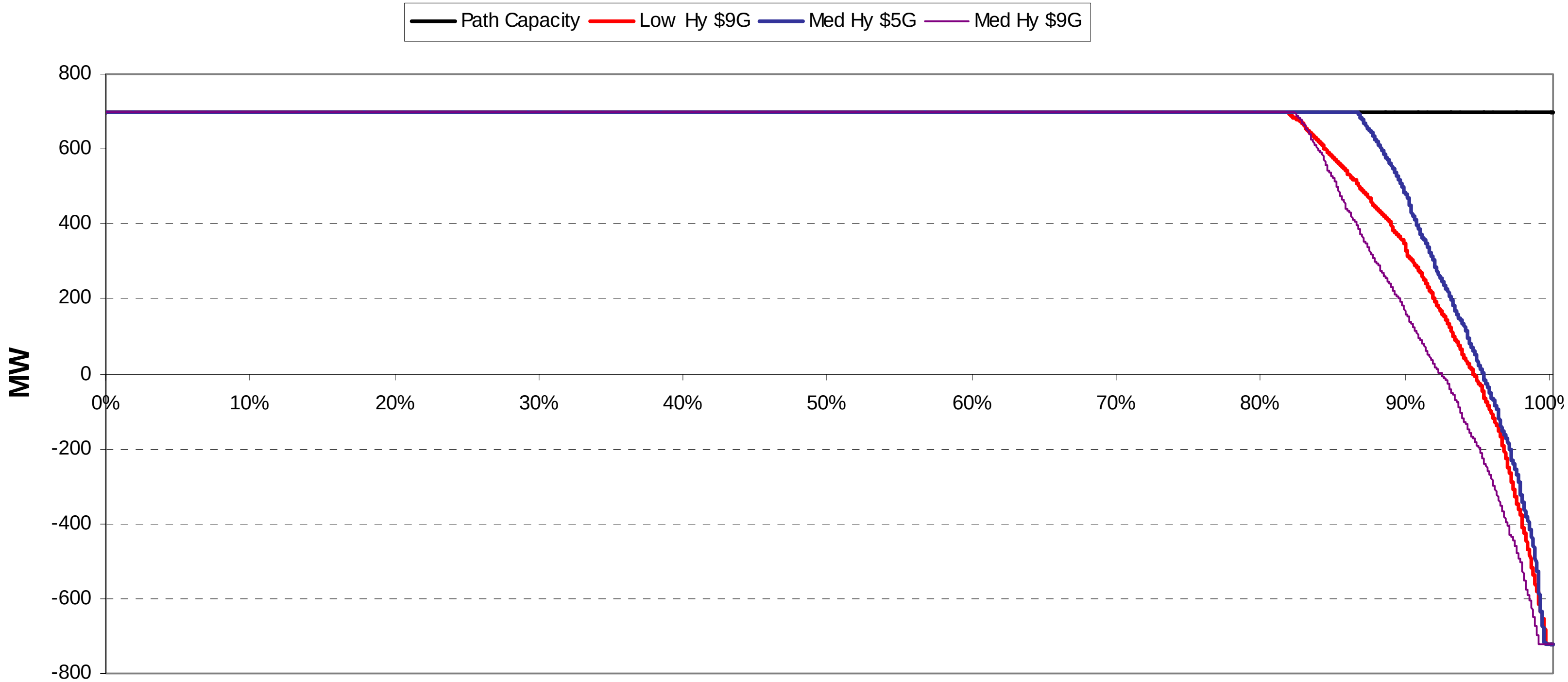
Alberta to BC

2008 Path Flow – MW



SSGwi

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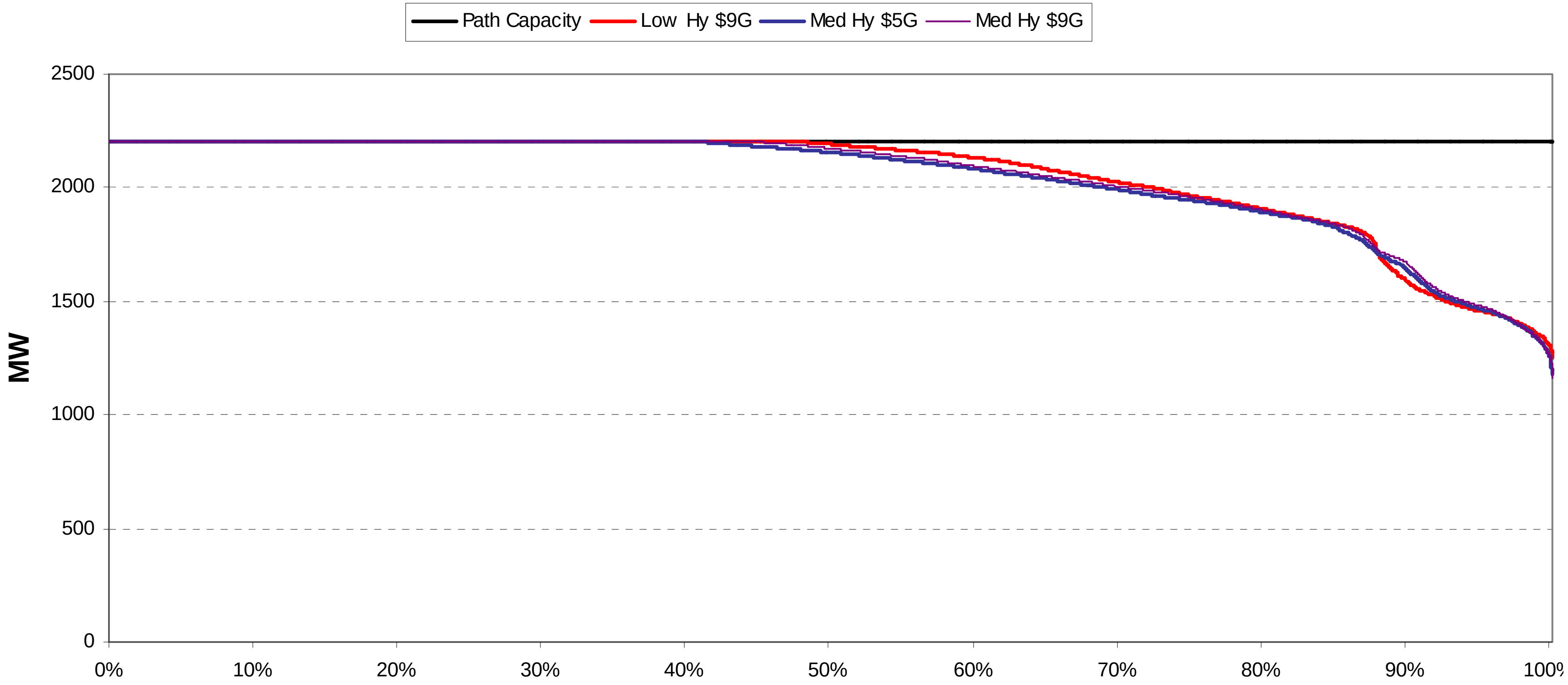
Bridger West

2008 Path Flow – MW



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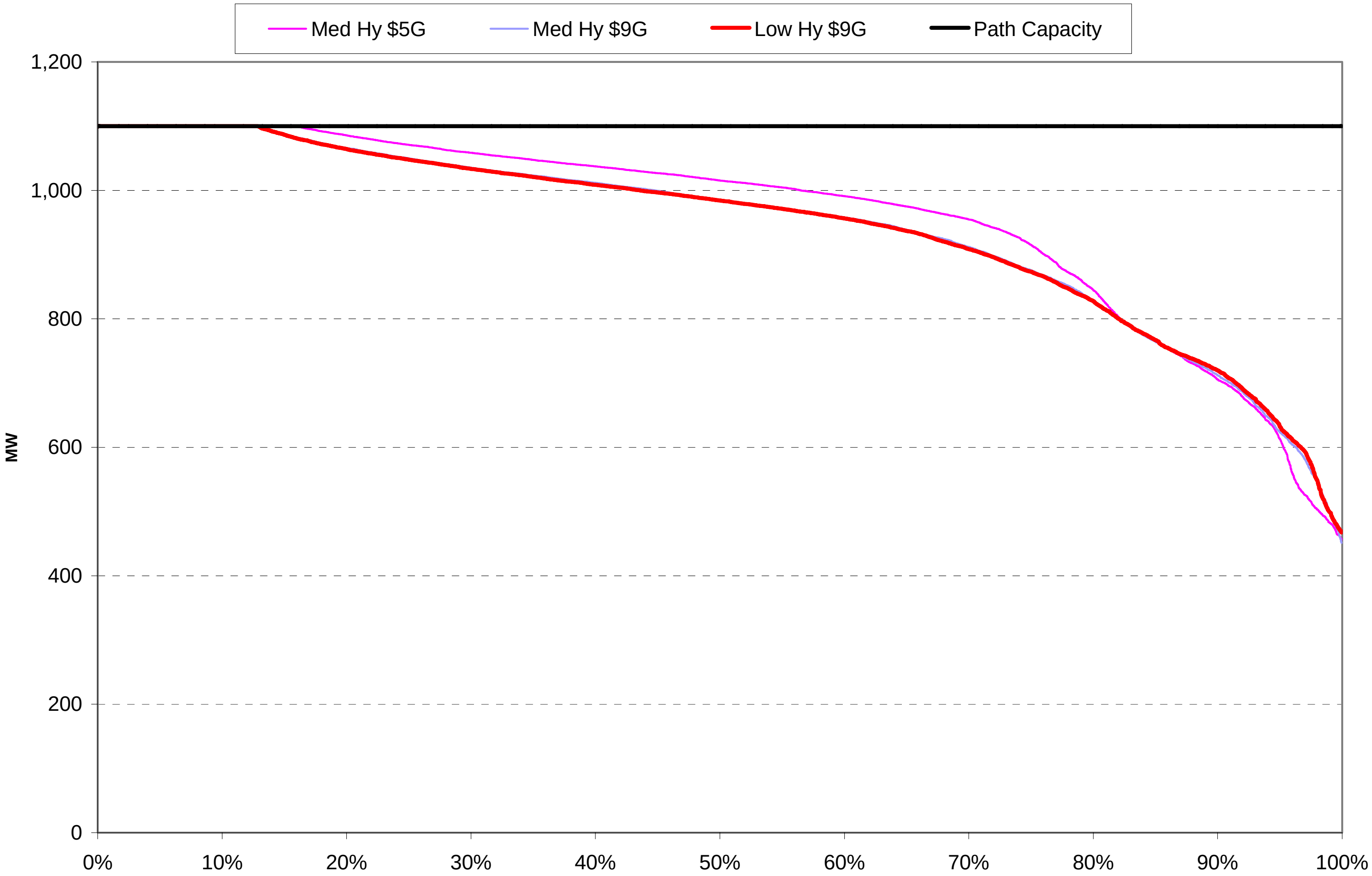
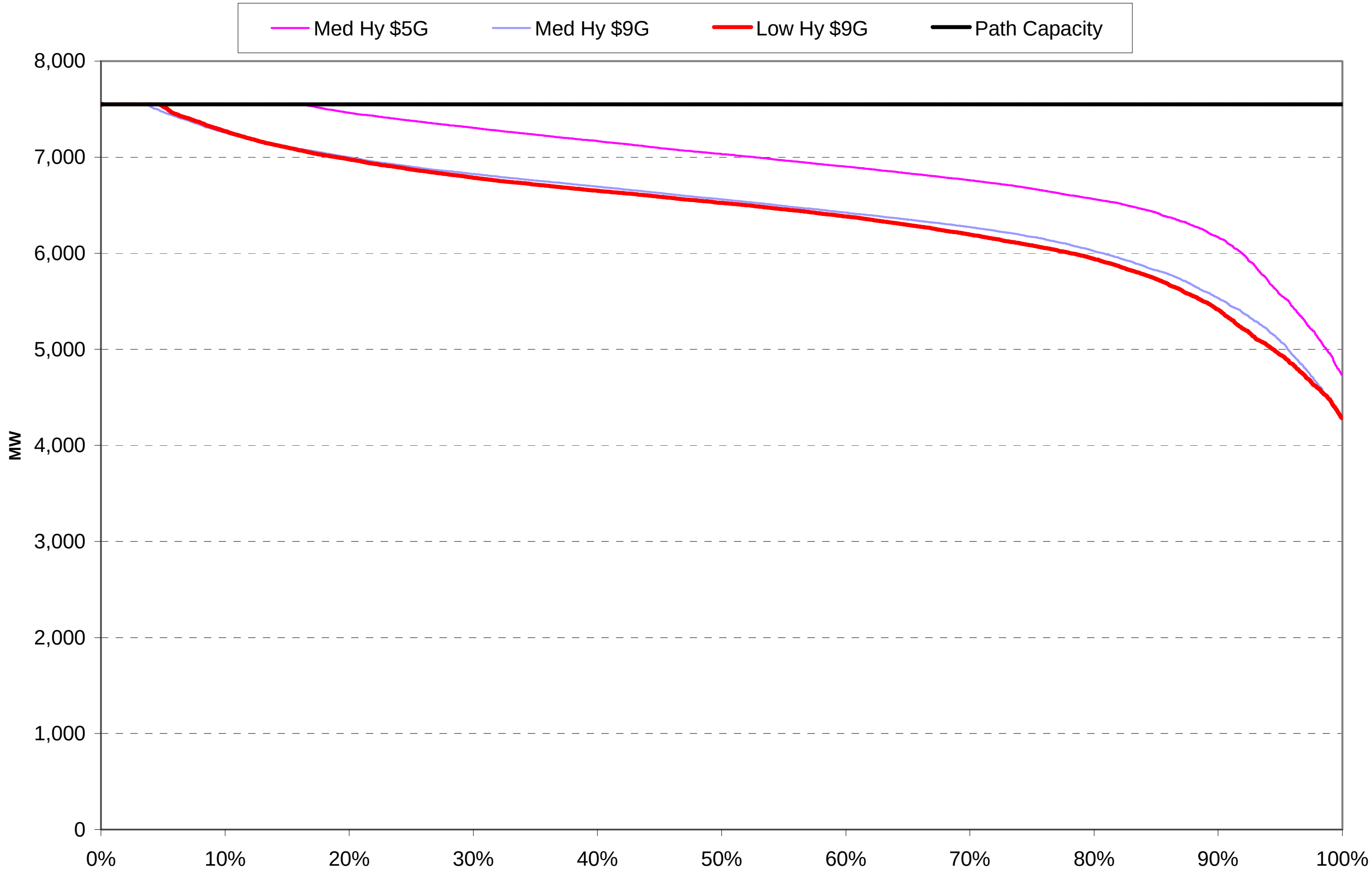
Coronado to Silver King

2008 Path Flow – MW



EOR

2008 Path Flow – MW



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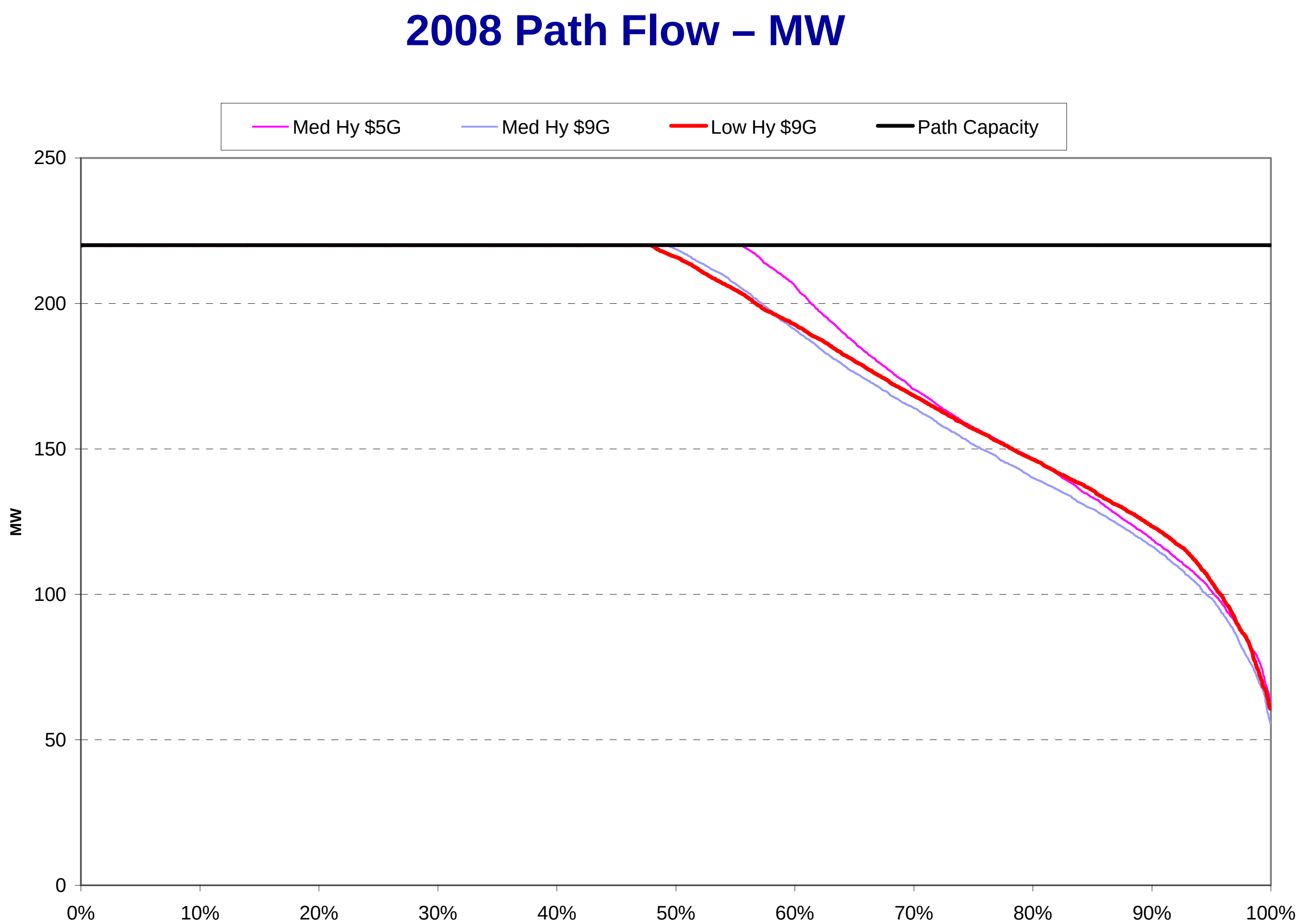
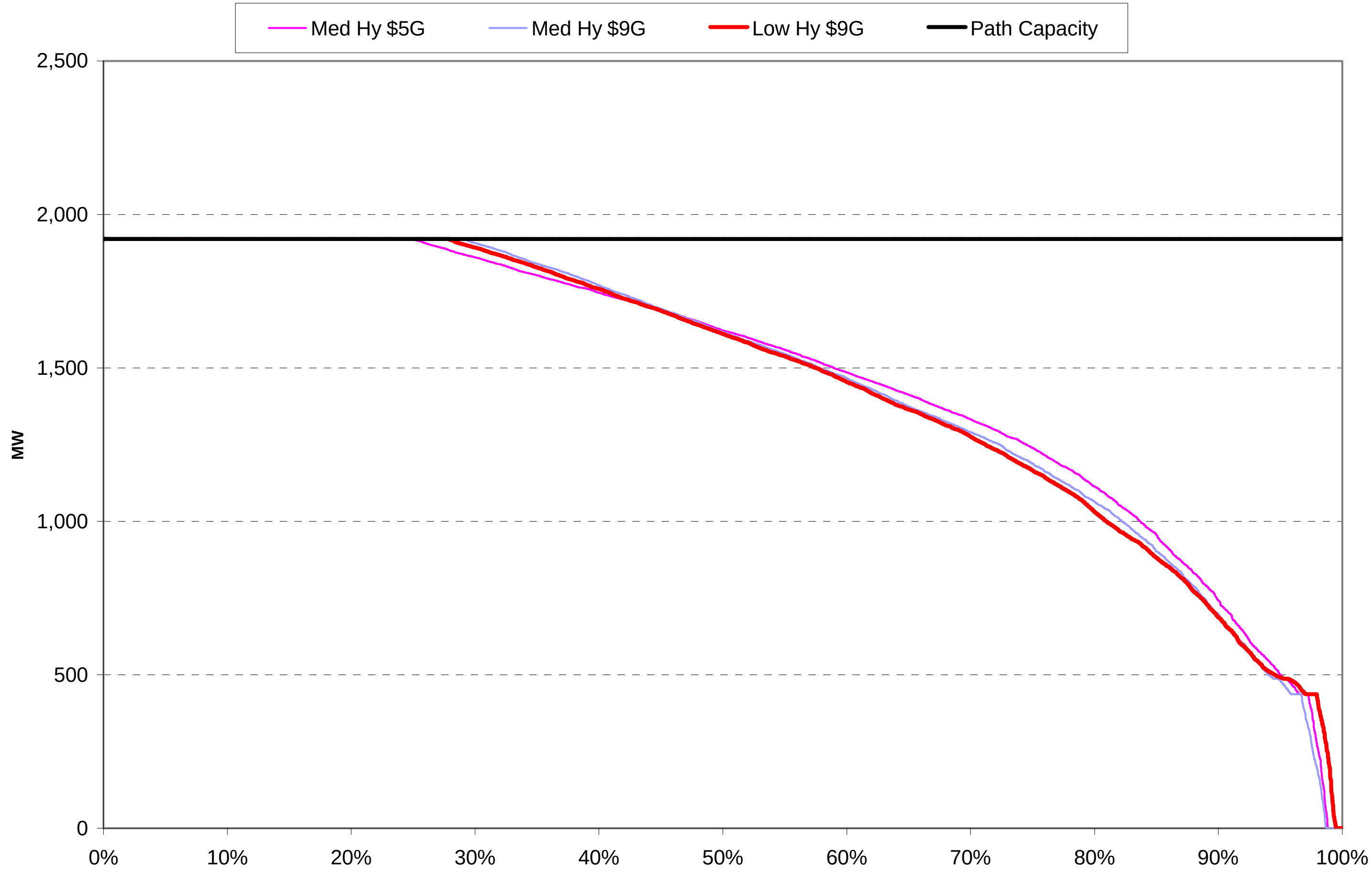
Intermountain to Gonder



