INTEGRATED FORECAST AND RESERVOIR MANAGEMENT (INFORM) FOR NORTHERN CALIFORNIA

2015 Water Resources Assessment for Northern California

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Summary

Based on the hydroclimatic forecasts of March 1, the 2015 season from March to Nevember is projected to be dry with respect to total basin inflow. The initial system storage is somewhat higher than the storage on May 1, 2014, but it is still only about 40% of the system capacity. The individual reservoir storages are at the lower 10th percentile of their historical distribution (of the last 33 years). As a result, the ability of the Northern California reservoir system to provide water deliveries and generate energy is significantly impaired. Depending on the carry-over storage target (at the end of November, 2015), water deliveries are expected to be in the range 2.5 to 3.5 million acre feet (MAF), corresponding to 60% of the deliveries that can be provided on an average hydrologic year under the same storage conditions as 2015. Likewise, energy generation in 2015 is expected to be 75% of the energy that can be generated on an average hydrologic year under the same storage conditions.

April 2015

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1. Introduction

The current assessment uses the integrated forecast-management system developed under the INFORM Phase II project to assess the anticipated conditions of the northern California reservoir system over the period from March 1, 2015, to November 30, 2015. Ensemble infllow forecasts were generated by the Hydrologic Research Center (HRC), and used by the INFORM management system developed by the Georgia Water Resources Institute (GWRI). A brief discussion of the forecast and managment models is provided next followed by a detailed discussion of the assessment findings.

2. Integrated INFORM DSS and Forecasting Models

The INFORM DSS includes three modeling layers (Figure 1) designed to support decisions pertaining to various temporal scales and objectives. The three modeling layers include (1) turbine load dispatching (which models each turbine and hydraulic outlet and has hourly resolution over a horizon of one day), (2) short/mid range reservoir control (which has a daily resolution and a horizon of one month), and (3) long range reservoir control (which has a monthly resolution and a horizon of up to one year).

Both the long range control model and the mid/short range control model use inflow forecasts as inputs. The integration of the decision models and inflow forecasting models are done through data exchange. The forecasted inflows are saved in a pre-formatted Excel file. The DSS provides easy tools to read the data in the Excel file and save it into the database. The DSS also provides tools to plot and validate the forecasting results.

The long range control model is designed to consider long range issues such as whether water conservation strategies are appropriate for the upcoming year using the provided hydrologic forecasts. As part of these considerations, the DSS would quantify several tradeoffs of possible interest to the management agencies and system stakeholders. These include, among others, relative water allocations to water users throughout the system (including ecosystem demands), reservoir coordination strategies and target levels, water quality constraints, and energy generation targets. This information would be provided to the forum of management agencies (the planning departments) to use it as part of their decision process together with other information. After completing these deliberations, key decisions would be made on monthly water supply contracts, reservoir releases, energy generation, and reservoir coordination strategies.

The short/mid range control model considers the system operation at finer time scales. The objectives addressed are more operational than planning and include flood management, water supply, and power plant scheduling. This model uses hydrologic forecasts with a daily resolution and can quantify the relative importance of, say, upstream versus downstream flooding risks, energy generation versus flood control, and other applicable tradeoffs. Such information is again provided to the forum of management agencies (the operational departments) to use it within their decision processes to select the most preferable operational policy. Such policies are revised as new information on reservoir levels and flow forecasts comes in. The model is constrained by the long range decisions, unless current conditions indicate that a departure is warranted.

The three modeling layers address planning *and* management decisions. The scenario/policy assessment model addresses longer term planning issues such as increasing demands, infrastructure change (water transfers options), potential hydro-climatic changes, and mitigation measures. The approach taken in this DSS layer is to simulate and inter-compare the system response under various inflow, demand, development, and management conditions.

Altogether, the INFORM DSS provides a comprehensive modeling framework responsive to the information needs of the decision making process at all relevant time scales.

This progress report discusses results of the long range model using the ensemble inflow forecasts for year 2014.

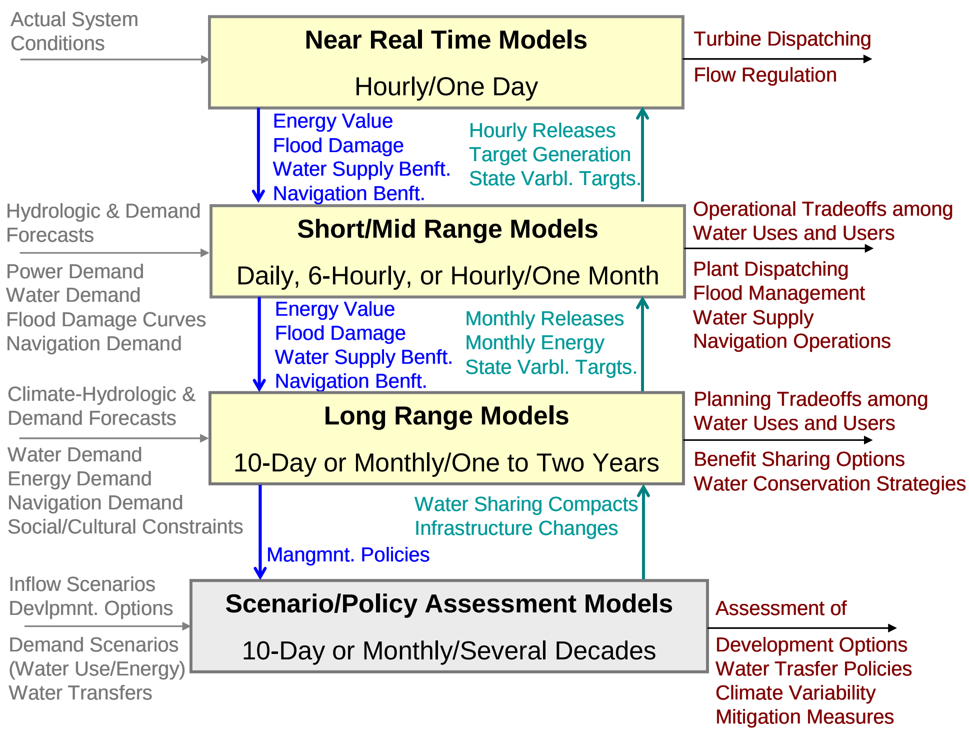

Figure 1: INFORM DSS Models

3. 2015 Assessment

The application described here utilizes the following input data:

- Forecasted inflows start from March 1st, 2015 (98 traces, 9 month horizon, and five locations: Clair Engle Lake, Shasta, Oroville, Folsom, and Yuba);
- Historical monthly average values are used for locations where forecasted inflows are not available (Table 1);
- Monthly reservoir parameters and constraints (max, min, and target storage, evaporation rates; Table 2);
- Minimum river flow requirements (Table 3);
- Base monthly demands at all locations (Table 4);
- Reservoir initial storages are set to their actual values on March 1st, 2015.

Inflows: Monthly ensemble inflow forecasts are shown in Figure 2. Comparisons between the forecasted inflow means and the corresponding historical means for the four major reservoirs are plotted in Figures 3 through 6. As shown, the forecasted inflow means at all locations are much lower than the historical means, especially at Trinity and Folsom. Figures 7 and 8 compare the seasonal inflow forecasts of 2015 to the historical means by sub-basin and systemwide. The forecasts indicate that 2015 inflow is expected to be approximately 25% lower than the inflow of an average hydrologic year. Figures 9 and 10 show the initial reservoir storages on March 1st for 2006 through 2015. As Figure 10 indicates, the total system storage is the third lowest in the last 10 years.

Water Deliveries and Energy Generation: Using the forecasted inflows, tradeoffs are generated by changing the base demands at all locations by factors ranging from 20 to 60%. The tradeoff curves between the system carryover storage and the system energy versus the system water deliveries are depicted in Figures 11 and 12. As demands increase, the reservoir carry-over storages decrease. Energy generation increases as downstream demands increase because of higher reservoir releases.

The expected water deliveries and energy generation for 2015 are compared to those of an average hydrologic year for the same initial and carryover storage targets in Figures 13 and 14. The results show that the system can provide water deliveries in the range 2,500 to 3,500 TAF, corresponding to about 60% of the deliveries that can be provided on an average year for the same storage conditions. Meeting demands beyond this level would result in significant reservoir drawdown (especially at Shasta and Orroville), and diminished carryover storage. Average energy generation is expected to be 75% of the energy generated on an average hydrologic year under the same storage conditions.

Specifically, for a system target carryover storage of 7,428 TAF on November 1st, the 2015 expected water deliveries amount to 3,248 TAF compared to 5,482 TAF in an average historical year. For the same carryover storage target (3rd tradeoff point), the 2015 energy generation is 3,718 GWh compared to 4,882 GWh of an average hydrologic year, corresponding to a 25% reduction. Thus, significant reductions of both water deliveries and energy generation are expected.

The carryover storage distributions corresponding to different water deliveries are presented in Figure 15. The figure shows that the 2015 initial system storage on March 1st is on the tail end of the historical distribution (89%). Furthermore, in spite of the reduced water deliveries, the expected carryover storage (on November 1) is also expected to be in the lower part of its historical distribution. Selected reservoir elevation, release, and energy generation sequences corresponding to a 3,248 thousand acre feet (TAF) water delivery level are shown in Figures 16 through 18.

X2 and Delta Outflow: The X2 location sequences are shown in Figure 19, indicating all traces below 80 km, the maximum constraint set in the study. The X2 location stays within this constraint for all tradeoff points. The Delta outflow sequences are plotted in Figure 20.

