Analysis of "Loss of Load Probability" (LOLP) at various Planning Reserve Margins

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Public Service Company of Colorado

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EXECUTIVE SUMMARY

At the request of Public Service Company of Colorado (PSCo), Ventyx performed a stochastic analysis of the relationship between electric generating capacity reserve margin (aka, planning reserves) and the ability of the PSCo system to reliably maintain service to load. The analysis focused on the year 2013 and accounts for PSCo existing and expected generation resources and the anticipated availability characteristics of those resources. The analysis takes into consideration PSCo's hourly customer electric demands and the volatility of those demands due to weather. The analysis incorporates a representation of the reliability support that PSCo can expect to receive from the Rocky Mountain Reserve Group (RMRG) under single contingency events of 200 MW or greater. The reserve margin study also incorporates PSCo's obligation to carry approximately 419 MW of operating reserves for year 2013 as part of its membership in the RMRG. Additionally, the analysis considers the reliability contribution of transmission lifeline capacity generally reserved for system emergencies.

Ventyx performed the analysis using the Market Analytic's Planning & Risk Module (PaR). The load, wind generation, and unit availability were treated stochastically. The level of energy not served from the PaR modeling work was used to determine the expected level of reliability for the system for different levels of capacity reserve margin. The analysis indicates that a Planning Reserve Margin of 16.3% would provide an expected probability that the PSCo system would be unable to serve firm load customers approximately 1-day-in-10-years. This level of reliability is considered acceptable and often used as a standard for reliable systems within the electric utility industry.

1 RECENTLY ACCEPTED APPROACHES

1.1 PREVIOUS LOLP STUDIES

In 2003 Resource Plan Filings with the California Public Utility Commission, three different Investor Owned Utilities (PG&E, SCE, and SDG&E) all performed portfolio stochastic analysis to assess appropriate levels of planning reserves. In these analyses, the utilities selected an upcoming applicable year and tested the ability of their power supply systems to meet customer loads in that year under different utility supply portfolios that gave different levels of planning reserve. The methodology involved performing hourly economic dispatch of resources against loads for each hour of the year. Because of the uncertainties of unit forced outage and load level variations caused by weather, multiple iterations of the year were performed. Under each iteration, Monte Carlo draws were made daily that adjusted load levels either upward or downward. Further, Monte Carlo draws were made to reflect possibilities of unit forced outage. The California PUC accepted the methodology at that time, but more recently some utilities have indicated that higher reserve margins should be required because of the possibility of non-performance of PPAs, etc. The California PUC has therefore opened another proceeding to discuss possible changes to reflect these matters.

It is typical to use a 1-day-in-10-year Loss of Load Probability (LOLP) when determining the needed Planning Reserve Margin. This level of LOLP is equivalent to failing to serve the energy requirements of the system for 2.4 hours each year or 24 hours during a 10-year period.

2 PSCO FOCUSED ANALYSIS USING PORTFOLIO STATISTICAL ANALYSIS AND EXPECTED ENERGY NOT SERVED (ENS)

2.1 OVERVIEW OF ANALYSIS PERFORMED

Ventyx has performed a stochastic analysis of Loss of Load Probability on the PSCo system in a manner similar to the analysis performed by California investor owned utilities in the year 2003 and accepted by the California PUC as well as by PSCo in 2004 (filed with PSCo's 2003 LCP). In particular, Ventyx focused on PSCo existing and expected generation resources and loads in year 2013. The analysis also reflects a PSCo operating reserve of 419 MW, which represents PSCo's expected operating reserve obligation under the RMRG after the Comanche 3 unit becomes operational.

Ventyx utilized its regional Market Analytics software module, Planning & Risk, to perform this stochastic reserve margin analysis of the PSCo system. The key factors represented stochastically in this analysis are:

- Unit forced outages and maintenance,
- Weather related load volatility,
- Wind generation, and
- Transmission lifeline capacity.

Ventyx stochastically simulated the hourly dispatch of the PSCo system for year 2013, where Monte Carlo draws were performed for 100 iterations in order to capture the impact of uncertainties in these key factors.

2.2 TEST YEAR FOR ANALYSIS

Consistent with PSCo's 2007 CRP, PSCo provided the portfolio of resources, wind pattern, unit maintenance and forced outages and the hourly load forecast for the year 2013 for the purpose of this study.

2.3 RESOURCES IN THE BASE YEAR

PSCo generation resources in the year 2013 reflected in the analyses are listed in Table 1 below. The Comanche 3 facility was modeled at it full expected capacity of 784 MW and the full load requirements of IREA and Holy Cross were included in the modeling of customer demand (i.e., as opposed to modeling only PSCo's share of Comanche 3 and removing the portion of IREA and Holy Cross's load that will be served by their ownership share of Comanche 3).

