Hydropower Feasibility Update

Pueblo Dam Hydroelectric Project

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Executive Summary

The Pueblo Dam Hydropower Project (PDHP) Feasibility Update was performed to provide Southeastern Colorado Water Conservancy District (District) with an updated assessment for constructing and operating a hydroelectric facility at Pueblo Dam. The Feasibility Update undertook the following tasks:

- Data and requirements used for the 2011 Lease of Power Privilege (LoPP) Application were updated and revised to reflect current assumptions.
- The available flow regime and net head for the PDHP were re-evaluated, resulting in a change to generating unit selection and sizing.
- Power plant and site arrangement were updated to reflect the selected equipment and actual site location, as established by the 66-inch turnouts from the 90-inch Reclamation Pipeline currently under construction.
- Where certain project features or assumptions were unchanged or yet to be defined by the District, the values used in the 2011 Proposal Application were retained. These include energy sales price, economic assumptions, and electrical interconnection scheme and requirements.
- Energy production and budgetary cost were revised to reflect the updated project concept.

Comparisons of proposed principal features of PDHP development from the 2011 LoPP Application to the 2014 Feasibility Update are summarized in Table 1A.

The following sections summarize the changes that have occurred with regard to site characteristics and equipment selection between the 2011 LoPP Proposal and the 2014 Feasibility Update.

TABLE 1A

Principle Project Feature Comparison between 2011 LoPP and 2014 Feasibility Update

Feature	2011 LoPP	2014 Feasibility Update
Project rated flow	600 cfs	734 cfs
Project rated head	120 ft	110 ft
Equipment selection	Twin Horizontal Francis-Type Units Rated for 300 cfs	Two Horizontal Francis-Type Units. Turbine No. 1 rated for 540 cfs
Average Annual Energy production	19,710,000 kWh	18,654,808 kWh
Estimated Development Cost	$18.0 M	$19.7 M
Sale Price of Energy Year 1 Assumed	$51/MWh	$55/MWh
PV Benefit/Cost Ratio	1.00	1.07

Notes:

cfs = cubic feet per second
ft = feet
kWh = kilowatt-hours
M = million
MWh = Megawatt-hour
SDS = Southern Delivery System

Flow

Flow available to the hydroelectric facility has increased from that employed during the 2011 LoPP Application. Primary criteria and assumptions that were confirmed for use in the 2014 Feasibility Update are summarized below.

- Mandatory capacity reserves in the 90-inch-diameter Reclamation Pipeline decreased from an assumed 399 cfs during LoPP efforts to 148 cfs, making more of the 90-inch supply pipeline's capacity available to the hydroelectric facility.
- Arkansas River flow reductions, applied to daily flow data rather than to annual energy production, were incorporated into the calculations to better understand their impact on turbine operating conditions and annual energy production.
- The design and associated hydraulic analyses of the SDS Work Package 1A and 1B were finalized, establishing detailed head losses and a Reclamation-approved maximum velocity of 20 feet/second (ft/sec) in the 90-inch Pipeline, dictating maximum allowable flow of 883 cfs to the hydroelectric facility.

Net Head

Net available head at the hydroelectric facility has decreased from values assumed during 2011 LoPP efforts. The reasons for this decrease are summarized below.

- A refined hydraulic analysis based on final designs the Southern Delivery System (SDS) Work Package 1A and 1B indicate indicated an increase head loss. This resulted in both an expanded range and lower bound of net available head at the turbines. As a result, net available head falls outside turbine limits an increased percentage of time.
- A detailed evaluation of Pueblo Reservoir water surface elevation, using daily adjustments because of future SDS, Pueblo West, and Fry-Ark operations, was incorporated into the calculations to better understand impacts on turbine operating conditions and annual energy production.

Equipment Recommendation

- During the 2011 LoPP Proposal efforts, available information on site flow and head characteristics suggested a preliminary equipment selection of twin 300-cfs (total 600 cfs hydraulic capacity) horizontal Francis turbines. Each unit would be rated for 120 ft of head and output of 2,842 kilowatts (kW) (total 5,684 kW).
- Re-evaluation of unit sizing and selection, employing endorsed available flow and net available head, resulted in the selection of two unequally sized units. Total output for both units would be 7,010 kW. These unequally sized units more effectively capitalize on the project's variable hydrograph by employing the lower flow reach of a smaller unit while covering the same total rated flow range as two equally sized machines.