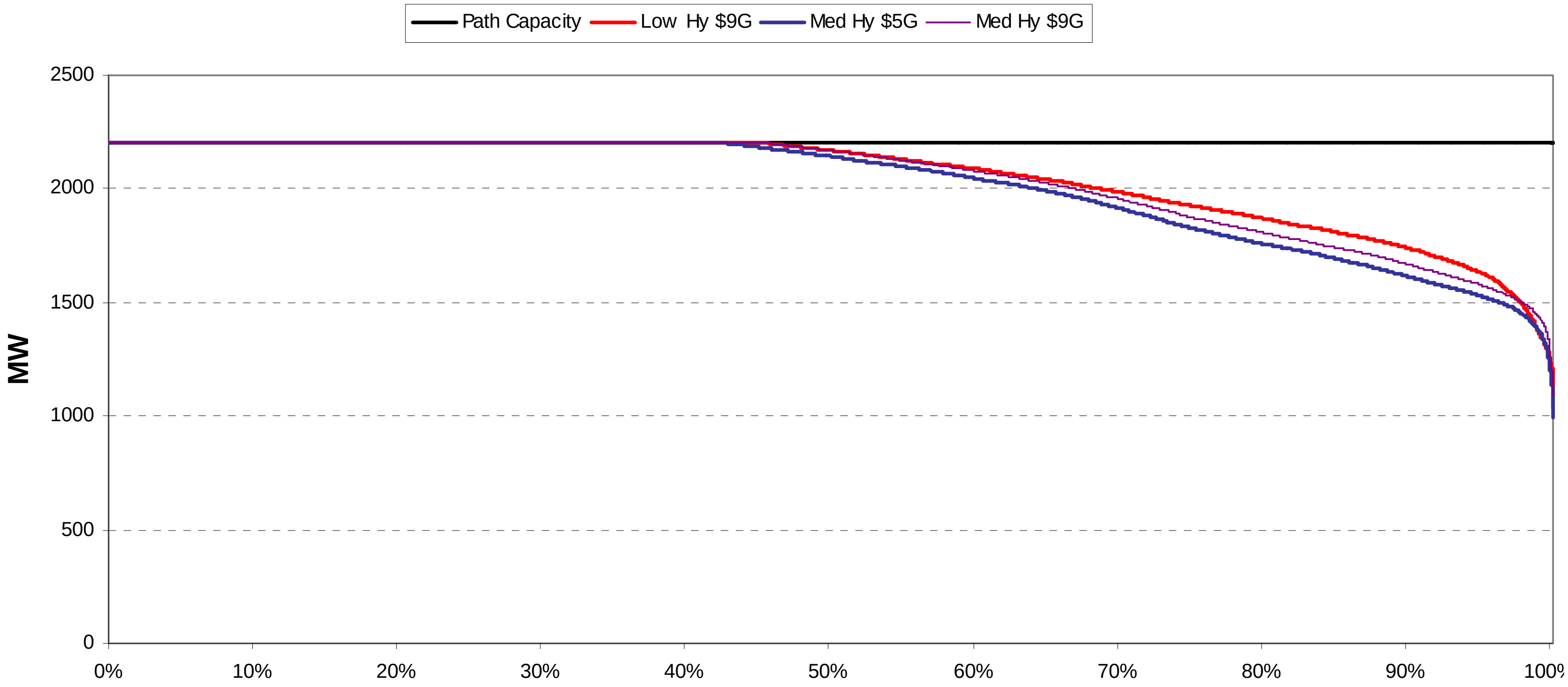
IPP DC

2008 Path Flow – MW



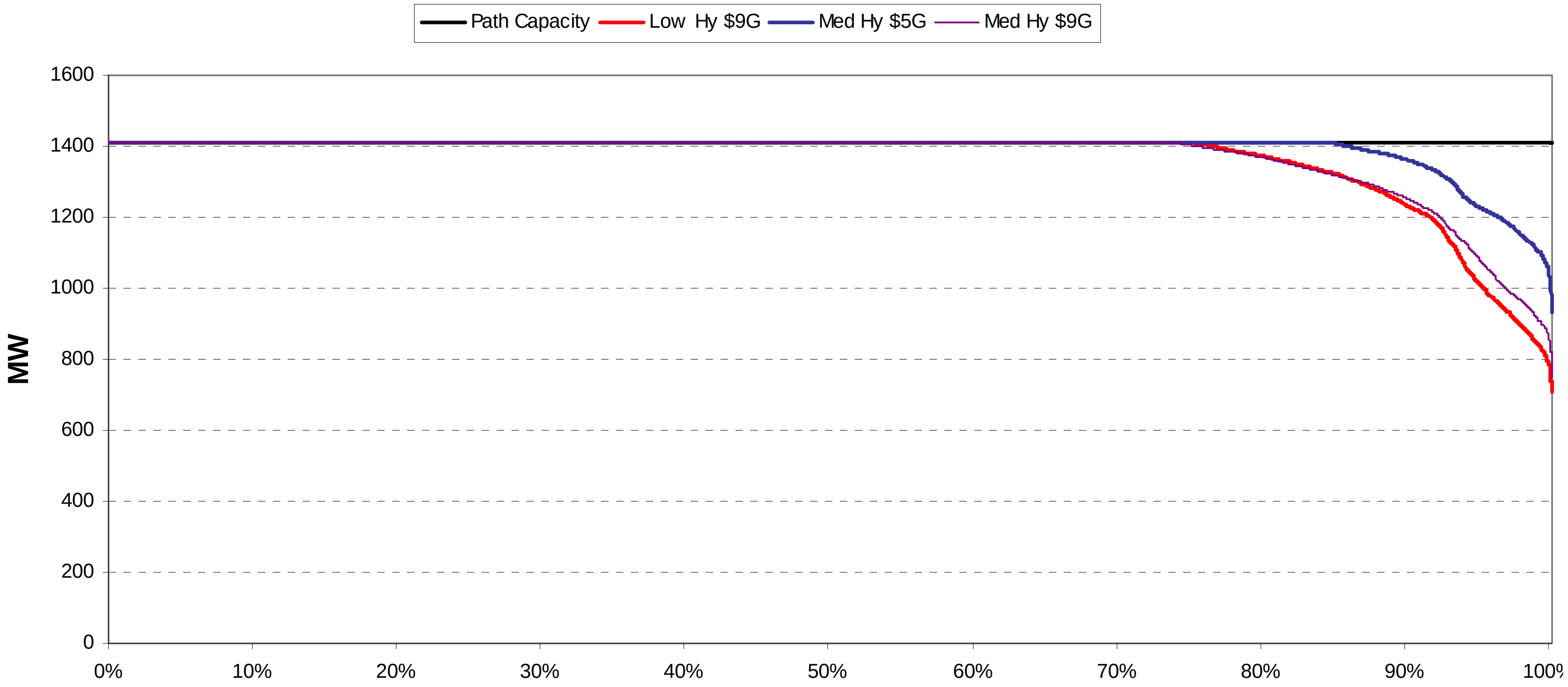
Montana to Northwest

2008 Path Flow – MW



Navajo to Crystal

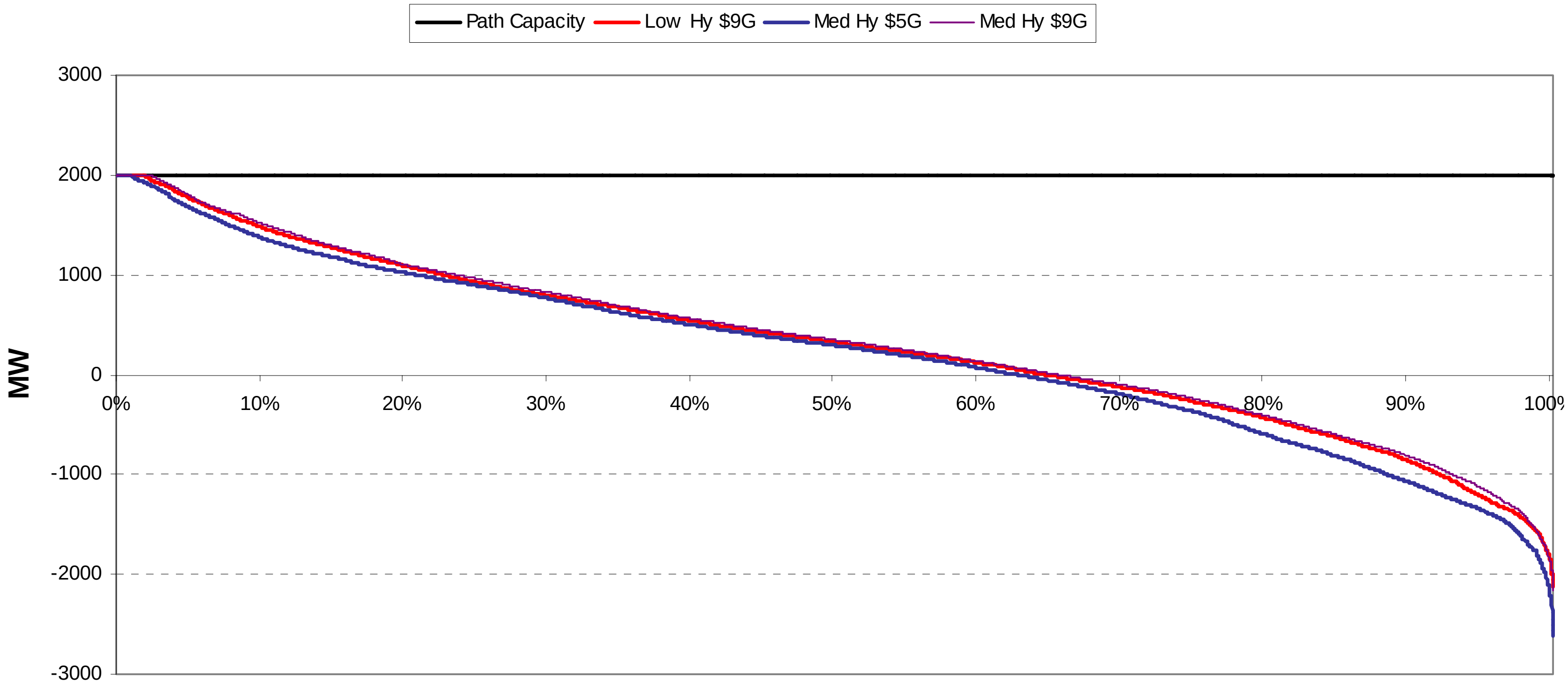
2008 Path Flow – MW



Northwest to Canada

Washington and southern British Columbia

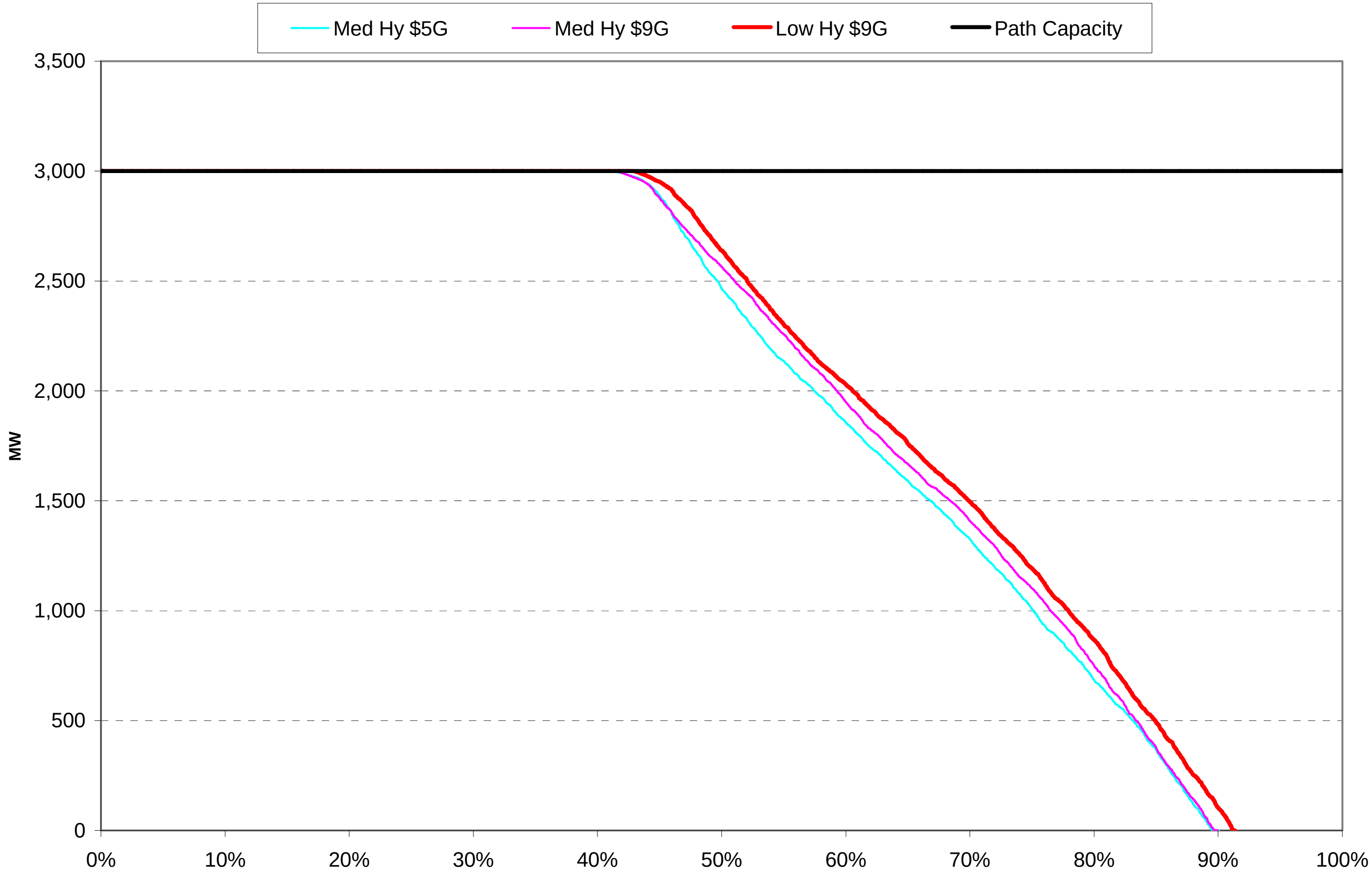
2008 Path Flow – MW



PDCI

Between Northern Oregon and Los Angeles

2008 Path Flow – MW



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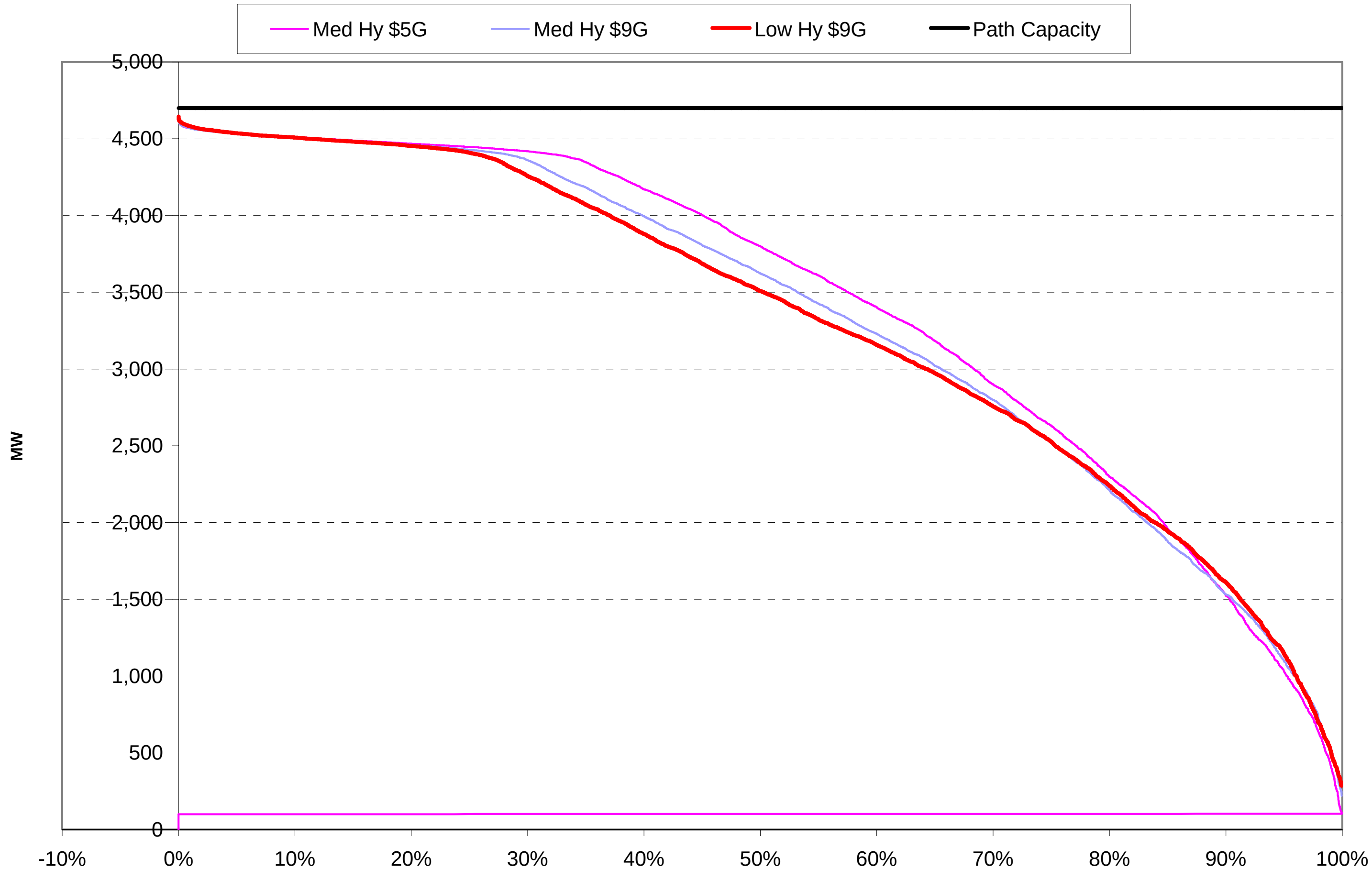
PACI (COI)

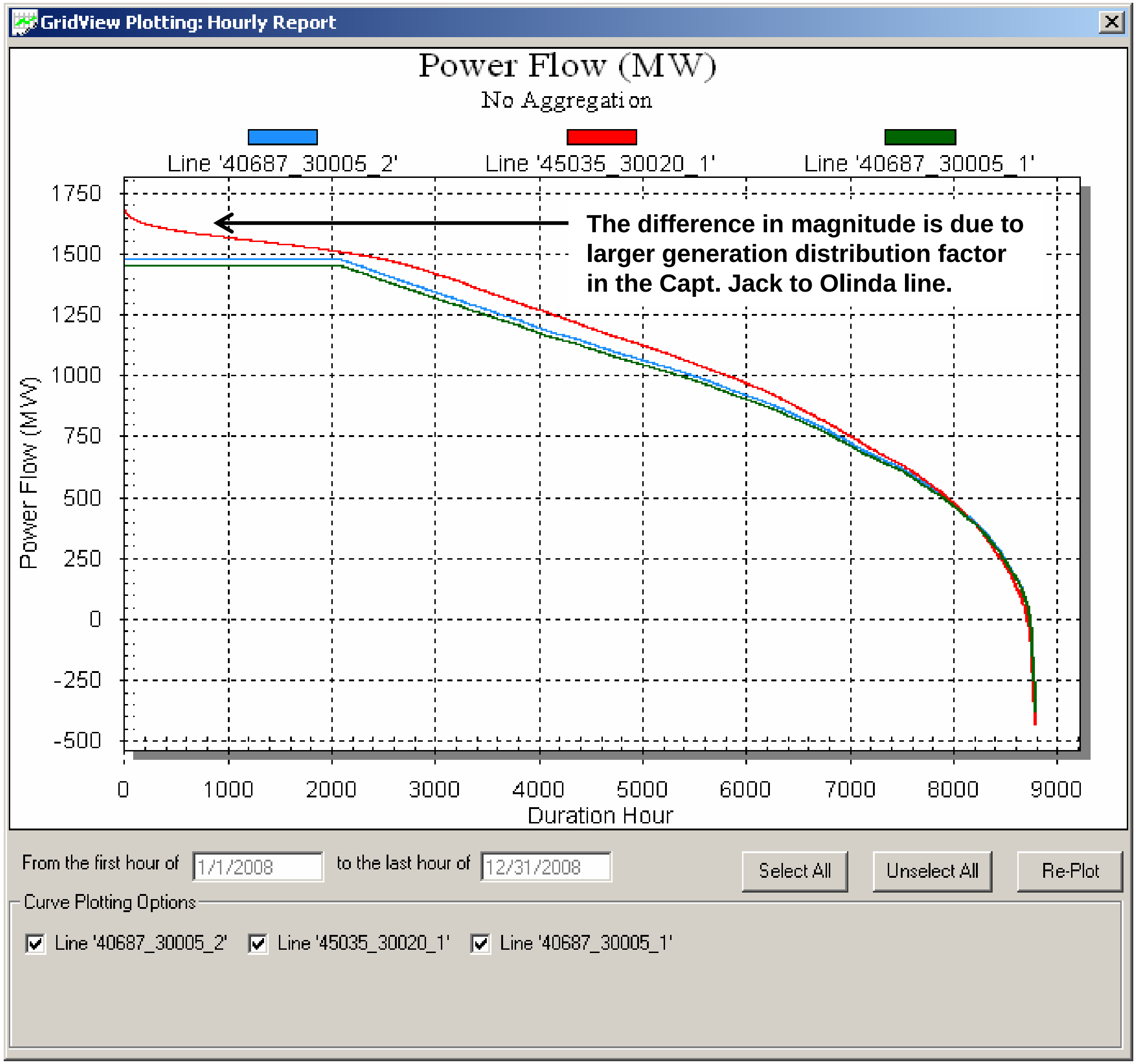
2008 Path Flow – MW



PACI (COI lines)

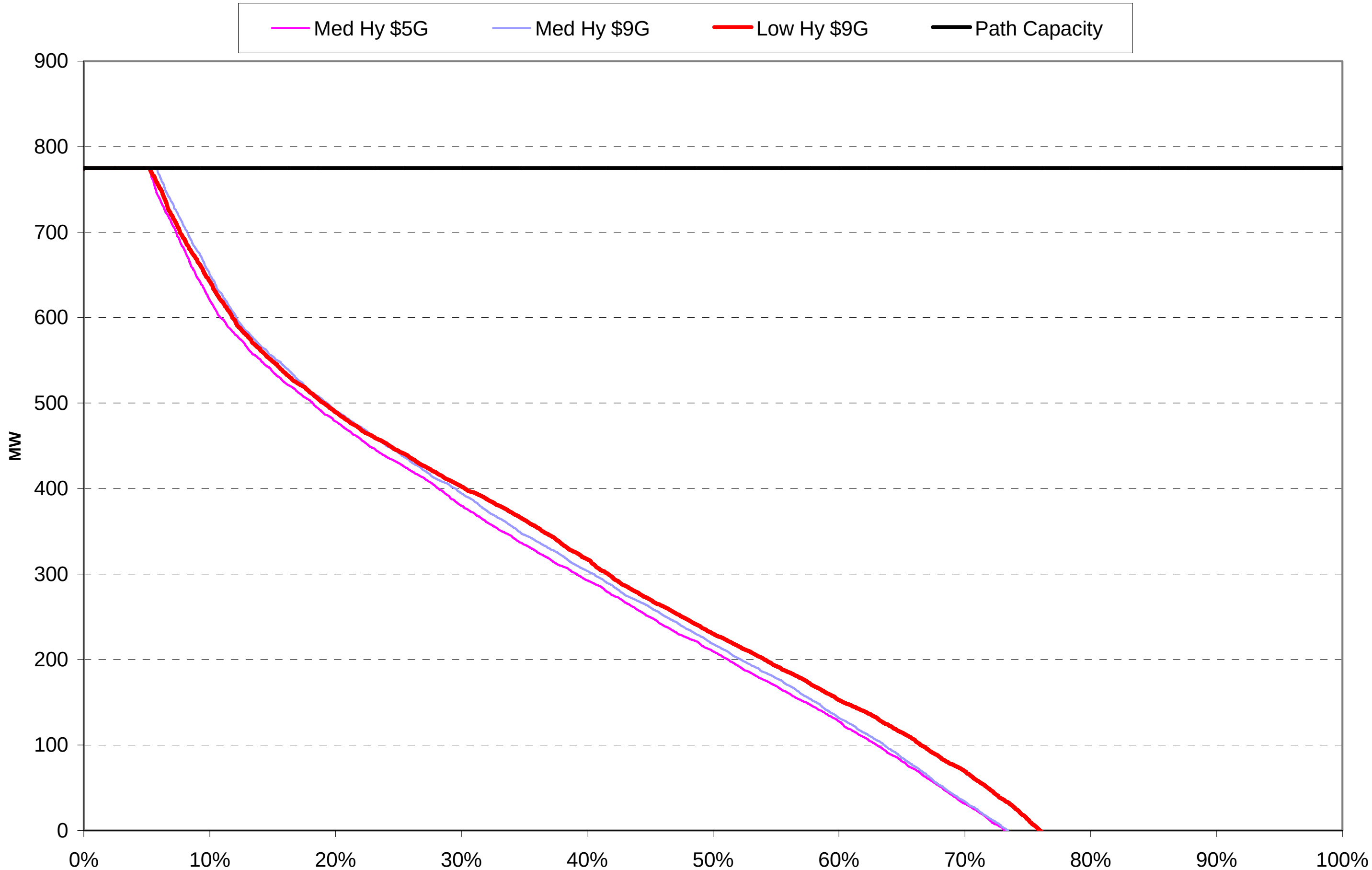
Between Oregon and Northern California

$9 Gas, Low Hydro



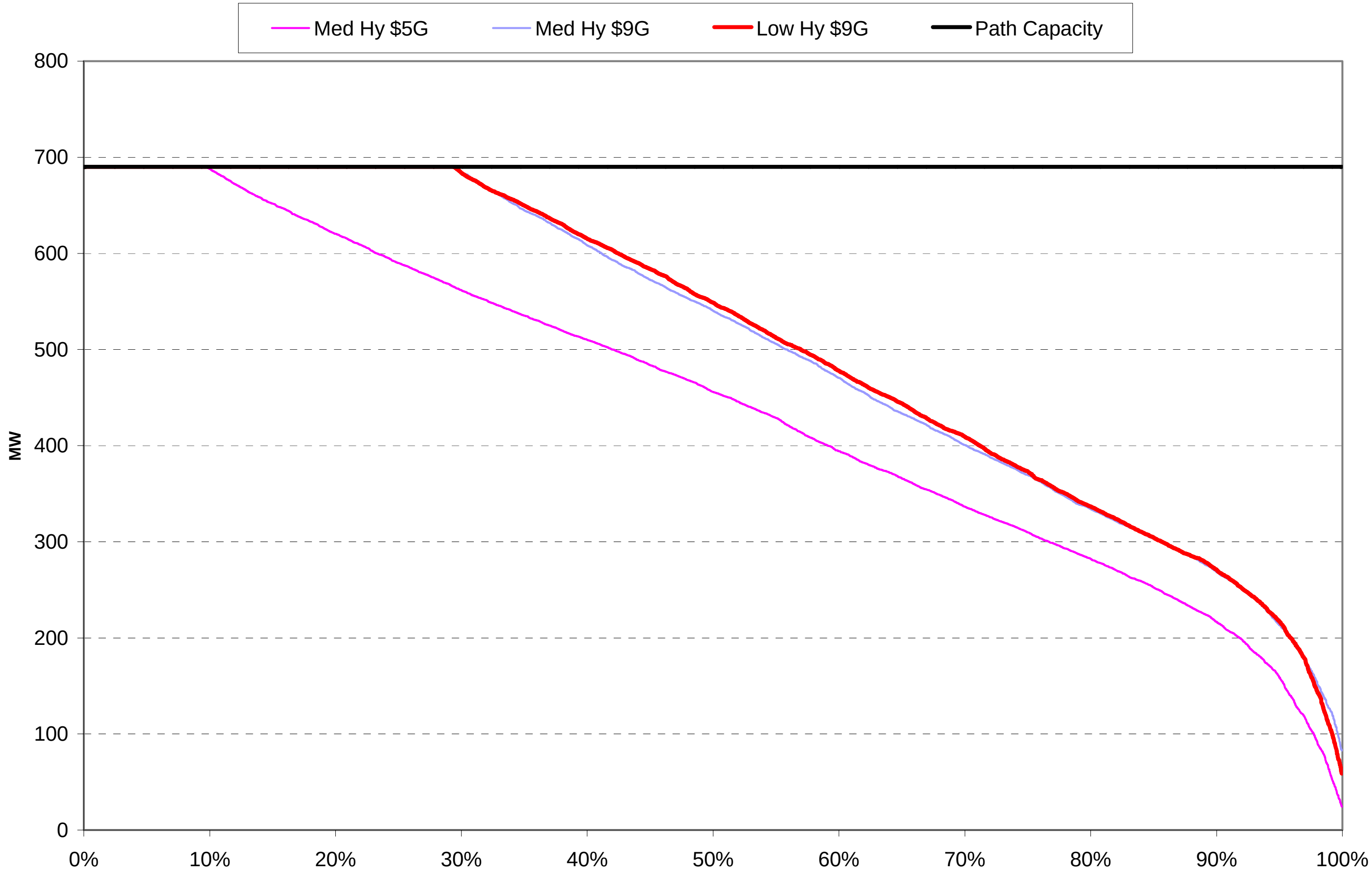
Path C

2008 Path Flow – MW



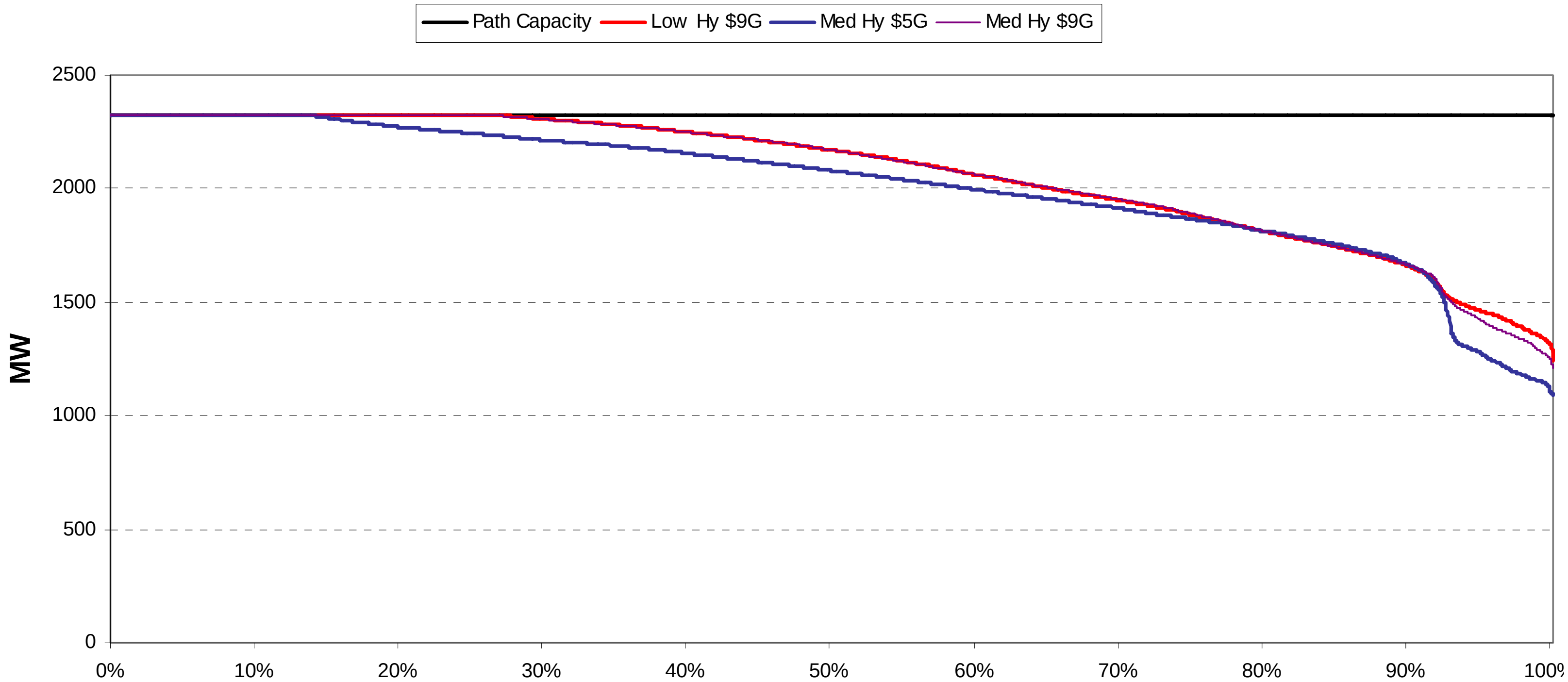
TOT 2A

2008 Path Flow – MW



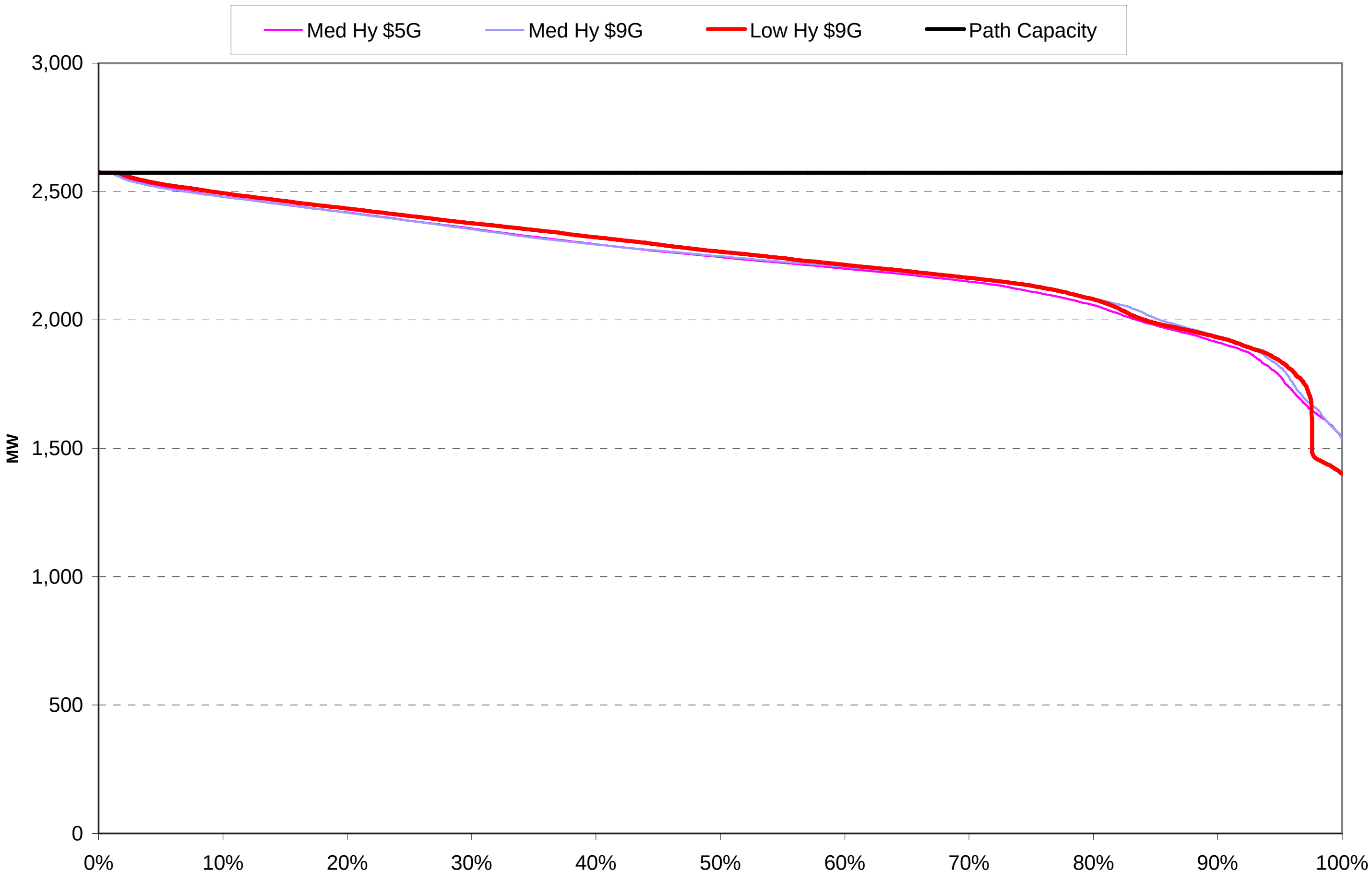
Southwest of Four Corners

2008 Path Flow – MW



West of Broadview

2008 Path Flow – MW



Western Congestion Assessment Study

Summary Templates for Existing and New Projects/Studies (DOE Tasks 1 and 3)

Prepared by the Western Congestion Analysis Task Force

May 8, 2006

CONTENTS

Studies/Reports – Related to DOE Task 1

Studies/Reports – Related to DOE Task 3

Information related to the Preparation and Use of the attached Summary Templates

1. **Information in the attached Templates is current as of April 14, 2006**

2. **Information reported was summarized by the submitters from detailed reports and studies. Those interested in additional information about a project or study should contact the indicated individual listed in the template.**

3. **Information in the templates is intended for use as a summary project overview. Important details may not be included in the summaries. For this reason, it is recommended that the enclosed summary material not be quoted or cited as reference, rather, if such is desired, that information be taken from the detailed project reports or from the identified contact individuals.**

4. **Material in the summary templates is included in this report as received from those providing the information, without editing by the WCATF.**

5. **The studies reported in the summary templates are in varying stages of completion. In a few cases, the reports are based upon internal studies and have not yet been subject to outside review. Other reports have been prepared through SSG-WI or Subregional Planning Group open review processes. Each template notes the extent of outside review. The organization submitting each template is indicated in the Table of Contents. The WCATF encourages open processes with study work, review, and report development.**

General Instructions for Preparation of Templates for Summarizing Transmission Studies and Potential Transmission Projects

The following directions were provided to the submitters of the templates:

General Instructions: Each of those providing studies should answer the Part I questions to characterize the study. Those providing studies should also list transmission projects proposed and/or discussed in the study and for each project answer the Part II questions (if needed copy the Part II form multiple times, select view/toolbars/forms to unprotect the form). Answer the questions as much as possible from existing reports and materials: this form is not intended to require further study work. If additional questions are relevant, please provide the additional questions and answer them too.

SSG-WI 2003 Study Program

Part I: Characterization of the Study:

1. What was the name of the study? Seams Steering Group - Western Interconnection (SSG-WI) 2003 Study Program

2. Provide the title(s) and completion dates of available report(s) regarding the study: "Framework for Expansion of the Western Interconnection Transmission System, October 2003"

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): Web address: http://www.ssgwi.com. After May 31, 2006, the report will be available on the WECC Web Site at http://www.wecc.biz.. Also may obtain the report by contacting Dean Perry at dean.perry@nwpp.org

4. Provide a contact person to obtain project details: name, phone, email: Dean Perry, (503) 816-6992, dean.perry@nwpp.org

5. What was the purpose of the study (e.g., what problem was the study intended to address)? Purpose of the study was to identify potential locations of transmission congestion in the bulk transmission system of the western interconnection in the 2008 and 2013 time frame, and to identify at a high level, alternative transmission solutions. The study provides transmission owners, users of the transmission system and state entities, insight into potential areas of transmission congestion based upon a one-utility least cost use of the regions resources.