Table 1
Public Service of Colorado expected 2013 Summer Resource Capacity

Resource	Peak Capacity MW	Resource	Peak Capacity MW	Resource	Peak Capacity MW	Resource	Peak Capacity MW
Alamosa 1	12.82	Comanche 1	325	Hayden 1	139	Sunshine Hydro	0.7
Alamosa 2	13.5	Comanche 2	335	Hayden 2	99	Tacoma Hydro	8.5
AMES HYDRO	3.75	Comanche 3	784	HillCrest Hydro	2.3	Thermo RS1 31CC	152
Arapahoe CC	479	Craig 1	41.6	Kohler Hydro	0.15	Tower04WT	42.12
Basin1 LRS2	50	Craig 2	41.6	LakeGeorge Hydro	0.23	Tower41WT	98.75
Basin1 LRS3	50	CT_129_A	258.6	Manchief CT	260.7	Tower49WT	41.37
Basin2 LRS2	37.5	Dillon Hydro	1.9	Maxwell Hydro	0.15	Tri2 Craig1	9.93
Basin2 LRS3	37.5	Foothills Hydro	2.3	On_Site Solar	11.89	Tri2 Craig2	9.93
Betasso Hydro	8.57	Fruita	15	Orodell Hydro	0.22	Tri2 Craig3	38.29
BioGas 75th ST	0.5	FSV CC 1x1	226	Ouray Hydro	0.5	Tri2 LRS2	19.18
BioMass	4	FSV CC 2x1	252	Palisade Hydro	1.7	Tri2 LRS3	19.18
Brush 13	75	FSV CC 3x1	230	Pawnee 1	505	Tri3 Craig1	2.49
Brush 4D CC2	133	FSV CT	270	PlainsEnd2 CC	224	Tri3 Craig2	2.49
Cabin Crk Gen1	105	Ft Lupton 1	44.7	Redlands Hydro	1.4	Tri3 Craig3	9.84
Cabin Crk Gen2	105	Ft Lupton 2	44.7	Roberts T Hydro	6.1	Tri3 LRS2	4.8
Central Solar	11.12	Georgetown Hydro	1.2	Rocky Mtn CC21	601	Tri3 LRS3	4.8
Cherokee 1	107	Gross Res Hydro	8.1	Salida Hydro	1.4	TST Brighton	132
Cherokee 2	106	Spindle_CT	269	Shoshone Hydro	15	TST Limon	66
Cherokee 3	152	SPS TieLine	101	Stagecoach Hydro	0.8	UNC Greeley EXT	68.86
Cherokee 4	352	Valmont 6	43	Strontia Hydro	1.2	Valmont 5	186
Cherokee Diesel	5.5	WM Landfill Gas	3.2	SunEdison Solar	2.87		

(Wind contributed 12.5% of nameplate, Solar at 58% and Cabin Creek 210 MW)

In the analysis, the PSCo wind generation resources were lumped together into three distinct geographic zones: Colorado/Wyoming border zone near the existing Ponnequin facility, northeast zone near Peetz Table, and the southern zone near the Colorado Green facility. The three wind zones provide geographic diversity for wind generation based on the modeling techniques applied for stochastic wind generation discussed later in this report. For the calculation of planning reserves, the wind capacity is counted at 12.5% of their nameplate capacity.

2.4 YEAR 2013 LOADS

The analysis applied Monte Carlo draws on load to reflect the likelihood that loads will be higher or lower as a result of weather, than what is being forecast for year 2013. To perform this type of Monte Carlo analysis, an hourly profile of PSCo loads for the year 2013 was developed. The forecasted peak demand for year 2013 is 7,310 MW, which is comprised of the September 2007 peak demand of 7,094 MW and an additional 216 MW of coincident peak demand from IREA and Holy Cross. As seen above Comanche 3 was modeled at its full capacity to accommodate serving the full load requirements of IREA and Holy Cross. While IREA and Holy Cross will have a 250 MW share of the Comanche 3 unit, it is expected that only 216 MW of load would be coincidental with the PSCo peak demand and only that coincident amount was considered for the total 2013 PSCo peak demand. As described above, PSCo's portion of Comanche 3 and IREA's and Holy Cross's portion of Comanche 3, totaling to 784 MW of capacity for Comanche 3, was also included since IREA and Holy Cross wholesale load requirements were included as part of the PSCo load.

2.4.1 Load Stochastic Process and Volatility Parameters

The stochastic model used to perform the stochastic draws on load is a two-factor model in which one factor represents short-term or temporary deviations and the other factor represents long-term or cumulative deviations. Long-term effects include trends such as change in annual peak demand growth and other forces whose effects are of long duration, which follow a random walk. In the short term, shocks may drive variables away from their long-term equilibrium level, but adjustment processes tend to pull them back to their equilibrium or expected level in the short term. In other words, short-term shocks such as changes to load due to weather are mean reverting. The rate at which the random variable tends to revert to the expected value is an input to the process. This is referred to as the mean reversion rate. The two-factor model combines the short-term mean reverting process with the long-term random walk process.

