RESERVOIR MODELING REPORT

CLAYTOR PROJECT
FERC NO. 739

The Louis Berger Group, Inc.
75 Second Avenue
Suite 700
Needham, MA 02494

January 2009

TABLE OF CONTENTS

LIST OF FIGURES

INTRODUCTION

Appalachian Power Company (Appalachian) is making application to the Federal Energy Regulatory Commission (FERC) for a new license for the Claytor Hydroelectric Project (No. 739), located on the New River in southwestern Virginia. The process selected by Appalachian for applying for a new license is the Integrated Licensing Process (ILP), as defined under FERC rules and regulations (18 CFR Part 5). As part of this licensing process, Appalachian solicited input from stakeholders, including governmental agencies and non-governmental organizations, to identify potential project-related issues that should be addressed during the licensing process.

Initial instream flow study plan meetings were held with stakeholders on July 19 and 20, 2006. A workgroup, comprising representatives from state resource agencies, universities, non-governmental organizations, and interested citizens, met in August 2006 to address specifics of the instream flow needs study. These meetings resulted in the development of a revised study plan, dated November 21, 2006.

A reservoir routing model was developed to analyze the effects of water level restrictions, inflow, power generation schedules, and minimum flow releases. The model used the U.S. Army Corps of Engineers HEC-ResSim (Reservoir Simulation) program, the successor to the HEC-5 program. Water withdrawals and evaporation effects, both of which are relatively minor, were not included in the model. These factors can be added at a later point if desired. There is only one existing water withdrawal on Claytor Lake, the Pulaski County Public Service Authority, which has a capacity of 3 million gallons per day (MGD), but actual withdrawals have averaged about 2 MGD. Both of these values are less than 5 cubic feet per second (cfs). Evaporation is harder to quantify, but, based on the surface area and known evaporation rates, on a yearly average approximately 20 cfs would be lost to evaporation. Any operational changes, other than ones that would significantly change the surface area of the reservoir would have very limited effects on the evaporation rates.

MODEL DESCRIPTION

Key input data for the HEC-ResSim model include:

- Inflow: Hourly inflow was calculated from the 15-minute data from U.S. Geological Survey (USGS) gage no. 03168000 New River at Allisonia. These data were prorated by 1.076 to represent the drainage area of Claytor reservoir (2,380 square miles) as compared to the drainage area at the gage (2,212 square miles). Using these data, dry months and years were defined by flows lower than those that occur 75 percent of the time, and wet months and years were defined by flows greater than those that occurred 25 percent of the time, with average years occurring between these ranges. While it was not possible to find a continuous 75 week period where every month fit the dry, average, or wet definition, the following three periods were determined to be the most representative of each water year type, especially for the normally drier summer and fall months:

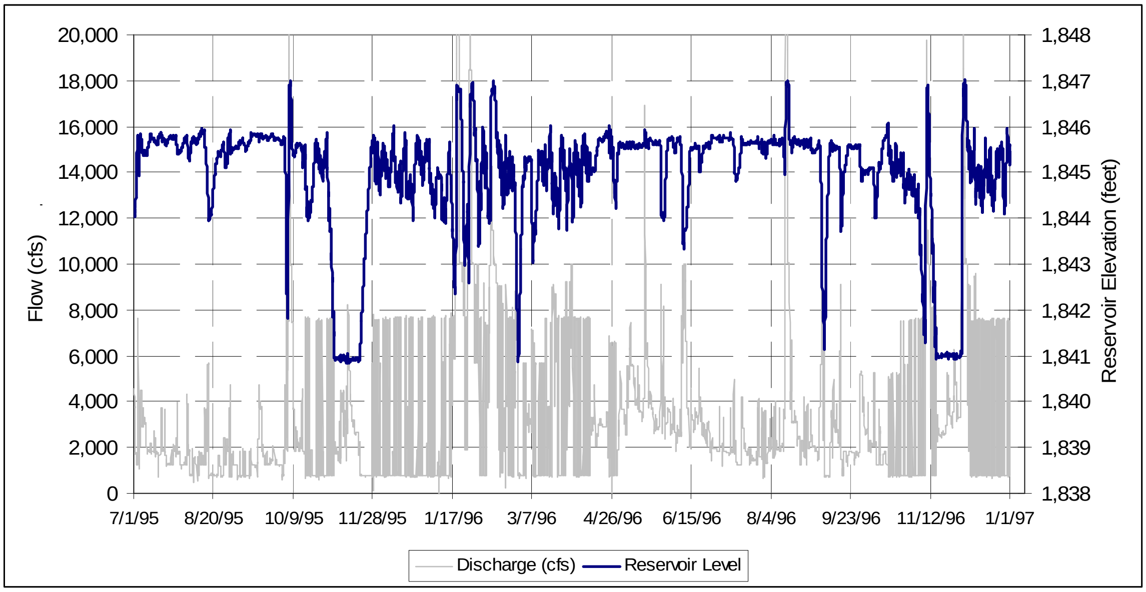
Average:	July 1995 to December 1996
Dry:	July 2000 to December 2001
Wet:	July 2003 to December 2004

- Reservoir Storage: The HEC-ResSim model used the updated reservoir storage volumes from the Sedimentation Study Report for the Claytor Hydroelectric Project dated March 2008 as provided below:

Elevation	**Storage (acre-feet)**
1,740	742
1,750	3,525
1,760	9,982
1,770	20,247
1,780	34,152
1,790	50,882
1,800	70,006
1,810	91,620
1,820	116,389
1,830	144,653
1,838	171,089
1,840	178,526
1,844	194,674
1,846	203,394
1,850	221,478

- Operations: Four turbines were modeled with normal maximum flow of 2,000 cfs each (8,000 cfs total) but with a total station capacity of 10,000 cfs operated currently as a peaking facility on a weekly cycle.
- Current minimum flow of 750 cfs.
- Current reservoir level management:
  - April 15 to June 15: stable reservoir elevations at or above and elevation 1,844 feet to protect spawning habitat.
  - June 16 to October 15: More levelized flows for downstream recreation with reservoir levels between about 1,845 and 1,846.
  - October 16 to April 14: peaking with a reservoir fluctuating between 1,844 and 1,846 feet.
  - A late fall / early winter drawdown (modeled as the last 2 weeks in December) of 5 to 6 feet to allow for maintenance of docks, bulkheads, and boat ramps.

Figure 1. Historical, non-modeled, conditions during the July 1, 1995, to December 31, 1996, period.



MODEL SCENARIOS

Peaking operations were modeled by specifying a combined turbine flow rate that increased with available storage and reservoir inflow. Turbine flow rates increased at discrete levels to represent generating using a combination of 4 turbines (i.e., 2,000, 4,000, 6,000, and 8,000 cfs). Peaking operations occurred between the weekday hours of 11:00 am and 6:00 pm. Weekend peaking operations occurred only during periods with high inflow with reservoir levels within the designated rule curve. Reservoir elevation and minimum flow requirements superseded peaking operations.

Six arbitrary reservoir modeling scenarios were developed for the modeling of the minimum flow requirements, reservoir levels, and operations and are summarized below. During all scenarios, the minimum flows were maintained at all times which resulted at time in reservoir levels below the designated elevation during low inflow periods.

Scenario 1:

- Minimum Flow: 750 cfs
- Reservoir Levels: April 15 to June 15: generally between 1,844 to 1,844.5
  June 16 to April 14, 1,844 to 1,846
- Peaking: between the hours of 11 am and 6 pm with weekday priority.

Scenario 2:

- Minimum Flow: 1,000 cfs
- Reservoir Levels: April 15 to June 15: generally between 1,844 to 1,844.5
  June 16 to April 14, 1,844 to 1,846
- Peaking: between the hours of 11 am and 6 pm with weekday priority.

Scenario 3:

- Minimum Flow: 1,250 cfs
- Reservoir Levels: April 15 to June 15: generally between 1,844 to 1,844.5
  June 16 to April 14, 1,844 to 1,846
- Peaking: between the hours of 11 am and 6 pm with weekday priority.

Scenario 4:

- 750 cfs Minimum Flow October 1 to February 28
- 1,000 cfs Minimum Flow March 1 to September 30
- Reservoir Levels: April 15 to June 15: generally between 1,844 to 1,844.5
  June 16 to April 14, 1,844 to 1,846
- Peaking: between the hours of 11 am and 6 pm with weekday priority.

Scenario 5:

- 750 cfs Minimum Flow October 1 to February 28

- 1,250 cfs Minimum Flow March 1 to September 30
- Reservoir Levels: April 15 to June 15: generally between 1,844 to 1,844.5
June 16 to April 14, 1,844 to 1,846
- Peaking: between the hours of 11 am and 6 pm with weekday priority.

Scenario 6:

- Run of River Operations
- Reservoir Levels: Year round 1,844.5 to 1,845.5

GRAPHIC MODEL OUTPUT:

Figures 2 through 4 provide model output graphs for flow and reservoir elevation during three representative three-month periods of dry conditions:

- July 1, 2000, to September 30, 2000;
- April 1, 2001, to June 30, 2001; and
- November 1, 2000, to January 31, 2001.

Only three of the six scenarios are shown in figures 2 through 4: 750 and 1,250 cfs minimum flow and run of river conditions.

Dry Conditions

For dry conditions these figures show that peak generation opportunities would be substantially decreased in both the summer and winter periods with the higher minimum flow scenario of 1,250 cfs, but to a lesser extent in the higher inflow spring time conditions. In addition, the graphs show that reservoir levels would fall below elevation 1,844 feet with the 1,250 cfs minimum flow scenario if minimum flow continuance is given a priority over reservoir levels.