4. Summary

Based on the hydroclimatic forecasts of March 1, the 2015 season from March to Nevember is projected to be dry with respect to total basin inflow. The initial system storage is somewhat higher than the storage on May 1, 2014, but it is still only about 40% of the system capacity. The individual reservoir storages are at the lower 10th percentile of their historical distribution (of the last 33 years). As a result, the ability of the Northern California reservoir system to provide water deliveries and generate energy is significantly impaired. Depending on the carry-over storage target (at the end of November, 2015), water deliveries are expected to be in the range 2.5 to 3.5 million acre feet (MAF), corresponding to 60% of the deliveries that can be provided on an average hydrologic year under the same storage conditions as 2015. Likewise, energy generation in 2015 is expected to be 75% of the energy that can be generated on an average hydrologic year under the same storage conditions.

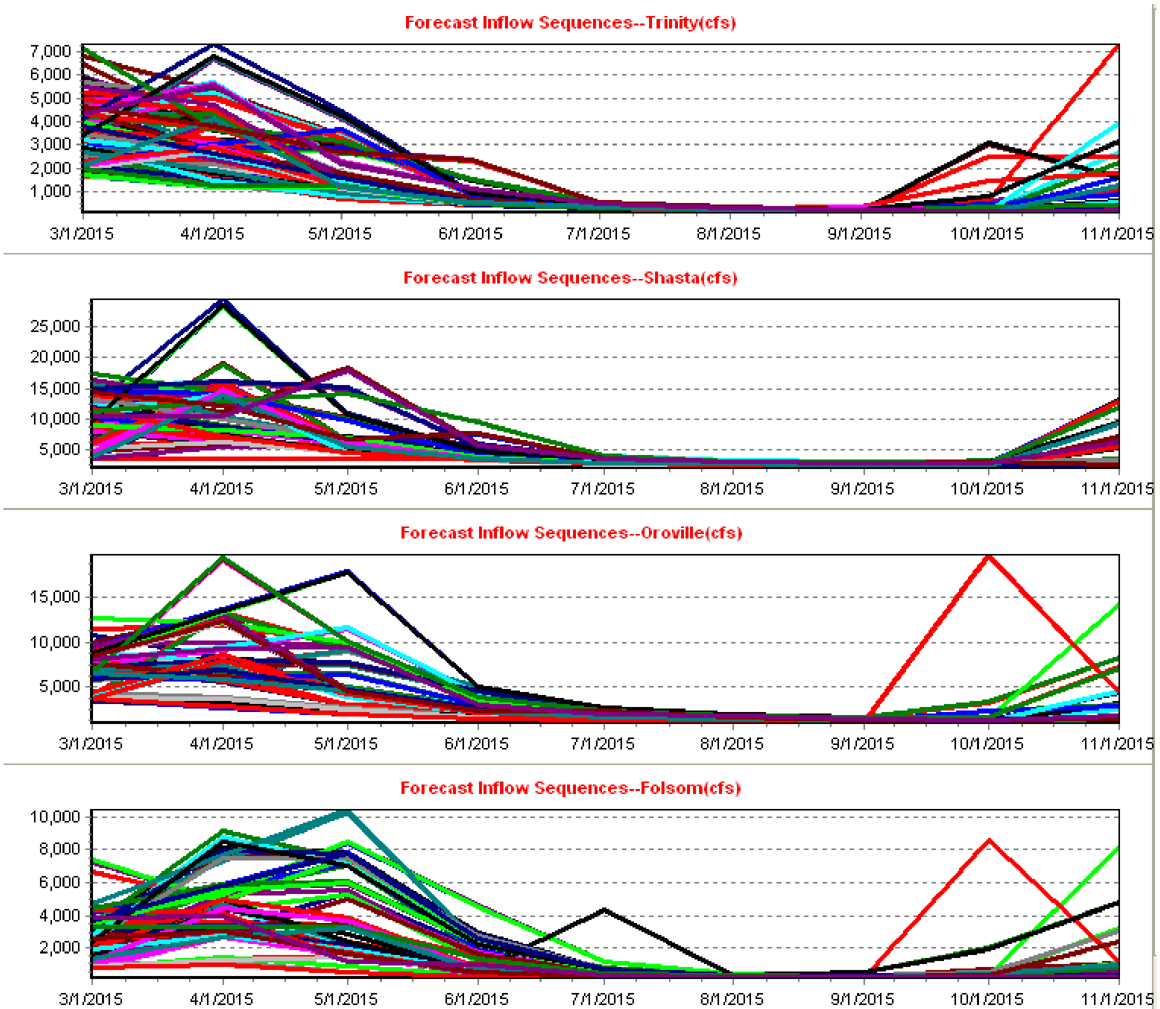

Figure 2: Long Range Inflow Forecast Ensembles

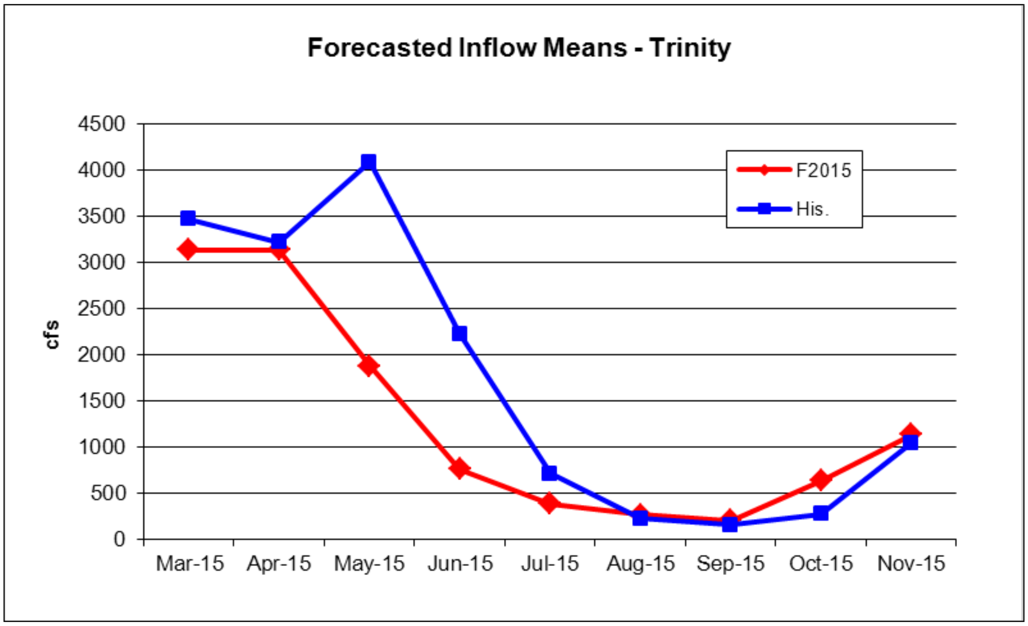

Figure 3: Comparison of Inflow Forecasts vs. Historical Means for Trinity

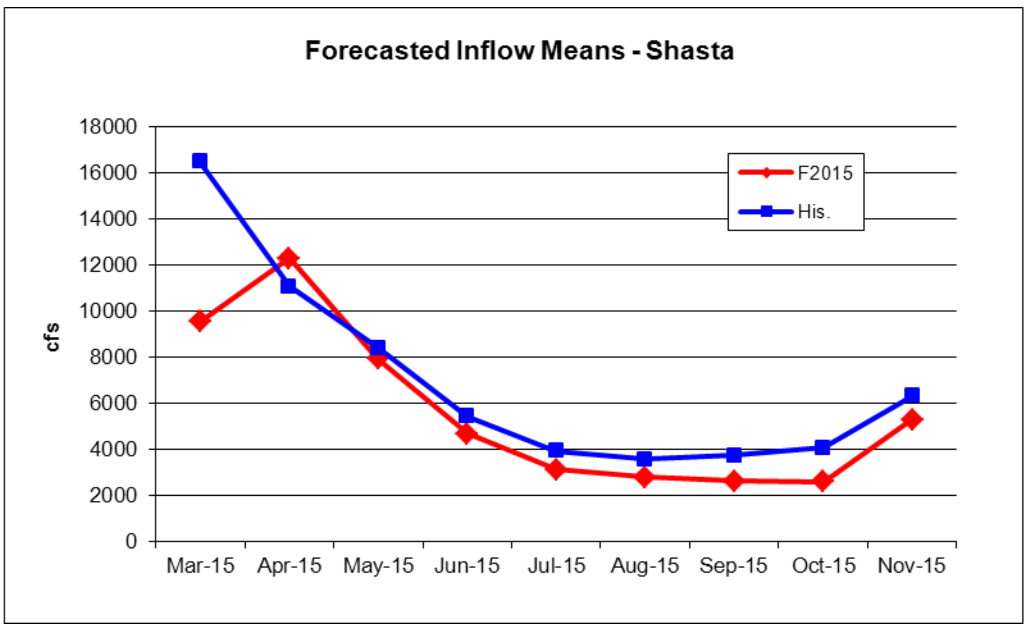

Figure 4: Comparison of Inflow Forecasts vs. Historical Means for Shasta

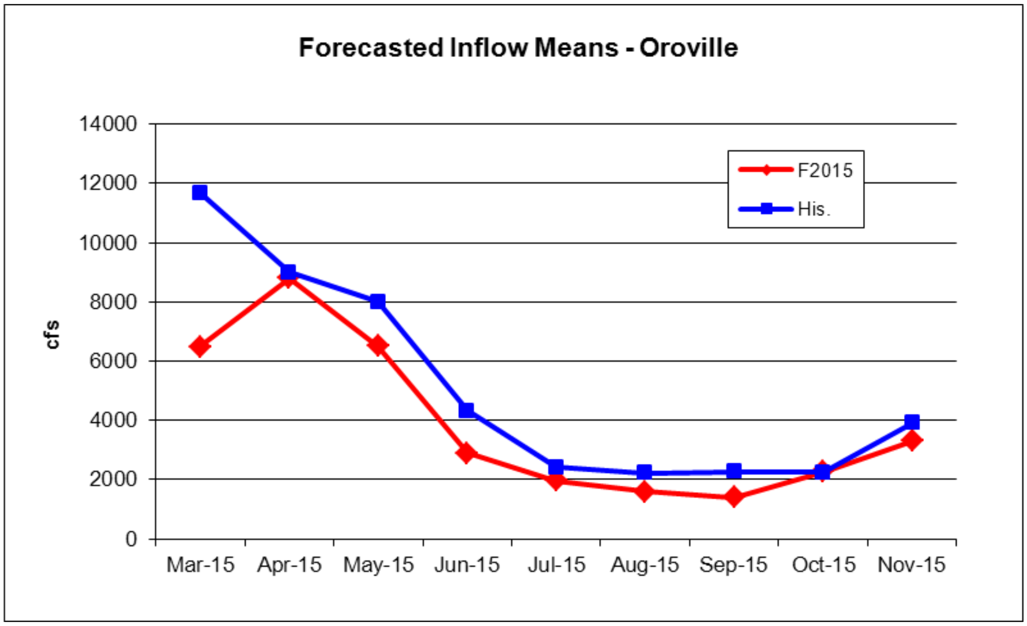

Figure 5: Comparison of Inflow Forecasts vs. Historical Means for Oroville

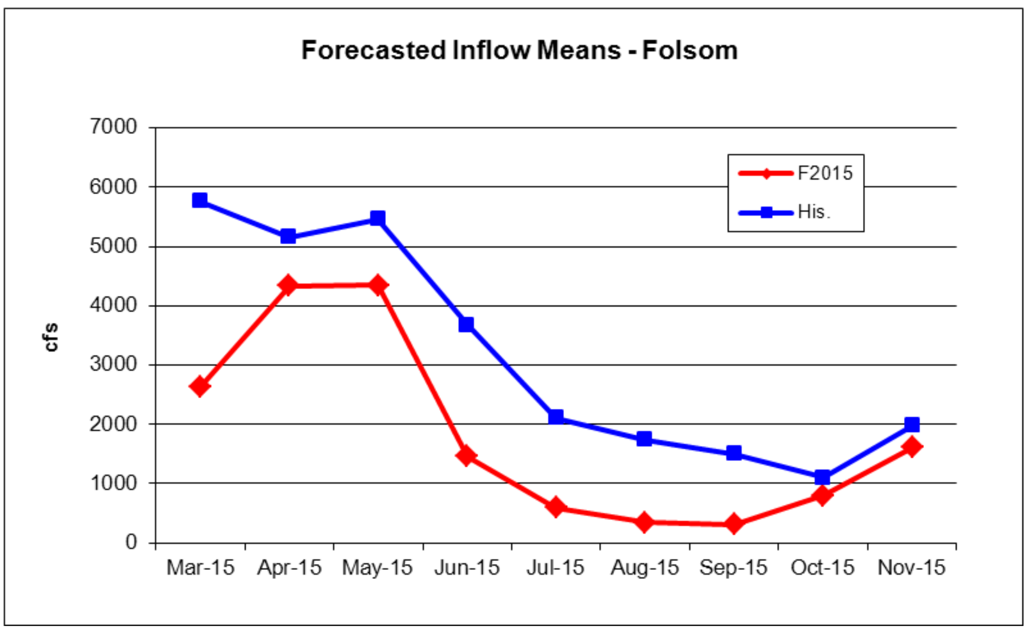

Figure 6: Comparison of Inflow Forecasts vs. Historical Means for Folsom

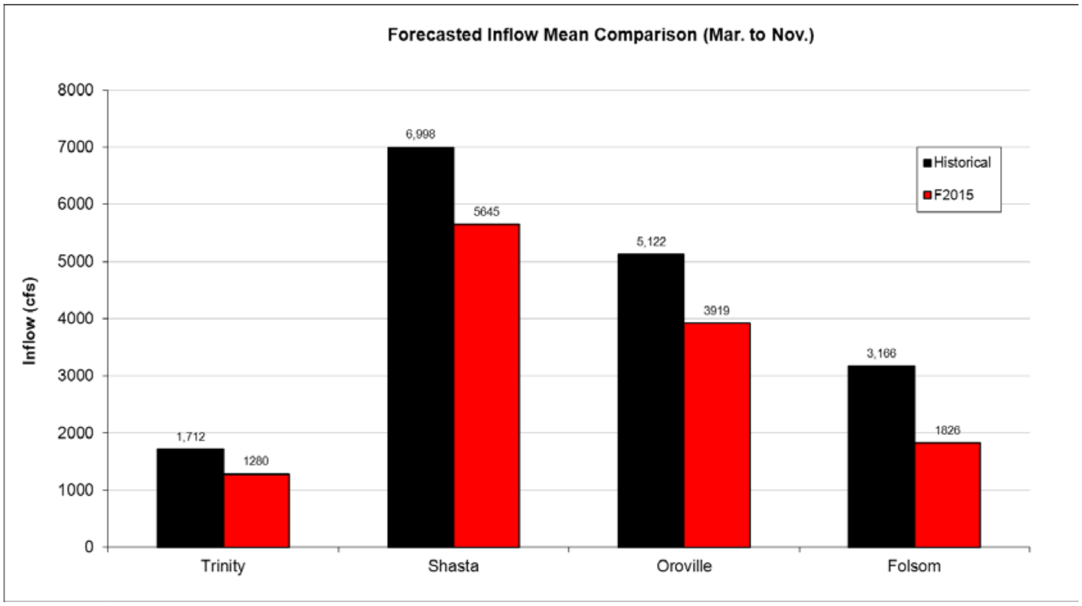

Figure 7: Inflow Forecast (Mar. – Nov.) vs. Average Inflow Comparison by major Sub-basin

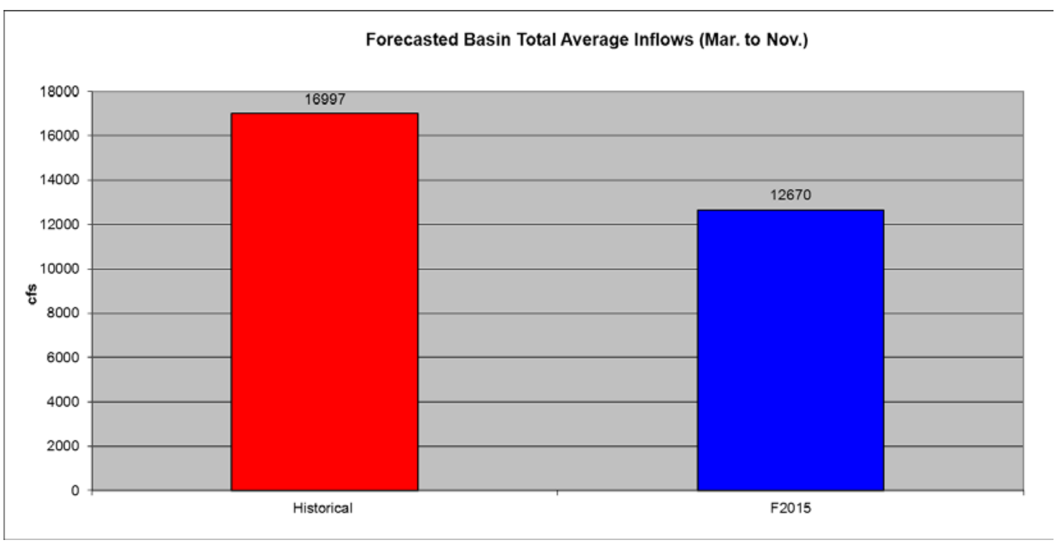

Figure 8: Systemwide Inflow Forecast vs. Average Inflow Comparison

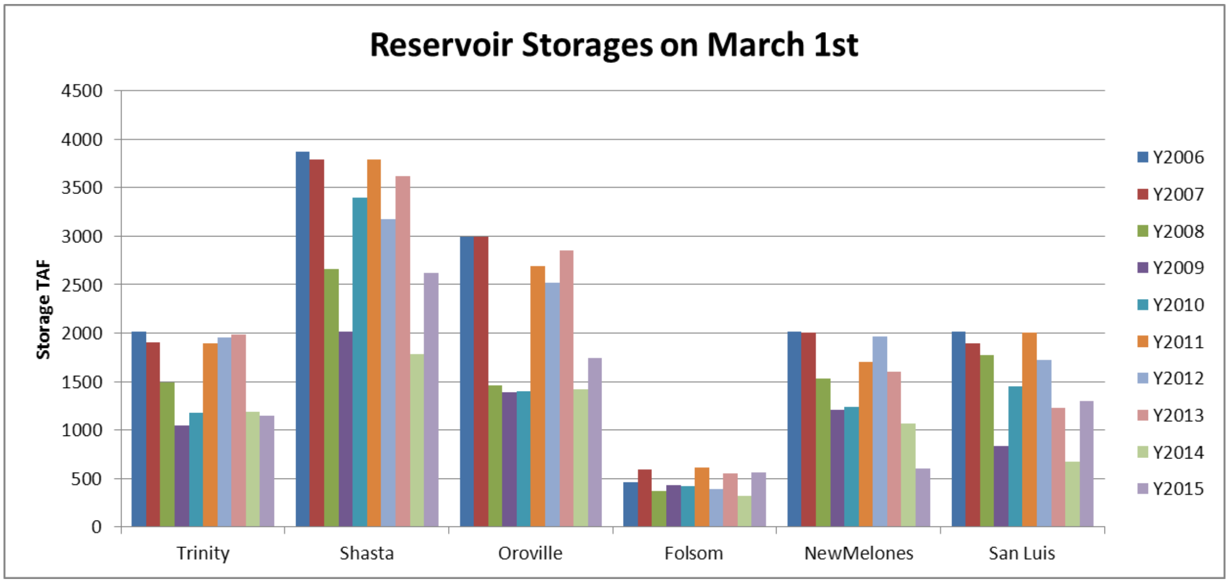

Figure 9: Historical Individual Reservoir Storages on March 1st.