The volatility estimates for PSCo load in this study were developed from historical hourly load data from 1996-2007. The estimated short-term stochastic parameters for PSCo load, used as inputs into the Planning & Risk models stochastic analysis, are presented in Table 2 below. Long-term stochastic parameters were not necessary since the study period is a single year. As a result of these stochastic parameter inputs, a distribution of load volatility is created.

Table 2
PSCo Load Stochastic Parameters

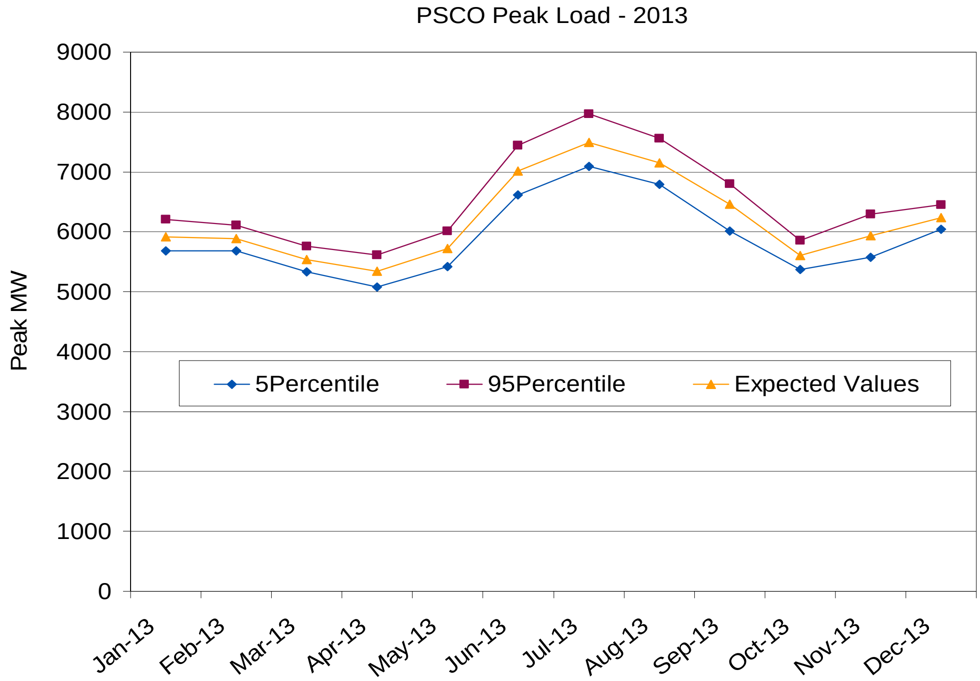
Season[1]	Load PSCo	
2013	**Alpha**	**Sigma**
Winter	0.275	0.014
Spring	0.266	0.015
Summer	0.195	0.016
Fall	0.276	0.019

Source: Ventyx.

Figure 1 illustrates the 5th, Average, and 95th confidence intervals of load distribution for the year 2013.

[1] Season definition: Winter = December-February; Spring = March-May; Summer = June-August; Fall = September-November. Sigma is the volatility parameter and alpha is the mean reversion parameter.

Figure 1
PSCo Load Distribution - Confidence Intervals



2.5 Modeling Of Wind Volatility

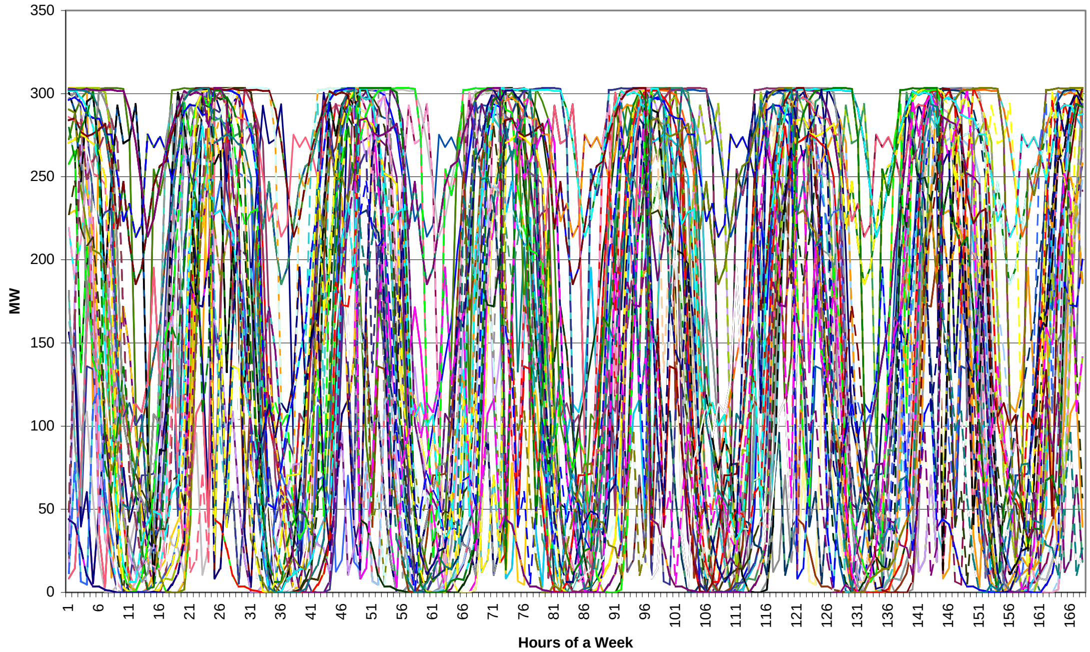
Using historical hourly wind generation from existing PSCo wind facilities, Ventyx created 100 different hourly wind patterns that reflect the unpredictable nature of the PSCo wind resource. PSCo provided wind shapes for three wind zones: Colorado/Wyoming border, northeast Colorado, and southeast Colorado. These three wind shapes were utilized to model wind variability within the analysis.