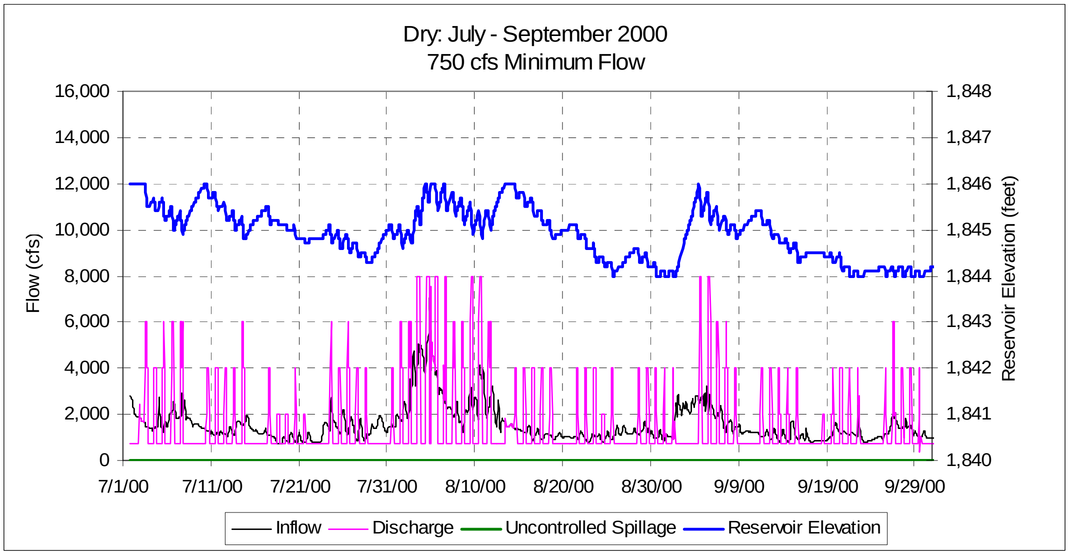
Average Conditions

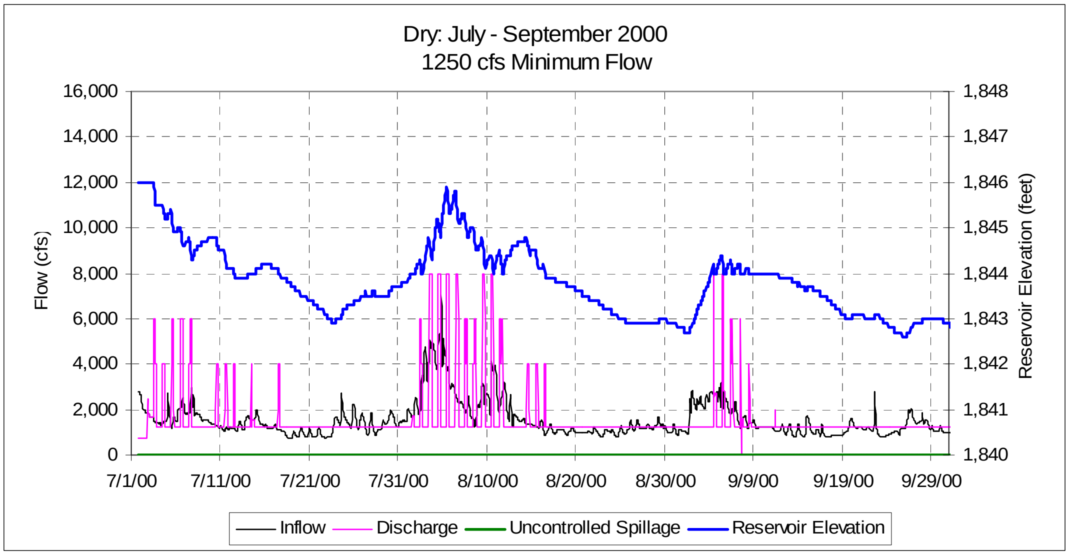
For average conditions, figures 5 through 7 show lower peaking generation opportunities in the summer period with a minimum flow of 1,250 cfs, but much lesser effects on the reservoir levels, as compared to the dry conditions graphs. In addition, there are limited graphical changes between the 750 and 1,250 cfs during the higher inflow spring and winter periods as shown in figures 6 and 7.

Wet Conditions

For wet conditions, figures 8 through 10; limited differences are indicated between the graphs representing 750 and 1,250 cfs minimum flow scenarios, indicating that inflow was high enough to meet the modeled minimum flow and reservoir level requirements.

Figure 2. Dry conditions represented by July through September 2000.





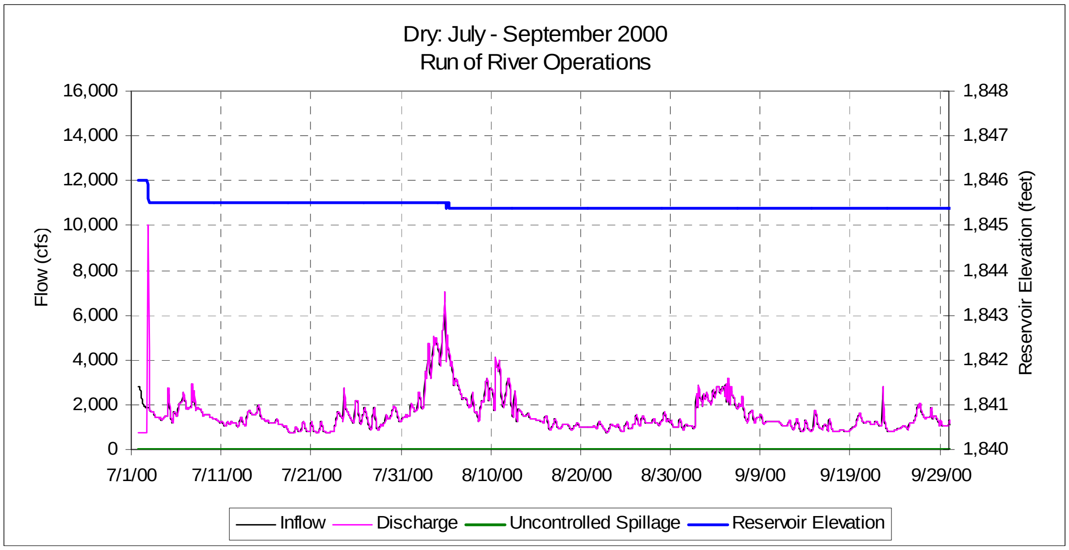


Figure 3. Dry conditions represented by April through June 2001.