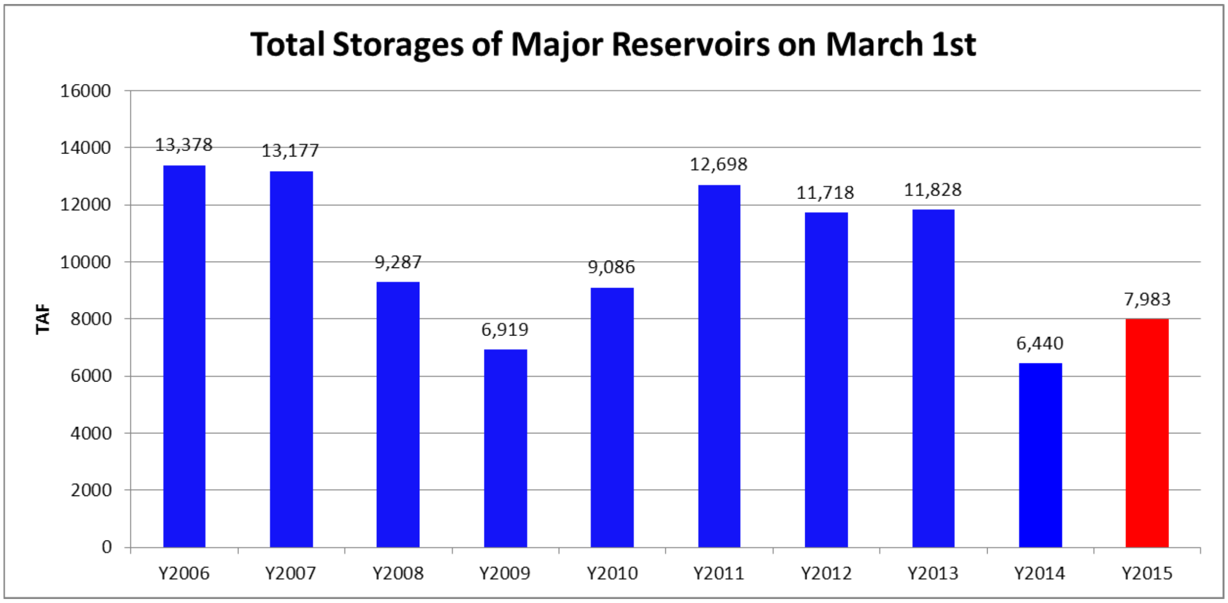

Figure 10: Historical System Storage on March 1st

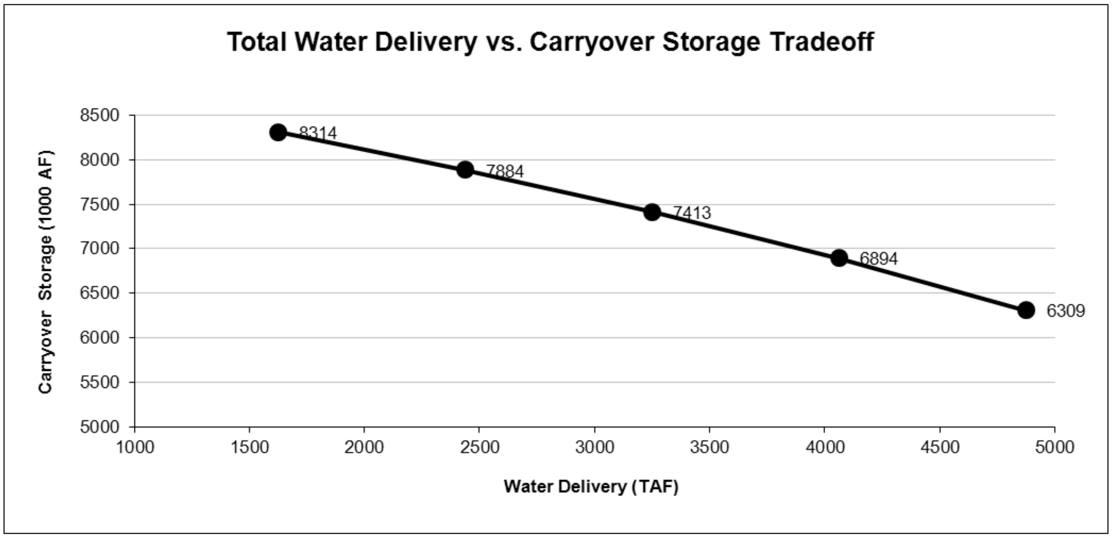

Figure 11: Water Deliveries vs. Carryover Storage Tradeoff

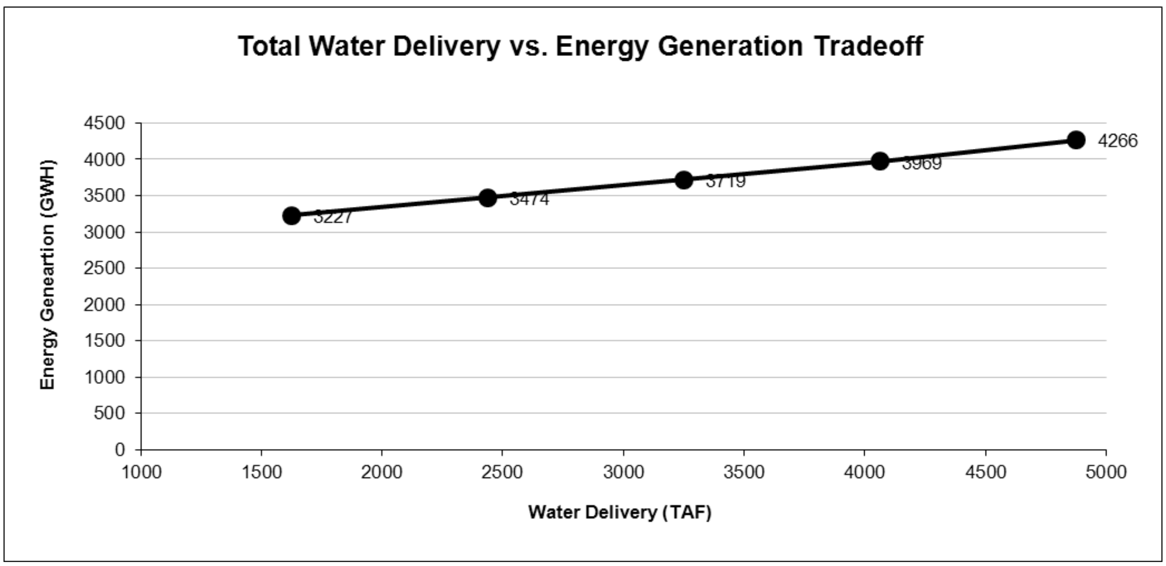

Figure 12: Water Deliveries vs. Energy Generation Tradeoff

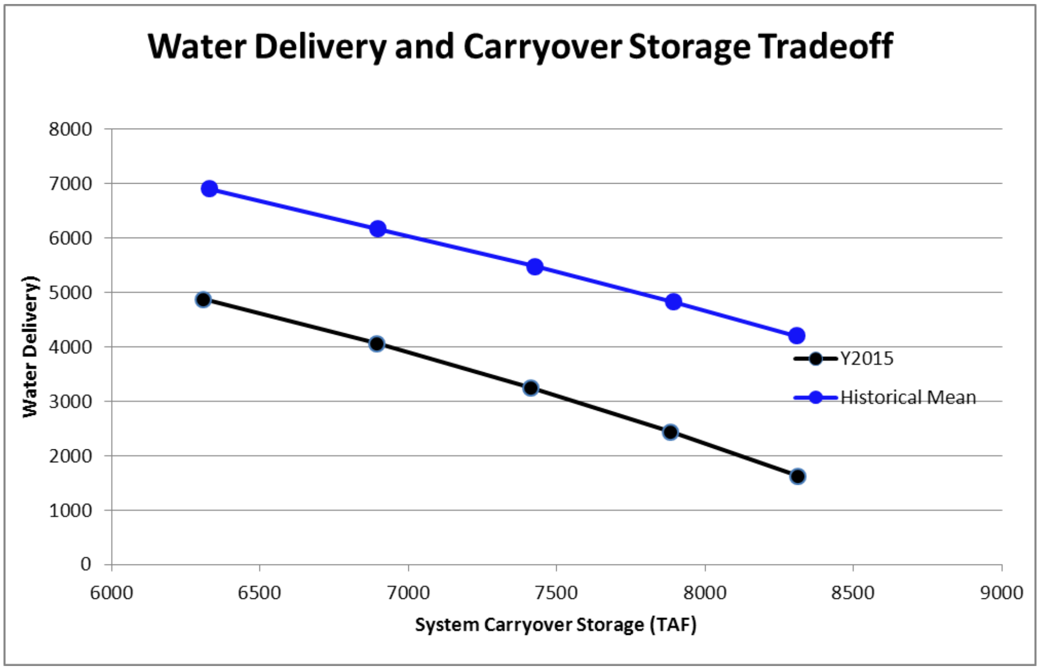

Figure 13: Expected Water Deliveries for 2105 and for an Average Hydrologic Year

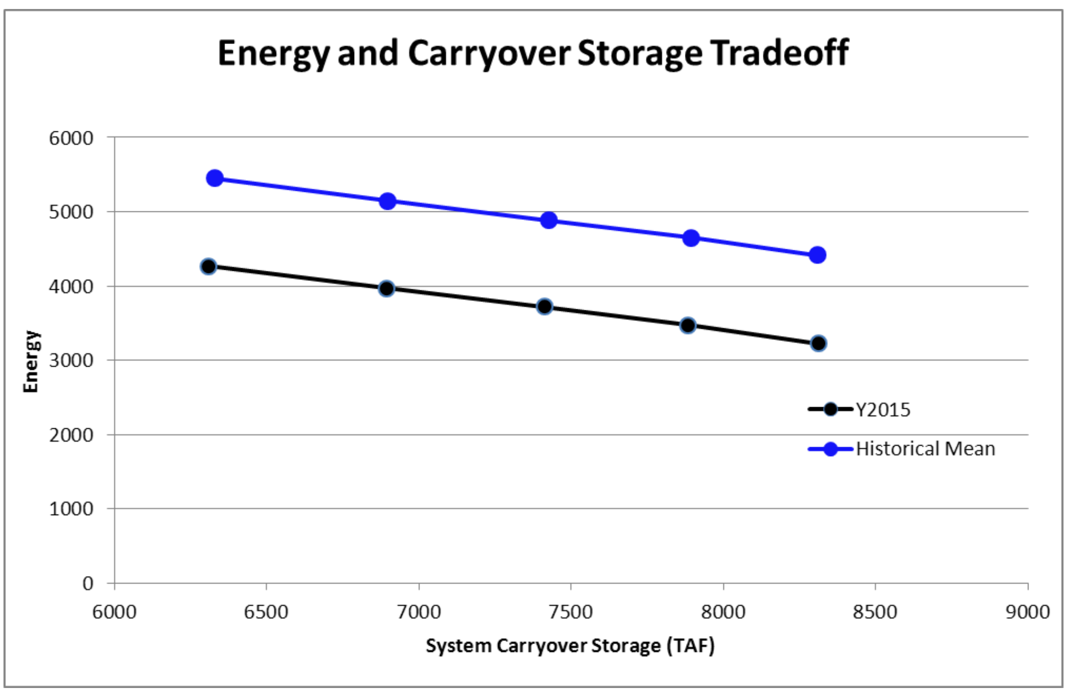

Figure 14: Expected Energy Generation for 2015 and for an Average Hydrologic Year