6. Provide a brief summary description characterizing the study: The study looked at two future time frames; a 5-year time frame (2008) based upon resource and transmission projects permitted or under construction for operation by 2008, and a 10-year time frame (2013) for which resource and transmission development plans may still be undecided. Because of the uncertainty in resource development, the 2013 studies model three resource development scenarios, each stressing development of a particular resource type; namely gas, coal and renewables. Hydro and gas price sensitivities were also studied. From observed congestion in the studies, potential transmission development options were simulated in the model to determine their impact on congestion and production costs.

7. What was the geography of the study? The entire Western Interconnection

8. What was the study period? 2008 and 2013

9. Describe the study type (such as who initiated the study and why): The study was initiated by the SSG-WI Planning WG as part of its biennial western interconnection transmission study program.

10. Characterize the study participants: The study was conducted under the auspices of the SSG-WI Planning WG and was open to all interested participants. Those participating included transmission owners, transmission customers, representatives of state governments, marketers and resource developers. Representatives of each of the five Subregional Planning Groups also particiapted in the studies. Modeling studies were run by staff from Pacificorp.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: (1) Studies were run with transmission paths modeled both with and without transfer capability limits to determine how much power would flow on the path if path flow was not limited by path capacity. (2) Transmission shadow prices were calculated to give one indication of the west-wide economic benefit of increasing path capacity. (3) LMPs were calculated to identify the cost impact on generators and loads of transmission constraints resulting in localized areas of resource surplus and deficit.

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. The study did not explicitly define the term "congestion", however congestion was assumed to be occurring when, with path limits not enforced, flows were found to exceed published path limits. For purposes of estimating where economic fixes might be applied, paths experiencing congestion a "significant amount of the time", i.e. greater than 25% of the time were identified. The model outputs used to identify congested areas included LMPs, annual production costs and transmission shadow prices (savings associated with a 1 MW increase in path capacity).

Transmission "solutions" were identified using an iterative process. For the first iteration, all limits were removed from the paths and flows exceeding path capacity were noted. Transmission was added so that unconstrained path flows were below capacity 75% of the time. This criterion was used as an approximation of an economic solution, assuming it is not economic to eliminate congestion 100% of the time. Approximately 90% of path congestion was relieved with the first iteration. A second iteration was then run, using shadow prices as an indicator of where additional economic transmission might be added. Congestion Rents (shadow prices x path flow) exceeding $20,000 per MW were reviewed and a judgment made whether further capacity additions might economically reduce congestion.

13. Congestion identified: In the 2008 case, congestion was observed, much of which will be eliminated with transmission additions planned to be in place by 2013. The areas of observed congestion in 2008 with planned facilities in place, based upon shadow prices, were Arizona to California, Alberta to British Columbia, southern New Mexico area, Southern California to Mexico and TOT 3 between northeast Colorado and southeast Wyoming. It was estimated that congestion in 2008 would result in increased regional variable O&M costs of $110 million annually (in 2003 dollars).

In the 2013 studies, a reference case was created with loads increased to 2013 levels and resources and transmission fixed at 2008 levels. Three 2013 resource addition scenarios were studied, i.e. gas, coal and renewables with transmission added. The gas addition scenario reduced annual VOM costs compared to the reference case by approximately $2 billion, the coal scenario by $6 billion and the renewable scenario by $5 billion. Simple payback years were calculated for the capital cost of generation and transmission additions.

In the 2013 case, transmission was added to relieve congestion in all three scenarios between Alberta to BC to the Northwest, between Arizona and California, into San Diego area, into Puget Sound area and between Colorado and Utah. Additional integrating transmission was required for both the coal and renewable scenarios. The coal scenario required the most transmission additions, followed by the renewable scenario and then the gas scenario.

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives.
Specific separate cases were not developed to examine the impact of accelerated energy efficiency and demand response investments or expanded use of distributed generation. However, the modeling results provide some indication on the potential impacts such development would have on transmission. The 2008 case can be roughly considered a 2013 case with reduced load growth. The report concludes that if load growth were reduced by 50%, transmission needs in 2013 could be met with the transmission in place in 2008. An indication of the impact of distributed generation can be garnered by comparing the gas development case (which essentially represents reduced loads) with the results of the coal and renewable resource cases.

15. Describe new transmission technologies (if any) that were considered. None were evaluated in the study.

16. Describe the six most important study assumptions (e.g. fixed hydro dispatch) :
1) model assumes hard wired hydro, wind and solar dispatch
2) optimization is based on a one-utility dispatch
3) study does not incorporate market-bidding behavior
4) model assumes identical load shapes for all loads within a bubble
5) DSM and conservation is assumed incorporated in load forecasts
6) gas assumptions - - gas price assumptions. Also, the model assumes adequate gas pipeline transmission is in place

17. For each of the following, describe the assumptions made (if applicable) :

a. **Gas price (indicate base year and units):** 2003 dollars: Low Gas - $2.15 in 2008 and $2.69 in 2013; Medium $3.23 in 2008 and $3.77 in 2013; High - $4.84 in 2008 and $5.30 in 2013.

b. **Year(s) studied:** 2008 and 2013
c. **Load shapes (year and/or source):** Forecasted WECC load shapes for 2008 and 2013.
d. **Powerflow database case source(s):** WECC 2008 LSP1-SA base case

Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): NO SPECIFIC PROJECTS ARE IDENTIFIED IN THE SSG-WI STUDY PROGRAM. STUDY RESULTS ARE HIGH LEVEL AND ARE INTENDED TO BE USED AS A BASIS FOR FURTHER STUDY BY OTHERS TO DEVELOP SPECIFIC PROJECTS.

SSG-WI 2003 Path Utilization Study

Part I: Characterization of the Study:

1. What was the name of the study? 2003 Path Utilization Study

2. Provide the title(s) and completion dates of available report(s) regarding the study: "Western Interconnection Transmission Path Flow Study" - February 2003

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): Available at http://ssgwi.com under the Planning WG page and list of PWG documents. After May 31, 2006, the reports will be available on the WECC web site at http://www.wecc.biz. Reports may also be obtained from Dean Perry.

4. Provide a contact person to obtain study details: name, phone, email: Dean Perry, 503-816-6992, dean.perry@nwpp.org

5. What was the purpose of the study (e.g., what problem was the study intended to address)? Purpose of the study was to analyze statistically the MW flows on the major transmission paths in the western interconnection. Results of the study are used to verify performance of production simulation models of the western system. Results are also used by Transmission Owners and Transmission Customers to better understand actual utilization of the paths in the western transmission system. The study is part of a program initiated in 1999 to analyze on a biennial basis, the path utilization in the western interconnection. No specific transmission problem is addressed.

6. Provide a brief summary description characterizing the study: Using historical hourly MW flow data from the WECC EHV Data Pool, actual historical power flow on 33 transmission paths in the western interconnection was statistically analyzed and presented as seasonal frequency distribution curves.

7. What was the geography of the study? western interconnection transmission system

8. What was the study period? Winter 1998-1999 through Spring 2002

9. Describe the study type (such as who initiated the study and why): The study was sponsored by the Seams Steering Group - Western Interconnection (SSG-WI) as part of a an ongoing biennial update of the path utilization study which was initiated in 1999.

10. Characterize the study participants: The analysis was performed by the SSG-WI Planning WG, which includes Transmission Owners, Transmission Customers, state and provincial representatives, marketers and resource developers.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: A "utilization indicator" was calculated, defined as the percentage of time the path exceeds 75% of its operating transfer capability. This indicator was chosen as an indication of a path that may be considered heavily utilized. The magnitude of the indicator is not necessarily an indication that there is congestion on the path. A second indicator was also calculated, this being the peak loading on the path.

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. The calculated "utilization indicator" was used in the study, however this is not necessarily an indication of congestion. Future path utilization studies plan to include an analysis of path ATC and scheduling data to give a better indication of path congestion.

13. Congestion identified: Congestion was not measured. However heavy path usage was found to exist on the West of Bridger and on the IPP transmission because of the dedicated usage of those paths by the owners of generation at one end of the paths. In addition to these "dedicated" usage paths, heavy path usage was found between Canada and the Pacific Northwest, between Colorado and Utah, between Colorado and Wyoming, into the Phoenix area from the Colorado area, and into the El Paso area in New Mexico. This is based upon the paths exceeding the "75% utilization indicator" at least 50% of the time during one season of the year.

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives. Not applicable to this analysis.

15. Describe new transmission technologies (if any) that were considered. Not applicable to this analysis

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation): Not applicable. This was not a "study", rather an analsyis of historical data.

17. For each of the following, describe the assumptions made (if applicable) :

a. **Gas price (indicate base year and units):** Not Applicable
b. **Year(s) studied:** Not Applicable
c. **Load shapes (year and/or source):** Not Applicable
d. **Powerflow data base case source(s):** Not Appliable

Part II: Not Applicable to the Path Utilization Study

<u>Canada – NW – California Transmission</u>

<u>Part I: Characterization of the Study:</u>

1. What was the name of the study? NTAC Canada-NW-California Transmission Options

2. Provide the title(s) and completion dates of available report(s) regarding the study: Study is still in progress

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): Will eventually be posted at www.nwpp.org/ntac

4. Provide a contact person to obtain study details: name, phone, email: Marv Landauer, 503-230-4105, mjlandauer@bpa.gov

5. What was the purpose of the study (e.g., what problem was the study intended to address)? The objective of the Canada-NW-California studies is to provide high-level information on the feasibility of potential transmission projects to transfer a variety of new resources out of Canada into the Northwest and California. This study is intended to provide information to potential resource developers and buyers on the expected cost of delivering various recources to the load. The study is intended to be modular in nature, i.e. additional options could be developed from the information provided.

6. Provide a brief summary description characterizing the study: This study developed about 20 transmission options between Canada, the NW and California. The analysis included proposing routes, verifying transfer capability and developing cost estimates for each option. The study is developing an assessment of the cost of delivered energy which includes estimates of the resource cost along with the necessary transmission development.

7. What was the geography of the study? Western Interconnection but mostly BC, Alberta, Washington, Oregon, Idaho, Montana, California, Nevada

8. What was the study period? 2007 and beyond

9. Describe the study type (such as who initiated the study and why): This study was initiated by NTAC in response to needs expressed at open meetings.

10. Characterize the study participants: Members of NTAC: transmission owners,operators, users and developers, resource developers, regulatory.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: Study assumed that new transmission would be needed to transmit new resources to the load (there is insufficient ATC so new transmission is needed).

Proposed AC transmission options were tested at an incremental 1500 MW capacity and verified by powerflow analysis along with estimated construction costs. DC options up to 3000 MW were evaluated economically. All options were compared using delivered cost of energy. The purpose of this study was to assess transmission requirements and costs and cost of delivered energy for subsequent assessment of the cost effectiveness of new remote resources

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. The study involved adding new capacity wherever required based on planners knowledge. No congestion definition was used.

13. Congestion identified: There are many congested paths in the West. This study group used its judgment to identify congested paths and upgrades to relieve that congestion so that new remote resources could get to the load.

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives. None were explicitly identified; non-transmission alternatives would entail locating new generation closer to load. Local generation additions that did not require major transmission upgrades were compared in the cost of delivered energy analysis.

15. Describe new transmission technologies (if any) that were considered. Study considered overhead AC transmission, overhead DC transmission, underwater DC transmission.

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation): RAS - The goal of this study is to develop new transmission options without relying heavily on new RAS systems.
Cost estimates were done in generic form on a per mile basis for different geographic areas based on utility and/or developer experience.
Most existing paths are loaded to their limit today.
New 500-kV AC line projects are expected to add about 1500 MW capability (verified by powerflow analysis). New DC line projects were expected to add up to 3000 MW of capacity.

17. For each of the following, describe the assumptions made (if applicable) :

a. **Gas price (indicate base year and units):** N/A
b. **Year(s) studied:** 2007
c. **Load shapes (year and/or source):** N/A
d. **Powerflow database case source(s):** Study used 2007 HS2A WECC Case modified to fully load the North to south paths from Canada to California.

<u>Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:</u>

1. Characterization of the project (name): Although several developers and utilities are proposing some of these projects, this study will not be proposing any alternatives for implementation.

Colorado Long Range Transmission Planning Study

Part I: Characterization of the Study:

1. What was the name of the study? Colorado Long Range Transmission Planning Study.

2. Provide the title(s) and completion dates of available report(s) regarding the study: Study Report dated April 27, 2004

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): see www.westtrrans.net under Public Service Company of Colorado (PSCo) link OR http://www.rmao.com/wtpp/psco_studies.html

4. Provide a contact person to obtain project details: name, phone, email: Bob Easton (970) 461-7272, aeaston@wapa.gov; OR Chuck Sisk (719) 668-8025, csisk@csu.org.

5. What was the purpose of the study (e.g., what problem was the study intended to address)? To address a 10-year horizon case with resources identified from the PSCo Least Cost Resource Plan Request for Proposals and other queued resource requests with the sub-regional utilities in the Wyoming/Colorado area.

6. Provide a brief summary description characterizing the study: To jointly explore the potential for developing a "back-bone" transmission system network in the State of Colorado that could benefit all the Load Serving Entities (LSEs) in the state.

7. What was the geography of the study? Western Area Colorado/Missouri (WACM) and Public Service Company of Colorado (PSCo) balancing authority footprint.

8. What was the study period? 2014

9. Describe the study type (such as who initiated the study and why): Reliability-based analysis - looking at a heavy summer peak load condition in the ten-year timeframe.

10. Characterize the study participants: Aquila Networks Colorado, Colorado Springs Utilities, Platte River Power Authority, Tri-State Generation & Transmission Association, Inc., Western Area Power Administration, Xcel Energy/Public Service Company of Colorado.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: Based on LSEs projected load growth between 2004 and 2014. Three separate resource scenarios and associated transmission additions were tested against the load projections of 2700 MW additional MW by 2014. The resource scenarios modeled were: Heavy additions in NE Colorado; Heavy additions in SE Colorado; Balanced additions between NE and SE Colorado. This was a reliability-based analysis (powerflow and stability).

12. What criteria and metrics did the study use when defining congestion and a solution (Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings)? There was a range of proposed solutions, based on the three separate resource scenarios. All new resources were sited on the load-side of TOT3 and TOT5 as increasing these transfer paths was not considered for this study. There was also a number of "regional" transmission fixes that were identified as needed no matter which resource scenario were to develop. The intent was to develop a robust back-bone (230-kV and higher) transmission system that eliminates the typical "piece-meal" approach to transmission additions. The criteria used were reliability-based; no production-costing simulations were run. Economic congestion was not assessed.

13. Congestion identified: Depending on resource scenario - Heavy NE Colorado - need to add transmission facilities between Ft. Morgan, Colorado and Ft. Lupton/NE Denver metro area. For Heavy SE Colorado - need to add transmission facilities between Lamar, Colorado and Limon/Colorado Spring/SE Denver metro area.

14. Were non-transmission alternatives compared with transmission alternatives? The load projections included any known interruptible and demand-side management programs as submitted by the LSEs.

15. Were new transmission technologies considered? None.

16. Describe the six most important study assumptions (e.g. fixed hydro dispatch) : Load and Resource balancing; Heavy summer peak load condition studied; No transmission system criteria violations; Many of the generation additions were taken from the LSEs OASIS queues; TOT impacts were not evaluated; agreement on 2014 base case initial topology.

17. For each of the following, describe the assumptions made (if applicable):

a. **Gas Price (indicate base year and units):** *N/A*
b. **Year(s) studied:** *2014*
c. **Load shapes (year and/or source):** *2014 – Heavy Summer peak load*
d. **Powerflow database case source(s):** *WECC – 2014 HS base case*

<u>Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:</u>

1. Characterization of the project (name): Comanche - Daniels Park double circuit 345-kV addition

2. Description of issue(s) the project will address: Allow integration of Comanche Unit #3 (750 MW coal plant)

3. Expected and/or needed date of commercial operation: 2011

4. Termination 1 – location of one end point of associated facility upgrades: Comanche

5. Termination 2 – location of other end point of associated facility upgrades: Daniels Park

6. Characterization of other available routing information: several ROWs presented in Study results

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): New ROW; addition of 345-kV voltage class to Comanche and south Denver metro transmission system; new 345-kV substation and 345/230-kV transformer additions.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: Generation integration - 750 MW coal plant to serve increase in south Denver metro load.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.): N/A

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate): N/A

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: Begin conversion of Denver-area loop transmission system to 345-kV operation.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): Outage of one of the new parallel 345-kV lines - resulted in loading the other 345-kV line to thermal limit (part of conductor-sizing analysis for the new lines).

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. Not known.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? Not yet.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? Yes.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: Develop transmission that could accommodate a variety of generation placements; Maximize use of existing corridors; establish new ROWs; pre-construct for future higher voltage class operation; See Table below:

Potential Transmission Infrastructure

Scenario	Description	Entity	Element
1	S.Gens	PSCo	Comanche – Daniels Park 345kV X2
1	S. Gens	PSCo	Comanche - Boone 345kV X2
1	S. Gens	PSCo	Boone - Corner Point (via B.Sandy) 345kV X2
1	S. Gens	PSCo	345/230kV autos at Boone, Corner Pt., Spruce, Daniels, Green Valley, Comanche
1	S. Gens	TSGT	SECoal - Boone 230 / 345kV
1	S. Gens	TSGT	SECoal - Lamar 230kV
1	S. Gens	PSCo	Big Sandy - Corner Point 345kV
1	S. Gens	TSGT	SECoal – Walsenburg 230 / 345kV
1	S. Gens	WAPA	Burlington - Wray 230kV
1	S. Gens	PSCo	Corner - Smoky / Daniels 345kV
1	S. Gens	PSCo	DC Tie expansion 230MW
1	S. Gens	PSCo	Boone - Lamar 230kV rebuild to Double-ckt 230kV
1	S. Gens	PSCo	Blue Spruce - Green Valley 345kV upgrade double-ckt
1	S. Gens	PSCo	Blue Spruce - Smoky Hill 345kV
1	S. Gens	PSCo	Blue Spruce - Daniels Park 345kV
1	S. Gens	CSU	Kelker - Drake upgrade from 115kV to 230kV
1	S. Gens	CSU	230/115kV auto at Drake
2	N. Gens	PSCo	Pawnee - Ft.Lupton double-ckt 230kV
2	N. Gens	PSCo	Pawnee - Corner Point 345kV X2
2	N. Gens	PSCo	Corner Point - Daniels Park 345kV X2
2	N. Gens	PSCo	Corner Point - Smoky Hill230kV X2
2	N. Gens	PSCo	Blue Spruce - Smoky Hill 345kV
2	N. Gens	PSCo	345/230kV autos at Pawnee(2), Corner Point(2), Daniels Park(3),
2	N. Gens	WAPA	Beaver Creek - Brush Upgrade
2	N. Gens	WAPA	Beaver Creek - Hoyt 230kV

2	N. Gens	WAPA	Beaver Creek 230/115kV two new parallel transformers
2	N. Gens	PSCo	St.Vrain - Niwot - Lookout sectionalize at Plains End
2	N. Gens	PSCo	Big Sandy - Corner Point 230 / 345kV
2	N. Gens	CSU	Kelker - Drake upgrade from 115kV to 230kV
2	N. Gens	CSU	230/115kV auto at Drake
2	N. Gens	WAPA	Poncha – east
3	Balanced	PSCo	Comanche – Daniels Park 345kV X2
3	Balanced	PSCo	Comanche - Boone 345kV X2
3	Balanced	PSCo	Boone - Big Sandy 345kV X2
3	Balanced	PSCo	Big Sandy - Corner Point 345kV X2
3	Balanced	PSCo	345/230kV autos at Corner Point, Daniels Park, Comanche, Pawnee
3	Balanced	CSU	Kelker - Drake upgrade from 115kV to 230kV
3	Balanced	CSU	230/115kV auto at Drake
3	Balanced	PSCo	Pawnee - Ft.Lupton double-ckt 230kV
3	Balanced	PSCo	Pawnee - Corner Point 345kV X2
3	Balanced	PSCo	Corner Point - Daniels Park 345kV X2
3	Balanced	PSCo	Corner Point - Smoky Hill 230kV X2
3	Balanced	PSCo	Blue Spruce - Smoky Hill 345kV
3	Balanced	TSGT	SECoal - Boone 230 / 345kV
3	Balanced	TSGT	SECoal - Lamar 230kV
3	Balanced	TSGT	SECoal – Walsenburg 230 / 345kV

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: N/A

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? Several projects are under development and should be in-service by 2014.

Conceptual Plans for Electricity Transmission in the West
Report to the Western Governors' Association

Part I: Characterization of the Study:

1. What was the name of the study?
"Conceptual Plans for Electricity Transmission in the West", Report to the Western Governors' Association

2. Provide the title(s) and completion dates of available report(s) regarding the study:
"Conceptual Plans for Electricity Transmission in the West", Report to the Western Governors' Association, (August 2001)

3. Provide the details regarding how to obtain any available reports (Web address if available on internet):
http://www.westgov.org/wga/initiatives/energy/transmission_rpt.pdf

4. Provide a contact person to obtain project details: name, phone, email:
Doug Larson, Western Interstate Energy Board, 303-573-8910, dlarson@westgov.org

5. What was the purpose of the study (e.g., what problem was the study intended to address)?
Western Governors requested a study in May 2001 to address the need for transmission enhancements in the Western Interconnection. The focus of the study was on transmission to support alternative generation futures. This 60-day effort was the first pro-active, stakeholder-driven study of interconnection-wide transmission needs.

6. Provide a brief summary description characterizing the study:
The study used a production cost model (ABB) to evaluate the demand for new transmission under two basic scenarios – gas-fired generation near load centers and an "other-than-gas" scenario that assumed new coal, wind, hydro and geothermal generation located in remote areas. The study forecasted 2010 loads based on WECC data. Two alternative generation scenarios were postulated for 2010. The model was validated by comparing actual flows on major transmission paths in 2000 with flows generated by the model. A 2004 base case was developed that included transmission projects committed or under construction. LMPs were calculated under the two generation scenarios. Transmission was added in each scenario to equalize LMPs. The costs of transmission additions and operating costs were estimated for the scenarios. Sensitivity analysis was performed for low hydro generation and high gas prices.

The results illustrated bookends of potential transmission needs in the Western Interconnection under widely different generation scenarios. The gas-fired generation scenario did not require signficant new transmission. By comparison, the "other-than-gas" scenario required more transmission with capital costs equal to $8 to $12 billion. The "other-than-gas" scenario yielded annual savings of $3.4 billion to $5.4 billion

(2010$), assuming base case gas price of $4.30/mmBtu and high gas prices of $7.00/mmBtu, respectively. The study suggested improvements in future modeling analysis.

7. What was the geography of the study?
Western Interconnection

8. What was the study period?
2001-2010

9. Describe the study type (such as who initiated the study and why):
Western Governors requested this study in May 2001 to address the need for transmission enhancements in the Western Interconnection. The Transmission Working Group was formed to develop conceptual transmission plans.

10. Characterize the study participants:
The Transmission Working Group was a broad-based group of public- and private-sector representatives. Two co-chairs led the Transmission Working Group: Jack E. Davis, president of Pinnacle West Capital Corporation; and Marsha H. Smith, commissioner for the Idaho Public Utilities and chair of the Committee for Regional Electric Power Cooperation.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed:
The model calculated LMPs under the two generation scenarios. Transmission was added in each scenario to equalize LMPs. The capital cost of transmission additions and interconnection-wide operating costs were estimated for the scenarios. The results derived operating cost savings between the generation scenarios.

12. What criteria and metrics did the study use when defining congestion and a solution (Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings)?
The fundamental criterion for defining a transmission solution was the degree to which the solution equalized LMPs in generation scenarios. LMPs were calculated under the two generation scenarios. Transmission was added in each scenario to equalize LMPs. The costs of transmission additions and operating costs were estimated for the scenarios. Sensitivity analysis was performed for low hydro generation and high gas prices.
The results illustrated bookends of potential transmission needs in the Western Interconnection under widely different generation scenarios. The gas-fired generation scenario did not require significant new transmission. The “other-than-gas” scenario required more transmission with capital costs equal to $8 to $12 billion. The "other-than-gas" scenario yielded annual savings of $3.4 billion to $5.4 billion (2010$), assuming base case gas price of $4.30/mmBtu and high gas prices of $7.00/mmBtu, respectively.

13. Congestion identified:
Differential of LMPs across the Western Interconnection.

14. Were non-transmission alternatives compared with transmission alternatives?
No. Non-transmission alternatives were discussed but not quantified.

15. Were new transmission technologies considered?
Yes. Several new transmission technologies were identified. However, they were not part of the quantitative study.

16. Describe the six most important study assumptions (e.g. fixed hydro dispatch) :
(1) The study used a production cost model (ABB). (2) Two "bookend" generation scenarios assumed: (a) new generation additions from natural gas-fired generation located close to load areas, and (b) new generation additions largely from coal, wind, hydro, geothermal resources located in remote areas. (3) Forecasted loads developed from the Western Systems Coordinating Council's report "Summary of Estimated Loads and Resources, May 2000. (4) Reserve margin specified to be 25% above forecasted load. (5) Natural gas prices were specified for a base case based the Energy Information Administration forecast of $4.68/mmBtu, and a high case of $7.02/mmBtu. (6) Hydro sensitivity analysis was based on data from recent years with low and high hydro conditions.

17. For each of the following, describe the assumptions made (if applicable):

a. **Gas Price (indicate base year and units):**
   Natural gas prices were specified for a base case based the Energy Information Administration forecast of $4.68/mmBtu, and a high case of $7.02/mmBtu.

b. **Year(s) studied:**
   2004 Base Case Transmission
   2010 Transmission Expansion Scenarios (Gas Case; Other-Than-Gas Case)

c. **Load shapes (year and/or source):**
   2010 load forecast developed from the Western Systems Coordinating Council's Report "Summary of Estimated Loads and Resources" issued May 2000.

Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name):
The study assumed new generation and transmission, not specific proposed power plants or specific proposed transmission projects.

The remainder of Part II is Not Applicable

T4 Wind Project
Nevada State Office of Energy (NSOE)

Part I: Characterization of the Study:

1. What was the name of the study?
"T4 Wind Project" by the Nevada State Office of Energy ("NSOE")

2. Provide the title(s) and completion dates of available report(s) regarding the study:
Northwestern Consortia to Study the Regional Wind Development Benefits of Upgrades to Nevada Transmission Systems (May 10, 2005)

3. Provide the details regarding how to obtain any available reports (Web address if available on internet):
http://www.energy.state.nv.us/T4Wind/TWind.htm

4. Provide a contact person to obtain project details: name, phone, email:
John E. Candelaria, NV Public Utility Commission, 702-486-7210, jcandela@puc.state.nv.us
Pete Konesky, NV State Office of Energy, 775-684-8735, pkonesky@dbi.state.nv.us

5. What was the purpose of the study (e.g., what problem was the study intended to address)?
The project objective was to complete an integrated assessment of the wind energy potential in Nevada and southern Idaho, and evaluate transmission alternatives to support wind energy development in Nevada, Idaho and neighboring states.

6. Provide a brief summary description characterizing the study:
This study evaluated wind resources from 13 sites in northern Nevada and 4 sites across southern Idaho. Initial estimates identified seven sites with over 2000 MW of commercially developable wind generation capacity, at Class 4 sites or better, in regions that would likely have no major siting or permitting impediments.
Sierra Pacific Power Company's (SPPC) current electric system is not capable of supporting a significant amount of new wind generation capacity. This study identified transmission upgrades and additions that could deliver wind energy to load centers throughout northern and southern Nevada and other regions in the Western Interconnection. Two key transmission additions for future wind energy development in this region were: (1) interconnection of SPPC's transmission system to the Pacific DC Intertie near Gerlach; and (2) the Gonder to Harry Allen 500 kV AC transmission line. SPPC and Nevada Power Company (NPC) transmission planners studied the interconnection of wind generation from seven wind development sites assuming that various transmission upgrades were included in SPPC's electric system. Each wind development site was studied independently (i.e., the transmission planners limited the

integration of wind development sites into SPPC's electric system to one wind development site at a time). The load flow contingency analyses, stability (transient) studies and fault duty analyses performed for these proposed sites in most cases showed no significant adverse impact to SPPC's electric system. Interconnecting the generation from each site in Nevada to SPPC's transmission system appears plausible. However, studies for the Nevada/Idaho border wind generation site demonstrated unacceptable system performance without corrective action. Proposed generation capacity at this proposed location exacerbated system performance. The analysis indicated that for some generation sites additional VAR compensation would be required. The amount of additional VAR compensation directly depended on the location and size of the proposed wind generation facility.

The transmission studies indicate that the transmission system is capable of delivering the wind output, but the studies do not reflect the operational necessity of continuing to deliver electricity when the wind stops. The transmission planners assumed in their studies that backup or firming resources were available to accommodate the wind generation capacity that was added to SPPC's transmission system.

7. What was the geography of the study?
Nevada and Southern Idaho

8. What was the study period?
2004-2005

9. Describe the study type (such as who initiated the study and why):
Nevada State Energy Office, under contract with the U.S. Departmant of Energy, served as the lead for a project team that examined near term wind energy development potential and associated electric transmission development needs for a region encompassing northern Neveda and southern Idaho.

10. Characterize the study participants:
Nevada State Office of Energy (NSOE), project lead and prime contractor;
Desert Research Institute (DRI), Nevada wind energy characterization;
Idaho Energy Office and the Center for Resource Solutions, Idaho wind energy characterization;
Sierra Pacific Power Company and Nevada Power Company, transmission analysis.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed:
The assessment of Nevada wind resources was based on DOE/NREL 50m Wind Power map of Nevada and collaboration with the Desert Research Institute. Idaho wind resources were analyzed by the Idaho Energy Division using the True Wind/Northwest Sustainable Energy for Economic Development (NWSEED) wind map.
Transmission planners from SPPC and NPC studied the interconnection of wind generation from proposed sites assuming specific upgrades to the system. This analysis included load flow contingency analysis, stability studies, and fault duty analyses.

12. What criteria and metrics did the study use when defining congestion and a solution (Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings)?
This study did not explicitly define or measure the degree of congestion. Wind resources were identified. Interconnection studies evaluated the transmission needed to deliver the potential wind resources.

13. Congestion identified:
Congestion is implicit in the analysis since wind energy generation could not be delivered by the current electrical system.

14. Were non-transmission alternatives compared with transmission alternatives?
No

15. Were new transmission technologies considered?
No

16. Describe the six most important study assumptions (e.g. fixed hydro dispatch) :
(1) The study identified 7 potential wind sites (6 in Nevada, 1 in Idaho) for interconnection analysis based on wind resource maps, land ownership patterns, and likelihood of receiving permits. The combined capacity of the 7 sites was 2000 MW. (2) Each wind site was evaluated independently. (3) The analysis utilized assumptions from the Western Electricity Coordinating Council's (WECC) 2012 Heavy Summer base case, and load levels anticipated in this time frame. (4) The interconnection studies assumed the installation of a tap of the DC Intertie and/or the completion of a Gonder to Harry Allen 500 kV AC transmission line. (5) Cost estimates for integrating each wind site into SPPC's tranmission system were based on current transmission costs estimates (in 2004 dollars) and engineering and construction judgement. (6) The analysis did not consider or evaluate systems operation issues associated with integrating wind energy in the control area.