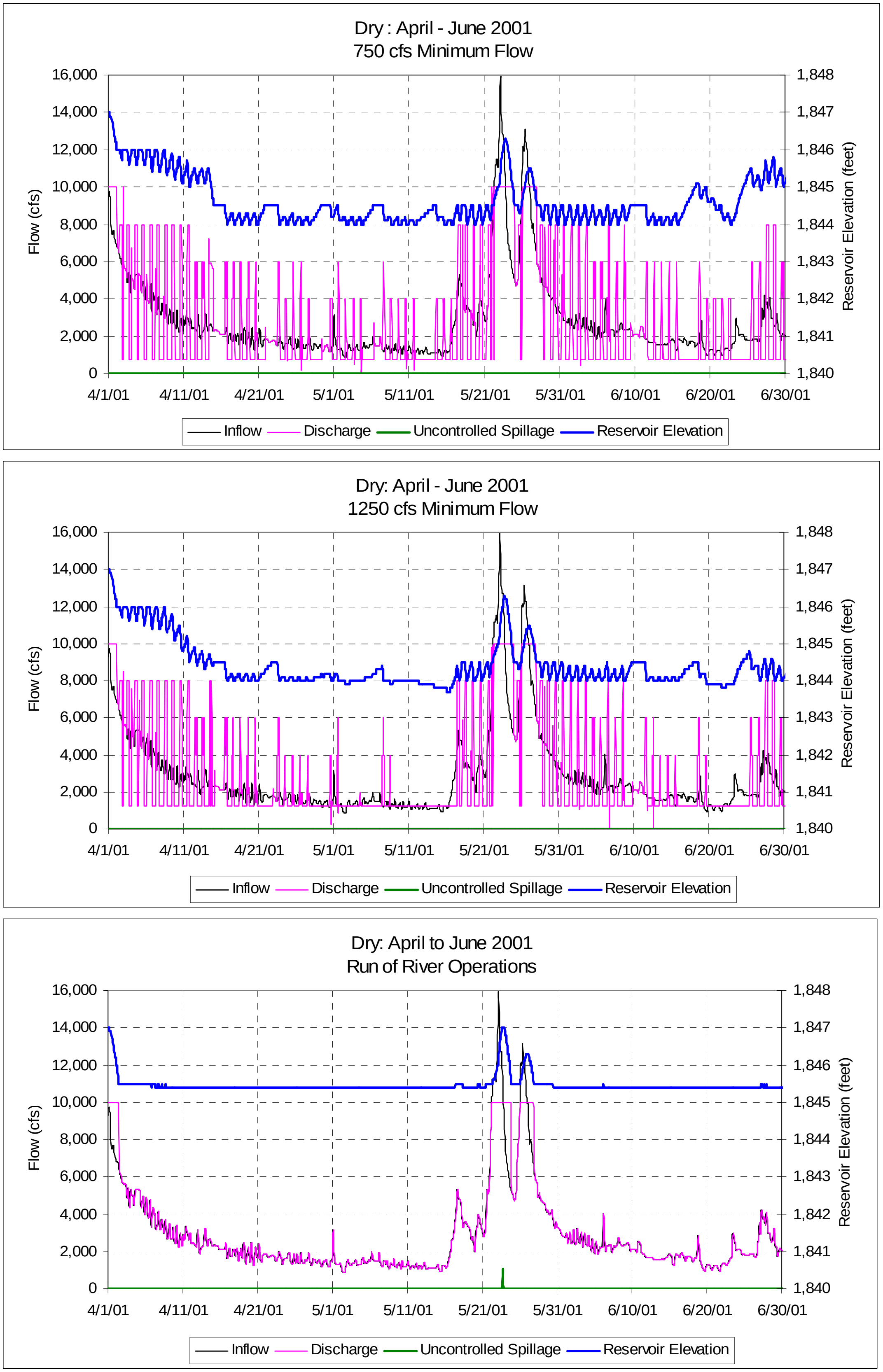
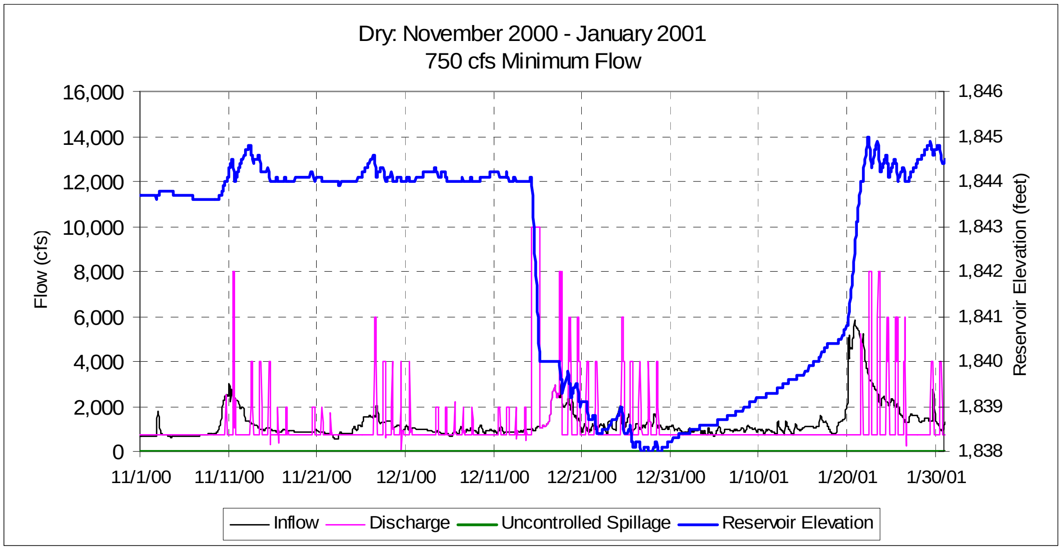
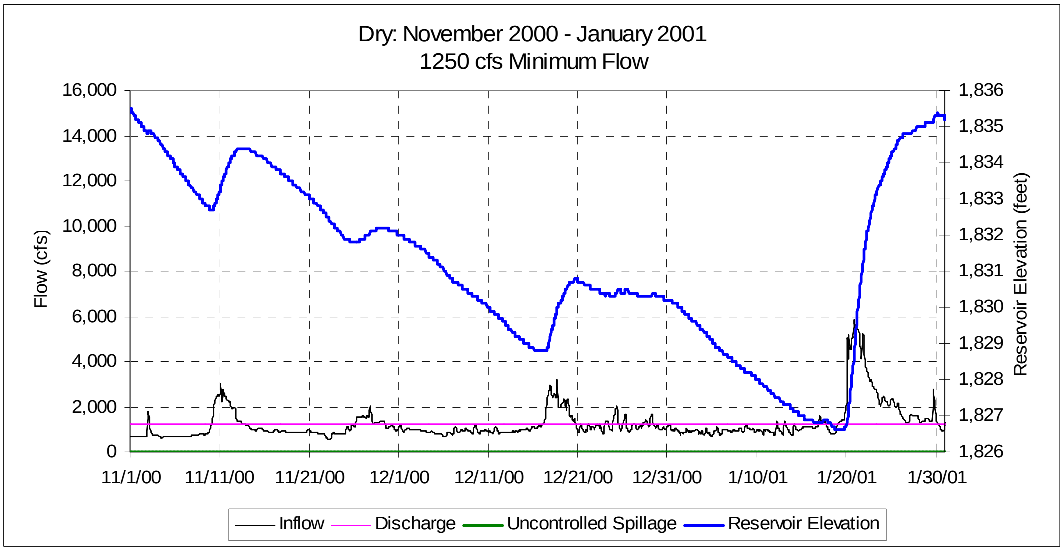


Figure 4. Dry Conditions represented by November 2000 through January 2001.





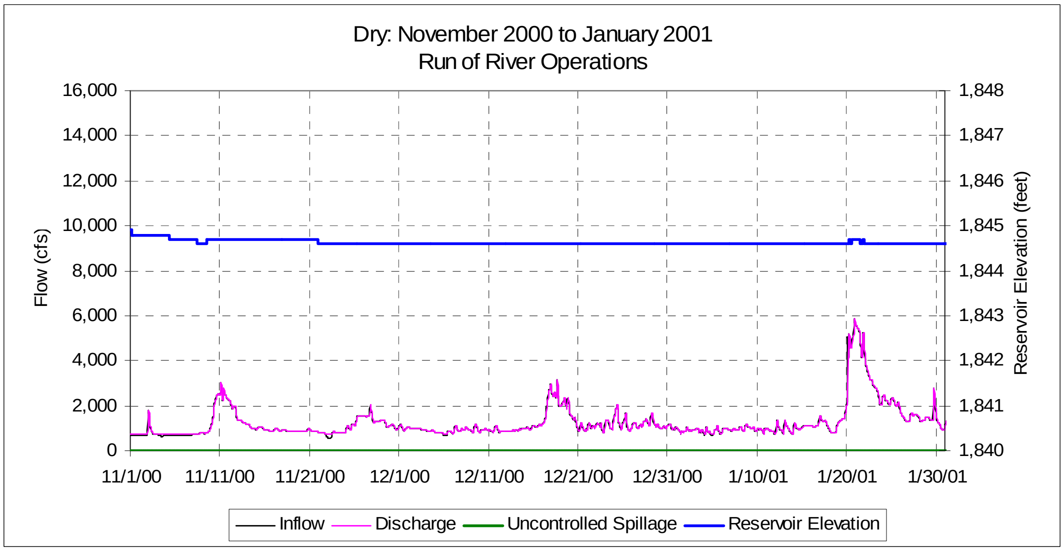
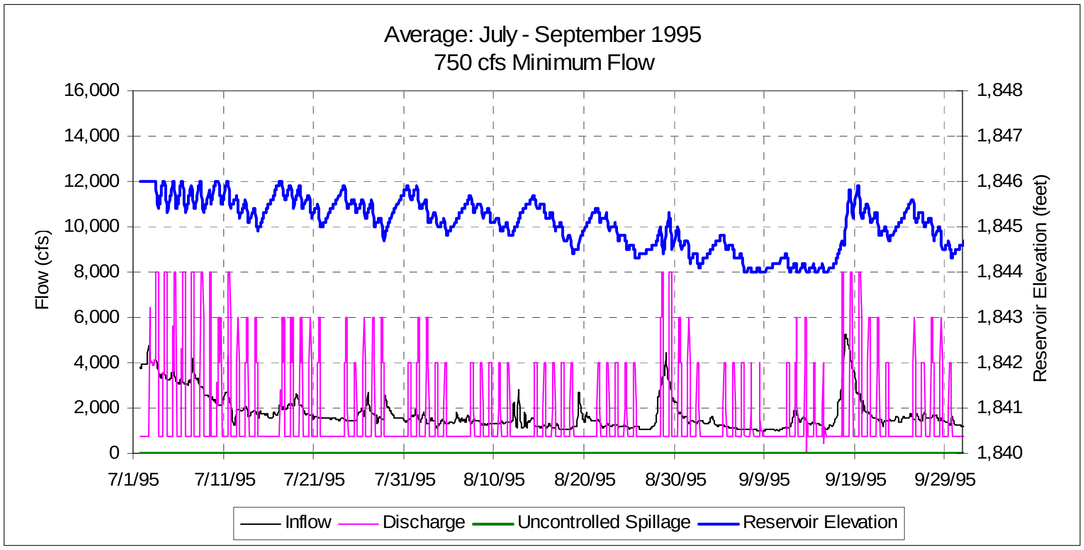
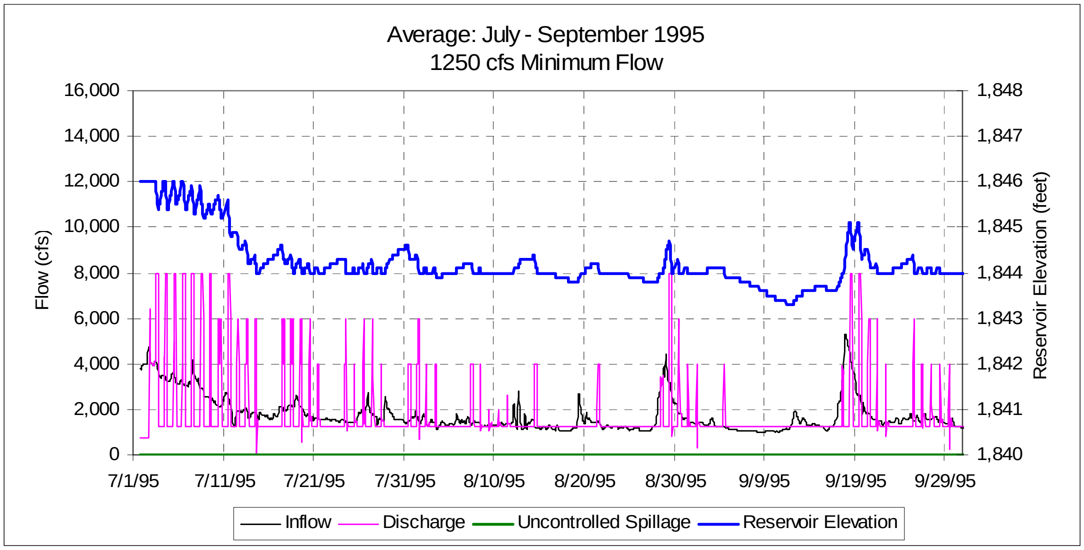


Figure 5. Average Conditions represented by July through September 1995.