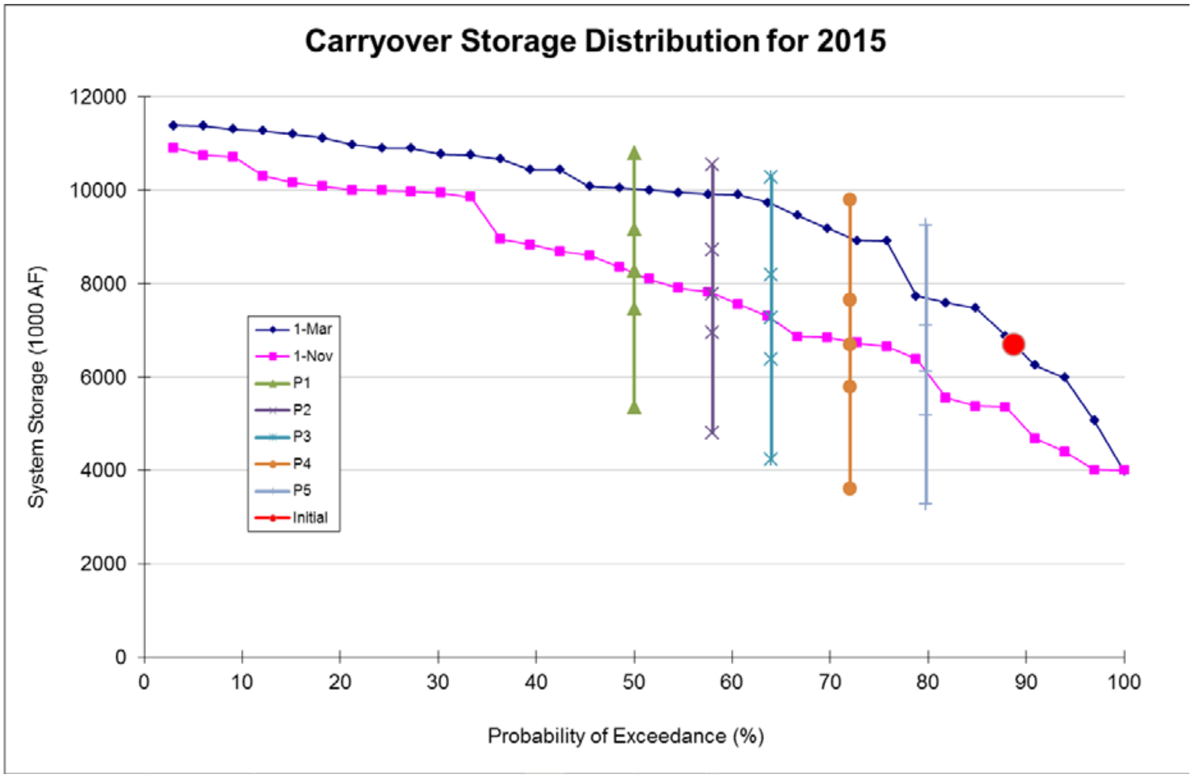

Figure 15: Comparisons with Historical Storage Conditions

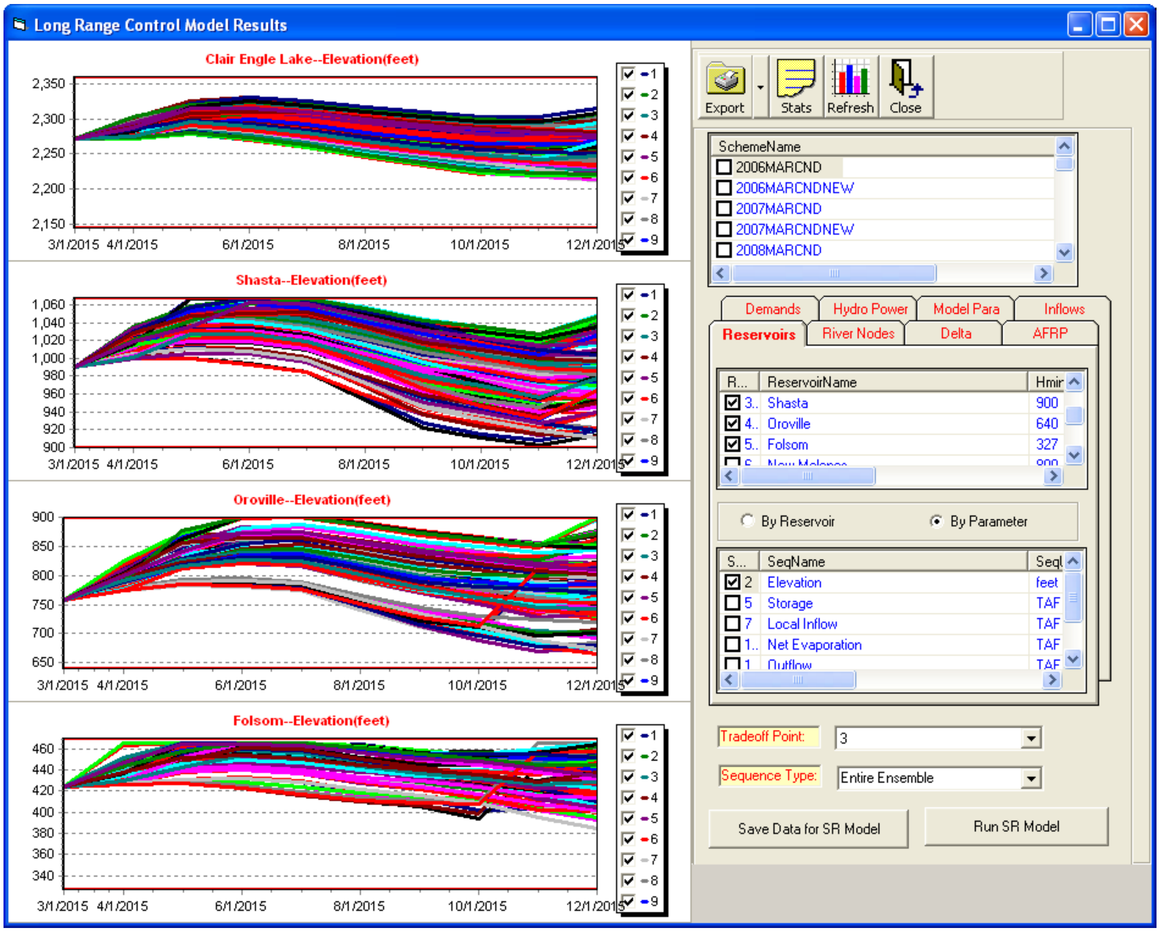

Figure 16: Reservoir Elevation Sequences for Tradeoff Point 3

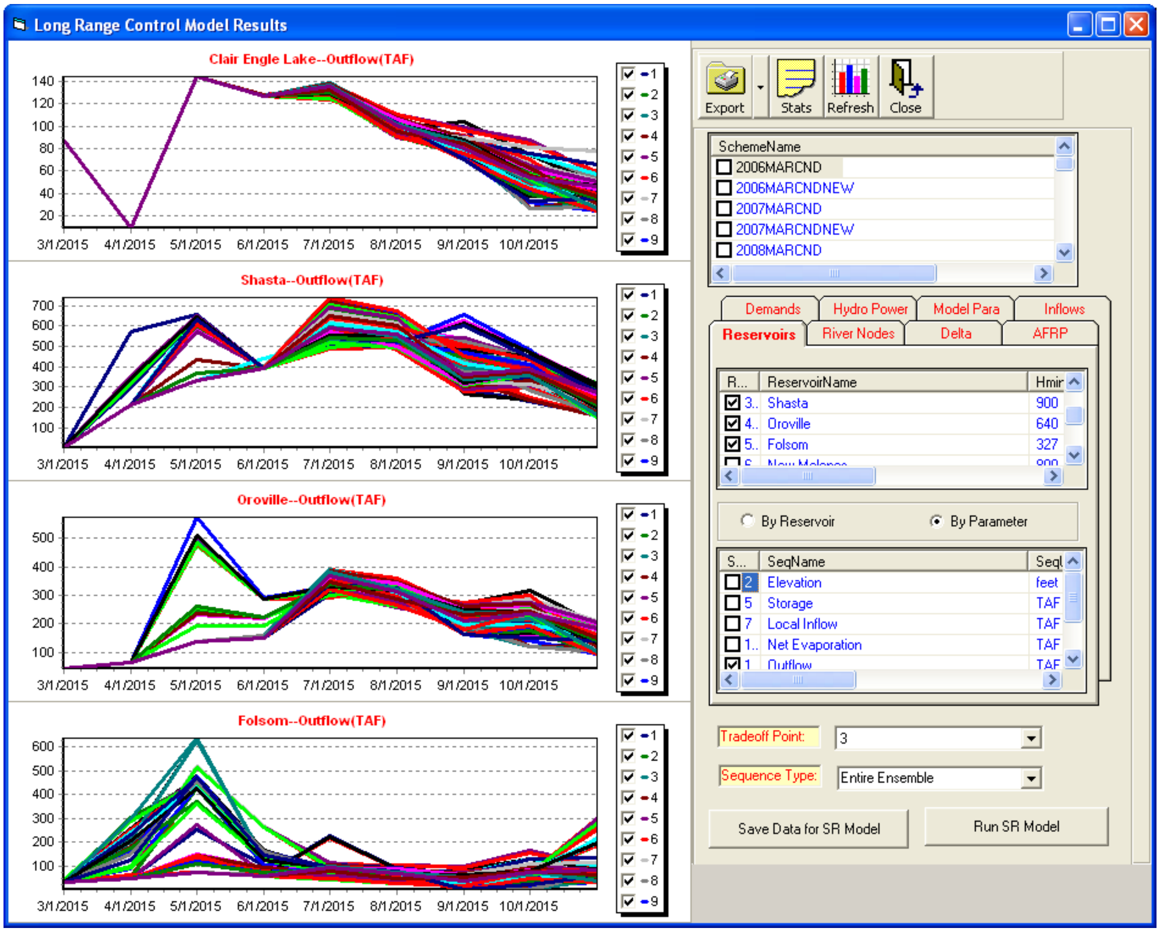

Figure 17: Reservoir Release Sequences for Tradeoff Point 3

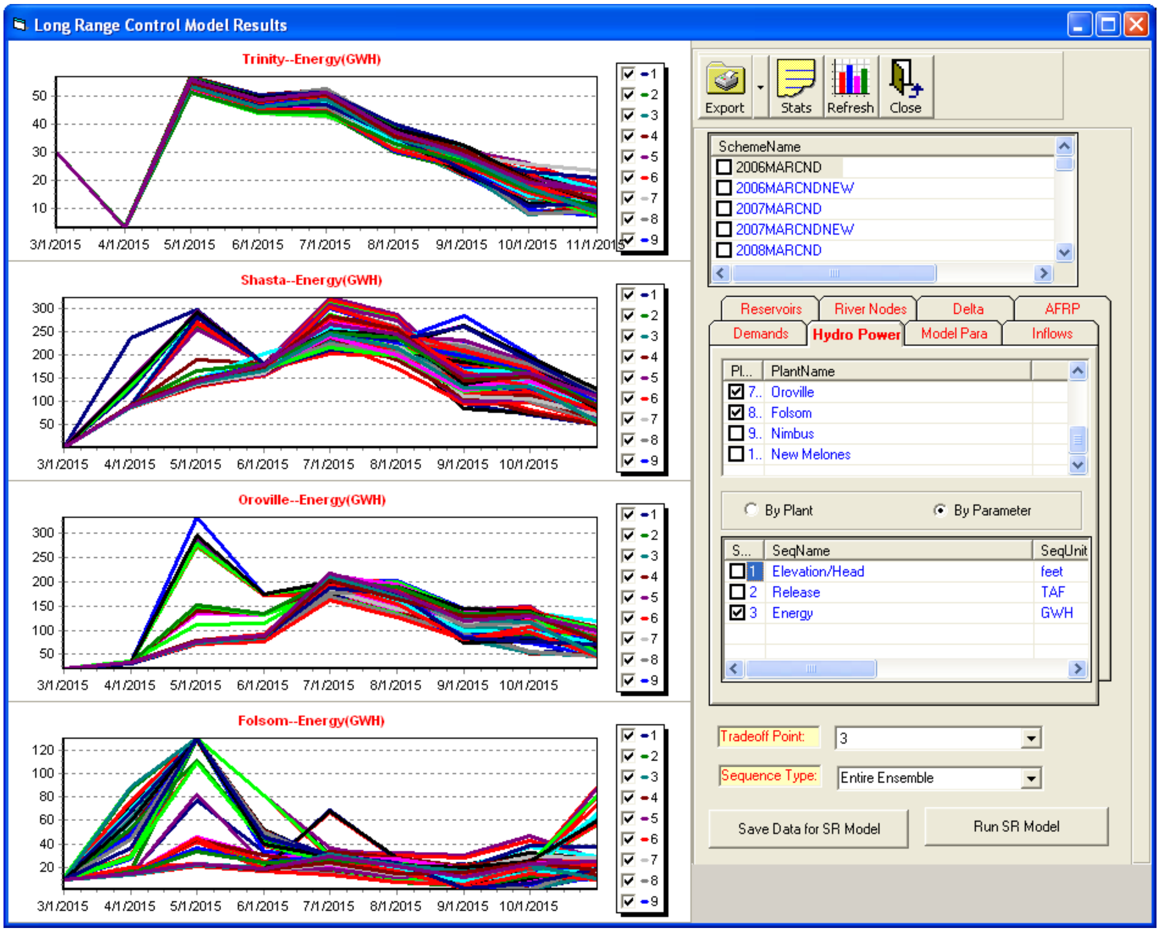

Figure 18: Reservoir Energy Generation Sequences for Tradeoff Point 3

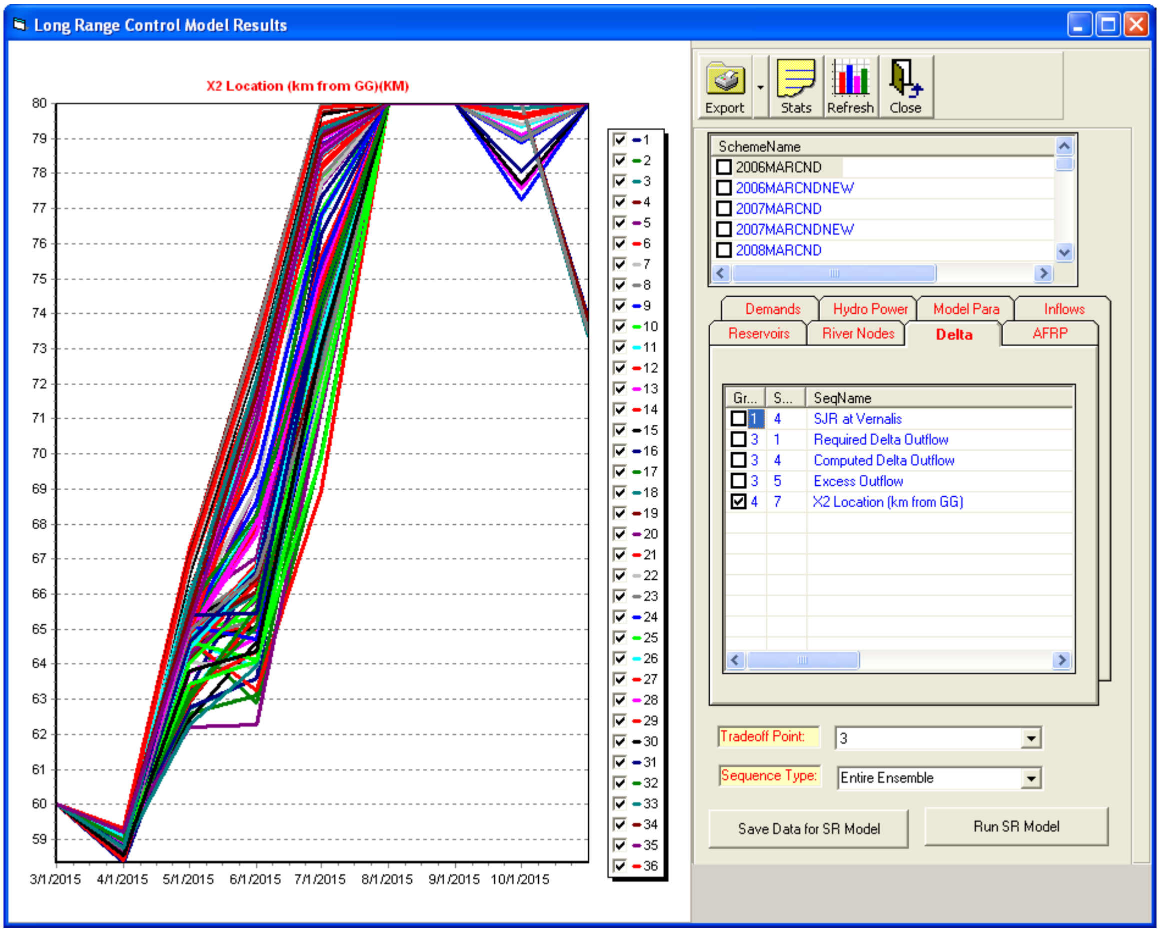

Figure 19: X2 Location Sequences for Tradeoff Point 3

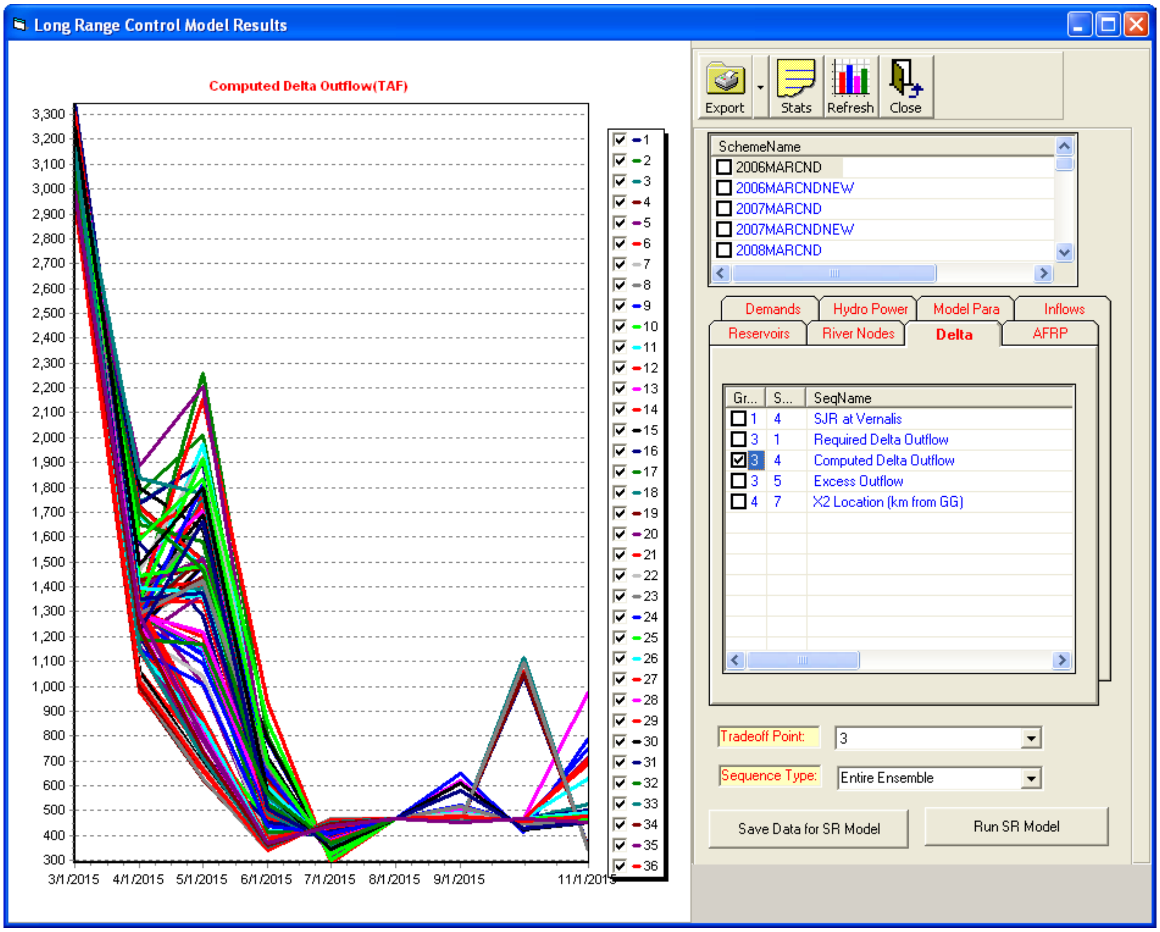

Figure 20: Delta Outflow Sequences for Tradeoff Point 3

Table 1: Monthly Average Inflows for Selected Locations (TAF)

Month	Whisktown	Keswick-Wilkens	Sacrament Misc	Eastside Streams	Delta Misc Creeks	New Melones	SJR
Jan	8.	-211.27	-100.	80.67	25.5	76.	133.
Feb	4.	-299.69	-220.	60.44	25.5	43.	31.
Mar	2.	-370.28	-330.	20.72	29.	34.	33.
Apr	1.	-267.47	-175.	21.89	19.	33.	28.
May	1.	-117.56	45.	28.71	11.1	31.	33.