17. For each of the following, describe the assumptions made (if applicable):

a. **Gas Price (indicate base year and units):**
b. **Year(s) studies:**
c. **Load shapes (year and/or source):**
d. **Powerflow database case source(s):”**
   The analysis utilized assumptions from the Western Electricity Coordinating Council's (WECC) 2012 Heavy Summer base case, and load levels anticipated in this time frame.

<u>Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:</u>

1. Characterization of the project (name):
1) Proposed SPPC transmission facilities that would tap the Pacific DC Intertie (DC Tap) near Gerlach. Details provided in SPPC 2004 Resource Plan, Item 29, page 14 of Technical Appendix II.
2) Gonder to Harry Allen 500 kV AC transmission line.

2. Description of issue(s) the project will address:
Facilities intended to deliver wind energy from northern Nevada and southern Idaho to loads in Nevada and neighboring states.

3. Expected and/or needed date of commercial operation:
Not identified or applicable to this study (N.A.)

4. Termination 1 – location of one end point of associated facility upgrades:
DC Tap -- Gerlach
Gonder to Harry Allen 500 kV line - Ely

5. Termination 2 – location of other end point of associated facility upgrades:
DC Tap -- 345 kV facilities to Doyle and Reno
Gonder to Harry Allen 500 kV - Las Vegas area

6. Characterization of other available routing information:
N.A.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.):
N.A.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc:
Generation interconnection and transmission to deliver wind energy.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.): N.A.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate): N.A.

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: N.A.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): N.A.

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. N.A.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? N.A

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? N.A.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: N.A.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: N.A

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? N.A

Rocky Mountain Area Transmission Study (RMATS)

Part I: Characterization of the Study:

1. What was the name of the study? Rocky Mountain Area Transmission Study (RMATS)

2. Provide the title(s) and completion dates of available report(s) regarding the study: Rocky Mountain Area Transmission Study - September 2004

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): http://psc.state.wy.us/htdocs/subregional/Reports.htm

4. Provide a contact person to obtain Study details: name, phone, email: Ray Brush, Northwestern Energy, 406-497-4278, ray.brush@northwestern.com

5. What was the purpose of the study (e.g., what problem was the study intended to address)? Concerns about the lack of transmission investment in the west. and resulting congestion.

6. Provide a brief summary description characterizing the study: In the RMATS process, stakeholders joined in work groups on load forecasting, resource additions, and transmission additions which developed assumptions that were input into a production cost model to examine the value of potential transmission expansion under different generation scenarios. A steering committee guided the integration of the activities of the work groups and the RMATS modeling team to: (1) evaluate the overall economics of transmission expansion under different generation scenarios; and, (2) identify transmission projects that may be economic and feasible because of the savings they provide Rocky Mountain region and elsewhere in the West. The analysis tested the sensitivity of the results under a variety of assumptions, such as high and low hydroelectric generation, high and low natural gas prices, significant improvements in energy efficiency, and potential imposition of constraints on carbon dioxide emissions. The RMATS economic screening studies assumed the benefits of a regionally operated system that avoids rate pancaking, consolidates control areas, and removed other institutional impediments to fuller use of the existing system.

The most feasible transmission additions in the RMATS recommendations were recommended to proceed to a follow on Phase II. The purpose of Phase II is to conduct transmission technical studies, address siting and cost assignment and recovery issues, identify project sponsors, and arrange project financing. Phase II activities are ongoing.

7. What was the geography of the study? The RMATS footprint covered the States of Colorado, Idaho Montana, Utah and Wyoming, but the area modeled was the entire Western Interconnection.

8. What was the study period? The RMATS process was carried out from fourth quarter 2003 to third quarter 2004. The time frame studied was a test year of 2008 and a future transmission expansion period of 2013.

9. Describe the study type (such as who initiated the study and why): The Governors of Utah and Wyoming initiated RMATS out of a concern that the electric power industry had been reluctant to invest in new transmission infrastructure due to protracted regulatory uncertainties. Without such investment, the region may not be able to tap lower cost coal and wind generation, as well as export generation to other parts of the Western Interconnection. RMATS was planned as a Stakeholder driven study of economic implications of transmission expansion alternatives for the Rocky Mountain States and for the West.

10. Characterize the study participants: A broad range of stakeholders from utilities, private energy and transmission developers, state and federal government regulators and energy policy officials, and consumer, public interest and environmental groups.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: Economic screening study using ABB Market Simulator production cost model to simulate transmission congestion, marginal prices at the nodal level, and system-wide fuel and other variable production costs for alternatives developed during the study process.

12. What criteria and metrics did the study use when defining congestion and a solution (Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings)?

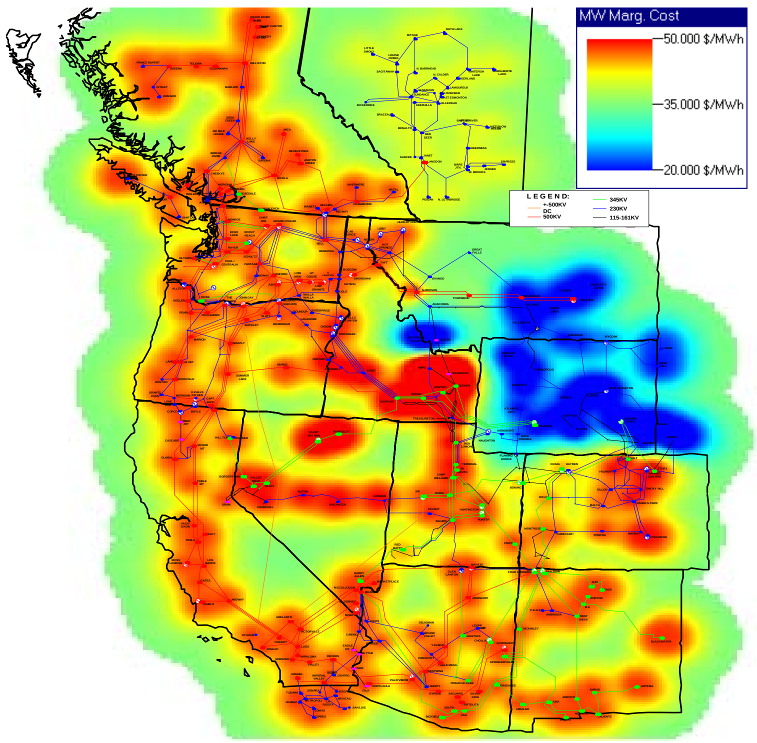
The RMATS study evaluated the economic cost of projected congestion as measured through hourly LMPs and annual production cost savings. The annualized fixed and variable costs including resource and transmission capital charges and annual carrying cost, fixed O&M and production cost savings were totaled and scenarios compared to estimate relative costs or savings.

13. Congestion Identified

RMATS ran many alternative simulations, which added additional Powder River Basin coal and open range wind generation in the Rocky Mountain Region without adding additional transmission to the region. Congestion was identified as demonstrated in the following pictorial graph. The blue areas indicate low cost power ($20/MWh) and the red area indicates high cost areas ($50/MWh). The low cost generation added was trapped in the Rocky Mountain Region due to lack of transmission..

Figure S-1

Representative Congestion in the Rocky Mountain Area



Following this initial identification of potential congestion, RMATS workgroups identified individual congested paths, ranked congested paths according to economic impact, and developed transmission addition recommendations which would most efficiently relieve these constraints.

14. Were non-transmission alternatives compared with transmission alternatives?
Yes, aggressive DSM was modeled, but the study Steering Committee determined that the study conclusions were still valid with perhaps a several year shift in the time frame for the new transmission construction.

15. Were new transmission technologies considered?

New transmission technologies were considered as possible solutions to transmission congestion, but were not analyzed in the economic modeling nor were specific technologies evaluated.

16. Describe the six most important study assumptions (e.g. fixed hydro dispatch) :

1) The model assumes a regionally operated one world dispatch with no pancaking,

market bidding behavior or other institutional impediments.

2) Generation additions in the Rocky Mountain area as determined by the Resource Additions Work Group (predominately Powder River coal and open range wind in WY and MT).

3) The model assumed hard wired hydro dispatch as in the SSG-WI study and wind plant capacity factors based on regional wind availability profiles from NREL .

4) The study applied the path and nomogram ratings posted in the WECC February 2003 Path Rating Catalog.

5) Natural gas costs as determined by the Gas Pricing Subcommittee - $6.50/MMBtu at Henry Hub in $2013 with basis differential to point of use set to match the 5th Northwest Conservation & Electric Power Plan.

6) A 15% planning margin was applied to load to cover the Western Interconnect system operating reserves and plant forced outages.

17. For each of the following, describe the assumptions made (if applicable):

a. Gas Price (indicate base year and units):

For the 2008 Base Case, the U.S. average wellhead price was $4.00/MMBtu in 2008 dollars ($3.60 in 2004 dollars) for the low gas price, and $5.00/MMBtu ($4.50 in 2004 dollars) for the high gas price. For the 2013 study, prices used were $4.50/MMBtu in 2013 dollars ($3.60 in 2004 dollars) and $6.50/MMBtu ($5.20 in 2004 dollars), respectively. Differentials were included for the various locations consistent with the Fifth Northwest Conservation and Electric Power Plan.

b. Year(s) studied:

The Base Case was 2008 and the test year was 2013.

c. Load shapes (year and/or source):

Loads were based on the WECC Spring 2003 forecast as modified and updated by the RMATS Load Forecasting Work Group. To determine hourly demand for each node, load distribution factor from the WECC power flow case were fitted into the load shapes in the load forecast. Load shapes for areas outside RMATS were taken from the SSG-WI database.

d. Powerflow database case source(s):

The WECC 2008 LSP1-SA (light load-spring) approved power flow case was the starting point for all analysis.

<u>Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:</u>

A. RMATS Recommendation 1: Expansion Projects within the Rocky Mountain Footprint
Recommendation 1 was based on the addition of wind and coal generation resources in Montana, Wyoming, and Colorado of 3900 MW to match the load growth in the region.

Project 1: Montana System Upgrade Project (See Figure S-2)

1. Characterization of the project (name): Montana System Upgrade Project

1a. **Provide a contact person to obtain project details: name, phone, email:** Ray Brush, Northwestern Energy, 406-497-4278 , ray.brush@northwestern.com

2. Description of issue(s) the project will address: Adds transfer capacity to the existing Montana 500 kV transmission system to enable exports from the Rocky Mountain region to the Pacific Northwest without building new transmission lines.

3. Expected and/or needed date of commercial operation: The date of needed commercial operation is dependent on the development of resources in Eastern Montana that drives the need to upgrade the capacity.

4. Termination 1 – location of one end point of associated facility upgrades: Colstrip

5. Termination 2 – location of other end point of associated facility upgrades: Taft

6. Characterization of other available routing information: This project relies on upgrading the existing transmission system and does not require any additional right-of-way. The only new sites added are the two new 500 kV substations added.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.):
Installing series compensation in the 500 kV lines from Colstrip to Taft, adding a 500/230 kV autotransformer at Colstrip, and adding two new substations on the 500 kV transmission system near Ringling and Missoula., transfer capacity on this path will increase by 500 MW. In addition, subsequent studies have shown the need for voltage support equipment along the 500 kV transmission.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: This project upgrades the existing Montana 500 kV transmission system to enable exports of anticipated new wind and coal generation from the Rocky Mountain region to the Pacific Northwest.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2004 dollars, assumed escalation rate, fuel costs, etc.): Recommendation 1 in total would provide $531 million in saving compared to an all gas case, or $61 million in saving compared to an IRP based case.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2004 dollars, assumed escalation rate): The capital cost for the Montana System Upgrade project is estimated to be $72 million.in $2004

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: Reliability analysis not done in this study, hence this section does not apply.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): The limiting outage is loss of the Ringling (or Townsend) to Garrison double circuit 500 kV lines. The ability to upgrade the system is predicated on being able to adequately modify the generator tripping scheme. The limiting factor is transient stability.

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. The system upgrades will increase the capacity across the West of Colstrip (existing capacity-2598 MW, new capacity-3348 MW), West of Crossover (exisitng-2598 MW, new-3348 MW), west of Broadview (exisitng-2573, new-3323 MW) and Montana-Northwest (exisitng-2200 MW, new-2950 MW).

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? The project is just being considered by the transmission owners is not at the point to take it through the WECC processes.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? No, see explanation for 12.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: AMPS line Phase Shifter and anticipated new wind and coal generation in Eastern and Central Montana.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: Upgrades to the Northwest may reduce the need to upgrade the Montana-Idaho Path (Path 18).

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? Transmission owners are assessing viability of upgrading this path. If the resources are developed that were assumed in the study, then it is highly likely that the upgrade will be in place by 2015. However, there is a caution that this upgrade is based on satisfactory modifications to Generator RAS.

Project 2: Bridger Expansion Project (See Figure S-2)

1. Characterization of the project (name): Bridger Expansion Project

1a. Provide a contact person to obtain project details: name, phone, email: Ken Morris, PacifiCorp, 801-220-4277, ken.morris@pacificorp.com

2. Description of issue(s) the project will address: These additions would increase transfer capacity by an estimated 1,350 MW and support the resource additions of 1,375 MW of wind generation and 575 MW of (Bridger) coal-fired generation in southwest Wyoming and southern Idaho.

3. Expected and/or needed date of commercial operation: Undetermined. Depends on resource development in Wyoming.

4. Termination 1 – location of one end point of associated facility upgrades: Miners in Wyoming

5. Termination 2 – location of other end point of associated facility upgrades: Ben Lomond in Utah and Midpoint in Idaho.

6. Characterization of other available routing information: No routing information has been determined at this point.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): Expansion of the Bridger 345 kV transmission system involves the addition of 345 kV transmission facilities from Miners to Bridger in Wyoming and from Bridger to Ben Lomond in Utah and to Midpoint in Idaho.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: These additions would increase transfer capacity by an estimated 1,350 MW and support the resource additions of 1,375 MW of wind generation and 575 MW of (Bridger) coal-fired generation in southwest Wyoming and southern Idaho.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2004 dollars, assumed escalation rate, fuel costs, etc.): Recommendation 1 in total would provide $531 million in saving compared to an all gas case, or $61 million in saving compared to an IRP based case. Individual Recommendation 1 Projects were not broken out.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2004 dollars, assumed escalation rate): The capital cost of the Bridger Expansion project is estimated to be $580 million in $2004

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: Studies have not yet been done to determine reliability benefits.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): Not determined until studies are conducted.

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. Bridger West Path (before - 2200, after - 3550); Borah West Path (before - 2307, after - 3057); Naughton West Path (before - 920, after - 1520); Bridger East Path (before - 600, after - 1100).

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? No, not yet.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? No.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: Resource additions of 1,375 MW of wind generation and 575 MW of (Bridger) coal-fired generation in southwest Wyoming and southern Idaho.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: This would displace upgrades for the Bridger East Path and the Wyoming to Utah Path.

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? Not yet initiated. This will depend on requests for transmission service.

Project 3: Wyoming to Colorado Transmission Project (See Figure S-2)

1. Characterization of the project (name): Wyoming to Colorado Transmission Project

1a. Provide a contact person to obtain project details: name, phone, email: Bob Easton, Western Area Power Administration, 970-461-7272, aeaston@wapa.gov

2. Description of issue(s) the project will address: Increase transfer capacity 750 MW and support the assumed resource additions of 500 MW of wind and 700 MW of coal-fired generation capacity.

3. Expected and/or needed date of commercial operation: 2011-2013

4. Termination 1 – location of one end point of associated facility upgrades: Antelope Mine

5. Termination 2 – location of other end point of associated facility upgrades: Green Valley

6. Characterization of other available routing information: Expand existing ROWs, if possible.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): This project involves the addition of a 345 kV line from northeastern Wyoming across the constrained path between Wyoming and Colorado to Denver.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: Provide transmission capacity to support the assumed resource additions of 500 MW of wind and 700 MW of coal-fired generation capacity.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2004 dollars, assumed escalation rate, fuel costs, etc.): Recommendation 1 in total would provide $531 million in saving compared to an all gas case, or $61 million in saving compared to an IRP based case. Individual Recommendation 1 Projects were not broken out.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2004 dollars, assumed escalation rate): The capital requirements for the Wyoming to Colorado project are an estimated $318 million in $2004

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: Increasing TOT3 Accepted Rating.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): No reliability analysis was done as part of the RMATS study. However, the existing TOT3 limit is typically loss of the Laramie River Station (LRS) to Story 345-kV line loads the LRS – Ault 345-kV to it's thermal capacity (956 MVA based on equipment at both LRS and Ault).

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. Path 36 – 1680 MW as of 2010; would add between 500 – 750 MW as of 2015.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? Not yet.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? No

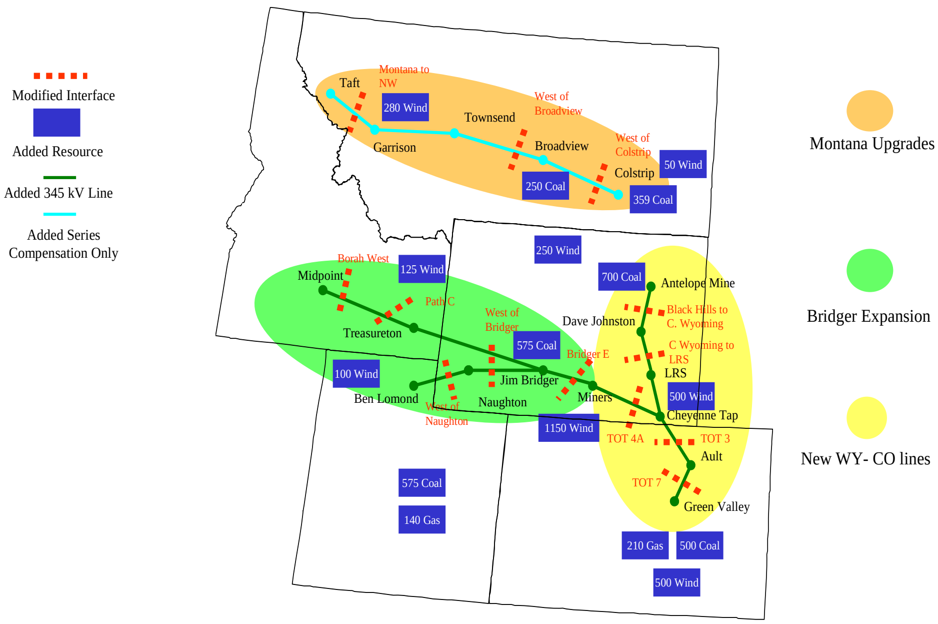
14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: Miners to Cheyenne Tap 345 kV line and improvements to the Public Service Company of Colorado (PSCo) system beyond their Green Valley substation.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: None known. Potential OASIS requests may be able to be consolidated.

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? Trans-Elect, the Wyoming Infrastructure Authority and Western Area Power Administration have signed a joint MOU that resulted in publishing a Federal Register Notice requesting potential interest an a feasibility study for expansion of the TOT3 transfer boundary. Not sure whether any Project will be completed by 2015. Western Area Power Administration is planning the upgrade of one 115-kV line between Miracle Mile - Laramie - Cheyenne - Ault to 230-kV by 2009. This upgrade will add approximately 75 MW to the TOT3 TTC.

Figure S-2

Recommendation 1: Transmission Expansion in the Rocky Mountain Area



B. RMATS Recommendation 2: Export Projects Beyond the RMATS Footprint
RMATS also recommended transmission expansions that extend beyond the Rocky Mountain States to enable exports of generation. This is a longer-term export proposal that: (1) includes the generating resources assumed for the projects in Recommendation 1; (2) assumes construction of an additional 3,900 MW of coal generation and remote wind resources; and, (3) builds two (of five potential) 500 kV export paths to the West Coast, Nevada and Arizona markets. (See Figure S-3)

1. Characterization of the project (name): 2-500kV lines for Export

1a. Provide a contact person to obtain project updates: name, phone, email: Steve Waddington, Wyoming Infrastructure Authority, 307-635-3573, stevew@wyia.org

2. Description of issue(s) the project will address: Increase transfer capacity from the Rocky Mountain States to enable exports of generation to West Coast, Nevada and Arizona markets. The viability of Recommendation 2 depends on the fuel preferences of load-serving entities (LSEs) outside the Rocky Mountain region.

3. Expected and/or needed date of commercial operation: 2013

4. Termination 1 – location of one end point of associated facility upgrades:
Broadview, MT; Midpoint, ID; or Ben Lomond Utah

5. Termination 2 – location of other end point of associated facility upgrades: Ashe, WA; Grizzly, OR; Market Place, NV

6. Characterization of other available routing information: Two of five potential 500kV paths

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): This project involves the addition of two 500kV lines from the Rocky Mountain Region to West Coast, Nevada and Arizona markets.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: This project provides additional capacity to bring wind and coal power generation to from the Rocky Mountain Region to western markets, inproving fuel diversity.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2004 dollars, assumed escalation rate, fuel costs, etc.): Recommendation 2 in total would provide $986 million in saving compared to an all gas case, or $516 million in saving compared to an IRP based case.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2004 dollars, assumed escalation rate): The capital cost for the Recommendation 2 transmission expansion is estimated to be $4.265 billion in $2004.

10. For a reliability analysis:

10a. Describe the reliability benefits of the project:

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc):

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. Approximately 3900 MW additional capacity (more specificity not possible).

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? No

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? No

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: Additional transmission upgrades in the Rocky Mountain region beyond those identified in Recommendation 1 are also part of Recommendation 2, including:

- Upgrading the Bridger Expansion project from 345 kV to 500 kV west of Bridger.
- Adding new 345 kV lines between Grand Junction and Emery, Antelope and Laramie River Station, and Dave Johnston to Bridger.

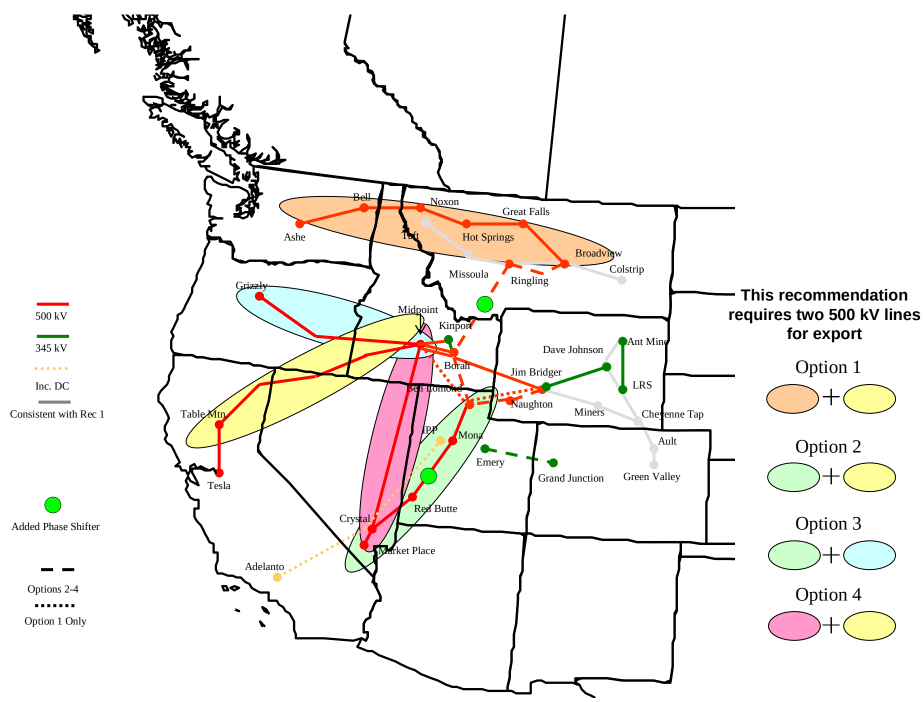
And also upgrading the capacity of the IPP-Adelanto DC line by 500 MW.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: ?

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? This project is still early in the conceptual stage, however the Arizona Public Service Company has announced its interest in building project it calls the Trans West Express consisting of 500 KV transmission lines from Wyoming to the Phoenix/Tucson area.

Figure S-3

Recommendation 2: Transmission Expansion Extending Beyond the Rocky Mountain Region



Puget Sound Area Upgrade Study Report

Part I: Characterization of the Study:

1. What was the name of the study? Puget Sound Area Upgrade Study Report

2. Provide the title(s) and completion dates of available report(s) regarding the study: Puget Sound Area Upgrade Study Report completed November, 2004

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): The study may be obtain by web-link: http://www.nwpp.org/ntac/pdf/PSASG%20Final%20Draft.pdf

4. Provide a contact person to obtain study details: name, phone, email: John Phillips, 425-462-3579

5. What was the purpose of the study (e.g., what problem was the study intended to address)? The purpose of the study was to improve the robustness of the Puget Sound area's transmission system's transfer capacity and load service under all expected operating conditions. There are multiple forced and maintenance outages that can cause reduction in firm load service and transfer obligations.

6. Provide a brief summary description characterizing the study: The study addressed all limiting outages and rank them based on the seriousness of the outage. Several transmission portfolios were developed to solve the constraints.

7. What was the geography of the study? The Puget Sound region which is located in Western Washington

8. What was the study period? 2005-2012

9. Describe the study type (such as who initiated the study and why): The study was initiated by the utilites located in the Puget Sound region and BCTC. The study was completed in the Northwest Transmission Assessment Committee forum

10. Characterize the study participants: Regional transmission providers and transmission customer affected by the constraints located in Western Washington

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: The method developed for the study was called "Transmission Curtailment Risk"

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion,

e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. The study used NERC/WECC reliabilty criteria. The study focused on improving the robustness of the system for both load service capability and transfer path capability.

13. Congestion identified: The congestion identified is an ongoing operating problem.

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives. None were considered other than generation redispatch.

15. Describe new transmission technologies (if any) that were considered. None

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation): BPA operational study cases and nomograms were used. Load shapes covered all operating seasons. Firm transmission obligations were modeled.

17. For each of the following, describe the assumptions made (if applicable) :

a. **Gas price (indicate base year and units):**
b. **Year(s) studied:** 2005-2012
c. **Load shapes (year and/or source):** All seasonal peak and off-peak loads
d. **Powerflow database case source(s):** BPA operational study cases.

Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): Puget Sound Area Upgrade projects

1a. Provide a contact person to obtain project details (if different from study). Provide name and contact for more than one person if appropriate: name, phone, email: Same as above

2. Description of issue(s) the project will address: The Puget Sound Area transmission system serves several functions including moving generating resources within the area to load, bringing generation from outside the region to serve load as well as serving as a west of Cascade path for imports and exports between the United States and Canada. When system components are out of service due to emergencies or scheduled maintenance, the system is severely constrained under various operating conditions. In addition, the system is highly dependent on Remedial Action Schemes (RAS), it serves a high growth area and it has potential interest for further resource expansion in the area. The goal of this high level study is to explore options that would make the transmission system in the Puget Sound area more robust when system components are out of service in meeting its current needs and to explore how these improvements may impact future load service capability, integration of resources, reduction in RAS, and higher import capability

3. Expected and/or needed date of commercial operation: 2005-2012

4. Termination 1 – location of one end point of associated facility upgrades: Covington 230 kV Substation

5. Termination 2 – location of other end point of associated facility upgrades: Monroe 500 kV substation

6. Characterization of other available routing information: Maps and diagrams are included in the study

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, include details including number of added lines, voltage category): Reconductor of existing 230 kV lines, a new 230 kV line, and new 500 kV lines, substation reconfigurations and modification of existing RAS.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: Load Service, US-Canada Treaty Obligation, regional economic power sales.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.):

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate):

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: Additional firm transmission capacity

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): There are multiple outages in the Puget Sound region that can reduce transfer capability

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. No net gain in transmission capacity, just increase in usable transmission capacity

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? No, not applicable

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? yes

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects:

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa:

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? Most project components will be completed by 2015.

Montana – Northwest Transmission Equal Angle Study Report

Part I: Characterization of the Study:

1. What was the name of the study? Montana-Northwest Transmission Equal Angle Study Report

2. Provide the title(s) and completion dates of available report(s) regarding the study: Montana-Northwest Transmission Equal Angle Study Report, completed October 12, 2005

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): The report may be obtained by the following Web link: http://www.nwpp.org/ntac/pdf/MT-NW%20Study%20Report%202005-Oct.zip

4. Provide a contact person to obtain study details: name, phone, email: Scott Waples, 509-495-4462, scott.waples@avistacorp.com

5. What was the purpose of the study (e.g., what problem was the study intended to address)? The purpose of the study was to determined preliminary upgrades and costs for an approximate increase of 750 MW firm capacity between eastern Montana and western Washington/Oregon

6. Provide a brief summary description characterizing the study: The study determined the minimum facilities that would be needed to upgrade 750 MW of transfer capacity between Montana and the Northwest Pacific coast with minimal construction of new transmission lines. The study primarily focused on using series capacitor upgrades to keep the new power transfer on the existing path without affecting adjacent paths.

7. What was the geography of the study? Eastern Montana to the Northwest Pacific Coast

8. What was the study period? Not applicable. The study was to determine capacity upgrade options that would facilitate potential new generation integration

9. Describe the study type (such as who initiated the study and why): The study was initiated under the Northwest Transmission Assessment Committee for the purpose of providing potential resource developers and buyers with initial capacity gains and expected costing information for an upgrade of the transmission system capacity.

10. Characterize the study participants: The study participants were the regional stakeholders in the Northwest.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: The firm capacity between Montana and the Pacific Northwest is essentially already committed to firm contract rights holders. If new resources are to receive firm transmission, additional capacity will be needed. The method used in the study to measure the effect of the system additions was to keep the existing power angle the same after the addition of new generation.

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. The metric used was an equal power angle analysis. The measure of congestion was increased power transfer.

13. Congestion identified: 750 MW

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives.

15. Describe new transmission technologies (if any) that were considered.

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation): WECC powerflow case. New generation was added in Montana.
A. WECC powerflow case was an approved 2003 West of Hatwai Light Summer basecase.
B. Light summer case provided heaviest power transfer scenario, east to west, due to high hydro capability and low load in Idaho and eastern Washington.
C. 750 MW of Generation was added at Colstrip (furthest point east) and 750 MW of additional load was distributed between load zones in the greater Puget Sound and Portland areas (furthest points west) in order to further stress the transmission system east to west.
D. Basecase swing bus was changed to Centralia (from Coulee). This was also done to stress the transmission system as much as possible.