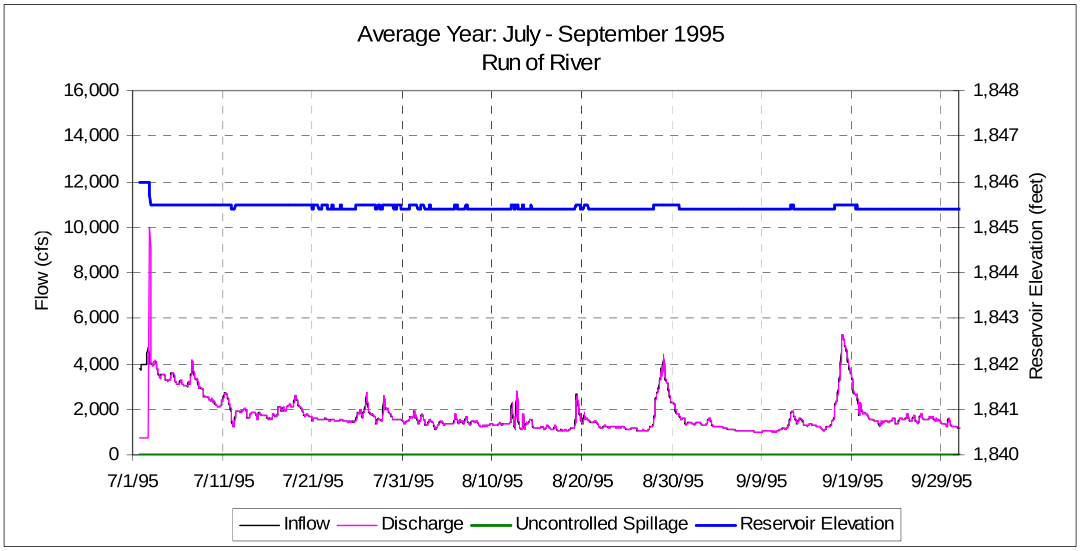


Figure 6. Average Conditions represented by April through June 1996.

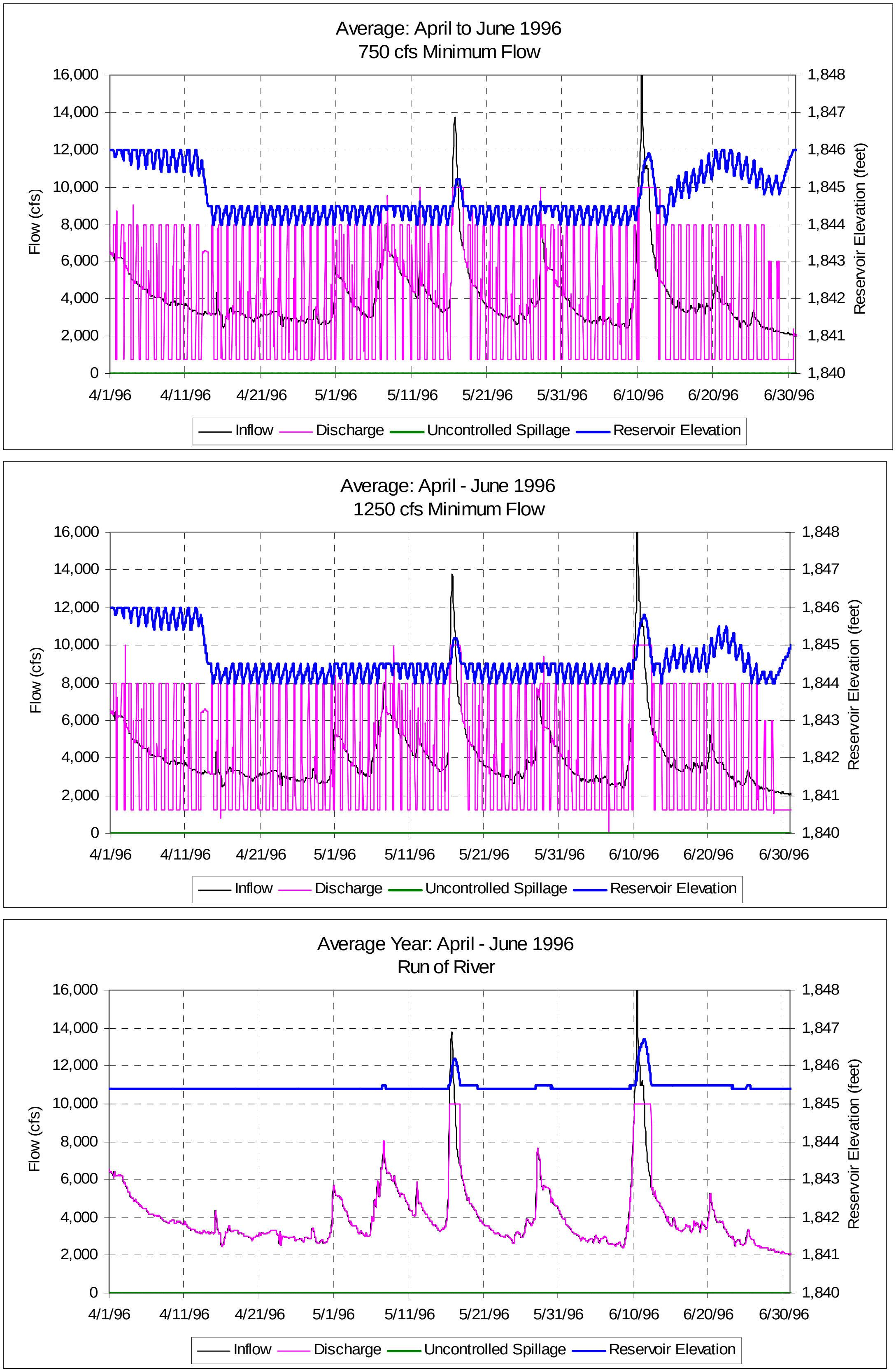
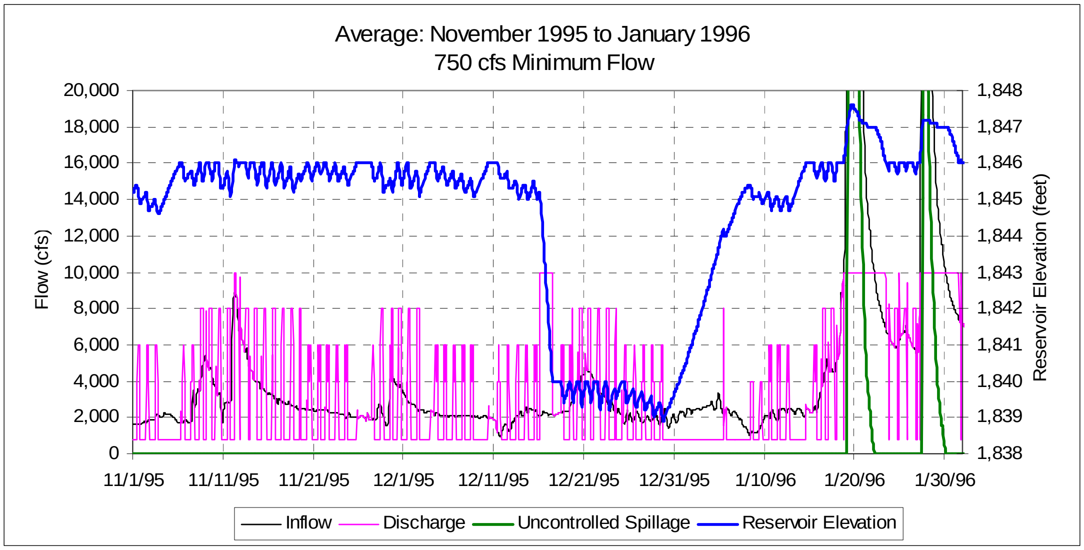
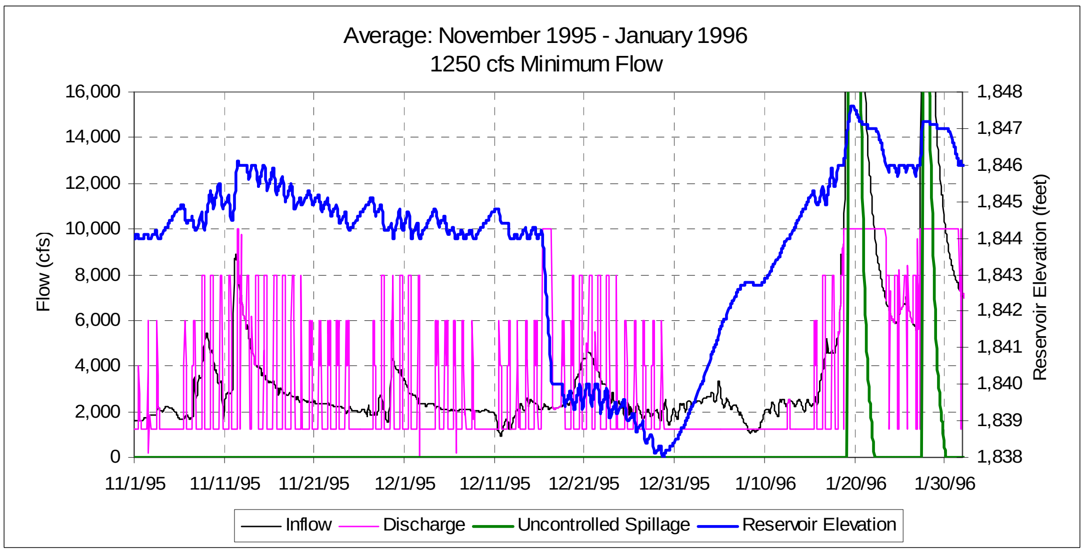


Figure 7. Average conditions represented by November 1995 through January 1996.