Jun	2.	-125.	-15.	33.2	0.8	30.	71.
Jul	2.	-31.24	121.	30.74	0.9	30.	62.
Aug	4.	564.46	981.	21.52	1.2	30.	63.
Sep	8.	841.7	1465.	21.52	1.8	30.	78.
Oct	12.	1767.58	2482.	40.03	32.3	40.	94.
Nov	45.	1021.	1763.	67.33	17.4	70.	103.
Dec	16.	74.65	328.	146.34	15.4	110.	126.

Table D.2: Reservoir Monthly Parameters

Name	Month	Smax (TAF)	Smin (TAF)	Starget (TAF)	Evap Rate (feet)
Clair Engle	Jan	2287.00	312.63	2287.00	0.17
Clair Engle	Feb	2287.00	312.63	2287.00	0.13
Clair Engle	Mar	2287.00	312.63	2287.00	0.20
Clair Engle	Apr	2287.00	312.63	2287.00	0.39
Clair Engle	May	2287.00	312.63	2287.00	0.51
Clair Engle	Jun	2287.00	312.63	2287.00	0.58
Clair Engle	Jul	2287.00	312.63	2287.00	0.76
Clair Engle	Aug	2287.00	312.63	2287.00	0.71
Clair Engle	Sep	2287.00	312.63	2287.00	0.60
Clair Engle	Oct	2287.00	312.63	2287.00	0.30
Clair Engle	Nov	2287.00	312.63	2287.00	0.15
Clair Engle	Dec	2287.00	312.63	2287.00	0.09
WhiskeyTown	Jan	237.90	200.00	205.70	0.17