Introduction

The objective of this technical memorandum (TM) is to provide the District with an updated assessment for the feasibility of constructing a hydroelectric facility at Pueblo Dam. This assessment will provide a basis for the District to consider whether to proceed with developing the PDHP. This work was performed by CH2M HILL Engineers, Inc (CH2M HILL) in consultation with the District and certain members of the project's Partnership, including the District, Colorado Springs Utilities, and the Board of Water Works of Pueblo, Colorado. This TM is organized in the following ten sections:

- Development Concept Background
- Hydropower Background
- Site Characteristics
- Equipment
- Energy Production
- Power Plant Arrangement and Electrical Interconnection
- Order-of-Magnitude Cost
- Economic Feasibility
- Summary of Assessment and Considerations
- District Action Items

Detailed supporting information is included in the following six appendices:

- Appendix A: Net Head/Turbine Flow Comparisons 1984-2013
- Appendix B: Net Head Exceedance and Variability Curves
- Appendix C: Equipment Quotation and Performance Curve
- Appendix D: Feasibility Level Drawings
- Appendix E: Order-of-Magnitude Cost Estimate
- Appendix F: Basic Economic-Feasibility Evaluation

Development Concept Background

Various development concepts were evaluated as a part of the overall LoPP proposal efforts completed in October 2011. At that time, available information depicting site characteristics suggested a preliminary equipment selection of twin 300-cfs (total 600 cfs hydraulic capacity) horizontal Francis turbines. Each unit would be rated for 120 ft of head and output of 2,842 kW. This 2011 equipment selection considered hydrologic and statistical analyses of the Arkansas River flow below Pueblo Dam, available hydraulic head given historical forebay (Pueblo Reservoir) elevation data, capacity of the 90-inch Reclamation pipeline, flow demands in the Reclamation pipeline, and upper and lower flow and head limits specific to this preliminary equipment selection. In addition, the 2011 preliminary equipment determination was based on certain assumptions, including the following:

- Preliminary design elements and hydraulic analyses of the SDS Work Package 1A and 1B.

- Preliminary determination of mandated capacity reserves in the Reclamation pipeline for SDS project stakeholders as they affect available flow to a hydroelectric facility.
- Preliminary determination of staging of stakeholder flow demands in relation to time.
- Preliminary discussions of the effect future SDS, Pueblo West, and Fry-Ark Project operations may have on flow available to a hydroelectric plant as compared to historical streamflow data.
- Effects that future SDS, Pueblo West, and Fry-Ark Project operations will have Pueblo Dam Forebay elevations as they compare to historical levels.

This feasibility review was performed to re-evaluate the 2011 equipment selection with certain project particulars (such as flow, head, analysis period, escalations) established by the District. This evaluation will specifically reconsider more and less aggressive use of the available hydrograph, net available head based on headlosses that increased from those analyzed in 2011, and long-term influence that SDS and Pueblo West operation may have on energy production.

Hydropower Background

Power output from a hydropower turbine, regardless of size or type, is proportional to flow through the turbine and the head (or differential pressure) across the turbine. In principle, low-head/high-flow and high-head/low-flow conditions offer the same power and energy potential. The following is the power formula for a hydraulic turbine-generator:

$$\text{Power output in kW} = \frac{\text{Q (cfs) x H (ft) x Turbine-generator efficiency}}{11.82}$$

The energy produced in kWh equals the average power multiplied by the operating time in hours. Turbine equipment using large flows under low head is more costly than that operating under high heads at low flows. Further, turbine performance is also based upon operation under fairly constant head—conditions in which operating head varies result in lower average efficiency and limitations in operating range.

Water supply and conveyance processes that experience conditions of excess available head are fairly common. Because of the relatively high cost of features associated with hydropower production, such as permitting, utility interconnection, and conveyance feature modifications necessary to install the turbine, the conventional economic feasibility of these installations can be limited. However, financial or tax incentives, along with broader sustainability goals, can strongly influence overall feasibility. The opportunity or applicability of financial or tax incentives is not discussed in this TM.

Site Characteristics

The following presents the hydrology, net head, and methodology for calculating available flow and head for the PDHP.