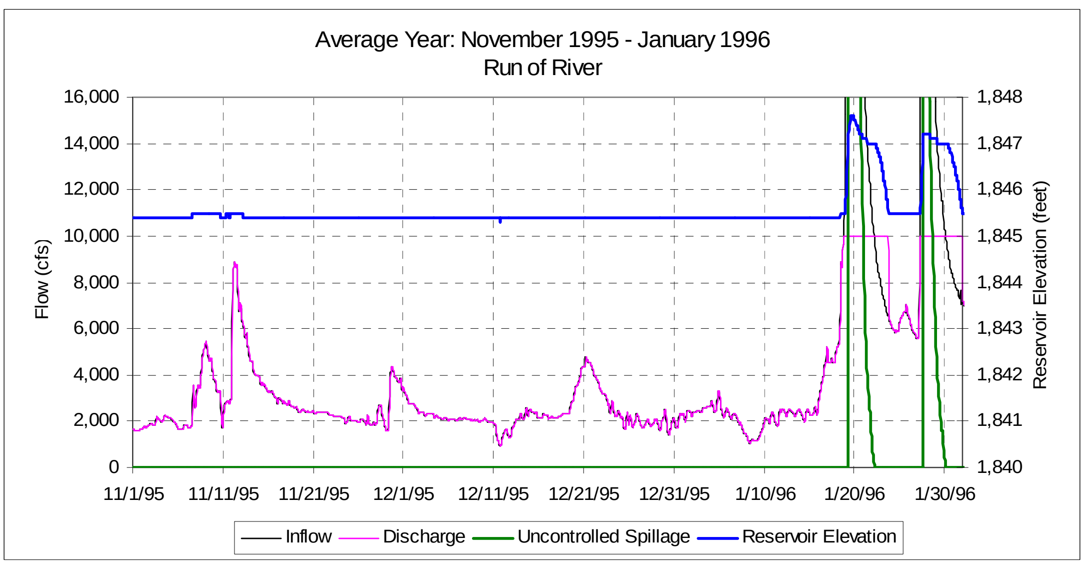
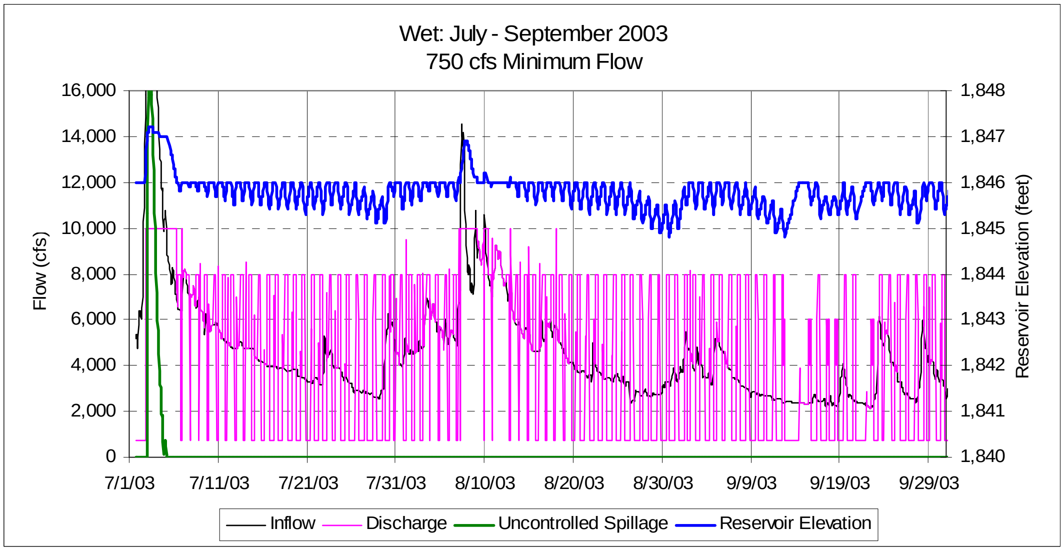
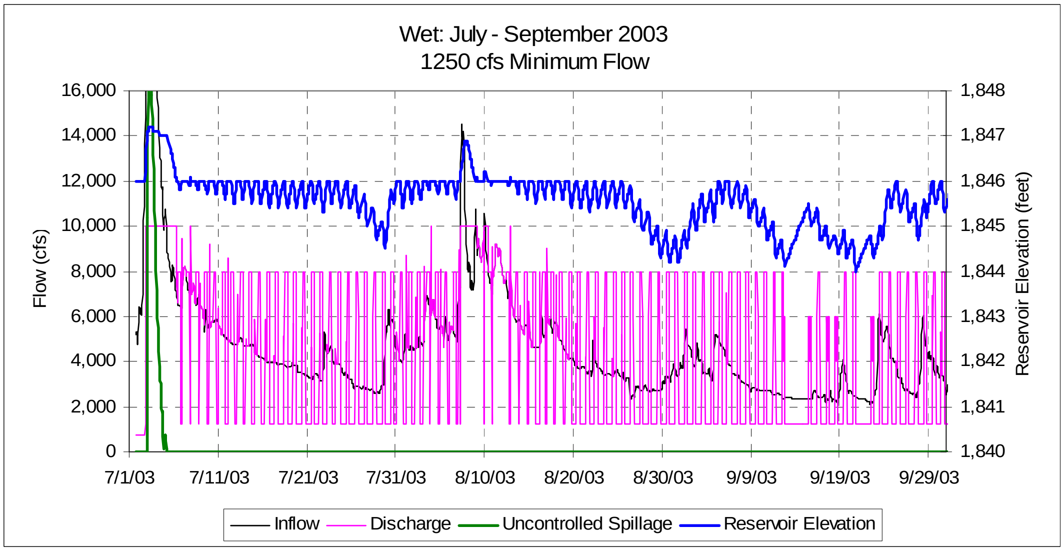


Figure 8. Wet conditions represented by July through September 2003.





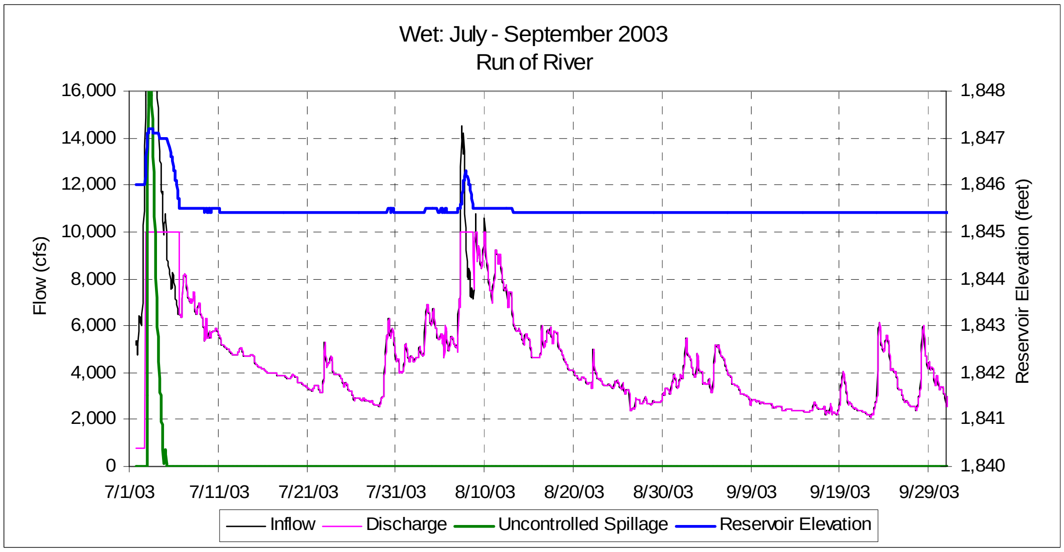
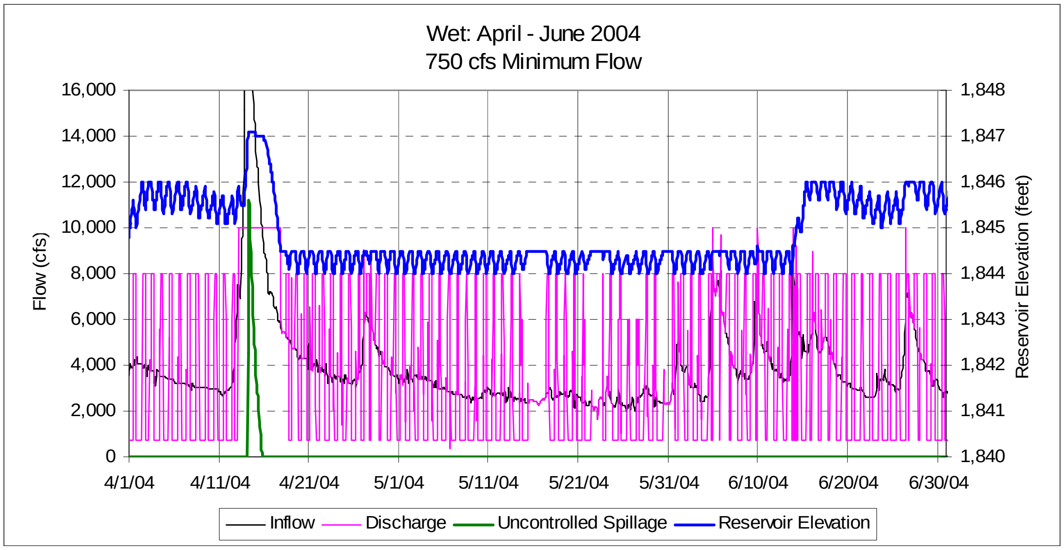
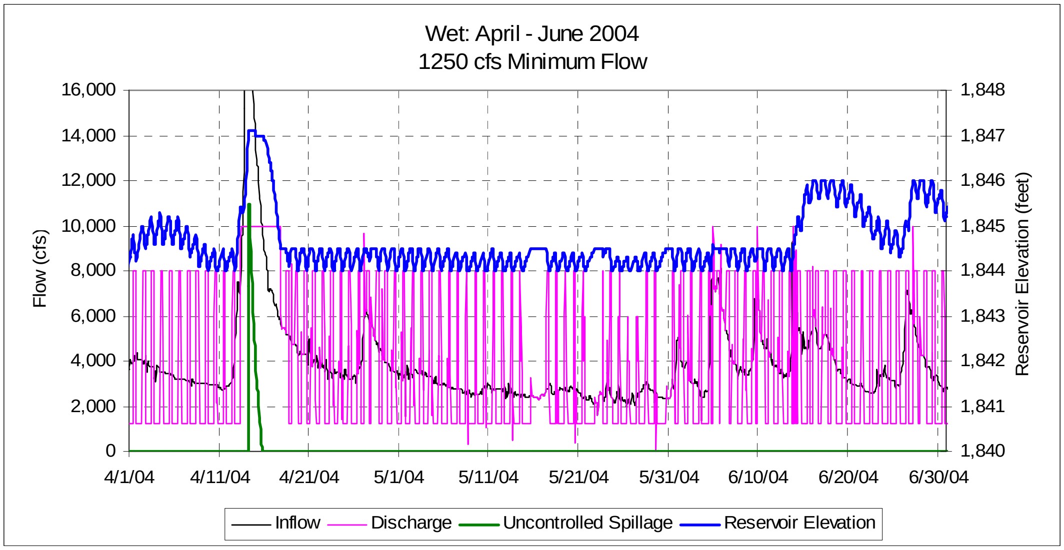