17. For each of the following, describe the assumptions made (if applicable) :

- **a. Gas price (indicate base year and units):** NA
- **b. Year(s) studied:** NA
- **c. Load shapes (year and/or source):** Light Summer

d. Powerflow database case source(s): WECC base cases

<u>Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:</u>

1. Characterization of the project (name): Montana-Northwest Transmission Equal Angle projects

1a. Provide a contact person to obtain project details (if different from study). Provide name and contact for more than one person if appropriate: name, phone, email: Same as above

2. Description of issue(s) the project will address: Increased transfer capacity between Montana and the Pacific Northwest coast

3. Expected and/or needed date of commercial operation: Commercial operation date depends on whether there is are buyers located in Washington/Oregon for new generation constructed in Montana

4. Termination 1 – location of one end point of associated facility upgrades: Colstrip, Montana

5. Termination 2 – location of other end point of associated facility upgrades: Western Washington and Oregon

6. Characterization of other available routing information: Existing transmission system maps.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, include details including number of added lines, voltage category): The new facilities are primarily series capacitor upgrades. There is some new 230 kV and 500 kV line work in Washington and Oregon

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: The purpose is generation integration and load service

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.):

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate):

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: Increased power transfer.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): The limiting outages are located between Montana and Washington.

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. A net 750 MW capacity across West of Broadview, West of Garrison, West of Hatwai, North Cross Cascades and South Cross Cascades paths.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? No.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? No

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: Generation would have to be constructed and a committed buyer of the transmission capacity.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa:

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? Uncertain at this time. There are multiple resource options for potential purchasers of new resource.

<u>West of Hatwai System Upgrade Project – Phase 2 Report</u>

<u>Part I: Characterization of the Study:</u>

1. What was the name of the study? West of Hatwai System Upgrade Projects Phase 2 Report

2. Provide the title(s) and completion dates of available report(s) regarding the study: February 28, 2005

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): The report is Critical Energy Infrastructure Information. It may be obtained by email from the contact person identified below.

4. Provide a contact person to obtain study details: name, phone, email: Chris Reese, 425-462-3055, chris.reese@pse.com

5. What was the purpose of the study (e.g., what problem was the study intended to address)? The purpose of the study was to upgrade the capacity of a major constraint for firm transfers of power from Montana, Eastern British Columbia, and Eastern Washington and to provide additional load service to Eastern Washington. In 2001 several major industrial loads shut down creating a net loss of approximately 1000 MW of net firm transfer capacity across the West of Hatwai cutplane under some operating conditions.

6. Provide a brief summary description characterizing the study: The purpose of the study was to improve firm capacity across the West of Hatwai cut-plane. The system conditions which result in high West of Hatwai flows include high Western Montana hydro generation, high Colstrip generation, high Boundary generation, and light loads.

7. What was the geography of the study? The study focused on the transmission system between eastern Montana (Colstrip project) and central Washington (Mid-Columbia)

8. What was the study period? The study period addressed existing net firm power transfer obligations near term expected load growth.

9. Describe the study type (such as who initiated the study and why): The Bonneville Power Administration and Avista Utilities intitiated the study at the request of affected regional wholesale customers

10. Characterize the study participants: BPA and Avista approached the Northwest Power Pool Transmission Planning Committee and requested that a study group be formed. The study group met during early 2002 and helped the two utilities develop the best technical plan to increase the path capability through a one-utility planning concept.

The study group reviewed the merits of the projects described above and compared a number of longer term alternatives.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: Load flow, Reactive Margin, and Stability Studies were used to assess the capacity increase under the NERC and WECC reliability criteria.

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. The metrics used to address congestion was insufficient firm transfer capacity to meet firm obligations. Load flow, Reactive Margin, and Stability Studies were used to assess the capacity increase under the NERC and WECC reliability criteria.

13. Congestion identified: Insufficient firm transfer capacity.

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives.

15. Describe new transmission technologies (if any) that were considered.

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation): WECC 2003 load flow and stability case was used in the analysis. The system conditions which result in high West of Hatwai flows include high Western Montana hydro generation, high Colstrip generation, high Boundary generation, and light loads

17. For each of the following, describe the assumptions made (if applicable):

a. **Gas price (indicate base year and units):** Not applicable
b. **Year(s) studied:** 2005-2010
c. **Load shapes (year and/or source):** Near Term
d. **Powerflow database case source(s):** WECC

<u>Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:</u>

1. Characterization of the project (name): West of Hatwai System Upgrade Projects

1a. Provide a contact person to obtain project details (if different from study). Provide name and contact for more than one person if appropriate: name, phone, email:

2. Description of issue(s) the project will address: Additional Transfer Capacity

3. Expected and/or needed date of commercial operation: 2005

4. Termination 1 – location of one end point of associated facility upgrades: Garrison 500 kV Substation

5. Termination 2 – location of other end point of associated facility upgrades: Coulee 500 kV Substation

6. Characterization of other available routing information: Maps contained in report

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, include details including number of added lines, voltage category): New 500 kV line, new and upgraded 230 kV lines, upgrades of series capacitors, new substation, and modified remedial action schemes.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: Load Service and transfer of power from remote generation to load. Western Montana hydro generation, Colstrip generation, and Boundary generation,

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.):

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate):

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: Increase transfer under NERC/WECC criteria

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): Multiple limiting outages under varying operating conditions. The limiting performance criteria would be system instability and thermal overloads

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. West of Hatwai. Increase to 4277 MW from approximately 2800 MW

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? Project went through all phases of WECC process

13. Is this project included in the most recent submittals of WECC Annual Progress Reports?

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects:

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa:

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? All portions of the project will be completed by 2015.

Central Arizona Transmission Study

Part I: Characterization of the Study:

1. What was the name of the study? Central Arizona Transmission Study

2. Provide the title(s) and completion dates of available report(s) regarding the study: (1.) Report on the Phase I Study of the Central Arizona Transmission System, July 20th, 2001 (2.) Report on the Phase II Study of the Central Arizona Transmission System, September 24th, 2002 (3.) Report on the Phase III Study of the Central Arizona Transmission System, January 27th, 2004.

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): Copies of these reports can be obtained for the Azpower.org web site. (http://www.azpower.org) under the section labeled CATS Study.

4. Provide a contact person to obtain project details: name, phone, email: Gary T. Romero, 602-236-0974, gtromero@srpnet.com or Robert Kondziolka, 602-236-0971, rekondzi@srpnet.com.

5. What was the purpose of the study (e.g., what problem was the study intended to address)? The purpose of the study addressed the following:

- Improve the use of the existing transmission system.
- Increase the Power transfer import level into Phoenix, into Tucson the into the area between Phoenix and Tucson.
- Encourage future generation additions to areas that improve the performance and efficiency of the transmission system.
- Provide additional Transmission capacity to and from the Palo Verde Hub.

6. Provide a brief summary description characterizing the study: The CATS studies were collaborative regional transmission studies with the purpose of addressing the needs of all stakeholders in the Arizona portion of the Desert Southwest region. The CATS Phase I study developed a high-level long-term transmission plan for Central Arizona that focused on maximizing regional benefits. The CATS Phase I work incorporated a comparitive assessment of a significant number of options to develop an initial transmission plan. The CATS Phase II study work updated the long range plan incorporating improved assumptions/modeling and by performing a series of comparisons of proposed alternatives with the base plan from Phase I. The elements providing the best overall performance were incorporated as part of the plan. Phase I and Phase II studies were long range plans based on a long term load growth scenario and did not represent a specific time frame.

The CATS Phase III study built on the work of Phase I and II studies with the purpose of developing the transmission facilities during the next ten years for the study area. One of the innovative elements of the CATS Phase III studies was to develop a new process which would take each participant’s individual ten-year propoosed requirements in a single uniform study and analyze how they perform in a regional environment. The end result was a collaberative Ten-year regional plan for study area a ten year coordinated base case.

7. What was the geography of the study? The region for the CATS study encompassed the area bounded by the Phoenix Metropolitan area to the north, the Tucson Metropolitan area to the south, the Palo Verde Generation Station and environs to the west and east the Arizona/New Mexico border. The area includes Coolidge, Casa Grande, Eloy, Marana, Florence, Maricopa as well as the Major metropolitan areas of Phoenix and Tucson.

8. What was the study period? For the CATS Phase I and Phase II Studies, there was no specific time period assessed to these studies. Load and Generation were raised until and EHV facilities limits were reached. For the CATS Phase III study, the study period was summer 2012.

9. Describe the study type (such as who initiated the study and why): The genesis was a result of a flood of new generation proposals in Arizona and no associated transmission expansion. Questions arose about the adequacy of the existing transmission system, could all the generation reach the intended market, who would plan the transmission to meet the needs of IPP plants, how would the needs of IPP plants be incorporated with the plans of utilities and transmission dependent load serving entities, will reliability requirements be met, is there a better way to have generation proposed, what are the environmental impacts with the current process, and what is the proper balance of transmission and generation? An initial meeting was held in March 2000 to evaluate the conceptual aspects of a proposed approach to develop a regional plan for the Arizona area. A kickoff meeting was held in June of 2000 to formalize the CATS regional study group and process.

10. Characterize the study participants: Arizona transmission owners, Arizona regulators, independent power producers, transmission dependent & load serving entities, and market participants.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: Power flow analysis was used to compare the performance of a multitude of generation and transmission scenarios. Transmission alternatives, which demonstrated the best performance were carried on to the next level of study.

12. What criteria and metrics did the study use when defining congestion and a solution (Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings)?

NERC/WECC reliability criteria (primarily N-0 and N-1 overloads) and transfer capability.

13. Congestion identified: Overload of the Palo Verde East transmission system and import capability into the Phoenix and Tucson areas.

14. Were non-transmission alternatives compared with transmission alternatives? Generation alternatives were evaluated.

15. Were new transmission technologies considered?

FACTS devices such as series compensation, static var compensation, and phase shifting transformers.

16. Describe the six most important study assumptions (e.g. fixed hydro dispatch) :
1) Generation location and dispatch pattern
2) Load growth
3) Transmission scenarios developed
4) Transmission voltage used for different alternatives
5) High import levels into load centers
6) Not analyzed as utility specific elements. Modeled regional transmission system to provide a balanced approach to meet aggregate needs of all participants.

17. For each of the following, describe the assumptions made (if applicable):

a. **Gas Price (indicate base year and units):** N/A

b. **Year(s) studied**: Phase I and II N/A, Phase III - 2012

c. **Load shapes (year and/or source):** N/A

d. **Powerflow database case source(s):** Phase I and II – WSCC 2002LS1
Phase III – WECC 2006 HS

Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name):

a.) Palo Verde to Pinal West I and II 500kV Line
b.) Pinal West to South East Valley/Browning 500kV Line
c.) Pinal West to Saguaro 500kV Line
d.) Saguaro to South 500kV Line
e.) Southeast Valley or Pinal South to Winchester 500kV Line
f.) Winchester to South 500kV Line
g.) Cholla/Saguaro 500kV loop into Silver King

2. Description of issue(s) the project will address:

a.) The Palo Verde to Pinal West I and II 500kV Lines will serve as interconnection points from the Palo Verde Hub into the Phoenix, Tucson and the area between Phoenix and Tucson. These lines are common to the development of all parts of the planned system.
b.) The Pinal West to South East Valley/Browning 500kV Line will provide additional import capability into Phoenix and additional load serving capability for the Phoenix Valley. The project is required to meet reliability requirements (voltage, post-transient, and load serving capability). The project provides interconnection opportunity, access to market energy for load serving entities, and strong sources for developing sub-transmission systems in the Pinal County area.
c.) The Pinal West to Saguaro 500kV Line will strengthen the Saguaro 500kV station making it a strong source for Southern Arizona
d.) The Saguaro to South 500kV Linewill provide additional import capability into Tucson and addition load serving capability for the Southern Arizona.
e.) The development of Winchester substation and a 500kV line from South East Valley or Pinal South will reinforce the existing eastern EHV system along the Arizona and New Mexico border and feed into Tucson and Southern Arizona from the east.
f.) Looping the Cholla to Saguaro 500kV line into Silver King will further enhance the eastern EHV transmission system feed into Phoenix and Tucson.

3. Expected and/or needed date of commercial operation:

a.) Palo Verde to Pinal West I: Completed federal and state permitting in 2004. Expected in-service date is 2008
b.) Palo Verde to Pinal West II: Completed federal and state permitting in 2004. Expected in-service date is 2015 to 2020.
c.) Pinal West to South East Valley Browning 500kV Line: Completed state permitting in 2005. Expected in-service date is 2011.
d.) Pinal West to Saguaro 500kV Line: To be determined
e.) Saguaro to South 500kV Line: To be determined
f.) South East Valley or Pinal South to Winchester 500kV Line: To be determined
g.) The Winchester Station was permitted in 2003 and constructed in 2004.
h.) Winchester to South 500kV Line: To be determined
i.) Cholla/Saguaro 500kV loop into Silver King: To be determined

4. Termination 1 – location of one end point of associated facility upgrades:

5. Termination 2 – location of other end point of associated facility upgrades:

6. Characterization of other available routing information: For the Palo Verde to Pinal West Project, permitting process included environmental evaluation of route options on federal, state, and private lands. The Federal permitting process was in accordance with NEPA requirements and an Environmental Assessment was required. Federal lands incorporated use of a designated utility corridor identified in BLM plans and generally parralled other transmission lines or a major high-pressure natural gas pipeline. BLM plans developed in accordance with FLPMA. BLM recommended route only used on federal lands. BLM recommended route not used on private lands. The Arizona Power Plant and Transmission Line Siting Committee and Arizona Corporation Commission selected a deviation from the BLM utility corridor on private lands that they believed reduced impacts to local residences.

For the Pinal West to Southeast Valley/Browning Project, the permitting process included environmental evaluation of route options on state and private lands. There were significant differences in the route options, relative locations, line lengths, and cost to evaluate. The Power Plant and Transmission Line Siting Committee recommended a route that incorpoated a majority of the project sponsor's preferred route. The Siting Committee recommended route was the longest length option and selected to incorporate access to future generation and improved expansion opportunity for future transmission in accordance with CATS studies. The recommended route also included a major deviation from the preferred route to have improved reliability performamce. The Arizona Corporation Commissioners, in the final decision making process, accepted almost all of the route recommended by the Siting Committee, but also incorporated a signficant deviation from the Siting Committee deviation to address citizen concerns and improve reliabillity.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): As previously described, there two projects combined add 152 miles of 500kV transmission line between the Palo Verde hub and the existing Browning station, add 3 new 500kV stations to provide access and injection opportunities, and incorporates 230kV capability on the structures. The 230kV option was included to address local transmission needs and minimize the visual impacts of transmission facilities on communities.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: The combined projects provide:
1) Increased load serving capability.
2) Increases import capability.
3) Access to Palo Verde markets.

4) Incorporates interconnection of future generation. Encourages generation into more desirable locations.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.): Not applicable.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate): $215M for the 500kV elements.

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: Meet NERC/WECC criteria to for load serving and import capability under N-0, N-1, and certain N-2 conditions.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): Varies by individual segment and time frame. Most frequent is loss of Palo Verde to Rudd which produces thermal overloads on transformers and lines (Jojoba to Kyrene).

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. Not applicable. However, the combined projects increase the Palo Verde East path from 6970MW to 8375MW (1405MW).

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? Already went through regional planning. Not a WECC rated path.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? Yes.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: Total evaluation performed. Underlying 230kV and 69kV systems incorporated into required facilites. Will allow for permitted and new generation to be built.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: Will not displace other projects. Proposed system enhances expansion of all related items in the plan and enhances expansion of other proposed projects such as the Pinnacle Peak to Raceway 500kV Project and the Palo Verde to TS5 500kV Project.

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? Yes. Both projects are currently in design and land/row acquistion.

<u>Path 49 (East of River) Transmission Upgrades</u>

<u>Part I: Characterization of the Study:</u>

1. What was the name of the study? Path 49 (East of River) Transmission Upgrades

2. Provide the title(s) and completion dates of available report(s) regarding the study: (a) Southwest Power Link and Palo Verde - Devers 500kV Series Capacitor Upgrade Project (Increasing the East of River Path (Path 49) rating from 7,550 MW to 8,055 MW, dated December 2, 2004, (b) Devers - Palo Verde No. 2 (DPV2) Accepted Path 49 Rating Study Report (for EOR of 9255 MW), dated July 25, 2005, (c) EOR 9000+ Upgrade Project Accepted Path 49 Rating Study Report, dated August 10, 2005.

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): Contact WECC for Phase 3 Accepted Path Rating Study Reports.

4. Provide a contact person to obtain project details: name, phone, email: David Le, (916) 608-7302, e-mail: dle@caiso.com

5. What was the purpose of the study (e.g., what problem was the study intended to address)? To mitigate congestion between Arizona and California and between Arizona and Nevada at off-peak time, with high Arizona generation conditions.

6. Provide a brief summary description characterizing the study:

(a) Path 49 Short-Term Transmission Upgrades included economic evaluation for the benefit of upgrading Path 49 (East of River) by 505 MW to increase the transfer capability between Arizona and California interface. The study also included technical evaluation with transient stability, post-transient and power flow analyses that culminated in WECC Phase 3 approval for an increase of 505 MW on the East of River path to 8,055 MW. Proposed to begin operation in 2006.

(b) The Devers - Palo Verde No. 2 (DPV2) 500kV Line Project included economic evaluation for the benefit of upgrading Path 49 (East of River) by an additional 1,200 MW for the transfer capability between Arizona and California interface. Technical studies included transient stability, post-transient and power flow analyses and were submitted to WECC for Phase 3 approval of an increase of additional 1,200 MW on the East of the River path to 9,255 MW. Proposed to begin operation in 2009.

(c) The EOR 9000+ Upgrade Project, a parallel effort to increase East of River but instead of increasing the path rating from Arizona to California interface, this Project was proposed to increase the East of River path rating from Arizona to Southern Nevada interface. The study included economic evaluation for the benefit of upgrading Path 49 (EOR) by an additional 1,245 MW for the transfer capability between Arizona and Southern Nevada interface. Technical studies included transient stability, post-transient and power flow analyses and were submitted to WECC for Phase 3 approval of an increase of 1,245 MW on the East of River Path to 9,300 MW.

7. What was the geography of the study? Western Arizona, Southern Nevada and Southern California

8. What was the study period? Heavy Autumn 2006

9. Describe the study type (such as who initiated the study and why): (a) For Path 49 Short-Term Upgrades, Sempra Energy Resources initiated the study on March 28, 2003, to increase the transfer capability to mitigate congestion on the two southern lines on the East of River (EOR) path; however, project sponsorship was later transferred to the CAISO on June 7, 2004; (b) For DPV2 Project, Southern California Edison (SCE) initiated the study to provide additional transfer capability between Arizona and California and to access inexpensive generation in the Southwest; (c) for EOR 9000+ Project, Salt River Project (SRP) initiated the study on behalf of the Project Sponsors (SRP, APS, WAPA, LADWP, USBR) to increase the transfer capability from Arizona to Southern Nevada.

10. Characterize the study participants: The study participants at the Southwest Transmission Expansion Plan (STEP) forum included the Transmission Owners in California and the Southwest, California and Arizona regulators, merchant transmission owners, energy companies, independent power producers, marketers and trading companies and subregional planning groups.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: Utilize and modify the 2008 base case production cost model developed by the Seams Steering Group - Western Interconnect (SSG-WI). The SSG-WI model is a simplified model of the CAISO's Transmission Economic Assessment Methodology (TEAM) and quantifies the amount of, among other things, variable operation and maintenance cost (predominantly fuel cost) with and without transmission upgrades.

12. What criteria and metrics did the study use when defining congestion and a solution (Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings)?

Economic studies were performed to determine whether the Project would have net economic benefits to the consumers. A Benefit to Cost Ratio was evaluated to determine if the Project's benefits outweighed its cost. Annual production cost savings were one of the metrics used in defining congestion and a solution. The change in production costs due to implementation of the proposed transmission project: (a) change (reduction) in power price to CAISO consumers; (b) change in producer revenue for utility-retained generation; (c) change in congestion revenue that would flow to the CAISO consumers. The summation of these three metrics equals the energy benefits to ratepayers in the CAISO area. These three metrics are done on a participant test, which accounts for those who participate in funding the Project. The change in production costs WECC wide was also calculated.

13. Congestion identified: (a) For Path 49 Short-Term Upgrades, a reduction of $142 million (on annual basis) of energy costs to ratepayers in the CAISO area was estimated; however, the total production cost saving WECC wide was also estimated to be $27 million per year; (b) for DPV2 Project, a reduction of $56 million of energy cost to ratepayers in the CAISO area (only) was estimated; however, the total production cost saving WECC wide was estimated to be $54 million per year (based on expected value of 17 cases in 2013); (c) for EOR 9000+ Project, sensitivity analysis indicated an estimate of $99 thousand (~ $100K) of total production cost saving WECC wide.

14. Were non-transmission alternatives compared with transmission alternatives? Yes, for DPV2 Project, these non-transmission alternatives were also considered: demand side programs, renewable energy and new combined cycle power plants sited in Southern California.

15. Were new transmission technologies considered? Yes (FACTS devices)

16. Describe the six most important study assumptions (e.g. fixed hydro dispatch):

The SSG-WI 2008 data was utilized to perform the economic study. The following are some of the major study assumptions:

a) "normal" hydro year;

b) gas price forecast of $4 per Mcf;

c) generation that is currently in service or in advanced stage of construction;

d) generation expected to be retired or off line

e) transmission network data with correctly represented constrained paths;

f) hourly load forecast;

g) costs for generation (fuel, O&M).

17. For each of the following, describe the assumptions made (if applicable):

a) Gas Price (indicate base year and units): $4 per Mcf (2008)

b) Year(s) studied: 2008

c) Load shapes (year and/or source): 2008 SSG-WI data

d) Powerflow database case source(s): WECC/WATS-approved power flow base cases for Path 49 Short-Term Upgrades, PVD2 and EOR 9300 MW Projects.

Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): Path 49 (East of River) Upgrades Due to the following: Short-Term Transmission Upgrades, DPV2 Project and EOR 9000+ Project

2. Description of issue(s) the project will address: Mitigate congestion between Arizona and Southern California and between Arizona and Southern Nevada.

3. Expected and/or needed date of commercial operation: (a) Path 49 Short-Term Upgrades: summer 2006, (b) DPV2 Project: summer 2009, (c) EOR 9000+ Project: between 2007 and 2008.

4. Termination 1 – location of one end point of associated facility upgrades: (a) for Path 49 Short-Term Upgrades: Palo Verde and Hassayampa 500kV; (b) for DPV 2 Project: Harquahala; (c) for EOR 9000+ Project: Perkins 500kV.

5. Termination 2 – location of other end point of associated facility upgrades: (a) for Path 49 Short-Term Upgrades: Devers and North Gila/Imperial Valley 500kV; (b) for DPV2 Project: Devers 500kV; (c) for EOR 9000+ Project: Mead 500kV.

6. Characterization of other available routing information: (a) for Path 49 Short-Term Upgrades: Utilize existing lines (Palo Verde - Devers and Hassayampa - N. Gila - Imperial Valley 500kV lines); (b) for DPV2 Project: utilize common Rights-of-Way of the DPV1 line; (c) for EOR 9000+ Project: utilize existing Perkins - Mead 500kV line.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): (a) For Path 49 Short-Term Upgrades: upgrade series capacitors, add transformer, add dynamic voltage support, add phase-shifting transformer, add new Special Protection System (SPS) for generation tripping (i.e., West of Devers 230kV short-term upgrades); (b) For DPV2 Project: construct new 500kV line, install additional dynamic voltage support, re-conductor 230kV lines west of Devers; (c) For EOR 9000+ Project: by-pass Perkins - Mead 500kV phase shifter, upgrade the existing Perkins - Mead, Perkins - Westwing and Navajo - Crystal 500kV lines, install additional dynamic voltage support.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: Mitigating congestion between Arizona and California and between Arizona and Southern Nevada, accessing inexpensive generation located in western Arizona.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.): (a) For Path 49 Short-Term Upgrades Project: $27 million saving for the entire WECC system ($142 million for the CAISO system); (b) For DPV2 Project: $54 million saving for the entire

WECC system ($56 million of saving was estimated to the CAISO system); (c) For EOR 9000+ Project: about $100K saving for the entire WECC system.

The Division of Rate payer Advocates (formally known as ORA) for the CPUC conducted an independent economic analysis of DPV2 and recommends that the project is needed based upon a benefit-to-cost ratio of 1.4:1 (Source: page ES-1, ORA's DPV2 Testimony Vol. 2 of 3, November 22, 2005.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate): $148 million (2006 dollars) for the Path 49 Short-Term Upgrades Project; $680 million (2009 dollars). No estimate is available for EOR 9000+ Project.

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: For Path 49 Short-Term Upgrades and DPV2 Project: potential reduction in reliability must run (RMR) generation in L.A. Basin and San Diego areas.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): For all three projects: N-1 of Hassayampa - N. Gila 500kV line, causing transient voltage dip at Devers 500kV bus.

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. (a) Path 49 (East of River) Short-Term Upgrades: Path 49 from 7,550 MW to 8,055 MW, Path 46 (West of River) from 10,118 MW to 10,623 MW; (b) DPV2 Project: Path 49 from 8,055 MW to 9,255 MW, Path 49 from 10,623 MW to 11,823 MW; (c) EOR 9000+ Project: Path 49 from 8,055 MW to 9,300 MW, no estimate for Path 46 after-project rating. The combined DPV2 and EOR 9000+ Project path rating study is under way at WECC/WATS forum.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? Yes

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? Yes.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: LADWP-proposed Green Path Project (i.e., Indian Hills - Devers - Upland 500kV Line Project).

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: None

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? (a) Path 49 Short-Term Upgrades: project is under construction with anticipated completion date of summer 2006 (fall 2006 for completing the dynamic voltage support at Devers); (b) DPV2 Project: anticipated summer 2009, project is under permitting review by the CPUC and the ACC; (c) EOR 9000+ Project: potential combined project with DPV2 - currently the combined DPV2 and EOR 9000+ path rating study is under way at WECC/WATS forum.

California Energy Commission
Strategic Transmission Investment Plan

Part I: Characterization of the Study:

1. What was the name of the study? Strategic Transmission Investment Plan (Strategic Plan)

2. Provide the title(s) and completion dates of available report(s) regarding the study: Committee Final Strategic Transmission Investment Plan (Committee Final Strategic Plan), California Energy Commission, November 2005.

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): Energy Commission Publication No. CEC 100-2005-006CTF, available at: http://www.energy.ca.gov/2005publications/CEC-100-2005-006/CEC-100-2005-006-CTF.PDF.

4. Provide a contact person to obtain project details: name, phone, email: (1) Jim Bartridge, (916) 654-4169, jbartrid@enery.state.ca.us; (2) Judy Grau, (916) 653-1610, jgrau@energy.state.ca.us.

5. What was the purpose of the study (e.g., what problem was the study intended to address)? California Public Resources Code section 25324 directs the Energy Commission to adopt a strategic plan for the state's electric transmission grid that identifies and recommends actions required to implement investments needed to ensure reliability, relieve congestion, and meet future growth in load and generation, including but not limited to renewable resources, energy efficiency, and other demand reduction measures. This first plan was due on November 1, 2005 as part of the Energy Commission's biennial integrated energy policy report proceeding.

6. Provide a brief summary description characterizing the study: The Strategic Plan provides an overview of the significant transmission planning and system issues hindering development of a robust electric transmission grid in California. The Strategic Plan recommends actions to improve California's transmission system in the areas of transmission planning and permitting; congestion and renewable resources integration; continued transmission R&D via the Energy Commission's Public Interest Energy Research (PIER) program; and specific project investments (see Part II below).

7. What was the geography of the study? The Strategic Plan assessed 21 transmission projects proposed to address reliability, congestion, or renewables connection concerns that were examined in the Energy Commission Staff Report entitled *Upgrading California's Electric Transmission System: Issues and Actions for 2005 and Beyond (Staff Transmission Report)* (Energy Commission Publication no. CEC 700-2005-018, July 2005, http://www.energy.ca.gov/2005publications/CEC-700-2005-018/CEC-700-2005-018.PDF). Eighteen of those 21 projects are located either within California or connect to California, while the remaining three (the Northern Lights Project, the Southwest Intertie Project, and the East-of-River 9000+ Project) do not terminate within California but could affect power flows into California.

8. What was the study period? The Strategic Plan focuses on near-term projects that could be on line by 2010.

9. Describe the study type (such as who initiated the study and why): As noted in the response to question #5, the Strategic Plan was prepared by the Energy Commission to comply with Senate Bill 1565 (Bowen), Chapter 692, Statutes of 2004, which added Section 25324 to the California Public Resources Code.

10. Characterize the study participants: The Energy Commission's Integrated Energy Policy Report Committee (Energy Report Committee) held several workshops on transmission-related topics in 2005. Comments received at and after these workshops helped form the basis for the *Staff Transmission Report*. After completion of the *Staff Transmission Report*, the Energy Report Committee held a hearing on July 28, 2005 to take comments on the *Staff Transmission Report*. Parties providing comments included California's three investor-owned utilities (San Diego Gas & Electric [SDG&E], Southern California Edison [SCE], Pacific Gas & Electric [PG&E]), two large municipal utilities (Los Angeles Department of Water & Power [LADWP], Imperial Irrigation District [IID]), the California Independent System Operator [CA ISO], consumer groups, and project proponents. Those comments were considered as the Committee Draft Strategic Plan was created. The Energy Report Committee then held a hearing on the Committee Draft Strategic Plan on September 23, 2005. Parties providing comments included SDG&E, SCE, PG&E, the League of Women Voters, CA ISO, National Grid, The Nevada Hydro Company, Inc., the Office of Ratepayer Advocates, and generation developers. These comments were considered for the Committee Final Strategic Plan.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: As noted in the response to question #7, the Strategic Plan used as its starting point the 21 transmission projects studied in the Energy Commission Staff Transmission Report. The 21 projects described in that staff report are specific projects that have been proposed to address reliability, congestion, or renewables connection concerns. The Energy Commission staff did not perform original work, but instead relied on publicly available information from project proponents and other sources to provide a detailed description of each project (including status, major issues, project benefits, planning and permitting status, and consequences of project delays.)
The Energy Commission then defined the parameters for consideration of the 21 projects in the Strategic Plan. In addition to the legislative requirements (see response to question #5), the Energy Commission added four more: (1) Project could be on line by 2010; (2) Siting approval has not yet been obtained; (3) Project provides strategic benefits such as insurance against low-probability/high-impact events and/or achievement of state policy objectives; and (4) Extent to which project conforms with state Senate Bill 2431 (Garamendi), Chapter 1457, Statutes of 1988, regarding efficient use of existing right-of-way and coordinated transmission planning.

Of the 21 projects described in the Energy Commission Staff Transmission Report, seven passed the initial screening parameters and were studied further. Of those seven, five projects were determined to be of strategic importance to California and were recommended as investments. The five projects are the Palo Verde-Devers No. 2 Project, the Sunrise Powerlink Project, Phase 1 of the Tehachapi Transmission Plan, an Imperial Valley upgrade project, and the Trans-Bay DC Cable Project.

The assessment of each of the five recommended projects is described further in Part II.A through Part II.E below.

12. What criteria and metrics did the study use when defining congestion and a solution (Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings)? The Energy Commission did not perform any congestion modeling but instead relied upon CA ISO documents such as the *2004 Annual Report on Market Issues and Performance* and monthly updates.

13. Congestion identified: According to the CA ISO *2004 Annual Report on Market Issues and Performance,* interzonal congestion revenues in 2004 were $55.8 million, a $29.7 million increase from 2003. The three largest sources of congestion revenues for 2004 were $21.7 million for Palo Verde-Devers, $11.0 million for the California-Oregon Intertie, and $9.8 million for Path 15 (within California).