The stochastic wind data was developed external to the Planning & Risk model, and introduced during model simulation. The following method was used in creating the stochastic wind data:

1. Hourly historical wind shapes for the three locations were developed and each fluctuates differently due to their location and associated wind pattern.
2. To capture the randomness of wind generation, Ventyx used its Hourly Historical Simulation Tool, which randomizes daily-hourly profiles within a month. This process was repeated for each aggregated wind location. For example, in creating the 24-hour by 100 iterations of data for January 1 for a location, the random number generator picked which hourly day profile in January to choose. Since January has 31 days, the random number generator chose any one of the 31 days of January for each of the 100 iterations for January 1. So for January 1, iteration 1 may use the hourly profile of day 30 of January, iteration 2 may use the hourly profile of day 2 of January and so on. This process was continued until all days of the year for each of the 100 iterations was developed. Figure 2 shows the stochastic wind data for a representative week in July.

3. The randomized wind data was then fed into Planning & Risk through XML integration and included in the model simulation.

Figure 2
PSCo Stochastic Wind Data for a Location



2.6 FORCED OUTAGE RATES ON SUPPLY RESOURCES

The expected level of forced outages for PSCo units (both owned and purchased) was estimated from actual historical availability data. The model assumed the following expected levels of forced outage rates on the following supplies.

Table 3
Public Service of Colorado Station Outage Rate

Station	EFOR	Station	EFOR	Station	EFOR
Alamosa 1	0.10%	Dillon Hydro	5.00%	Rocky Mtn CC21	5.00%
Alamosa 2	0.10%	Foothills Hydro	5.00%	Salida Hydro	3.00%
AMES HYDRO	6.00%	Fruita	7.30%	Shoshone Hydro	1.00%
ArapCC	1.60%	FSV CC 1x1	2.50%	Spindle_CT	3.00%
Basin1 LRS2	3.00%	FSV CC 2x1	2.50%	SPS TieLine	0.50%
Basin1 LRS3	3.00%	FSV CC 3x1	2.50%	Stagecoach Hydro	5.00%
Basin2 LRS2	3.00%	FSV CT	3.00%	Strontia Hydro	5.00%
Basin2 LRS3	3.00%	Ft Lupton 1	9.50%	Sunshine Hydro	5.00%
Betasso Hydro	5.00%	Ft Lupton 2	17.20%	Tacoma Hydro	5.00%
BioGas 75th ST	3.00%	Gen GT	3.60%	Thermo RS1 31CC	3.00%
BioMass	10.00%	Georgetown Hydro	2.00%	Tri2 Craig1	4.80%
Brush 13	2.00%	Gross Res Hydro	5.00%	Tri2 Craig2	4.80%
Brush 4D CC2	2.00%	Hayden 1	6.60%	Tri2 Craig3	3.00%
Cabin Crk Gen1	6.00%	Hayden 2	3.50%	Tri2 LRS2	3.00%
Cabin Crk Gen2	6.00%	HillCrest Hydro	5.00%	Tri2 LRS3	3.00%

Station	EFOR	Station	EFOR	Station	EFOR
Cherokee 1	9.50%	Kohler Hydro	5.00%	Tri3 Craig1	4.80%
Cherokee 2	12.40%	LakeGeorge Hydro	5.00%	Tri3 Craig2	4.80%
Cherokee 3	10.10%	Manchief CT	5.00%	Tri3 Craig3	3.00%
Cherokee 4	8.90%	Maxwell Hydro	5.00%	Tri3 LRS2	3.00%
Cherokee Diesel	9.40%	Orodell Hydro	5.00%	Tri3 LRS3	3.00%
Comanche 1	13.30%	Ouray Hydro	5.00%	TST Brighton	5.00%
Comanche 2	4.40%	Palisade Hydro	3.00%	TST Limon	5.00%
Comanche 3	6.30%	Pawnee 1	8.40%	UNC Greeley EXT	5.00%
Craig 1	4.80%	PlainsEnd2 CC	1.50%	Valmont 5	4.20%
Craig 2	4.80%	Redlands Hydro	5.00%	Valmont 6	9.90%
CT_129_A	1.00%	Roberts T Hydro	5.00%	WM Landfill Gas	5.00%

Table continued on next page.