WhiskeyTown	Feb	237.90	200.00	205.70	0.13
WhiskeyTown	Mar	237.90	200.00	205.70	0.20
WhiskeyTown	Apr	237.90	200.00	237.90	0.39
WhiskeyTown	May	237.90	200.00	237.90	0.51
WhiskeyTown	Jun	237.90	200.00	237.90	0.58
WhiskeyTown	Jul	237.90	200.00	237.90	0.76
WhiskeyTown	Aug	237.90	200.00	237.90	0.71
WhiskeyTown	Sep	237.90	200.00	238.00	0.60
WhiskeyTown	Oct	237.90	200.00	230.00	0.30
WhiskeyTown	Nov	237.90	200.00	205.70	0.15
WhiskeyTown	Dec	237.90	200.00	205.70	0.09
Shasta	Jan	4552	1168	4552	0.17
Shasta	Feb	4552	1168	4552	0.13
Shasta	Mar	4552	1168	4552	0.20
Shasta	Apr	4552	1168	4552	0.39
Shasta	May	4552	1168	4552	0.51
Shasta	Jun	4552	1168	4552	0.58
Shasta	Jul	4552	1168	3882	0.76
Shasta	Aug	4552	1168	3252	0.71
Shasta	Sep	4552	1168	3252	0.60
Shasta	Oct	4552	1168	3872	0.30
Shasta	Nov	4552	1168	4252	0.15
Shasta	Dec	4552	1168	4552	0.09
Oroville	Jan	3538	855	3458	0.17
Oroville	Feb	3538	855	3538	0.13
Oroville	Mar	3538	855	3538	0.20
Oroville	Apr	3538	855	3538	0.39