14. Were non-transmission alternatives compared with transmission alternatives? No, the Energy Commission did not perform any new studies to compare non-transmission alternatives with transmission alternatives, but instead relied upon studies performed by others.

15. Were new transmission technologies considered? The Strategic Plan did not consider new transmission technologies in its assessment of the proposed projects. However, there is a section in the Strategic Plan that discusses major efforts being funded by the Energy Commission PIER Transmission Research Program, including high-temperature, low-sag conductors; real-time rating of transmission systems; real-time system operations tools; and fault current limiters. In addition, the PIER Environmental Program is funding a web-based decision tool for siting transmission lines called "Planning Alternative Corridors for Transmission (PACT)."

16. Describe the six most important study assumptions (e.g. fixed hydro dispatch): Not applicable, since the Energy Commission did not perform independent production cost modeling.

17. For each of the following, describe the assumptions made (if applicable): N/A

- **a. Gas Price (indicate base year and units):**
- **b. Year(s) studies:**
- **c. Load shapes (year and/or source):**
- **d. Powerflow database case source(s):**

Part II.A: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): Palo Verde-Devers No. 2 500 kV Transmission Project

2. Description of issue(s) the project will address: congestion reduction, increased access to lower cost out-of-state generation

3. Expected and/or needed date of commercial operation: Assuming the project receives approval by the end of 2006, it could be operational by the end of 2009.

4. Termination 1 – location of one end point of associated facility upgrades: Harquahala Substation (in the Palo Verde area of Arizona)

5. Termination 2 – location of other end point of associated facility upgrades: Devers Substation in Southern California

6. Characterization of other available routing information: No other routing options are described in the Strategic Plan.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): New 500 kV line in the same corridor as the existing Palo Verde-Devers line, plus upgrade of four 230 kV lines west of the Devers Substation.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: In addition to reducing congestion and increasing access to lower cost out-of-state generation, the Strategic Plan notes the results of an Energy Commission consultant study which examined the extent to which the CA ISO and SCE economic assessments (see response to question #9) included strategic benefits. The consultant study found that the CA ISO economic assessment potentially undervalues the project because it does not consider strategic values such as its insurance value during abnormal system conditions and a decrease in the need for additional infrastructure such as gas pipelines. In addition, the consultant study found that several potential benefits were not included in the SCE economic assessment, including attracting new generation development east of the Devers Substation, reducing the potential for generators to exercise market power, and providing emergency value during a major import line and/or generating facility outage.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.): The Energy Commission did not perform an independent assessment of production cost savings but instead relied on the results of two assessments. The first is the CA ISO's *Economic*

Assessment of the Palo Verde-Devers No. 2, which was based on the CA ISO's Transmission Economic Assessment Methodology (TEAM). The CA ISO calculated total levelized lifecycle benefits between $84 and $225 million (2008 dollars), based on a 50-year economic life. The $84 million figure is for the CA ISO ratepayer perspective (Locational Marginal Pricing, LMP), while the $225 million figure is for the CA ISO ratepayer perspective with LMP and contract path.

The second assessment is SCE's *Proponent's Environmental Assessment*, which projects total benefits of $1,100 million (2005 dollars, net present value, 10.5 % discount rate). This figure includes $1,070 in energy benefits plus $30 million in third party transmission revenues.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate): According to the CA ISO assessment, the levelized cost for the project is $71 million (2008 dollars).
According to SCE's assessment, the total cost of the project is $650 million (2005 dollars, net present value, 10.5% discount rate).

10. For a reliability analysis: N/A

10a. Describe the reliability benefits of the project: N/A

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): N/A

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. The project would increase the non-simultaneous rating of Path 46 (West of Colorado River) by 1,200 MW, from 10,623 MW to 11,823 MW (Prior to the Palo Verde-Devers No. 2 Project in-service date, the Path 46 rating is expected to increase from its current limit of 10,118 MW to 10,623 MW due to the Path 49 Short-term Series Capacitor Upgrade Project). It would also increase the non-simultaneous rating of Path 49 (East of Colorado River) by 1,200 MW, from 8,055 MW to 9,255 MW.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? Yes. The Palo Verde-Devers No. 2 Project/Path 46 is currently in the Phase 1 process. The Palo Verde-Devers No. 2 Project/Path 49 (East of Colorado River) achieved Phase 3 status and an accepted rating of 9,255 MW in August 2005.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? Yes.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission

projects: SCE's economic analysis of the project assumes that the Path 49 (East-of-River 9000+) Project is constructed. The EOR 9000+ Project would increase the East-of-River transfer capability from 8,055 to 9,300 MW.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: No projects have been specifically identified, although the Frontier Project and the Northern Lights Project could include lines parallel to the Palo Verde-Devers No. 2 Project.

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? The project is currently undergoing review at the California Public Utilities Commission (CPUC) for a Certificate of Public Convenience and Necessity (CPCN). The application was submitted to the CPUC on April 11, 2005 and was deemed complete on September 30, 2005. The Draft Environmental Impact Report/ Environmental Impact Statement (EIR/EIS) is scheduled to be released in May 2006. A final CPUC Decision on the CPCN and certification of the Final EIR/EIS is scheduled for December 2006. Assuming that the CPCN is granted in December 2006, it is likely that the project can be operational in 2009.

Part II.B: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): Tehachapi Wind Integration Transmission Study –please see Template Parts I and II, page 82 in this report.

Part II.C: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): Sunrise PowerLink

2. Description of issue(s) the project will address: To Maintain Reliability; Promote Renewable Energy; and To Reduce Energy Costs.

3. Expected and/or needed date of commercial operation: Needed to meet the grid reliability requirements of the California Independent System Operator ("CAISO") in 2010.

4. Termination 1 – location of one end point of associated facility upgrades: The project will connect the existing Imperial Valley substation near El Centro, California.

5. Termination 2 – location of other end point of associated facility upgrades: A new "Central" substation located somewhere in central San Diego County.

6. Characterization of other available routing information: Where possible, SDG&E anticipates locating new facilities within or along existing rights-of-way. Although the specific routes for most segments of the project are not known at this time, the total mileage for the 500 kV portion of the project is estimated to be between 85 and 100 miles.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.):

A new 500kV line as noted in the termination questions above, and a 230 kV transmission line will then be constructed from the new substation to SDG&E's existing Sycamore Canyon substation located east of Scripps Ranch. Finally, the Sunrise Powerlink will continue from Sycamore Canyon and terminate at the existing Penasquitos substation just east of the I-5 freeway. The transmission facility additions for the two preferred – Sunrise Powerlink (IV-Central) and Imperial Valley –Central – Serrano/Valley 500 kV (Full Loop) are:

Sunrise Powerlink (IV – Central)	**(Full –Loop (IV –Central –Ser/Val)**
120-140 miles 1-500 kV line IV –Central (series compensated) 2-230 kV lines Central –Sycamore Canyon 1-230 kV line Sycamore Canyon –	200 -240 miles 1-500 kV line IV –Central (series compensated) –Ser/Val (series comp) 2-230 kV lines Central –Sycamore Canyon 1-230 kV line Sycamore Canyon –
Central Substation 2-500/230/12kV banks 8-45 MVAr 12 kV reactors 200 MVAr SVDs–Locations to be determined	**Central Substation** 2-500/230/12kV banks 8-45 MVAr 12 kV reactors 200 MVAr SVDs–Locations to be determined
3^RD Luis Rey230/69 kV –transformer SX –Elliott 69 kV reconductor	3^RD Luis Rey230/69 kV –transformer SX –Elliott 69 kV reconductor

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc:
The Sunrise Powerlink could import about 1,000 megawatts of electricity or enough power for about 650,000 SDG&E customers.

- Studied 2010
- SDG&E Import 4000 MW (SIL)
- Path 49 Upgrades (8055 MW) (In)
- Otay Mesa & Palomar Gen (On)
- Mountain View, Pastoria, Silver Hawk Gen (On)
- Mohave, South Bay Gen (Off)
- Palo Verde – Devers #2 (In)
    - Sensitivity, Stability, Post-Transient, Economic

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.): The CPUC did not perform an independent assessment of production cost savings but instead relied on reduced energy costs listed in the CPCN. The reduced energy costs are 200 million per year to ratepayers who receive service from facilities that are under the operational control of the CAISO.

The Base Economic Conditions used:

- •Expected loads, average hydro
- •Natural gas prices at $6.39/MMBTU in 2010
- •San Diego import limit increased from 2850 MW to at least 4000 MW
- •WECC load/resource assumptions
- •Imperial Valley renewables and IID grid expansion

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate): This information is not public this time under the confidentiality provisions of Cal. Pub. Util. Code § 583 and GO 66-C, because public availability of such information could hamper SDG&E's ability to receive low-cost bids and to build the project on a least-cost basis for its ratepayers.

10. For a reliability analysis:

10a. Describe the reliability benefits of the project:

The Sunrise Powerlink will enable SDG&E to address a potential grid reliability shortfall in 2010 identified in D.04-12-048. It will enable the San Diego transmission system to satisfy the CAISO's fundamental G-1/N-1 reliability requirement starting in 2010, thereby allowing SDG&E and other Load Serving Entities ("LSEs") within the San Diego area (i.e. energy service providers and potential community choice aggregators) to reliably serve their customers during periods of unanticipated high energy demand. The project will also allow increased flexibility in operating California's transmission grid and provide additional import capability that may be urgently needed during a major outage or emergency event.

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10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc):

Heavy Summer –critical contingency

IV-Miguel 500 kV with Gen drop RAS

- •Lowest Reactive Margin –South Bay 69 kV

Devers–Valley 500 kV

- •Lowest Reactive Margin –Highline 230 kV (IID)

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project.

San Diego import limit increased from 2850 MW to at least 4000 MW, specific increase for certain lines are unknown at this time.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process?

WECC Path Rating Review Process
•Initiate Phase 1 by End-of-Year 2005
•Coordinate with other proposed expansion projects in the area

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? Yes.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects

Imperial Valley renewables and IID grid expansion

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa:

Generation Addition - 2010

Power Plant Cost
750 MW new Combined Cycle
$683 million
OR
750 MW of new Gas Turbines
$560 million

System Upgrades - $140MM
230 kV Switchyard
ML 2nd 230/138 kV bank
SX – 3rd 230/69 kV bank
230 kV new lines
69 kV & 138 kV reconductors

Generation Addition – 2015

Power Plant Cost
900 MW new Combined Cycle
$930 million

System Upgrades - $131MM
Encina – 230/138kV bank
69 kV & 138 kV new lines
69 kV & 138 kV reconductors
CFE - 230 kV breaker upgrades

16. Describe the current project status. Include your assessment; Will this project be completed by 2015?

The project is being evaluated for before the California Public Utilities Commission CPCN process, and will file its formal application and environmental report on the project by mid-2006. If approved, the project is expected to be in service by the year 2010.

Part II.D: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): Imperial Valley Transmission Upgrade Project

2. Description of issue(s) the project will address: access to renewable resources needed to meet future load growth, support for California's RPS goals and significant near-term reliability benefits to California.

This project has continued to evolve since the Energy Commission's study of November 2005. The Imperial Valley Study Group (IVSG), a consortium of utilities, developers and regulators, developed transmission plans designed to deliver generation in the Imperial Valley (IV) to loads in California and the West, via San Diego Gas and Electric (SDG&E) and Southern California Edison (SCE). The IVSG development plan envisioned three phases.

In November 2005, the Energy Commission recommended Phase 1 of the IVSG's proposed plan, including a 500 kV link to SDG&E, with the belief that it would provide significant benefits to the state. The Energy Commission further recommended that transmission development in the Imperial Valley should be carefully coordinated in order to avoid duplication, and to develop a transmission plan that serves the needs of both California and the West. The information presented below reflects the Energy Commission's recommendation on Phase 1 of the IVSG development plan.

An outgrowth of the IVSG plan, the Imperial Irrigation District (IID) developed a four-phased plan that also was detailed in the Energy Commission's November 2005 study. The IID plan has continued to evolve since IID discussed it at an Energy Commission Workshop in April 2005. In November 2005, IID and the Los Angeles Department of Water and Power (LADWP) announced a partnership between them and Citizens Energy (Citizens) to construct the Green Path Coordinated Projects. In January 2006, Citizens filed an application with the California Independent System Operator (CA ISO) for consideration to become a financial participant in transmission facilities. In the application, the definition of the project was expanded to include the Greenpath Project – Southwest and the CAISO Extension Project.

3. Expected and/or needed date of commercial operation: The project could be operational by the end of 2010 if permitting work begins during 2007.

4. Termination 1 – location of one end point of associated facility upgrades: Highline Substation

5. Termination 2 – location of other end point of associated facility upgrades: El Centro Substation

6. Characterization of other available routing information: Phase 1 will consist of constructing the Highline to El Centro 230 kV double circuit line and associated substation facilities.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): Phase 1 consists of upgrades of the IID system and a 500 kV line to export power from the IV to San Diego. IID system upgrades include facilities anticipated to deliver power from the existing Midway 230 kV Substation to the existing IV 230 kV Substation. An existing double circuit (161 kV and 92 kV) transmission line between IID's Highline and El Centro Substations would be upgraded to double circuit 230 kV by utilizing existing towers insulated to 230 kV, and higher strength (ACSS, ACCC or equivalent) conductors to minimize clearance issues under emergency conditions. The existing El Centro to IV 230 kV line would be upgraded to double circuit 230 kV, with each circuit capable of a maximum of 800 MW capacity. The upgrade to this transmission line will require that IID first construct the proposed IV to Dixieland 230 kV line to provide a path for Palo Verde area schedules (i.e., SWPL rights) to be delivered to IID loads. The IV-to-San Diego 500 kV line will also be constructed.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: would provide access to valuable renewable resources needed to meet future load growth, support California's RPS goals and provide significant near-term reliability benefits to California.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.): The Energy Commission did not perform an independent assessment of production cost savings but relied on the work of the IVSG. The IVSG assessed transmission alternatives using Power Flow studies, stability and post-transient studies, production simulations, and production cost simulations.

The CA ISO performed production cost simulations to estimate the economic and physical performance of the final three configurations (alternatives) of the IVSG development plan. These simulations indicated that adding 2,200 MW of new geothermal generation and the associated transmission in each of the various alternatives reduces WECC annual production cost, and congestion, by significant amounts. Each of the project alternatives reduced the hours of transmission congestion across the WECC by, on average, 4400 hours/year, as the new transmission capacity supported greater power flows. Losses increased, because generation in the Imperial Valley displaced more expensive generation closer to load. Adding the renewable generation reduced the total variable cost of generation WECC-wide by more than $500 million/year.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate): These simulations performed by the CA ISO were designed to compare transmission alternatives, not to justify investment decisions. Since renewable generators have low marginal costs, adding them to the generation mix will displace higher cost resources, thus reducing system-wide production cost. The simulations performed, however, were not designed to produce a reliable forecast of the potential savings.

10. For a reliability analysis: N/A

10a. Describe the reliability benefits of the project: N/A

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): N/A

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. Phase 1 would allow exporting 645 MW of renewable resources out of the Imperial Valley by 2010.

Two alternatives were identified by IID during the IVSG work. Alternative A, for power flows from the Salton Sea geothermal field to the north, would entail upgrades to Path 42, increasing its export capability by 1000 MW (from 500 MW to 1600 MW of total transfer capability). Alternative B, for power flows from the Salton Sea geothermal field to the south and west, would entail upgrades of the existing lines from Highline substation to El Centro to Imperial Valley Substation, increasing the total transfer capability in that path to 1600 MW.

Alternative A would schedule new Imperial Valley flows across Path 42 to the CA ISO at the Devers Substation. Additional transfers through Devers to the west would be problematic. More than 5000 MW of new generation, located in both Arizona and California, is expected to flow to Devers; and much of this was already in the SCE interconnection queue at the time the IVSG plan was written. Also, as SCE was already developing a West of Devers upgrade plan, the SCE system cannot accept 645 MW at Devers Substation from the Imperial Valley. However, doing so would require further, large-scale upgrades of the SCE system in that region, such as a 500 kV tie from Devers to Valley, in addition to SCE's upgrade plan at that time. An export plan that relied on making Imperial Valley generation deliverable through Devers accordingly would risk delaying Imperial Valley development until a regional plan for resolving west of Devers issues was identified and approved. This alternative also required that the existing El Centro – Bannister 161 kV line be upgraded to 230 kV.

Alternative B would minimize Imperial Valley flows at Devers. Alternative B accommodates the export of at least 645 MW in Phase 1, with cost-effective upgrades of existing IID lines in that routing.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? Not at the time of the IVSG development plan.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? No.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: Although presented but not recommended in the Energy Commission's *Strategic Plan*, Phases 2 through 4, or their equivalent, would also need to be completed in order to access fully the renewable resources in the Imperial Valley. Phase 2 would upgrade the southern portion of IID's network and its connection with the Arizona Public Service (APS). This would allow delivery of an additional 600 MW of geothermal generation and could be completed by 2016. Phase 3, a long-term solution, consists of a new 500 kV Sunrise Powerlink – San Felipe Substation connected to IID's Bannister Substation via a new 500 kV transmission line that would bring the total export capacity to approximately 2000 MW. Phase 4 would bring the overall export capability to over 2000 MW by upgrading the interconnection between IID and the Western Area Power Authority.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: No projects have been specifically identified that would likely displace Phase 1 of the IVSG. However, since the Energy Commission's *Strategic Plan* was issued in November 2005, SDG&E has filed a permitting application with the California Public Utilities Commission for its Sunrise Powerlink Project. The Nevada Hydro Company's Lake Elsinore Advanced Pumped Storage Project ("LEAPS"), that includes a proposed 500 kV transmission line, is currently undergoing review at the Federal Energy Regulatory Commission.

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? The Energy Commission has not formally reviewed this project since November 2005. The developments of this project along with competing projects previously discussed continue to evolve. The Energy Commission anticipates successful resolution of the various issues so that power from the renewable resources in the Imperial Valley will be available before 2015.

Part II.E: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): Trans Bay DC Cable Project

2. Description of issue(s) the project will address: reliability and retirement of aging generating units in the San Francisco Peninsula area

3. Expected and/or needed date of commercial operation: Although the project is not needed for reliability purposes until 2012, the Energy Commission agrees with the California Independent System Operator's (CA ISO's) assessment that the project's expected in-service date of 2009 provides insurance benefits that exceed the net cost to CA ISO ratepayers of the advanced in-service date.

4. Termination 1 – location of one end point of associated facility upgrades: Pittsburg Substation in the City of Pittsburg, California

5. Termination 2 – location of other end point of associated facility upgrades: Potrero Substation in San Francisco, California

6. Characterization of other available routing information: No other routing options are described in the Strategic Plan.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): New +/- 400 kV, 400 MW, 50+ mile-long high-voltage direct current (HVDC) submarine cable from Pittsburg Substation to Potrero Substation, plus associated substation modifications and new converter stations at the Pittsburg and Potrero Substations. Most of the route would be under the Suisun, San Pablo, and San Francisco Bays, with the rest of the line (a few hundred yards at either end) buried underground.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: The project would help ensure reliability through 2015, serve growing loads in the City of San Francisco, take advantage of excess generation capacity in the Pittsburg area, and hasten the retirement of aging generators in the San Francisco Peninsula area by providing 400 MW of new import capability into downtown San Francisco. It will also help eliminate the need for reliability must-run contracts at the Hunters Point and Potrero Power Plants.

9. For a production cost analysis: N/A

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.): N/A

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate): N/A

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: The Energy Commission did not provide an independent assessment of the reliability benefits of the project, but instead relied upon the analysis performed by the San Francisco Stakeholder Group. In its November 14, 2005 final report entitled *San Francisco Peninsula Phase 2 Long-Term Electric Transmission Planning Technical Study*, the group determined that the preferred long-term reliable load-serving capability option for the San Francisco area is the Trans Bay DC Cable Project. As noted earlier, the project is needed to mitigate violation of reliability planning standards beginning in 2012.

With respect to the project's expected in-service date of 2009 (three years in advance of reliability need), the CA ISO's economic analysis concluded that there would be a net cost to CA ISO ratepayers of $26 million. The CA ISO concluded that this net cost is an acceptable "assurance cost" against intangible benefits such as immediate increased reliability to the San Francisco area, unforeseen load forecast errors, and project siting, schedule, and cost risks. The Energy Commission agrees with the CA ISO's assessment and therefore recommends the project for a 2009 in-service date.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): N/A

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. N/A

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? N/A

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? N/A

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: This project takes advantage of existing excess generation capacity available at the Pittsburg Substation.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: As noted earlier, this project will help enable the aging Potrero and Hunters Point Power Plant generating units to be retired.

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? On May 19, 2005 the Trans Bay Cable LLC filed with the FERC an Operating Memorandum among Trans Bay, the City of Pittsburg, and the Pittsburg Power Company. FERC issued an Order Accepting Operating Memorandum on July 22, 2005. The CA ISO Board of Governors approved the project on September 8, 2005. On January 13, 2006 Trans Bay Cable LLC filed an application to become a CA ISO participating transmission owner entity, turning transmission facility operational control over to the CA ISO, and executing the Transmission Control Agreement. It is likely that the project can be operational in 2009.

<u>Imperial Valley – San Felipe 500kV Transmission Project</u>

Part I. Characterization of the Study

Though not a part of the California Energy Commission's Strategic Transmission Investment Plan, refer to Part I. of the CEC's Template on page 65 of this Template Report for general background information on related projects (Sunshine Power Link Project and Imperial Valley Upgrade Project.)

Information on IID's proposed Imperial Valley – San Felipe 500 kV Transmission Project can be obtained by contacting David Barajas, General Superintendent, System Planning and Engineering, Imperial Irrigation District, phone (760) 482-3450, email dlbarajas@IID.com.

Part II. Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): Imperial Valley – San Felipe 500 kV Transmission Project

2. Description of issue(s) the project will address: congestion reduction, increased deliverability of renewable resources in the Imperial Valley.

3. Expected and/or needed date of commercial operation: December 2010 or earlier depending on coordination with SDG&E and CAISO.

4. Termination 1 – location of one end point of associated facility upgrades: Imperial Valley Substation (near El Centro, CA)

5. Termination 2 – location of other end point of associated facility upgrades: SDG&E Proposed Central Substation in Southern California, with an intermediate substation at the IID proposed San Felipe 500/230kV substation.

6. Characterization of other available routing information: Substantially follows the existing IID rights-of-way to San Felipe and Narrows.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): A component of the IID and LADWP Green Path Coordinated Project to be integrated with the IID internal upgrades to 230kV. This Project should also help to eliminate the need for the existing remedial action schemes installed as part of the Mexicali area generation projects.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc:
Imperial Irrigation District ("IID") currently utilizes 540 miles of high voltage transmission system (161kV and 230kV) to deliver the bulk power deliveries received from external (i.e. Palo Verde, Parker-Davis, and San Juan) and internal (i.e. El Centro) resources to bulk receiving stations located around the IID service territory. The majority of the transmission system (310 miles) is currently operated at a voltage of 161kV. The 161kV transmission system was originally built in approximately 1930 as part of the expansion of the Western Area Power Administration transmission system to deliver power for the regional irrigation districts from the Parker-Davis generating facilities. This system has helped to meet the load serving requirements for IID for over 50 years. However, as the load continued to grow in all regions of the IID territory, the need and plans to upgrade this transmission system has been reviewed for several years. The existing system has recently experienced additional stresses due to generating resources constructed near the edge of the IID service territory (i.e. Blythe and IV/Mexico generation). While IID continues to manage these additional unscheduled flows at the operations level, IID continues to experience additional losses and reductions in voltage profile as this system continues to be stressed.

In the 1983, a new 230kV, double circuit transmission system was constructed for the primary purpose of delivering over 500MW of "power generating facilities" (a.k.a. PGF resources, mostly consisting of renewable resources) contracted to Southern California Edison ("SCE"). Over the last several years IID has continually integrated the 230kV system into the IID transmission network capable of delivering the contractual obligations and to meet the load serving requirements of the IID control area.

Over the last few years, IID has reviewed and developed detailed long-term (defined as a minimum of ten years) transmission plans that would meet the load serving requirements of IID. The plans primarily have focused on the upgrades of the 161kV system to 230kV and to fully integrate the existing 230kV transmission in to a single 230kV transmission network. These transmission upgrades and improvements to increase the import capability together will increase the reliability (and voltage profile) and the ability for IID to meet its load serving needs for at least the next 20 years.

With California's interest and mandates in renewable resources, interest in Imperial Valley area renewables (both geothermal and solar) has substantially increased. In October 2004, the California Energy Commission and IID concluded that a long-term transmission study effort should be initiated to determine transmission issues related to delivering over 2000MW of additional renewable resources out of the Imperial Valley. This effort is known as the Imperial Valley Study Group ("IVSG"). With the completion of the IVSG effort coming to an end, it was clear that the proposed IID long-term transmission needs of both IID for load serving and to deliver over 2000MW of new renewable resources to the IID interconnection points with adjacent transmission systems would be a viable project for IID. While the development of the renewable resources has been slow due to execution of power purchase contracts with the regional load serving utilities, IID will continue to move forward with the long-term transmission plans and accelerate segments to facilitate additional resource deliveries and reinforce the reliability requirements to serve IID customers. The internal transmission expansion and upgrades are now known as the Green Path Project.

The IID Green Path Project originally only included internal the long-term plan upgrades of approximately 100 miles of 161kV transmission to 230kV, and to upgrade approximately 90 miles of existing 230kV to the long-term capacity requirements (double circuit, etc.). The remaining 161kV upgrades toward Blythe and Yuma will continued to be reviewed as other projects drive these upgrades and the need for additional import from these interconnection points. In November 2005, the IID Board approved Phase 1 (environmental, permitting, preliminary engineering, etc.) of the IID Green Path Project transmission expansion plan and is scheduled for completion by December 2006.

A critical component of the IVSG analysis and integrated as a component of the IID Green Path Project transmission expansion plans is the addition of a new 500kV line from the Imperial Valley ("IV") substation to a new substation located within the SDG&E load center. The IVSG analysis concluded that the most critical contingency impacting the region under the various resource scenarios is the loss of the existing Imperial Valley – Miguel 500kV line. The IVSG analysis also concluded that an extension of the IID transmission expansion plan from the geothermal collector system, i.e. a 230kV line from the Bannister substation, to the IV – San Diego 500kV line at a proposed San Felipe 500/230kV substation would provide substantial reliability improvements to the existing system and a reliable delivery of renewable resources interconnected to the IID transmission system. IID has entered into discussions with Citizens Energy to fund the majority of the IV – San Felipe Project, and coordinate with the overall Green Path Project to reliably deliver renewable resources to not only the SDG&E transmission system

but to the California Independent System Operator ("CAISO") into the "SP15" market. IID has included this project and is additional included in the Green Path Coordinated Projects.

An additional critical component identified as a part of IVSG analysis and a critical substation identified as an import/export "gate" to the IID transmission system, is a new 500/230kV interconnection at the proposed Indian Hills substation. The Los Angeles Department of Water and Power ("LADWP") also approached IID to directly interconnect their respective transmission systems to provide a transmission path to LADWP for the purposes of delivering renewable resources to the LADWP loads. LADWP has proposed to construct a new 500kV line from their proposed Upland substation to Indian Hills, and possibly interconnect the Palo Verde – Devers 500kV #2 line at Indian Hills. IID and LADWP have included this project as another key component of the Green Path Coordinated Projects. LADWP has filed a Comprehensive Progress Report for the Indian Hills – Upland Project.

9. For a production cost analysis: N/A

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.):

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate):

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: The IVSG analysis, as well as a significant amount of other studies and real time operations, concluded that the most critical contingency impacting the region under the various resource scenarios is the loss of the existing Imperial Valley – Miguel 500kV line.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): The Imperial Valley – Miguel 500kV line contingency currently requires a remedial action scheme to limit overloads to the CFE and IID transmission systems. Also, SDG&E has demonstrated that having a single 500kV source for the amount of system growth and diversity continues to provide needed voltage support and reliability.

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. This Project is not expected to increase the capability of existing WECC path Ratings, however, the SDG&E import capability and the amount of access to renewable energy in the Imperial Valley Region will provide a minimum of 1000MW of additional capacity.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? Yes. The IV-SF Project is currently in the regional planning and WECC Three Phase Rating Process.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? Yes.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: LADWP Green Path Project and other related facilities into the northern part of the IID service territory (e.g. the proposed Indian Hills substation, etc.) and additional resources to meet the RPS standards established by the City of LA. These projects in coordination with the IID internal upgrades have been substantially reviewed to deliver over 2000MW of renewable resources to the region.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: This Project takes advantage of the SDG&E Sunrise Project and related facilities within the San Diego County. Absent the Sunrise Project, or displaced by generation resources, the IV-SF Project would more than likely not be constructed as currently envisioned.

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? IID expects to work this in parallel with the SDG&E Sunrise Project and "work from each end" to meet at the proposed San Felipe substation. The SDG&E Sunrise Project has been filed with the CPUC for the first component of the CPCN process. IID has been working with the appropriate entities to proceed with the financing and environmental processes to meet the same schedule as the Sunrise Project. The expected in-service date of the Project is no later than December 2010.

Tehachapi Wind Transmission Study

Part I: Characterization of the Study:

1. What was the name of the study? Transmission in the Tehachapi Wind Resource Area

2. Provide the title(s) and completion dates of available report(s) regarding the study: Report of the Tehachapi Collaborative Study Group (March 16, 2005)

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): http://www.cpuc.ca.gov/Published/Graphics/48819.PDF

4. Provide a contact person to obtain project details: name, phone, email: Jorge Chacon via phone at (626) 302-9637 or e-mail at Jorge.Chacon@sce.com

5. What was the purpose of the study (e.g., what problem was the study intended to address)? The conceptual study identify conceptual transmission facilities needed to connect approximately 4000 MW of new wind generation in order to help California meet its legislatively mandated RPS goals.

6. Provide a brief summary description characterizing the study: The Study purpose is to identify conceptual transmission facilities needed connect approximately 4000 MW of wind generation in the Tehachapi region. The facilities identified include three high capacity 500 kV transmission lines connecting one central substation in the Tehachapi region to existing substations on the backbone grid. When the plan is completed, each of these lines will be able to carry approximately 1500 MW, one-third of the total. In addition, each phase requires additional infrastructure, such as substations, upgrades of existing lines and ancillary transmission equipment.

In addition to the infrastructure required simply to connect Tehachapi generation to the grid, other transmission facilities will be needed to relieve congestion and enable this power to reach load centers. This report describes alternatives for network upgrades with the understanding that further analysis is required to determine which projects are most cost effective and when they are needed.

7. What was the geography of the study? The geography covers Northern Los Angeles and Kern County collectively referred to as Tehachapi

8. What was the study period? 2010

9. Describe the study type (such as who initiated the study and why): Transmission constraints into the Tehachapi area have been discussed as part of Assembly Bill (AB) 970 and Investigation 00-11-001 with Phase 6 of the proceeding devoted to Tehachapi. The outcome of AB 970 Phase 6 an Interim Opinion on Transmission Needs in the Tehachapi Wind Resource Area which orders (CPUC Decision 04-06-010) the formation of a collaborative study group convened to develop a comprehensive transmission development plan for the phased expansion of transmission capabilities into the Tehachapi area.