100 iterations of the model were run for year 2013. Monte Carlo draws determined if a resource was on forced outage or not. In this case, the model was set up so that if a unit was forced out in a week as a result of a Monte Carlo draw, the unit is assumed out for the entire week. If a unit has an expected forced outage rate of, for example, 5%, then the average outage hours for that unit over the 100 iterations is 5% of the time. However, any individual iteration could have an outage rate for that iteration for the year of greater or less than 5%. The Monte Carlo draws are designed such that over a large number of random draws of unit outage, statistically one would expect the average hours of unit being forced out during a year to be 5%. However, statistically it is possible that over 100 iterations the average outage rate is slightly above or below the 5% number.

2.7 Rocky Mountain Reserve Group Support

One key aspect of the analysis was to reflect the reliability support that PSCo receives from neighboring electric systems. PSCo is a member of the Rocky Mountain Reserve Group (RMRG) and thus has the right to call for support from the group under certain qualifying contingency events. In accordance with the RMRG rules, PSCo must notify the RMRG group and may request group support for outages of PSCo plants of 200 MW and larger. For outage events of less than 200 MW, PSCo is not required to notify the RMRG group and generally covers the event using its own reserves. For this analysis Ventyx reflected RMRG support to PSCo for outages of plants of 200 MW or larger. Table 4 shows the RMRG Response Matrix and the contingency assistance provided to PSCo by the RMRG Members. The RMRG support contained in Table 4 is based on the individual members' forecasts of load for year 2013.

The RMRG Response Matrix details the amount of contingency assistance provided to PSCo at different megawatt levels of outages. The contingency assistance by RMRG rules is available only for the hour of the event and the following hour for a total of 2 hours per outage event per month. If multiple units are out at the same time, the contingency assistance is provided to the unit with largest capacity.

Based on the RMRG response matrix, Ventyx calculated the RMRG contingency assistance provided by the participating surrounding utilities to PSCo for the PSCo units above 200 MW. Table 5 summarizes the RMRG assistance available for each unit.

Table 4
Rocky Mountain Reserve Group Response Matrix

		B1	B2	B3	B4	B5	B6	B7	B8	B9	B10	B11	B12	B13	B14
RMRG responsibilty					**784**	**759**	**734**	**709**	**684**	**659**	**634**	**609**	**584**	**559**	**534**
EMERGENCY ASST * -> FOR PSCO					391	378	367	354	341	329	317	305	294	283	269
	RRR	**Member response requirement**													
MEAN	0.011756				10	9	9	9	8	8	8	7	7	7	7
WMPA	0.002232				2	2	2	2	2	2	1	1	1	1	1
TRIS	0.108974				88	85	83	80	77	75	72	69	66	64	61
BHPL	0.035493				29	28	27	26	25	24	23	23	22	21	20
CSU	0.074984				61	59	57	55	53	51	49	48	46	44	42
FRPC	0.007988				6	6	6	6	6	5	5	5	5	5	4
WACM	0.062762				51	49	48	46	44	43	41	40	38	37	35
					0	0	0	0	0	0	0	0	0	0	0
WALC	0.034187				28	27	26	25	24	23	23	22	21	20	19
					0	0	0	0	0	0	0	0	0	0	0
PRPA	0.060373				49	47	46	44	43	41	40	38	37	35	34
WPEC	0.014808				12	12	11	11	10	10	10	9	9	9	8
PSCO	0.517850				419	406	393	380	367	354	341	328	315	302	289
BEPC	0.068591				55	54	52	50	49	47	45	43	42	40	38
GROUP	1.0000				810	784	760	734	708	683	658	633	609	585	558
WACM AGC offsets					-297	-288	-282	-274	-265	-258	-249	-243	-235	-229	-220
After 15 minutes, change to:					-247	-238	-232	-224	-215	-208	-199	-193	-185	-179	-170
PSCO AGC offsets					-225	-215	-208	-199	-189	-181	-172	-165	-156	-149	-139
After 15 minutes, change to:					-275	-265	-258	-249	-239	-231	-222	-215	-206	-199	-189
WACM AGC offsets						-318	-312	-304	-295	-288	-279	-273	-265	-259	-250
After 10 minutes, change to:						-288	-282	-274	-265	-258	-249	-243	-235	-229	-220
PSCO AGC offsets						-245	-238	-229	-219	-211	-202	-195	-186	-179	-169
After 10 minutes, change to:						-315	-308	-299	-289	-281	-272	-265	-256	-249	-239
WALC AGC offsets					-28	-27	-26	-25	-24	-23	-23	-22	-21	-20	-19