Figure 9. Wet conditions represented by April through June 2004.





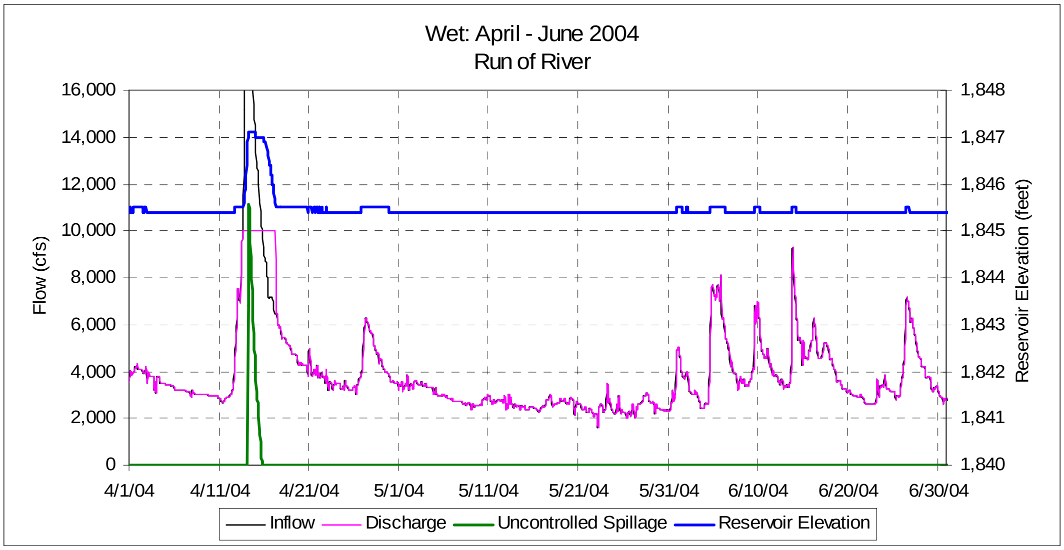
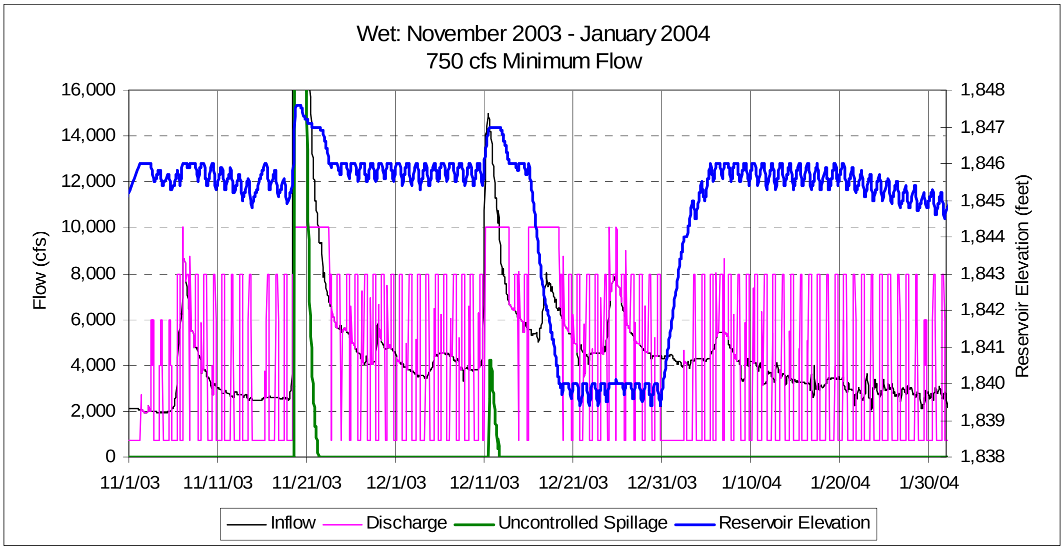
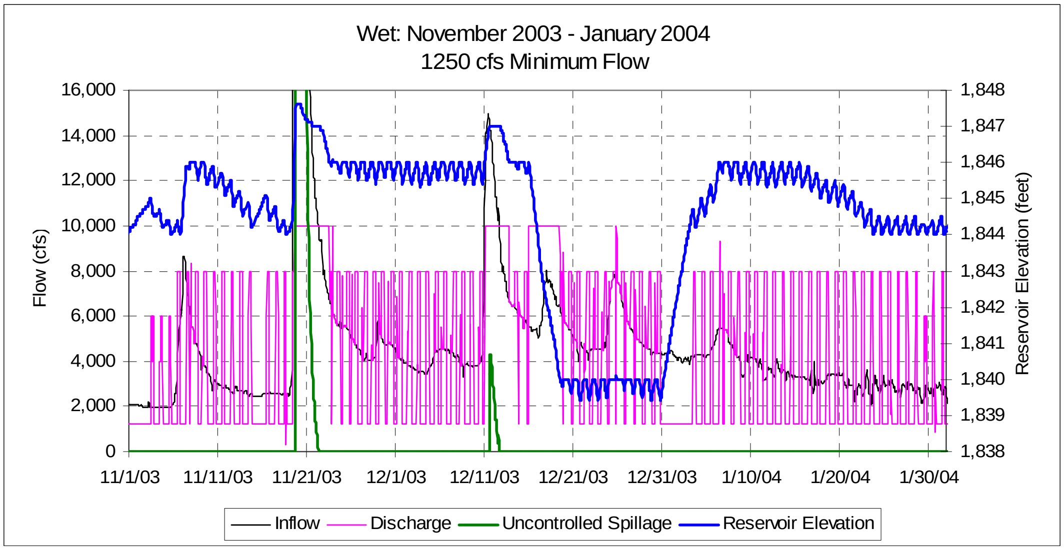
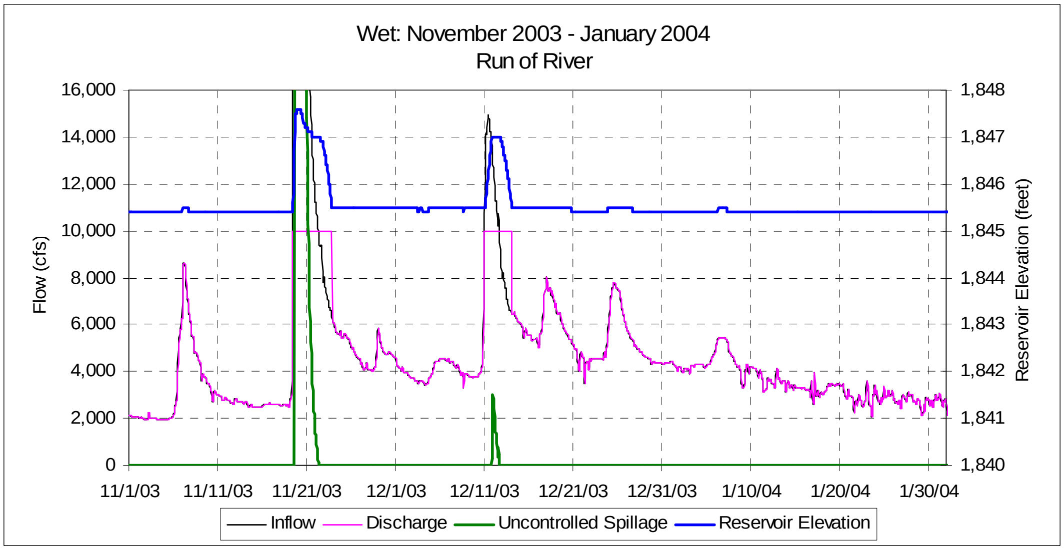


Figure 10. Wet conditions represented by November 2003 to January 2004.