10. Characterize the study participants: CAISO, IOUs, Wind Power developers and other Stakeholders

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: SCE utilized the latest heavy summer and light spring power flow cases developed for the 2004-2008, 2013 CAISO assessment recently completed. PG&E utilized the latest heavy summer light autumn power flow cases. For purposes of the plan power flow will be half north and half south.

12. What criteria and metrics did the study use when defining congestion and a solution (Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings)? The production cost modeling will be described and estimated costs of transmission facilities will be contained in the next available report expected in April, 2006.

13. Congestion identified: The CAISO is responsible for quantifying any additional congestion exposure on Path 26, Path 15 and other parts of the CAISO grid as a result of either connecting the Southern California Edison system with the PG&E system, delievering Tehachapi Area Wind Generation to SDG&E, or delivering Tehachapi Area Wind generation to PG&E.

14. Were non-transmission alternatives compared with transmission alternatives? No.

15. Were new transmission technologies considered? No

16. Describe the six most important study assumptions (e.g. fixed hydro dispatch) : Study assumptions will be documented in the April, 2006 report.

1) Load Assumptions

2) Generation Assumptions

3) Imports to SCE

4) Imports to PG&E

5) Generation Displacement

6)Other assumptions

a. The Tehachapi Comprehensive Transmission Development Assessment will comply with the CAISO Grid Planning Standards, which incorporate the NERC/WECC Planning Standards.

b. Existing or proposed special protection schemes in the Big Creek Corridor will be operational.

c. Comply with the CAISO guidelines on the use of Special Protection Schemes to integrated Tehachapi area generation. In particular, limit the tripping of generation to 1,150 MW for the loss of one transmission line and 1,400 MW for the loss of two transmission lines.

d. Major Path Flows will be modeled at reasonable and expected patterns.

e. For the long-term, include the generation projects identified by the CEC.

f. The existing Path 15 RAS and Path 26 RAS will be modeled in the studies.

17. For each of the following, describe the assumptions made (if applicable):

a. Gas Price (indicate base year and units):

Average monthly fuel (Gas, Coal, Uranium) prices for generation plants were forecasted for 2008. The prices were adjusted to account for the cost of delivering the fuel to the generation plant. Detailed description of SSG-WI fuel pricing assumptions is available at http://www.ssg-wi.com/documents/.

b. Year(s) studies:

Power flow studies were for 2004-2008, 2013 respectively. The TCSG report covers the planning beginning 2004 to final construction of the projects in 2010.

c. Load shapes (year and/or source):

Peak summer load conditions for SCE or PG&E will represent maximum anticipated loads based on a coincident load forecast, which will include consideration of a one-in-ten-year heat wave. Three cases will be used to represent coincident Control Area Peak, Northern California Peak and Southern California Peak.

d. Powerflow database case source(s):

PG&E and Edison utilized the latest heavy summer and light spring power flow cases developed for the 2004-2008, 2013 Annual CAISO Assessment recently completed.

<u>Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:</u>

1. Characterization of the project (name): Tehachapi Phase1
Tehachapi Phase 1 Segment 1 - Antelope to Pardee Transmission Line 500 kV (Initially Operated at 230 kV) including Antelope Substation Expansion to 500 kV Capability.
Tehachapi Phase 1 Segment 2 - Antelope to Vincent Transmission Line 500 kV (Initially Operated at 230 kV).
Tehachapi Phase 1 Segment 3 - A 230 kV Transmission Line will operate between Tehachapi substations 1 & 2 and a 500 kV line will operate between Tehachapi Substation 1 and Antelope Substation.

2. Description of issue(s) the project will address:
Additional Transmission Capacity for Wind Generation

3. Expected and/or needed date of commercial operation: 2010

4. Termination 1 – location of one end point of associated facility upgrades:
Segment 1 Antelope
Segment 2 Antelope
Segment 3 Antelope

5. Termination 2 – location of other end point of associated facility upgrades:
Segment 1 Pardee
Segment 2 Vincent
Segment 3 Tehachapi

6. Characterization of other available routing information: Several ROWs are being evaluated.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, etc.): Add lines.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: Wind Generation Integration

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.): Pending anticipated March 2006 updated TCSG report.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate): 207 million for all three segments of Phase 1 2005 $

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: Additional Capacity

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): Contingency evaluation will include selective single contingencies (e.g. loss of a transmission line, generating unit, or transformer bank) and selective multiple-contingencies (e.g. overlapping outage of two transmission lines), consistent with the CAISO Grid Planning Criteria. To the extent that thermal ratings during normal or contingencies are identified on either the SCE or PG&E systems corrective action will be taken by the responsible PTO.

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. Existing lines were operated at 66 kV and are not in the WECC Path Rating Catalog. The project will not increase transfer capability of existing path(s) from the WECC Path Rating Catalog.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? No, initail project (Antelope Transmission Project) does not require WECC regional planning process and/or the WECC Three Phase Rating Process. Future transmission needed to accommodate new wind generation beyond 700 MW may require undertaking the WECC regional planning process and/or the WECC Three Phase Rating Process.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? The System Impact Study of the first wind generation project triggering need for new Antelope-Pardee 500 kV transmission line has been submitted to the WECC as a progress report,

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: All three Segments of Phase 1 are interelated. In addition the all three future Phases in the TCSG are interelated order to complete the 4000 MW that are needed.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: None

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? Phase 1 is in the permitting and review stage. Assuming approval is provided by the CPUC, the project will be completed by 2015.

Canada to Northwest Intertie Expansion

Part I: Characterization of the Study:

1. What was the name of the study? Canada to Northwest Intertie Expansion

2. Provide the title(s) and completion dates of available report(s) regarding the study: Ongoing

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): This is an internal BC Transmission Corportation study which is still in progress

4. Provide a contact person to obtain study details: name, phone, email: Ron Sanderson, 604-699-7445, ron.sanderson@bctc.com

5. What was the purpose of the study (e.g., what problem was the study intended to address)? The purpose of this study is to determine, among three possible routing options, the most suitable, economic and strategic transmission corridor for capacity expansion between British Columbia and Washington State to facilitate electricity trade and resource sharing throughout the Pacific Northwest region.

6. Provide a brief summary description characterizing the study: The study is to evaluate the present and future electricity trade between Alberta, British Columbia and the United States depending upon present resource sharing and future generation development potential to provide the economic and reliability justifications for a potential expansion of transmission capacity directly between British Columbia and Washington State. This potential expansion is viewed as highly dependent upon related developments that are already underway in Alberta and proposed within Washington, Oregon and California. Due to the highly interdependent nature of the necessary transmission expansions required to move electricity from Alberta to California, this study takes a broad regional perspective It is likely that the present characterization of the BC to US intertie by existing electricy flows does not sufficiently illustrate the prospects for expanded trade. Significant levels of transmission congestion on the Alberta to BC and the North of John Day cutplane within the Bonneville Power Authority service region restrict the full utilization of the BC to US intertie.

7. What was the geography of the study? The footprint of this study generally covers Alberta, British Columbia, Washington, Oregon and Northern California.

8. What was the study period? The study looks to 2014 and beyond as a key milestone for the absorption of present BC-US intertie capacity and significant generation additions in both Alberta and British Columbia.

9. Describe the study type (such as who initiated the study and why): BC Transmission has initiated this study to estimate the trade and economic impacts of a range of transmission expansion levels and transmission paths.

10. Characterize the study participants: Only British Columbia Transmission Corportation

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: Transmission usage levels are forecast on each critical transmission path within BC Transmission's service region and a variety of future regional resource and load forecast scenarios have been modeled. The magnitude of the problem will be measured by the economic cost of restricted electricity trade flows that impact upon BCTC's service region.

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. Economic electricity trade flows will be modelled according to present trade strategies using high-load-hour and low-low-hour price differentials and seasonal price differentials at the Mid-Columbia and California-Oregon Border trading hubs. Congestion will be measured by the difference between "ideal" and actual economic trade flows.

13. Congestion identified: It has not yet been measured

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives. None.

15. Describe new transmission technologies (if any) that were considered. None.

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation): Existing hydro generation dispatch, customer load shapes and seasonal trade flows will be maintained in this study. The most important assumption will be the forecast natural gas price scenarios.

17. For each of the following, describe the assumptions made (if applicable) :

a. **Gas price (indicate base year and units):** Price has not yet been determined.
b. **Year(s) studied:** 2012, 2014, 2016, 2018
c. **Load shapes (year and/or source):** 2005
d. **Powerflow data base case source(s):** Not applicable

Protecting and Managing an Increasingly Congested Transmission System BPA Report

Part I: Characterization of the Study:

1. What was the name of the study? Protecting and managing an increasingly congested transmission system

2. Provide the title(s) and completion dates of available report(s) regarding the study: April 10, 2006

3. Provide the details regarding how to obtain any available reports (Web address if available on internet):
http://www.bpa.gov/corporate/pubs/Congestion_White_Paper_April06.pdf

4. Provide a contact person to obtain study details: name, phone, email: Marv Landauer, 503-230-4105, mjlandauer@bpa.gov

5. What was the purpose of the study (e.g., what problem was the study intended to address)? The purpose of this study was to explore what is causing the current congestion problems on the BPA system and options for dealing with it.

6. Provide a brief summary description characterizing the study: Included in Appenidix A of the paper is a listing of the OTC exceedances and dispatcher actions that occurred on three internal BPA paths in August 2005. These data show the number and extent of the path rating exceedances along with the time and extent of the dispatcher actions taken to relieve the exceedance.

7. What was the geography of the study? The paper was written to describe the operation of the BPA transmission system. The three specific paths listed and described in this paper are in Washington and NW Oregon. The paths are Paul-Allston, South of Allston (WECC Path #71) and North of Hanford.

8. What was the study period? August 2005

9. Describe the study type (such as who initiated the study and why): BPA initiated this study with the hopes that the issues raised in this paper would stimulate regional discussion.

10. Characterize the study participants: Internal BPA personnel.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: Number of flow excursions above path OTC and the dispatcher actions required to return the system to acceptable limits within 30 minutes.

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. The study used SCADA data as measured against posted path OTC, and recorded an "excursion" event when that situation persisted for 5 minutes. No other criteria other than quantifying the number of exceedances and the dispatcher actions needed to return the system to acceptable limits within 30 minutes.

13. Congestion identified: Congestion was not measured. Twenty events required dispatcher action during the month in question. Although this is the worst month of the year for these types of events, this amount of congestion is considered by BPA to be significant.

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives. Not applicable for this type of analysis.

15. Describe new transmission technologies (if any) that were considered. Not applicable for this type of analysis.

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation): Not applicable. This is not a "study", rather an analysis of historical data.

17. For each of the following, describe the assumptions made (if applicable) :

a. **Gas price (indicate base year and units):** Not applicable.
b. **Year(s) studied:** Not applicable.
c. **Load shapes (year and/or source):** Not applicable.
d. **Powerflow database case source(s):** Not applicable.

Part II is not applicable to this study.

Review of WECC Coordinated Phase Shifter Operation
2001 to 2005

Part I: Characterization of the Study:

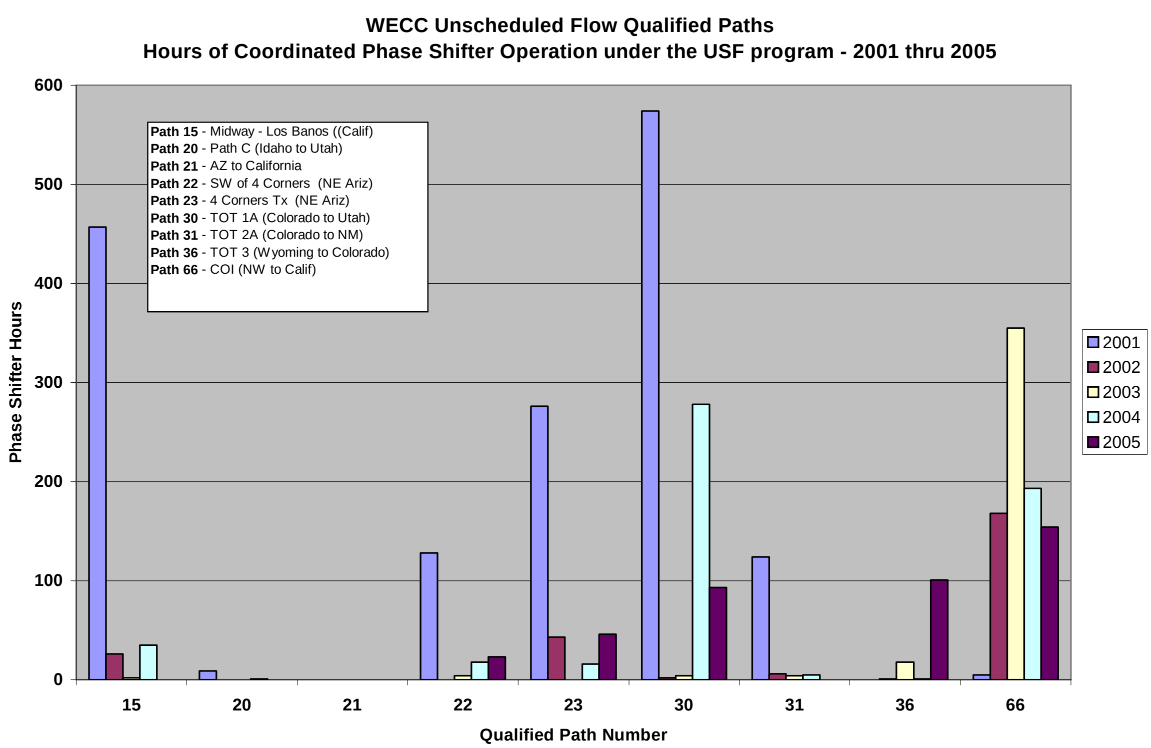
1. What was the name of the study? Review of WECC Coordinated Phase Shifter Operation - 2001 to 2005

2. Provide the title(s) and completion dates of available report(s) regarding the study: This work is part of an ongoing effort and annual review. No reports have been published.

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): Information on the WECC Unscheduled Flow (USF) Mitigation Plan can be obtained from the WECC web site at www.wecc.biz.

4. Provide a contact person to obtain study details: name, phone, email: Steve Ashbaker, 801-582-0353, Email - ashbaker@wecc.biz

5. What was the purpose of the study (e.g., what problem was the study intended to address)? Purpose of the study was to review and summarize operating experience with the coordinated phase shifter operation under the USF program, for use in identifying constraints areas within the Western Interconnection.



6. Provide a brief summary description characterizing the study: Results of the review of coordinated phase shifter operation in WECC under the USF program are presented in the above chart. The number of hours of coordinated phase shifter operation each year is dependent upon seasonal variations, such as resource availability, hydro conditions, fuel prices, etc. and can vary substantially from year to year. Construction of new facilities within the interconnection also impacts unscheduled flow and the impact of unscheduled flow on Qualified Paths. Paths identified as "Qualified Paths" can be considered constraint areas within the WECC interconnected system.

The hours of phase shifter operation reported in the above chart does not include those hours the phase shifters may be operated independently by phase shifter owners to relieve overloads on those paths that are not currently considered WECC "Qualified Paths" since this data is not collected in the USF Log.

7. What was the geography of the study? The Western Interconnection

8. What was the study period? 2001 to 2005

9. Describe the study type (such as who initiated the study and why): The USF program for coordinated operation of phase shifters was initiated 11 years ago as a means to control unscheduled flow within the western interconnected system. Performance of the program is reviewed annually.

10. Characterize the study participants: WECC members

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: The number of Hours for which coordinated operation of phase shifters was called upon for to relieve overloads due to unscheduled flow are reported and analyzed. Also reported are the number of hours when schedule curtailments were required to relieve overloads because phase shifters were no longer effecive in reducing path flows below path limits.

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. Hours of coordinated phase shifter operation as requested by qualified path operators to relieve path overloads.

13. Congestion identified: Paths must qualify to participate in the program, based upon the number of curtailment hours experienced. Those paths that are currently qualified are:
Path 15 - Midway - Los Banos (California)
Path 20 - Path C (Idaho to Utah)

Path 21 - AZ to California
Path 22 - SW of 4 Corners (NE Arizona)
Path 23 - 4 Corners Transformer (NE Arizona)
Path 30 - TOT 1A (Colorado to Utah)
Path 31 - TOT 2A (Colorado to New Mexico)
Path 36 - TOT 3 (Wyoming to Colorado)
Path 66 - COI (NW to California)

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives. Not Applicable

15. Describe new transmission technologies (if any) that were considered. Not Applicable

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation): Not Applicable

17. For each of the following, describe the assumptions made (if applicable) :

a. **Gas price (indicate base year and units):** Not Applicable
b. **Year(s) studied:** 2001 to 2005
c. **Load shapes (year and/or source):** Not Applicable
d. **Powerflow data base case source(s):** Not Applicable

Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): Part II is not applicable to this study

Lake Elsinore Advanced Pump Storage (LEAPS) and Talega – Escondido / Valley – Serrano (TE-VS) Transmission Line Projects

Part I: Characterization of the Study:

1. What was the name of the study? CAISO Staff Memorandum and Reliability Determination, CPUC Alternative Report, STEP Reliability Report, CEC STIP Report, USE Phase I and Phase II Report, FERC Reliability Determination

2. Provide the title(s) and completion dates of available report(s) regarding the study:

a) CAISO Staff Memorandum March 23, 2001, and Board Resolution March 30, 2001
b) CPUC Alternative Report November 2002
c) STEP Kyei Report from CAISO 2003
d) CEC STIP Report July 30, 2004
e) FERC Need Determination P-11858-002 Feburary 2006

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): All reports are availible on-line through the CAISO, CPUC, CEC and FERC Web Sites.

4. Provide a contact person to obtain study details: name, phone, email:
a) Contact Information: The Nevada Hydro Company, 2416 Cades Way, Vista CA 92081, Phone 760.599.0086, FAX 760.599.1815, rwait@controltechnology.org

5. What was the purpose of the study (e.g., what problem was the study intended to address)?

a) CAISO Board of Governors Reliability Determination for a new 500 kV transmission line into northern San Diego and non-wires alternative.

b) CPUC Alternative Report for the Valley-Rainbow 500 kV Transmission Project, showing the LEAPS project and the TE/VS 500 kV Transmission as electrically identical to the Valley-Rainbow Project, and therefore provide the same grid benefits.

c) CAISO/STEP Report for a 500 kV line into San Diego for reliability. Staff concluded that the LEAPS project would provide a higher import capability into San Diego than ISEP, (now Sunrise Power link). In addition they modeled various combinations of project elements to determine optimum configurations.

d) CEC Report for 2004 Strategic Transmission Investment Plan and determined that the LEAPS project may perform better than the former ISEP project, (now Sunrise Power link).

e) FERC P-11858-002 Draft EIS Needs Determination EIS 0191D, Appendix A and B. This document provides a Federal Determination of Need for the 500 MW LEAPS project and TE/VS 500 kV Transmission System for congestion.

6. Provide a brief summary description characterizing the study:

a) On March 30, 2001 the CAISO Board of Governors issued a resolution stating a finding of the Board of Governors. Under the resolution, the Board: finds that a 500 kV Project such as the Valley-Rainbow project, is needed (without selecting a prefered near-term alternative and without reguard for routing) to address the identified reliability concerns of San Diego and South Orange county portion of the ISO grid beginning 2004.

b) On November 2002 the CPUC performed an alternatives report at the close of the Valley-Rainbow project. In this report the LEAPS project and TE/VS 500 kV Transmission System were identified as electrically the same or similar to the Valley-Rainbow project, also providing the same grid benefits.

c) In 2004 the CAISO and STEP Study Group investigated the relative reliability of several transmission options of increasing import capability into San Diego. Staff acknowledged the need for an increase in San Diego import capability which is currently at 2850 MW. Staff then concluded that the LEAPS project would provide for a significant increase in San Diego import capability alone to 3600 MW. When combined with ISEP, (now Sunrise Powerlink) would further raise import to 3800 MW.

d) On July 30, 2004 the CEC issued a Stategic Transmission Investment Plan. In this plan they determine that a 500 kV line from SCE to northern San Diego would improve reliability of the states transmission system and increase the states overall ability to import lower-cost power from Arizona and Mexico.

e) The FERC on Febuary 2006 issued a Federal Draft EIS on the LEAPS project and TE/VS 500 kV Transmission System. The FERC project number is P-11858-002 and the EIS is issued as EIS-0191D. In this extensive report the FERC staff made a Need Determination. The following Federal Determination was made: Based on our review of available documentation, it appears that the TE/VS transmission line interconnection between the SCE and SDGE transmission systems would be an appropriate long-term solution to southern California's transmission congestion bottlenecks as well as the transmission-constrained, generation-deficient San Diego area. The TE/VS transmission line could provide 1000 MW of import capability into the San Diego area with up to 500 MW of this import being supplied by the LEAPS project during high-demand periods. This review by FERC staff is the highest level of evaluation that any project can undergo in the United States.

7. What was the geography of the study? California, Arizona and Mexico

8. What was the study period? The report study periods are specific to the report and agency.

9. Describe the study type (such as who initiated the study and why): The studies and reports were initiated independently by the California System Operator, California Energy Commission, Southwest Transmission Expansion Plan, the California Public Utilities Commission, and the Federal Energy Regulatory Commission.

10. Characterize the study participants: State and Federal agencies, IOU's, IPP's and Market Participants.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: Power flow analysis was used to compare the performance of a multitude of generation and transmission scenarios.

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. WECC and NERC reliability criteria and transfer capability.

13. Congestion identified: Overload of the San Diego transmission system, and import capability into San Diego.

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives. The LEAPS project provides both wires and non-wires alternatives. The LEAPS project provides 500 MW of advanced pumped storage including all ancilliary services, and stores 6000 MWH of renewable energy. The ramp rate of dispatch is 500 MW in 15 seconds. It will likely be the highest and most efficient facility in the Continental US. Current studies underway suggest that the TE/VS 500 kV transmission system may increase import levels up to 1000 MW into the northern San Diego system.

15. Describe new transmission technologies (if any) that were considered. The LEAPS project qualifies under the Energy Policy Act of 2005 as Advanced Transmission Technology, an Energy Storage-Pumped Storage Facility, under Section 1223, sub-section #11. This project also qualifies under sub-sections #2, #3, #12, #16 and #17.

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation):

a) Generation and Transmission location
b) California de-regulation issues
c) Load growth
d) Regionally best solution, in-service date, and lower cost than other alternatives, (better mouse trap) i.e. faster, better, lower cost.

e) Shaping and storage of renewable energy supplies.
f) Offsetting very, very high RMR costs due to congestion.

17. For each of the following, describe the assumptions made (if applicable) :
Gas price (indicate base year and units): N/A
Year(s) studied: Varies with report and agency
Load shapes (year and/or source): N/A
Power flow database case source(s): Varies with report and agency

Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): LEAPS project and TE/VS 500 kV Transmission System.

1a. Provide a contact person to obtain project details (if different from study). Provide name and contact for more than one person if appropriate: name, phone, email:

2. Description of issue(s) the project will address: To maintain reliability, promote store, and shape renewable energy supplies, provide ancillary services, reduce localized emissions and reduce state energy costs.

3. Expected and/or needed date of commercial operation: TE/VS 500 kV transmission system commercial operation very late 2007. The 500 MW LEAPS project commercial operation late 2009. The regional need varies with report. The CAISO decision in 2001, states need in 2004, later CPUC decision 2007, and Sunrise Power link publishes 2010.

4. Termination 1 – location of one end point of associated facility upgrades: The project will connect north in a new substation called Lee Lake between Valley and Serrano Substations at 500 kV in SCE service territory.

5. Termination 2 – location of other end point of associated facility upgrades: The project will terminate south in a new substation called Case Springs between Escondido and Talega Substations at 500/230 kV with flow control. This substation is located in SDGE service territory.

6. Characterization of other available routing information: See FERC draft EIS for details and routing. It is filed under FERC P-11858-002 and DEIS 0191D. The project is located north to south in the Cleveland National Forest, Trabuco Ranger District, approximately 30 statute miles at 500 kV. Also requires re-conductor upgrades of the Talega/Escondido 230 kV SDGE transmission lines.

7. Characterization of the system changes envisioned (i.e. add line, re-conductor line, upgrade series capacitors, add transformer, revise remedial action, include details including number of added lines, voltage category): Impacts are upgrades and are required to both SCE and SDGE systems. See system impact studies for details.

8. Characterize Project justification – load service, generation integration, diversity exchange, other. Include details of what type generation, location of load, etc: The LEAPS project and TE/VS 500 kV Transmission System will import 1000 MW, provide ancillary services, store and shape 6000 MWH of renewable supplies. See various reports and determinations for details.

9. For a production cost analysis:

9a. Indicate the estimated annual production cost savings realized from the project and the basis (i.e. 2005 dollars, assumed escalation rate, fuel costs, etc.): Varies with report and agency. The applicant is currently using $ 200 million per year in reduced energy costs.

9b. Provide the estimated project capital cost and the basis for the cost estimate (i.e. 2005 dollars, assumed escalation rate): The combined project is estimated just under one billion in 2006 dollars.

10. For a reliability analysis:

10a. Describe the reliability benefits of the project: The LEAPS project and TE/VS 500 kV Transmission System will provide reliability benefits in late 2007. It will also provide additional import into San Diego of 1000 MW. In late 2009 it will provide ancillary services and 6000 MWH of renewable storage and shaping. It will help with outages at SONGS, and provide much needed stability and reliability.

10b. List the limiting outage and/or element in determining the associated transfer capability. Also list the limiting performance (i.e. voltage dip, overload, etc): Heavy Summer Critical Contingency, IV-Miguel or Devers-Valley.

11. If this project will increase the transfer capability of existing path(s) from the WECC Path Rating Catalog, list the path(s), and the estimated transfer capabilities before and after the added project. Raise San Diego import capacity from 2850 MW to approximately 4000 MW.

12. Is this project going through the WECC regional planning process and/or the WECC Three Phase Rating Process? Yes, through Phase I.

13. Is this project included in the most recent submittals of WECC Annual Progress Reports? The WECC Annual Report did not contain the LEAPS Project. The Project is now included in the WECC database and will be in future reports and analysis.

14. List other projects that are linked to this project i.e. other projects that would be needed if this project is to be useful. Include both generation and transmission projects: None, but combined with Sunrise Power link, would increase import capability economics, and reliability. This would complete the 500 kV loop to IV, as per long term STEP upgrade recommendations.

15. List other projects that this project would be likely to displace, i.e. if this project is built they would not be needed and vice versa: This project is complimentary to other projects, renewable energy supplies, and the ratepayer.

16. Describe the current project status. Include your assessment; Will this project be completed by 2015? This project is currently under the last phase of FERC licensing under project number P-11858-002. The draft EIS has been issued. The final EIS and ROD are scheduled for July of 2006.

STUDIES/REPORTS

DOE Task 3

SSG-WI 2005 Study Program

Part I: Characterization of the Study:

1. What was the name of the study? Seams Steering Group - Western Interconnection (SSG-WI) 2005 Study Program

2. Provide the title(s) and completion dates of available report(s) regarding the study: There were no formal reports drafted for this study program, however, there are PowerPoint presentations available documenting key assumptions and outputs from the modeling process: SSG-WI 2008 Base Case (completed September 2005 and updated March 2006), SSG-WI 2015 IRP-RPS Reference Case (completed February 2006)

3. Provide the details regarding how to obtain any available reports (Web address if available on internet): Web address: http://www.ssgwi.com. Presentations outlining study results are posted on the SSG-WI web site under the Planning WG documents, or by contacting Dean Perry at dean.perry@nwpp.org directly. It is planned in the near future to post SSG-WI planning reports on the WECC web site at http://www.wecc.biz. Check the WECC web site if the SSG-WI web site is unavailable.

4. Provide a contact person to obtain study details: name, phone, email: Dean Perry, (503) 816-6992, dean.perry@nwpp.org

5. What was the purpose of the study (e.g., what problem was the study intended to address)? The planning program was intended to accomplish two goals:
(i) To update and expand a Western Interconnection-wide generating resource, transmission, load and fuel price database using publically available information that could be freely distributed to regional, sub-regional and other planning entities to evaluate the economic implications of generation resource and transmission expansion scenarios. See #11 below for more detail on the database; and
(ii) To establish a reference case to be used as a basis for comparing the economics of scenarios.

6. Provide a brief summary description characterizing the study: The study program sought to:
Provide a Reference Case for year 2015 based on a compilation of the West's Integrated Resource Plans (IRP) and Renewable Portfolio Standards (RPS) requirements, as well as incremental resources submitted by the California Energy Commission (CEC) as an IRP proxy for California's utilities, while limiting the addition of transmission facilities to those necessary to integrate the planned resources. The reference case represents the region's current planning path and as such, serves as a baseline for further study of transmission and generation resource alternatives.

7. What was the geography of the study? Western Interconnection, specifically the states of Washington, Oregon, California, Idaho Montana, Wyoming, Colorado, New Mexico, Arizona, Nevada, the Canadian Provinces Alberta and British Columbia, as well as portions of Northern Mexico.

8. What was the study period? The SSG-WI 2005 program was carried out from the first quarter of 2005 to the first quarter 2006. The study includes a 2008 Base Case (view of the existing system) and a 2015 IRP-RPS Reference Case (view of the region's current planning path).

9. Describe the study type (such as who initiated the study and why): The study was initiated by SSG-WI, a voluntary organization formed in 2001 by three proposed western RTOs: the California ISO, WestConnect and RTO West (now Grid West). Part of SSG-WI's charter is to identify areas of potential future transmission congestion in the Western Interconnection, to develop and analyze alternative solutions and to provide this information to all entities, including sub-regional planning groups (SPG) transmission providers, load-serving entities (LSE), state agencies, generation owners, marketers and others involved in regional planning. Since SSG-WI has no implementation authority, it is the role of these latter entities to review the SSG-WI analysis and pursue project implementation for those projects that they determine to have sufficient economic benefit.

10. Characterize the study participants: A broad range of stakeholders in the West including utilities, energy and transmission developers, state and federal government regulators and energy policy officials, and public interest groups took part in the study program. Stakeholder input was requested by and funneled through the four SSG-Wi work groups; the Transmission Sub-Group (TSG), the Generation Sub-Group (GSG) and the Loads Sub-Group (LSG) to a joint modeling team. Stakeholders also participated in open meetings to guide, evaluate and validate the analysis process. CAISO/PacifiCorp led the Transmission Sub-group and overall process, BPA led the Generation Sub-Group, WECC led the Loads Sub-group, and PacifiCorp led the joint modeling team. Each sub-group coordinated with stakeholders and others to collect, review and validate data and assumptions used in the study.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed: The study created a unit-level generation resource database and updated a detailed representation of the Western Interconnection. Combined with hourly load data and other expert input, the study simulated hourly, bus-level operation of the Western grid for the 2015 test year under three natural gas price scenarios.
Assembly of the database invoved compiling, reviewing, and integrating data from multiple sources through SSG-Wi's working sub-groups as described in #10 above:

- Existing generating resources (those assumed in service by 2008) were identified using the WECC significant additions report, the CEC, the Northwest Power and Conservation Council (NWPCC) reports, previous regional planning studies and review by State representatives and other resource planning experts. Resource additions, i.e. those coming on-line 2009-2015, were provided by stakeholders via the SSG-WI Generation Sub-Group in accordance with IRPs and RPSs as described in #6 above. See #16 below for further details on resource assumptions.