		B18	B19	B20	B21	B22	B23	B24	B25	B26	B27	B28	B29	B30	B31
RMRG responsibilty		**434**	**409**	**384**	**359**	**334**	**309**	**284**	**259**	**234**	**209**	**184**	**159**	**134**	**109**
EMERGENCY ASST * -> FOR		218	206	194	182	171	161	147	135	123	111	89	76	65	53
	RRR	**Member response requirement**													
MEAN	0.011756	5	5	5	4	4	4	4	3	3	3	2	2	2	1
WMPA	0.002232	1	1	1	1	1	1	1	1	1	1	0	0	0	0
TRIS	0.108974	49	47	44	41	39	36	33	30	28	25	20	17	15	12
BHPL	0.035493	16	15	14	13	13	12	11	10	9	8	7	6	5	4
CSU	0.074984	34	32	30	28	27	25	23	21	19	17	14	12	10	8
FRPC	0.007988	4	3	3	3	3	3	2	2	2	2	1	1	1	1
WACM	0.062762	28	27	25	24	22	21	19	18	16	14	12	10	8	7
	0.000000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
WALC	0.034187	16	15	14	13	12	11	10	10	9	8	6	5	5	4
	0.000000	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PRPA	0.060373	27	26	24	23	21	20	18	17	15	14	11	10	8	7
WPEC	0.014808	7	6	6	6	5	5	5	4	4	3	3	2	2	2
PSCO	0.517850	235	222	209	196	195	178	157	144	132	119	95	82	69	56
BEPC	0.068591	31	29	28	26	24	23	21	19	17	16	13	11	9	7
GROUP	1.0000	453	428	403	378	366	339	304	279	255	230	184	158	134	109
WACM AGC offsets		-137	-130	-122	-114	-109	-102	-93	-85	-78	-70	-56	-48	-41	-33
PSCO AGC offsets		-153	-145	-136	-127	-121	-113	-103	-95	-87	-78	-62	-53	-46	-37
WALC AGC offsets		-16	-15	-14	-13	-12	-11	-10	-10	-9	-8	-6	-5	-5	-4

Table 5
RMRG Contingency Assistance for PSCo Units Greater than 200 MW

PSCo Units > 200 MW	Capacity MW	RMRG Contingency Assistance MW (shadow station)
Comanche3	784	391
RockyMontCC2	601	301
Pawnee1	505	253
Cherokee4	352	179
Comanche2	335	171
Comanche1	325	167
RockyMontCC1	259	135
FSV2	252	132
FSV3	230	121
FSV1	226	119
Plainsend2	224	118

2.7.1 Modeling the RMRG Support

For each PSCo units ≥ 200 MW, Table 5, Ventyx modeled a corresponding RMRG support unit called a shadow station. The size of each RMRG shadow station was determined by the actual plant size and the corresponding assistance available as reported in Table 5.

To reflect the fact that each RMRG shadow station may only be called upon during its parent station's outage event, PaR Rules of Existence (Rule Groups) modeling was utilized. Rule Group modeling included assigning each of the RMRG Shadow Units to a Rule that tells PaR the RMRG unit can exist to help serve load only if the parent station is on outage.

Since only the largest station during overlapping outages receives the RMRG contingency assistance, a Rule Group hierarchy of RMRG shadow stations was implemented to ensure only the largest contingency was called upon.

Under the terms of the RMRG, pool members are required to provide contingency assistance to PSCo, if requested, for up to two hours for each qualifying contingency event. To reflect this real-life constraint, Ventyx modeled the RMRG Shadow Units as "limited energy" stations. For each of the RMRG shadow stations Ventyx input a weekly energy limit equal to 2 times the MW rating of the shadow unit (i.e., 2-hours of full load operation). Once the RMRG unit is been called upon in the modeling, it will not be available again for contingency assistance until the next outage. As a limited energy station, PaR will attempt to choose the best hours to run limited energy RMRG shadow station based on dispatch economics. For instance, if a 300 MW PSCo plant is tripped off-line at 12 am and is forced out for the week, PaR will not immediately activate the RMRG shadow station but rather will attempt to save the limited energy from the shadow unit for peak hours or for hours where energy not served exists. In other words, because the RMRG shadow stations are modeled with such a high cost of operating (i.e. just below the cost of ENS), the units will only be run when there would otherwise by ENS, and the units will only run for two hours following each outage. This methodology allowed the RMRG unit to be available to contribute generation assistance to PSCo after the station goes on forced outage and only during an ENS event. This limited energy methodology meets the two hour limitation of the RMRG but has a shortcoming in that it provides the two hours of generation support during the highest marginal energy cost hours. Given that high marginal energy costs typically occur during hours when system load is at it's highest, this means that the reliability contribution provided by the two hours of RMRG support is likely somewhat overstated in the PaR modeling To understand the potential magnitude by which the RMRG support might be overstated, a sensitivity was performed in which the RMRG units were excluded from the analysis. The results of this sensitivity showed the generation support provided by the RMRG acts to reduce the Planning Reserve Margin from approximately 17.8% to 16.3% or 1.5%. From this we can see that the limited energy methodology used to represent the RMRG support is likely to be a small factor in the overall reserve margin level required for the system (i.e., it is probably a small part of the 1.5% total impact of the RMRG support).