Oroville	May	3538	855	3538	0.51
Oroville	Jun	3538	855	3343	0.58
Oroville	Jul	3538	855	3163	0.76
Oroville	Aug	3538	855	3163	0.71
Oroville	Sep	3538	855	3163	0.60
Oroville	Oct	3538	855	3163	0.30
Oroville	Nov	3538	855	3163	0.15
Oroville	Dec	3538	855	3163	0.09
Folsom	Jan	975	83	805	0.17
Folsom	Feb	975	83	975	0.13
Folsom	Mar	975	83	975	0.20
Folsom	Apr	975	83	975	0.39
Folsom	May	975	83	975	0.51
Folsom	Jun	975	83	975	0.58
Folsom	Jul	975	83	700	0.76
Folsom	Aug	975	83	575	0.71
Folsom	Sep	975	83	575	0.60
Folsom	Oct	975	83	575	0.30
Folsom	Nov	975	83	575	0.15
Folsom	Dec	975	83	675	0.09
New Melones	Jan	2420	273	2230	0.17
New Melones	Feb	2420	273	2420	0.13
New Melones	Mar	2420	273	2420	0.20
New Melones	Apr	2420	273	2420	0.39
New Melones	May	2420	273	2420	0.51
New Melones	Jun	2420	273	2270	0.58
New Melones	Jul	2420	273	1970	0.76
New Melones	Aug	2420	273	1970	0.71
New Melones	Sep	2420	273	1970	0.60
New Melones	Oct	2420	273	1970	0.30
New Melones	Nov	2420	273	1970	0.15
New Melones	Dec	2420	273	2040	0.09
Tulloch	Jan	67	57	57	0.00
Tulloch	Feb	67	57	57	0.00
Tulloch	Mar	67	57	58	0.00
Tulloch	Apr	67	57	60	0.00
Tulloch	May	67	57	67	0.00
Tulloch	Jun	67	57	67	0.00
Tulloch	Jul	67	57	67	0.00
Tulloch	Aug	67	57	67	0.00
Tulloch	Sep	67	57	62	0.00
Tulloch	Oct	67	57	57	0.00
Tulloch	Nov	67	57	57	0.00
Tulloch	Dec	67	57	57	0.00
San Luis	Jan	2027	450.00	1000.00	0.17

San Luis	Feb	2027	631.60	1464.02	0.13
San Luis	Mar	2027	748.10	1806.84	0.20
San Luis	Apr	2027	835.60	1975.02	0.39
San Luis	May	2027	879.92	1976.43	0.51
San Luis	Jun	2027	694.72	1546.00	0.58
San Luis	Jul	2027	442.12	1062.95	0.76
San Luis	Aug	2027	181.12	642.62	0.71
San Luis	Sep	2027	9.72	352.64	0.60
San Luis	Oct	2027	8.32	312.90	0.30
San Luis	Nov	2027	115.02	354.13	0.15
San Luis	Dec	2027	286.72	514.21	0.09

Table 3: Monthly Minimum and Target River Flows

Name	Month	Rmin (cfs)	Rtarget (cfs)
Lewiston	Jan	300	300
Lewiston	Feb	300	300
Lewiston	Mar	300	300
Lewiston	Apr	300	300
Lewiston	May	3939	300
Lewiston	Jun	2507	783
Lewiston	Jul	1102	450
Lewiston	Aug	450	450
Lewiston	Sep	450	450
Lewiston	Oct	373	0
Lewiston	Nov	300	300
Lewiston	Dec	300	300
Clear Creek	Jan	150	150
Clear Creek	Feb	200	200
Clear Creek	Mar	200	200
Clear Creek	Apr	200	200
Clear Creek	May	200	200
Clear Creek	Jun	200	200
Clear Creek	Jul	200	200
Clear Creek	Aug	200	200
Clear Creek	Sep	200	200
Clear Creek	Oct	200	200
Clear Creek	Nov	90	90
Clear Creek	Dec	90	90
Spring Creek	Jan	325	325
Spring Creek	Feb	306	306
Spring Creek	Mar	2749	2749

Spring Creek	Apr	252	252
Spring Creek	May	813	813
Spring Creek	Jun	1681	1681
Spring Creek	Jul	2602	2602
Spring Creek	Aug	2114	2114
Spring Creek	Sep	2017	2017
Spring Creek	Oct	1138	1138
Spring Creek	Nov	504	504
Spring Creek	Dec	244	244
Keswick	Jan	3250	3250
Keswick	Feb	3250	3250
Keswick	Mar	3250	3250
Keswick	Apr	8000	8000
Keswick	May	9600	9600
Keswick	Jun	11000	11000
Keswick	Jul	14500	14500
Keswick	Aug	12000	12000
Keswick	Sep	5500	5500
Keswick	Oct	7200	7200
Keswick	Nov	5700	5700
Keswick	Dec	3250	3250
Wilkins	Jan	0	0
Wilkins	Feb	0	0
Wilkins	Mar	0	0
Wilkins	Apr	5000	5000
Wilkins	May	5000	5000
Wilkins	Jun	5000	5000
Wilkins	Jul	5000	5000
Wilkins	Aug	5000	5000
Wilkins	Sep	5000	5000
Wilkins	Oct	5000	5000
Wilkins	Nov	0	0
Wilkins	Dec	0	0
FeatherBelowThermalito	Jan	1250	0
FeatherBelowThermalito	Feb	1250	0
FeatherBelowThermalito	Mar	1250	0
FeatherBelowThermalito	Apr	1250	0
FeatherBelowThermalito	May	2030	0
FeatherBelowThermalito	Jun	0	2706
FeatherBelowThermalito	Jul	0	5692
FeatherBelowThermalito	Aug	5040	5156
FeatherBelowThermalito	Sep	0	4386
FeatherBelowThermalito	Oct	1980	2683
FeatherBelowThermalito	Nov	1750	1815
FeatherBelowThermalito	Dec	1250	0

AmericanRiverbelowNimbus	Jan	800	0
AmericanRiverbelowNimbus	Feb	800	0
AmericanRiverbelowNimbus	Mar	1000	0
AmericanRiverbelowNimbus	Apr	1500	0
AmericanRiverbelowNimbus	May	2300	0
AmericanRiverbelowNimbus	Jun	1800	0
AmericanRiverbelowNimbus	Jul	0	0
AmericanRiverbelowNimbus	Aug	0	0
AmericanRiverbelowNimbus	Sep	0	0
AmericanRiverbelowNimbus	Oct	0	0
AmericanRiverbelowNimbus	Nov	1000	0
AmericanRiverbelowNimbus	Dec	800	0
Goodwin	Jan	175	175
Goodwin	Feb	150	150
Goodwin	Mar	268	268
Goodwin	Apr	760	760
Goodwin	May	800	800
Goodwin	Jun	561	561
Goodwin	Jul	396	396
Goodwin	Aug	352	352
Goodwin	Sep	240	240
Goodwin	Oct	200	200
Goodwin	Nov	200	200
Goodwin	Dec	200	200
DeltaExit	Jan	6001	6001
DeltaExit	Feb	11398	11398
DeltaExit	Mar	11401	11401
DeltaExit	Apr	7848	7848
DeltaExit	May	9319	9319
DeltaExit	Jun	7092	7092
DeltaExit	Jul	6505	6505
DeltaExit	Aug	4261	4261
DeltaExit	Sep	3008	3008
DeltaExit	Oct	4001	4001
DeltaExit	Nov	4655	4655
DeltaExit	Dec	4505	4505

Table 4: Monthly Base Demands

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Thermolito	35	0	11	67	189	178	200	178	78	95	104	71
Folsom Pumping	4	4	4	7	8	12	13	12	10	7	5	4
Folsom South Canal	1	1	1	1	2	3	4	4	3	2	1	1
OID/SSJID	0	0	14	60	90	90	95	95	74	14	0	0
CVP Contractors	0	0	0	0	0	0	0	0	0	0	0	0
CCWD	14	17	18	18	14	14	13	13	13	10	11	13
Barker Slough	2	2	1	2	4	5	7	7	6	5	3	3
Federal Tracy PP	258	233	258	250	135	169	270	268	260	258	250	258
Federal Banks On-Peak	0	0	0	0	0	0	28	28	28	0	0	0
State Banks PP	390	355	241	68	108	125	271	278	238	175	193	390
State Tracy PP	0	0	0	0	0	0	0	0	0	0	0	0
Delta Mendota Canal	30	60	100	120	190	220	270	240	180	110	40	30
Federal Dos Amigos	40	50	60	70	110	180	238	178	68	30	30	30
Federal O'Neil to Dos Amigos	0	1	1	1	1	2	2	1	0	0	0	0
San Felipe	6	6	10	15	19	20	21	20	13	11	8	8
South Bay/San Jose	2	2	2	5	5	7	7	8	7	12	8	6
State Dos Amigos	105	127	158	105	348	348	423	388	269	229	196	61
Delta Consumptive Use	-56	-37	-10	63	121	191	268	252	174	118	55	2
Freeport Treatment Plant	14	13	14	12	12	12	12	13	12	12	12	13

Table 5: Initial Reservoir Storages on March 1, 2015

Reservoirs	Max. Storage	Min. Storage	Initial Storage	Ini Act. Sto. Fraction (%)
Clair Engle Lake	2287	312.63	1148	42.31
Whiskeytown	237.9	200	208	20.24
Shasta	4552	1168	2621	42.94
Oroville	3538	855	1739	32.96
Folsom	975	83	565	54.09
New Melones	2420	273	606	15.52
Tulloch	67	57	57	-1.39
San Luis	2027	0	1303	64.28
AVG	16103.9	2948.63	8248	40.28