FLOW DURATION CURVES

Figures 11 through 13 provide flow duration curves for turbine outflow during the modeled dry, average, and wet periods. Only four of the six scenarios described earlier are shown on these figures:

1. 750 cfs minimum flow;
2. 1,250 cfs minimum flow;
3. 750 cfs minimum flow during Fall and Winter and 1,250 cfs minimum flow during the Spring and Summer; and
4. run of river conditions.

Figures 11 through 13 include the entire 18 month period for the four scenarios. Therefore the flow duration differences between, 750 and 1,250 minimum flow scenarios would be more substantial during average to low flow periods (i.e., summer and fall) than is indicated by these graphs. Seasonal differences are graphically indicated by the flows and reservoir elevations displayed in figures 2, 4, and 5. Spillage flows are not represented in figures 11 through 13. This means the run of river scenario represents the inflow regime at flows below 10,000 cfs, but not above. The stepwise pattern of the peaking scenarios indicates the relative amount of time a given generation flow rate occurred over each 18-month period.

Figure 11. Modeled flow duration curve for dry conditions.

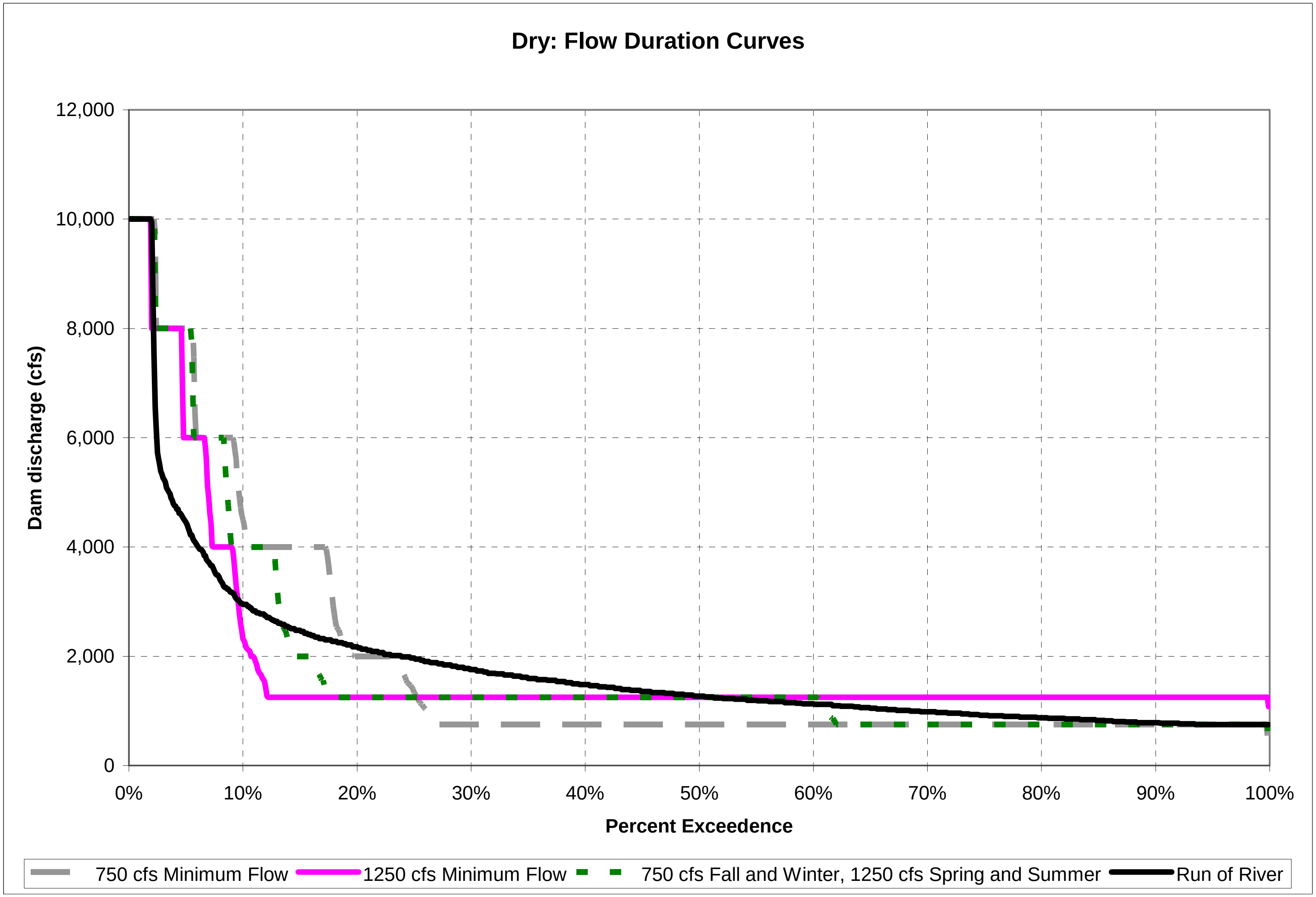


Figure 12. Modeled flow duration curve for average conditions.

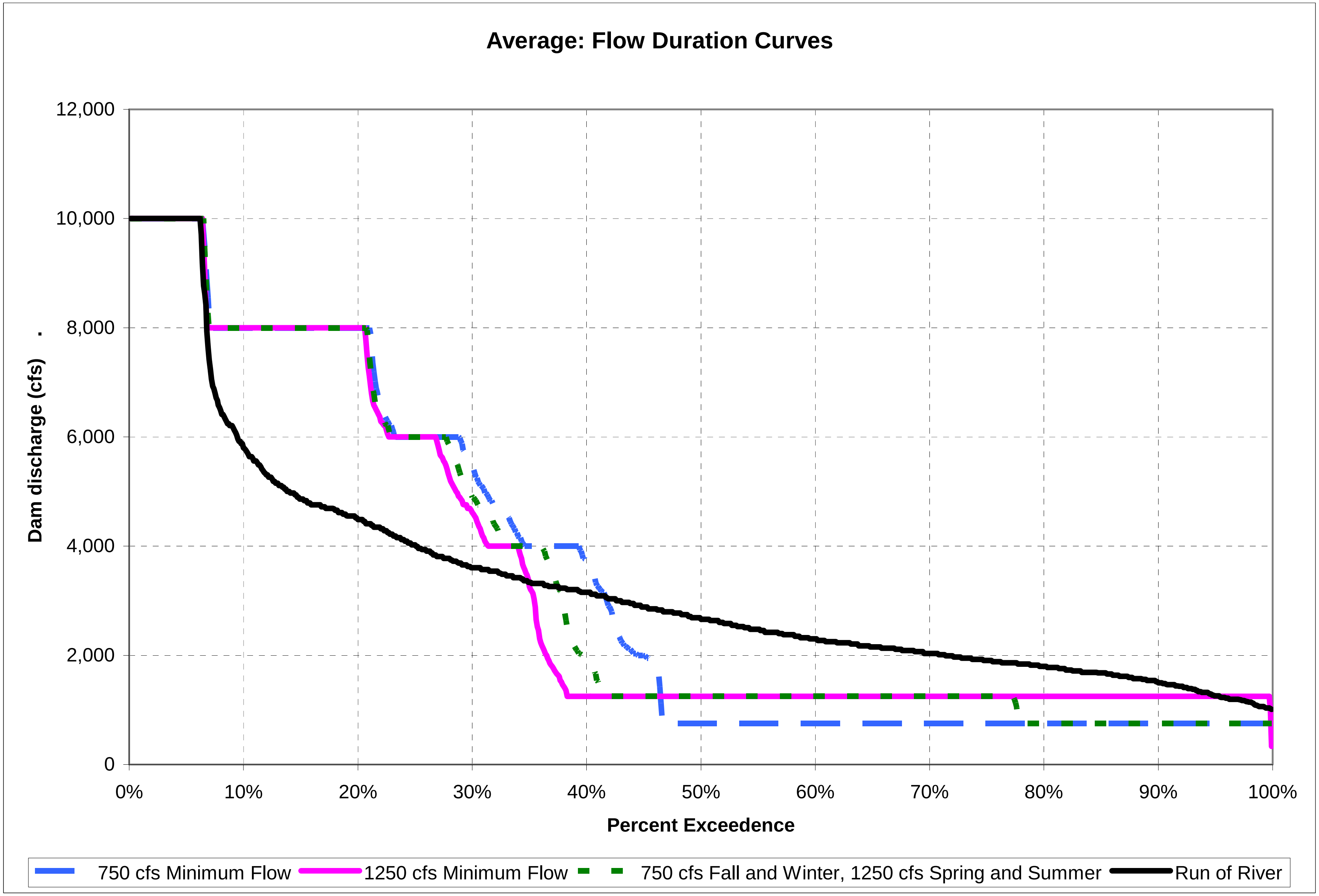
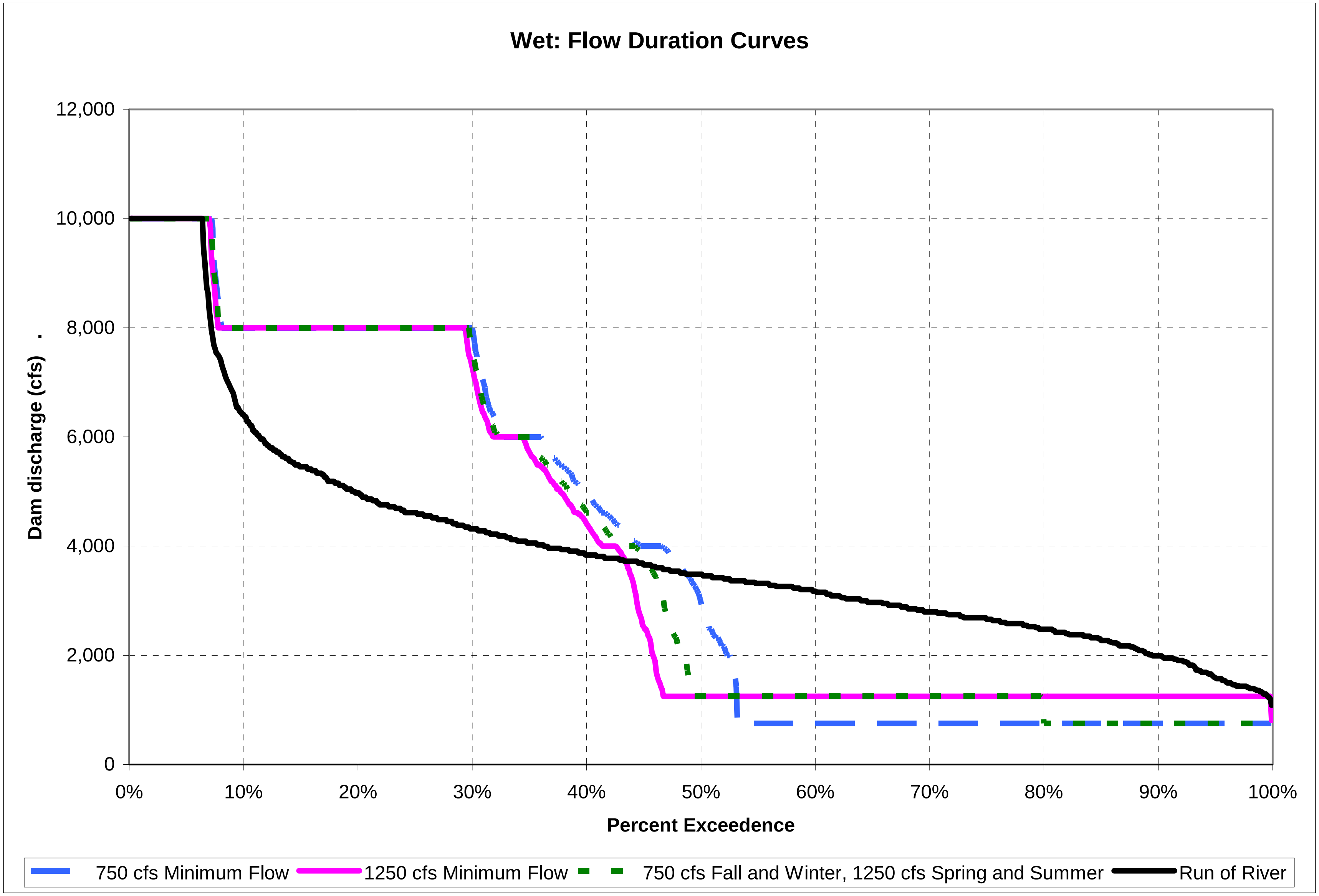