2.8 TRANSMISSION LIFELINE - NON PSCO IMPORTS

PSCo is interconnected with the Western Interconnect (WECC reliability council area) and expects that in an emergency situation it can utilize these interconnections to import additional power supplies into its system. The exact quantity of additional power supply is dependent on the availability of unused transmission capacity. PSCo estimates that it will have access to roughly 200 MW plus or minus 50 MW of unused transmission capacity during peak load periods. The reliability benefit of this transmission import capability was included in this analysis through the representation of an additional 200 MW of imports with Monte Carlo draws around plus or minus 50 MW.

Model runs were also performed without this 200 MW of import capability. These runs allowed PSCo to isolate the contribution that this 200 MW of import capability provides to the system through a reduction in the required planning reserve. As reported in Section 3 below, from this sensitivity run it was found that the existence the 200 MW Transmission LIFELINE allows reducing the Planning Reserve Margin from approximately 19.2% to 16.3% while maintaining the LOLP at 1-day-in-10-years.

2.9 USING A GENERIC GAS TURBINE AS A PROXY FOR INCREASING PLANNING RESERVES AT THE MARGIN

In order to perform this study, it was necessary to run the stochastic analysis at several different levels of planning reserve. For example if additional resources need to be added to the model in order to move the Planning Reserve Margin level from 10 percent to 12 percent and so on. The resource used to incrementally increase Planning Reserve Margin needs to be (a) highly reliable as a supply source and (b) relatively low cost to acquire since it will likely used at a very low capacity factor. While there are numerous supply technologies available for increasing supply, the reasonable supply unit to use for this purpose is a simple cycle GT.

2.10 DETERMINATION OF LOLP

The LOLP analysis methodology Ventyx applied in this study is a marked improvement over traditional methods for determining LOLP. Where, in the past, company's often computed an annual LOLP index as the summation of daily probabilities (often termed the "daily risks") over the entire year being studied, Ventyx computes LOLP based on a stochastic production cost model simulation where all relevant factors and uncertainties are included in the simulation. The analysis predicts both the probability of not serving a specific amount of load, and in addition provides insights into the dimension and amount of energy that would not be served—referred to as unserved energy or expected un-served energy (EUE). The Ventyx LOLP methodology calculates LOLP for each hour where the LOLP is the probability that available generation capacity in a given hour is less than the system load. The primary measurement used in accessing resource adequacy in this analysis is Loss of Load Hours (LOLH), which is typically used in the energy industry. Generally, if a utility's loss of load hours is not greater than or equals 1-day-in-10-years (or 2.4 hours in 1 year), it is seen as a reliable system. Unserved Energy (aka Energy Not Served…ENS) results in the model if on a particular hour the model is unable to find sufficient supply to meet the load plus the required operating reserve margin. If that happens on an hour, then this is counted as one LOLH. For LOLH counting purposes, there is a single LOLH if on an hour the load is not met. The counting is the same if the unserved load is 1 MW or if it is, for example, 200 MW. Given multiple iterations of the study year (with different Monte Carlo draws on loads and unit forced outages, etc), the metric used for this LOLP study is the average number of hours of LOLH over the 100 iterations. So if there are 99 iterations with zero LOLH and one iteration with 100 LOLH, then the expected (average) LOLH for the 100 iterations for this year is 1 LOLH. As indicated above, and average LOLH of 2.4 hours in the 1 year analysis is considered to be 24 LOLH hours in 10 years or 1 day in ten years.

For purposes of this study, Ventyx analysis looks for that Planning Reserve Margin level that will provide a 1-day-in-10-year LOLP.

2.10.1 Calculating The Planning Reserve Margin

A number of questions arise when the objective is calculating an accurate Planning Reserve Margin for a system. The common method of calculating Planning Reserve Margin is represented by the following equation:

$$\frac{[(\text{Resources} - \text{Peak Load}]}{(\text{Peak Load})}$$

<u>Peak Load</u>: Peak load is generally the needle peak load of the control area. In this study, where PSCo is modeled as a single zone, the peak hour for the entire system occurs in July.