- Load forecast information came largely from WECC's 2005 Load and Resources report with some exceptions as noted in #16 below.

- The transmission topology was based on the 22-bubble WECC topology with some refinements based on stakeholder input, and the detailed network representation was based on the WECC 2008 powerflow case with transmission additions and edits for 2015. See #16 and #17 below for more details.

The study program used the updated database with the ABB GridView production cost model to measure the level and cost of projected congestion as indicated by hourly LMPs (locational marginal prices), line loadings, and shadow prices (the reduction in production cost associated with relaxing a constraint by 1 MW). See #12 below. The GridView model performs economic dispatch such that transmission line limits are not violated under normal, as well as contingency conditions (physical and operating limits, not contractual).

Since the 2015 IRP-RPS Reference case was designed to be a benchmark study, it also took into account the capital carrying cost associated with the new generation resources and new transmission facilities forecast to be put in service between the 2008 Base Case year and the 2015 study year. This would allow further studies to gauge both the fixed and variable cost impacts of changing the resource and transmission configuration in the West (additions and/or subtractions of assets).

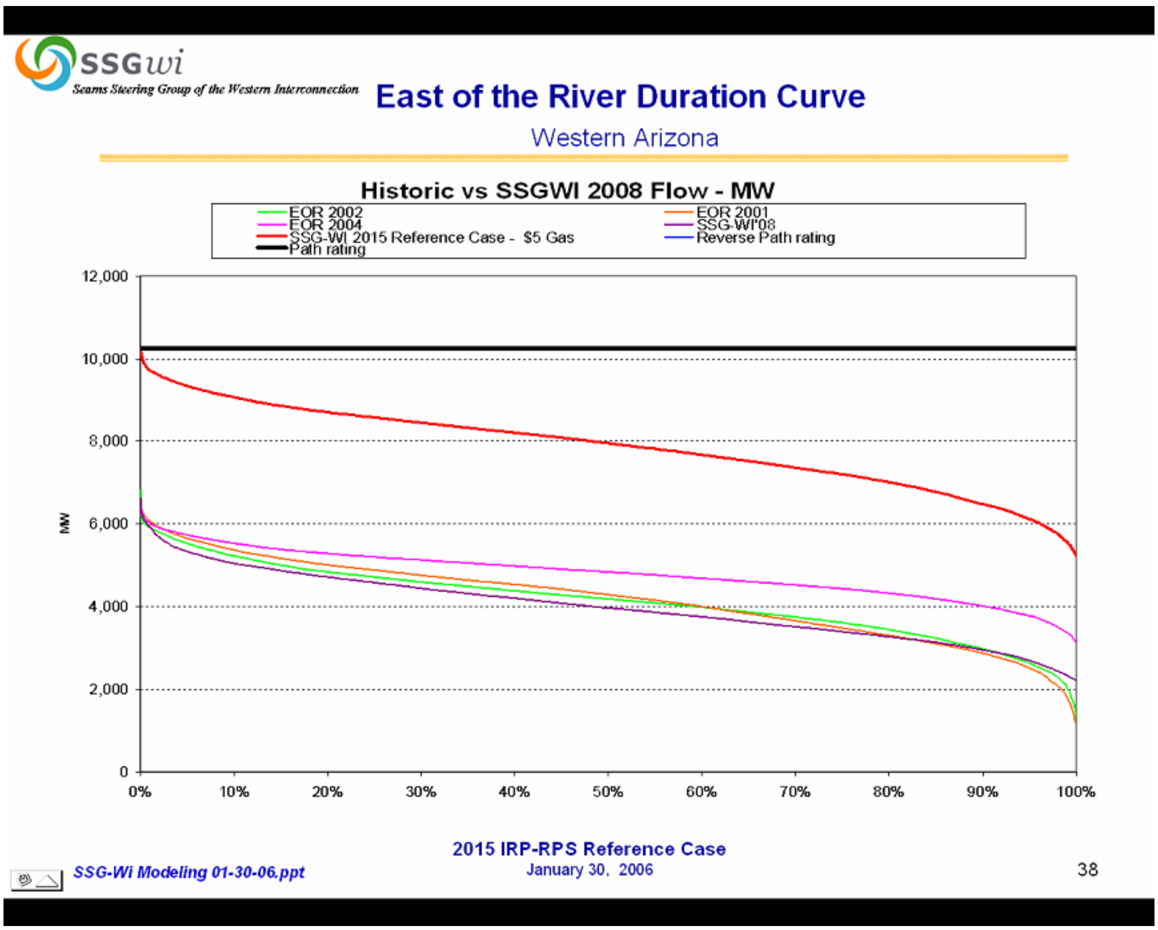
12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. The study viewed congestion in two ways: 1) physically-identified congestion, which was revealed by observing path flow results in the study as compared to historical path flows, and 2) congestion costs. The study group decided to use two methods for determining congestion cost in order to isolate the most congested paths in the West. The group tested the sensitivity of congestion cost rankings to changes in natural gas prices.

Method I: Method I ranks the paths based on congestion cost. The congestion cost for each congested path is defined as the hourly shadow price for each congested hour multiplied by the flow on the path for that hour, with the results summed for the year. The shadow price is the production cost decrease if 1 MW limit of the constraint is relaxed. (See the "Shadow Price X MW Flow" columns in the chart under #13 below).

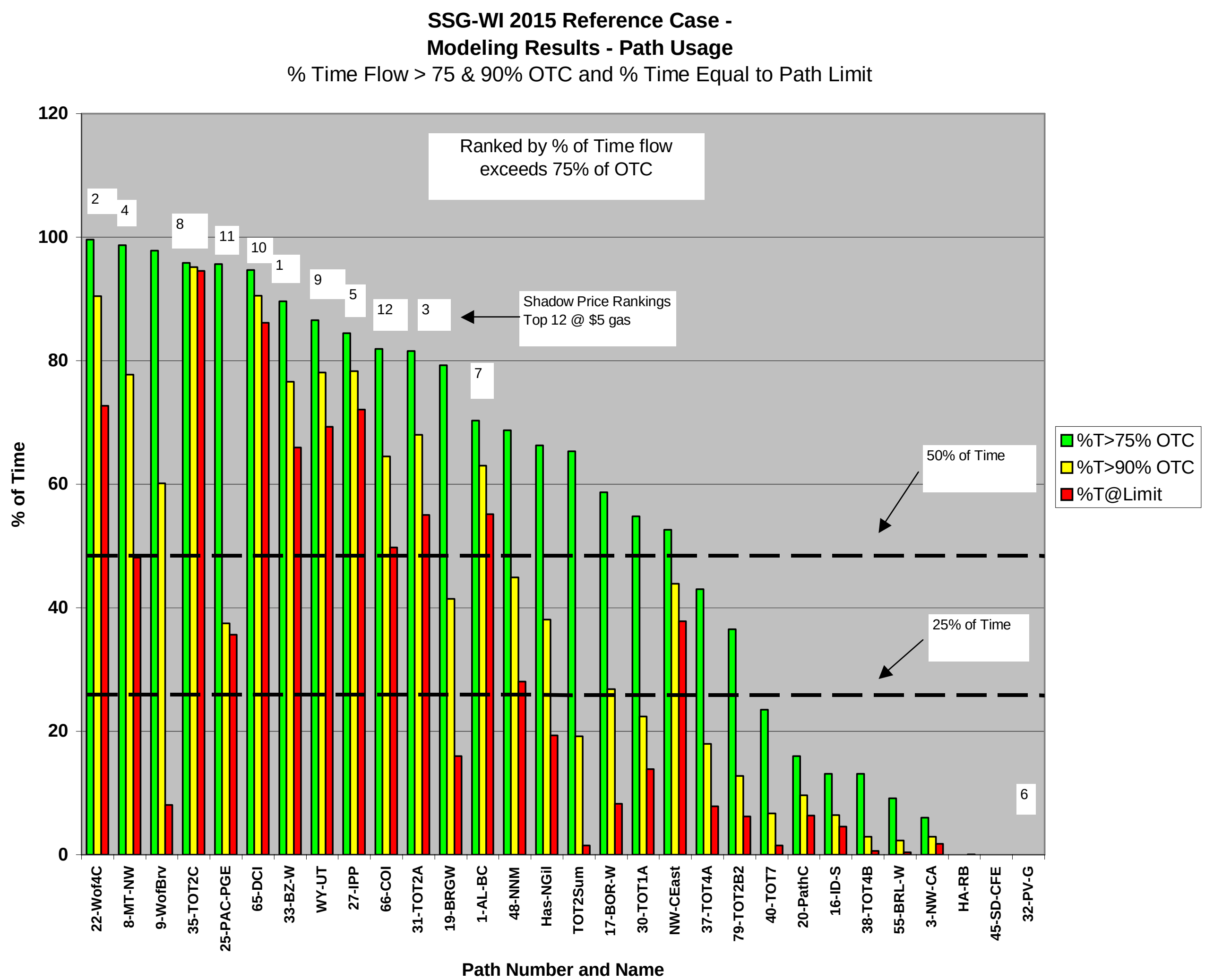
Method II: Method II ranks the paths based on the Annual Average Shadow Price alone. (See the "Shadow Price $/MW" columns in the chart under #13 below)

13. Congestion identified:

Physical congestion: The sample below demonstrates one of the ways the study identified congestion. By plotting the physical flows on a path next to its historic physical flows on the same path, the study group was able to see where model-projected path flows would put pressure on path limits. This example shows the East of River path would be more heavily used in 2015 than it has been during prior years of actual service.



Physical path flows for the WECC paths as calculated in the modeling studies are shown in the chart below for percent of time the flow exceeded 75% and 90% of the path limit and the percent of time the flow equaled the modeled path limit. For comparison purposes, the chart also shows the shadow price path ranking based upon the shadow price analysis described later.



Congestion Cost: The chart below shows the resulting rankings of 30 major paths in the Western Interconnect using the two congestion cost quantification methods. It appears from the chart below that changes in gas prices did not affect a path's congestion ranking as much as the method for measuring congestion. Alphabetically, the most congested paths in the 2015 IRP-RPS Reference Case as indicated by either method were: Bonanza West, IPP-DC Line, Montana-Northwest, Southwest of Four Corners, and TOT 2A.

Interface Name	Method I						Method II					
	(Shadow Price X MW Flow)						Shadow Price ($/MW)					
	($000)			Rank			(Annual Average)			Rank		
	$5G	$7G	$9G	$5G	$7G	$9G	$5G	$7G	$9G	$5G	$7G	$9G
ALBERTA - BRITISH COLUMBIA	34,199	52,040	69,270	10	11	10	5.57	0.49	11.29	7	7	7
BONANZA WEST	128,592	193,862	260,621	3	3	3	18.93	28.19	37.90	1	1	1
BORAH WEST	32,490	53,503	79,154	11	10	8	1.43	2.39	3.53	18	16	14
BRIDGER WEST	36,955	56,449	73,934	9	9	9	1.93	2.93	3.84	16	12	12
BROWNLEE EAST	847	950	1,041	29	30	29	0.05	0.06	0.06	30	30	29
CO	93,035	77,532	68,445	5	8	11	2.25	1.88	1.66	12	19	21
HA-Red Butte PS	5,030	6,865	9,252	19	20	20	2.04	2.61	3.52	13	14	15
Hassayampa - N. Gila	4,968	3,371	812	20	25	30	0.45	0.20	0.05	25	28	30
IDAHO - SIERRA	1,976	4,049	6,136	25	23	22	0.62	1.28	1.95	22	21	19
IPP DC LINE	117,109	172,445	227,726	4	4	4	6.86	10.25	13.54	5	6	6
MONTANA - NORTHWEST	209,939	334,400	491,463	2	2	2	8.22	12.94	19.02	4	4	4
NORTHWEST - CANADA	1,060	1,525	2,224	28	29	26	0.06	0.09	0.13	29	29	28
NW to Canada East BC	7,110	9,461	12,600	17	17	19	1.98	2.69	3.59	15	13	13
PACIFIC DC INTERTIE (PDCI)	86,728	103,170	117,562	6	6	6	3.47	4.21	4.79	10	10	11
PACIFICORP_PG&E 115 KV INTERCON	2,016	1,867	1,788	24	27	28	2.68	2.53	2.44	11	15	18
Path 45	3,914	5,725	5,905	23	22	23	0.78	0.82	0.86	21	23	24
PATH C	4,610	6,365	8,802	22	21	21	0.61	0.86	1.19	23	22	23
PAVANT INTRMTN - GONDER 230 KV	14,015	23,201	31,702	13	12	13	0.70	11.27	15.40	10	5	5
SOUTHERN NEW MEXICO (NM)	9,462	18,665	28,457	16	15	14	1.02	2.03	3.10	19	18	17
SOUTHWEST OF FOUR CORNERS	717,209	1,117,571	1,504,644	1	1	1	15.60	23.96	32.26	2	2	2
TOT 1A	6,846	9,158	12,935	18	18	17	0.96	1.31	1.85	20	20	20
TOT 2A	76,727	129,341	177,986	7	5	5	12.25	21.40	29.44	3	3	3
Tot2a 2b 2c Nomogram	1,357	3,414	4,815	27	24	24	0.09	0.25	0.35	28	27	26
TOT 2B2	4,929	9,095	12,634	21	19	18	2.01	3.92	5.46	14	11	10
TOT 2C	13,531	20,724	27,313	14	14	15	4.99	7.89	10.39	8	8	8
TOT 4A	10,252	15,543	24,952	15	16	16	1.57	2.19	3.52	17	17	16
TOT 4B	567	1,547	2,066	30	28	27	0.10	0.26	0.35	27	26	27
TOT 7	1,002	3,070	3,762	26	26	25	0.20	0.30	0.49	26	25	25
WEST OF BROADVIEW	14,280	21,085	39,050	12	13	12	0.52	0.72	1.34	24	24	22
WYOMING TO UTAH	57,250	81,758	107,017	8	7	7	3.87	5.49	7.19	9	9	9

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives. None

15. Describe new transmission technologies (if any) that were considered. None

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation

- LOADS: WECC's 2005 L&R load forecast was used for the 2015 studies, with three large exceptions:

  (1) Oregon, Washington and parts of Idaho: NWPCC's GENESYS/HELM models (relying on historical relationship between load and temperature) were used. The net result was hourly demand for 2015 given 2002 temperatures. 2002 was determined to be a medium hydrological year, and thus also drives the hydro generation data assumptions as described under "Hydro" below.

  (2) Colorado, parts of Idaho, Montana, Utah, Wyoming, and northern Nevada: the load forecast from the RMATS (Rocky Mountain Area Transmission Study, Sept. 2004) was used, escalated from 2008 to 2015 using rates approved by regional representatives.

(3) California: the latest CEC load forecast was used (Sept. 2005).

- RESOURCES: Resources planned to be on-line in the 2008 test year (existing) were identified through the WECC power flow case (2008 HS2A PF), the WECC Significant Additions reports, the database for the SSG-WI 2003 study, CEC data, the RMATS study, and other sources. Incremental resources (those planned to be placed on-line between 2008 and the 2015 IRP-RPS Reference Case year) were determined by the SSG-Wi Generation subgroup based on data collected from utilities' IRPs and coordinated with state representatives, NTAC (Northwest Transmission Assessment Committee) and NWPCC. RPS requirements and NREL's recommended wind generation additions were also considered.

- THERMAL UNITS: The study used a database built to economically dispatch thermal generation using unit-commitment logic. Because of the proprietary nature of unit operations and lack of actual data, the Generation Sub-Group and modeling team developed generic assumptions for 26 categories of thermal units based on fuel type, technology type, vintage, and capacity. These generic assumptions included data such as unit heat rate curves, minimum up and down times, start-up costs, etc. These generic assumptions were then assigned to the database units falling into each of the 26 thermal unit generic categories.

- HYDRO UNITS: Hydro unit output in the studies was fixed and used 2002 actual hydro data, reflecting a medium hydro year. For most northwest hydro units, project-specific actual hourly output data was used. For most of California and the BC Hydro areas, 2002 actual hourly generation data were aggregated by river system to protect confidentiality. The GridView model's peak shaving capability was used to model a limited number of units without 2002 actual data and for incremental hydro additions in the BC Hydro area.

- OTHER FIXED DISPATCH UNITS: Dispatch for non-thermal, non-hydro units, including wind, solar and geothermal types was modeled outside the GridView program and was treated as a fixed generation input. The majority of fixed dispatch profiles for wind, solar and geothermal generation were based on data from NREL (National Renewable Energy Laboratory). Several large geothermal and wind projects in California were modeled using aggregated actual hourly dispatch data for the project supplied by CAISO.

- FUEL PRICES: See details on natural gas price below under #17. The studies used a coal price forecast based on the US Energy Information Agency publication "Annual Energy Outlook 2005". Both the 2008 Base Case and the 2015 IRP-RPS Reference Case used the same fixed prices that the RMATS study used for generators not burning natural gas or coal.

The WECC load forecast included monthly peak and energy for each WECC bubble. The forecast was disaggregated to the 33-bubble SSG-WI topology, distributed to the bus level, and shaped to hourly load shapes based on FERC 714 filings and state and expert input.

- GENERAL: The study model did not incorporate contractual detail and assumed no transmission losses or tariffs for wheeling power across the western system. All costs were stated in 2005 dollars.

17. For each of the following, describe the assumptions made (if applicable):

Gas price (indicate base year and units): The gas commodity price used was a $5 Henry Hub base price and incorporated seasonal (monthly) and geographic price differentials based on the NWPCC's forecast methodology. The geographic differential from Henry Hub to regional hubs was included in the fuel price, while the cost of transportation from the regional hub to the burner tip was not. The cost of transportation from the regional hub to the burner tip was included in the economic analysis of fixed costs, which was done outside of the GridView model. Thermal dispatch and congestion sensitivity to gas price was tested using $5, $7, and $9 Henry Hub reference prices in 2005 U. S. dollars.

Coal price: The coal price forecast in the EIA's "Annual Energy Outlook 2005" was used. This forecast was based on historical trends. The EIA forecast of transportation costs included two tiers of transportation adders applied to each coal plant taking into account the sources of coal supplies and the demand area (generator location). The transportation adders were then added to the coal price to get the total price at each plant in the 2008 Base Case. The combined price was then averaged over all plants within each SSG-Wi topology bubble, and the averages were used to represent the SSG-Wi coal price for all coal-fired units in a bubble.

Year(s) studied: 2008 and 2015

Load shapes (year and/or source): WECC Load and Resource Report (2004) for 2008 and the 2005 Load and Resources Report for 2015. The loads were distributed to the bus level using the FERC Form 714 and refined with stakeholder expertise.

Powerflow database case source(s): WECC's 2008 Heavy Summer power flow case (2008 HS2A) was used for detailed representation of the transmission system for all months of the 2008 test year. This case was rerun to account for updates to transmission representation in CA, CO, NW, AZ, ID, WY, and UT. The 2015 IRP-RPS Reference Case further modified the 2008 Base Case network to include several major transmission additions.

Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:

1. Characterization of the project (name): No specific projects were identified in the SSG-WI 2005 study program. The database and cases developed during the program are intended to be used as a baseline study for future scenario planning at the regional and sub-regional levels, and to evaluate specific project proposals.

Western Interconnection 2006 Path Utilization Study

(Status report – to be updated after the path ATC data is analyzed)

Part I: Characterization of the Study:

1. What was the name of the study? 2006 Path Utilization Study

2. Provide the title(s) and completion dates of available report(s) regarding the study: Report to be written.

3. Provide the details regarding how to obtain any available reports (Web address if available on internet):

4. Provide a contact person to obtain study details: name, phone, email: Dean Perry, 503-816-6992, dean.perry@nwpp.org

5. What was the purpose of the study (e.g., what problem was the study intended to address)? Purpose of the study was to analyze statistically the "physical" MW flows on the major transmission paths in the western interconnection. Results of the study are used to verify performance of production simulation models of the western system. Results are also used by Transmission Owners and Transmission Customers to better understand actual utilization of the paths in the western transmission system. The study is part of a program initiated in 1999 to analyze on a biennial basis, the path utilization in the western interconnection. No specific transmission problem is addressed.

Previous to this 2006 study, only physical use has been analyzed. In this study, ATC and schedule data from the western OASIS sites will be analyzed to determine the "commercial" use of the major paths in the Western Interconnection. For a more complete understanding of western transmission path usage, both "physical" and "commercial" usage needs to be determined. The analysis of commercial use, together with the analysis of physical use, will improve our understanding of the historical usage and congestion on the major transmission paths in the West.

6. Provide a brief summary description characterizing the study: Using historical hourly MW flow data from the WECC EHV Data Pool, actual historical power flow on 33 transmission paths in the western interconnection was statistically analyzed and presented as seasonal frequency distribution curves.

In this 2006 update, hourly data on path ATC, reservations, schedules, CBM and TRM are included in the analysis. This data was obtained from the western OASIS sites by OATI, through a contract funded by the U.S. DOE, administered by the Lawrence Berkeley Laboratory. This data will be analyzed to understand where "commercial" congestion is occurring on the paths in the Western Interconnection.

7. What was the geography of the study? Western Interconnection Transmission system.

8. What was the study period? Winter 1998-1999 through Summer 2005.

9. Describe the study type (such as who initiated the study and why): The study was initiated by CREPC and SSG-WI. Grid West, WestConnect, WECC and the U.S. DOE provided funding. This is a continuation of an ongoing biennial update of the path utilization that was initiated in 1999.

10. Characterize the study participants: The analysis was performed by the SSG-WI PWG and by the WECC, which includes Transmission Owners, Transmission Customers, state and provincial representatives, marketers and resource developers.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed:

A reliability congestion index was calculated, defined as the percentage of time a path exceeds 75% and/or 90% of its operating transfer capability. This index was chosen as an indication of a path that may be considered to have high physical utilization. The magnitude of the index is not necessarily an indication that it is economical to add facilities to remove the physical congestion.

A commercial index will be calculated. This index defines the percentage of time a path has ATC available, using the same 75% and 90% indicators.

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used. The study calculates U75 and U90 congestion indices, indicating the percentage of time the physical flow or path schedules exceeded 75% and 90% of the path Operating Transfer Capability. These calculated physical and commercial "utilization indicators" are not necessarily a complete indication of congestion. Other economic factors must also be considered.

13. Congestion identified: Congestion was not measured. However heavy path usage was found to exist on the West of Bridger and on the IPP transmission because of the dedicated usage of those paths by the owners of generation at one end of the paths. In addition to these "dedicated" usage paths, heavy path usage was found between Canada and the Pacific Northwest, between Colorado and Utah, between Colorado and Wyoming, into the Phoenix area from the Colorado area, and into the El Paso area in New Mexico. This is based upon the paths exceeding the "75% utilization indicator" at least 50% of the time during one season of the year.

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives. Not applicable to this analysis.

15. Describe new transmission technologies (if any) that were considered. Not applicable to this analysis

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation): Not applicable. This was not a "study", rather an analsyis of historical data.

17. For each of the following, describe the assumptions made (if applicable) :

a. **Gas price (indicate base year and units):** Not Applicable
b. **Year(s) studied:** Not Applicable
c. **Load shapes (year and/or source):** Not Applicable
d. **Powerflow database case source(s):** Not Appliable

Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:

Not Applicable to this study

Clean and Diversified Energy Initiative

Part I: Characterization of the Study:

1. What was the name of the study?
Western Governors' Clean and Diversified Energy Initiative

2. Provide the title(s) and completion dates of available report(s) regarding the study:

CDEAC Transmission Task Force Draft Report
Forthcoming with expected completion date April 30, 2006

3. Provide the details regarding how to obtain any available reports (Web address if available on internet):

WGA's general CDEAC website:
http://www.westgov.org/wga/initiatives/cdeac/index.htm

CDEAC Transmission Task Force website:
http://www.westgov.org/wga/initiatives/cdeac/transmission.htm

4. Provide a contact person to obtain study details: name, phone, email:
Thomas Carr, 303-573-8910; tcarr@westgov.org

5. What was the purpose of the study (e.g., what problem was the study intended to address)?

The Western Governors' adopted the goals of adding 30,00 MW of clean and diversified energy and attaining 20% energy efficiency in the 18 state region of the Western Governors' Association (WGA). The Clean and Diversified Energy Advisory Committee (CDEAC) and numerous task forces were created to develop recommendations to attain the Governors' goals. The CDEAC Transmission Task Force analyzed new transmission needed to support proposed new generation recommended by other CDEAC task forces.

6. Provide a brief summary description characterizing the study:

The CDEAC Transmission Task Force relied on existing transmission studies to evaluate transmission requirements for WGA states in the Eastern Interconnection and ERCOT. For WGA states in the Western Interconnection, the CDEAC Transmission Task Force coordinated a modeling project that built upon the transmission modeling efforts of the Seams Steering Group-Western Interconnection (SSG-WI). The CDEAC transmission analysis identified and modeled transmission to support three bookend generation scenarios based on generation and demand-side actions postulated by CDEAC task forces: (1) High Efficiency Case, (2) High Renewables Case, and (3) High Coal Case.

The study performed an economic screening analysis comparing costs of the three scenarios relative to the SSG-WI 2015 Reference Case.

7. What was the geography of the study?

The CDEAC Transmission Task Force examined existing transmission studies for WGA states in the Eastern Interconnection (ND, SD, NB, KS) and ERCOT (TX). The CDEAC Transmission Task Force modeling effort of the 3 CDEAC scenarios covers the Western Inteconnection, which includes eleven states (WA, OR, CA, AZ, NV, ID, MT, WY, UT, CO, NM), two Canadian provinces (Alberta and British Columbia), and portions of northern Mexico.

8. What was the study period? 2015

9. Describe the study type (such as who initiated the study and why):

Production cost modeling of the Western Interconnection for CDEAC Transmission Task Force as part of the Western Governors' Clean and Diversified Energy Initiative.

10. Characterize the study participants:

This study was a collaborative effort that relied on numerous individuals from diverse organizations: Doug Larson and Thomas Carr (Western Interstate Energy Board, and CDEAC Transmission Task Force); Donald Davies (Western Electricity Coordinating Council); Doug Arent and Dick Watson (CDEAC Quantitative Work Group); Howard Geller (Southwest Energy Efficiency Project); Ron Benioff, Michael Milligan, Mark Mehos, Ralph Overend, Martin Vorum, Donna Heimiller (National Renewable Energy Laboratory); Jerry Vaninetti (Trans Elect); the SSG-WI Transmission Subgroup -- Jeff Miller (PacifiCorp), Dean Perry (SSG-WI), Marv Landauer (BPA), Ray Brush (NWE/RMATS), Chris Reese (PSE/NTAC), Peter Krzykos (APS/SWAT), Irina Green (CAISO), Roger Hamilton (Wind on the Wires), William Pascoe; and the ABB Modeling team -- Henry Chao, Lan Trinh, Maria Moore.

11. Describe methods (if any) used in studies to measure the magnitude of the problem addressed:

This study sought to analyze the transmission to support three bookend generation scenarios postulated for 2015.

The initial assumptions about loads, generation and transmission in 2015 for the Western Interconnection came from the SSG-WI 2015 Reference Case. The High Efficiency Case was modeled by reducing 2015 loads consistent with the recommendations of the CDEAC Energy Efficiency Task Force. The CDEAC fuel task forces provided the assumptions for generation resources in 2015 for the High Renewables and High Coal Cases.

The SSG-WI Transmission Subgroup reviewed an initial run of the model with additional generation but no new transmission, and made recommendations for new lines to be added. After several iterations within a short timeframe, the SSG-WI Transmission Subgroup added enough transmission to reduce congestion costs in the model to a reasonable level, although not necessarily the optimal solution.

The CDEAC scenario modeling used the same model used by the SSG-WI -- the ABB GridView production cost model. The GridView performs economic dispatch of generation resources subject to constraints such as transmission capacity in the system. An economic screening analysis to be performed will evaluate the costs of each scenario relative to the base case that accounts for operating cost savings, generation capital costs, and transmission capital costs.

12. What criteria and metrics did the study use (transfer capability, robustness, reinforcements, economics, etc)? For economic studies, how was congestion evaluated to develop solutions. Indicate the metric used for measuring congestion, e.g. hourly LMP or annual production cost savings, load service capability, transfer path capacity, voltage dip, etc.? Indicate the definition of congestion used.

The SSG-WI Transmission Subgroup made recommendations for new transmission under each scenario based on multiple measures of congestion including line loadings, LMPs, and shadow prices. Once sufficient transmission was added for each scenario, the production cost savings for each scenario were evaluated and compared to capital costs for the assumed new transmission and generation.

13. Congestion identified:

14. Describe non-transmission alternatives (if any) that were compared with transmission alternatives. The High Efficiency Case postulated reduced loads and enabled the system to operate without adding new transmission lines beyond the SSG-WI Reference case.

15. Describe new transmission technologies (if any) that were considered. None

16. Describe the six most important study assumptions (e.g. what database was used, years studied, gas prices, fixed hydro dispatch, load shapes, how dispatched generation):

(1) The most critical assumption in the CDEAC modeling was the specification of new generation and location of that generation added in the Western Interconnection. The study objective was to consider transmission needed under extreme bookend generation scenarios.

(2) Second most important assumption concerns the generation assumptions adopted in the SSG-WI 2015 Reference Case which served as the foundation for the CDEAC analysis. The SSG-WI 2015 Reference Case assumed incremental generation over the

period 2008 to 2015 that would meet utility integrated resource plans (IRPs) and compliance with state Renewable Portfolio Standards (RPS).

(3) Natural gas price based on $5 Henry Hub base price and incorporated seasonal and geographic price differentials.

(4) Hydro modeling assumed an average hydro year based on 2002 data.

(5) Dispatch for non-thermal, non-hydro units (wind, solar, geothermal) was modeled outside the GridView program and treated as a fixed generation input. The majority of fixed dispatch profiles for wind, solar and geothermal were based on data from the National Renewable Energy Laboratory.

(6) Loads were based on WECC's 2005 L&R load forecast with exceptions for parts of the Western Interconnection.

17. For each of the following, describe the assumptions made (if applicable) :

a. Gas price (indicate base year and units): Natural gas price based on $5 Henry Hub base price.

b. Year(s) studied: 2015

c. Load shapes (year and/or source): WECC Load and Resources Report for 2015. The loads were distributed to the bus level using FERC Form 714 and refined with stakeholder expertise.

d. Powerflow database case source(s): Same as SSG-WI 2015 Reference Case

Part II: Characterization of proposed projects. Complete Part II for each project the study addresses:

Not Applicable to CDEAC study