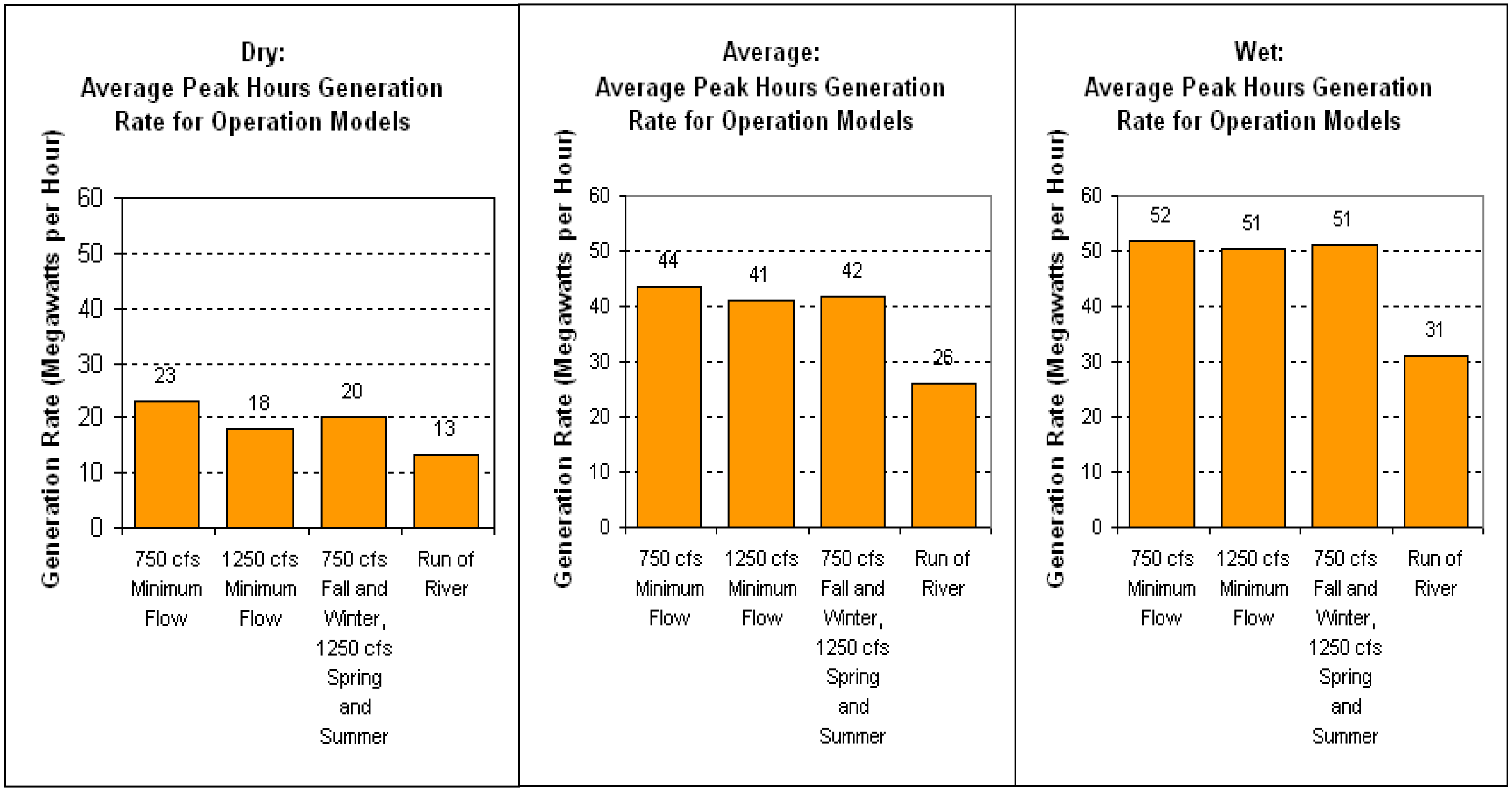
Figure 13. Modeled flow duration curve for wet conditions.



ESTIMATED GENERATION

Figure 14 provides the estimated generation during peaking operations for the same four modeled scenarios that were developed for the flow duration curves. These graphs do not include the generation during off peak hours, when outflow is generally used to regain the reservoir level and supply minimum flows.

Figure 14. Estimated generation for modeled condtions during peaking hours.



SUMMARY

The Claytor Hydroelectric Project operations were modeled using dry, average, and wet inflow conditions to assess the effects of different operating scenarios on reservoir elevation, power generation, and outflow. Physical reservoir information such as the elevation-storage relationship and generator capacity and efficiency were incorporated into our HEC-ResSim model. Spillage due to high inflows was simulated according to the general present operating parameters. The resulting output data are an estimation of project operations under different scenarios and inflows.

Our HEC-ResSim model allows for the designation of operational scenarios that incorporate a wide range of parameters and restrictions. To simulate peaking operations, a hierarchy of flow tiers was developed to determine how many turbines could be used and for how long during the designated peaking hours. During the modeled peaking hours of 11:00 am through 6:00 pm, the generation level was determined based on available storage and inflow in the prior 12 hours. Depending on the inflow, available storage and operational restrictions; generation levels increased at hourly intervals to simulate the option of using 1, 2, 3, or 4 generators, each at their typical operating capacity of 2,000 cfs.

These operational scenarios were chosen to analyze possible different minimum flow and operational conditions. Five of these operational scenarios used the aforementioned peaking tiers. The run of river scenario used a simple ‘inflow equals outflow’ rule to determine power generation. Minimum flow rules were prioritized over peaking operations and reservoir elevations; however other prioritizations are possible. The resulting effects of inflow variation and operational guidelines on reservoir elevation, power generation and outflow followed several predictable principles. Power generation was lowest under run of river scenario, and second lowest under the highest minimum flow scenario and during all scenarios, the differences were most noticeable during periods of low inflow. High inflow periods exhibit spillage due to flood pulses and allowed for higher and more frequent power generation under all modeled scenarios. Peaking operations cause an outflow oscillation on a weekly period based on reservoir storage.

These modeled scenarios represent only a few possible operational scenarios for the Claytor Hydroelectric Project. They are by no means the only scenarios that our HEC-ResSim model is capable of simulating. A multitude of operational scenarios may be used in our HEC-ResSim model to analyze project operation.