<u>Resources</u>: The peak capacities of thermal and hydro stations that are in PSCo are included in the calculation except for Cabin Creek Pumped Storage which is counted at 210 MW. Wind capacity is counted at 12.5% of nameplate rating. Interruptible loads and demand side management programs are included as resources but for load and resource balance purposes, they are subtracted from the peak load.

Table 6
2013 PSCo Expected Reserve Margin

2013 L&R	MW	LOLH
Peak Load 50th percentile	7310	
interruptible loads	-401	
Firm Peak Obligation	**6909**	
Net Dependable Capacity from Table I above not including CT 129A and not including FSV CT	7410	
NET Planning Reserve Margin in 2013 without CT 129A	7.3%	
Needed Operating Reserves	5.7%	
Effective Starting Point Planning Reserve Margin	13.0%	69.8
Recommended Reserve Margin -- 1 day in 10 years	16.3%	24.0

The conclusion of this LOLH is that a 16.3% PRM is needed to provide a 1 day in 10 year LOLP. This level is determined by performing analysis that does not interrupt load until the operating reserve drops below zero.

Table 7 in section 2.11 below reflects the loads and resources in the year 2013 for PSCo currently planned, but without the assumed generic CT 129A and without the new FSV CT units. This was the starting point for the LOLP analysis in this report. The generic CT 129A and FSV CT units were removed to assure that the starting analysis results in a LOLP that was greater than one-day-in-10 years. That staring point as indicated above resulted in a LOLH of 69.8 hours. A one-day-in-10 years would have an LOLH of 24.0 hours. To achieve that, Ventyx then started adding gas turbines until it found the level of Planning Reserve Margin that resulted in a LOLP of one-day-in-10 years.

2.11 ANALYSIS STARTING POINT OPERATING RESERVE MARGIN

For year 2013, PSCo estimates it will be required to maintain approximately 419 MW of operating reserves as its portion of the RMRG reserve obligation. If operating reserves fall below 419 MW, PSCo would likely curtail load if it cannot arrange for additional power supplies. The PaR model used to perform this LOLP analysis, however, is not capable of curtailing load (i.e., registering unserved energy) and enforcing an operating reserve requirement. The model will only register unserved energy events in hours where the sum of all generation resources operating at their full capability is less than the load on the system and there is energy not served.

To account for this PaR model limitation, it is necessary to add “operating reserves” to the “planning reserve” level included in the model run that produces a 1-day-in-10-year level of reliability. Based on the 2013 peak load forecast of 7,310 MW, the 419 MW operating reserve requirement represents 5.73% (419 MW/7,310 MW = 0.0573) that must be added to the model results. As summarized in Section 3 below, the starting point for the PSCo Planning Reserve Margin analysis is a 13.0% starting reserve level that resulted in an LOLH of 69.8, which is 2.9-days-in-10-years (69.8 / 24 hours = 2.9 days) as shown in the table above. To determine an expected LOLP of 1-day-in-10-year LOLP, Ventyx added 210 MW of generic CT generation and found a LOLP of slightly higher than 1-day-in-10-years, or 26.9 hours. This level equates to a Planning Reserve Margin of 16%. Ventyx then added another 60 MW of CT capacity which is a Planning Reserve Margin of 17% and found a LOLP of less than 1-day-in-10-years, or 17.7 hours.

Interpolating between these two LOLP values determines a Planning Reserve Margin of 16.3% equates to a target 1-day-in-10-years LOLH of 24.0 hours. This interpolation to a one-day-in-10-years indicates PSCo's Planning Reserve Margin should be 16.3%.

3 ANALYSIS RESULTS

The goal of this LOLP analysis was to determine the Planning Reserve Margin for the PSCo system that would achieve an LOLP of 1 day in 10 years or, an Energy Not Served (LOLH) of 24 hours in 10 years (or 2.4 hours in one year). Table 7 contains a summary of the relationship between reserve margin and LOLH, both with and without 200 MW of transmission lifelines (i.e., transmission capacity held for use in accessing additional power supplies on short notice). All reserve margin values in Table 7 include the effects of operating reserve requirements.

Table 7
LOLP Results Summary

Reserve Margin (no transmission lifelines)	Reserve Margin (with 200 MW transmission lifeline)	LOLH (hrs in 10 Years)
16%	13%	69.8
18%	15%	39.6
19%	16%	26.9
20%	17%	17.7
22%	19%	7.9
24%	21%	1.8

Figure 3 below is an illustration of the LOLH / Energy Not Served values provided in Table 7 as a function of reserve margin level. By interpolation a reserve margin of 16.3% (with 200 MW transmission lifeline) yields 1-day in 10 years level of LOLH

Figure 3
Expected Hours of Energy Not Served