Hydrology and Flow Available to the Hydropower Plant

Quantification and qualification of flow available to this hydropower facility are based on the following data and criteria:

- Historical daily average Arkansas River flows below Pueblo Dam as recorded at the Colorado Department of Water Resources Station: ARKPUECO.07099400 ARKANSAS RIVER ABOVE PUEBLO, CO – October 1, 1983 through December 31, 2013.
- The maximum capacity of the River Outlet Works through the Pueblo Dam Connection (Work Package 1A) is 1,120 cfs (based on previous work performed during design of the Southern Delivery System [SDS] Pueblo Dam Connection). If river demands greater than 1,120 cfs are required to be discharged through Pueblo Dam, flows above 1,120 cfs are passed by means of the dam's three spillway gates.

- Flow through the 90-inch Reclamation pipeline to meet participant ultimate demands total 399 cfs. Of the 399 cfs, SDS and Pueblo West ultimate demands total 148 cfs. It is assumed that normal operating capacity reserves in the Reclamation Pipeline only need to consider SDS and non-redundant Pueblo West demands. Redundant demands would be supplied solely during emergency conditions in the event the South Outlet Works experience an outage and therefore not considered factors in sizing the hydroelectric equipment. This assumption should be confirmed by the Partnership among SDS stakeholders. Total system demands by SDS participants are presented in Table 1B.

TABLE 1B
System Demands by Participant

	System Demand		
Demand Description	**(mgd)**	**(cfs)**	**Comments**
SDS	78	120	SDS Flow to Juniper Pump Station Turnout, Regular Capacity to be maintain in Pipeline
Pueblo West	18	28	SDS Flow to Pueblo West Turnout - Regular Capacity to be maintained in Pipeline
Pueblo West	12	19	JUM Existing Flow Redundancy to Pueblo West Turnout
Fountain Valley Authority	20	32	Intertie Redundancy
Arkansas Valley Conduit	20	32	Intertie Redundancy
Pueblo Board of Water Works at Comanche WTP	40	64	Intertie Redundancy
Pueblo Board of Water Works at Whitlock WTP	40	64	Intertie Redundancy
Fish Hatchery	26	40	Intertie Redundancy
Total	254	399	

Notes:

JUM = Joint Use Manifold
mgd = million gallons per day
WTP = water treatment plant

- Projected SDS and Pueblo West demands on water entering Pueblo Reservoir require a flow reduction be applied to historical Arkansas River streamflow data when used to project future flow available to the PDHP. These projected flow demands, in relation to time, are featured in Table 2.

TABLE 2
SDS and Pueblo West Demands on Water Entering Pueblo Reservoir

Time Period	SDS Mean Flow (mgd)	SDS Mean Flow (cfs)	Pueblo West Average Flow (mgd)	Pueblo West Average Flow (cfs)	Total Average Daily Demand (cfs)
2016 - 2020	5	7.74	0.8	1.24	8.97
2021 - 2025	14	21.66	1.6	2.48	24.14
2026 - 2030	10	15.47	2.5	3.87	19.34
2031 - 2035	15	23.21	3.5	5.42	28.63
2036 - 2040	21	32.49	4.4	6.81	39.30
2041 - 2045	26	40.23	5.4	8.36	48.59
2046 - 2050	30	46.42	6.4	9.90	56.32
2051 - 2053	35	54.16	7.1	10.99	65.14

- Hydraulic analyses performed by CH2M HILL indicate a Forebay elevation of 4824.0 ft provides sufficient hydraulic head to deliver the following flows: 120 cfs to the Juniper Pump Station, 28 cfs to Pueblo West Pump Station, and 734 cfs to the hydroelectric plant. A Forebay elevation of 4824.0 ft is associated with a gross (static) head of 80 ft at the turbines, which is expected to be less than the low head limit for operating the equipment (later defined) dictating the assessment of that effect. However, energy analyses can proceed independently of head evaluations for Pueblo West and Juniper Pump Stations, since flow can be delivered at all Forebay levels considered.
- Maximum allowable water velocity in the 90-inch Reclamation Pipeline was established during design of the SDS Pueblo Dam Connection to be 20 ft/sec, or 883 cfs. Thereby, the maximum allowable flow to the hydropower plant is 735 cfs (883 cfs minus 120 cfs {SDS} minus 28 cfs {PW}). The Reclamation Pipeline and 66-inch hydroelectric facility turnouts are lined with Seaguard 6000 Epoxy, tie coat, and surface coat.
- Maximum allowable velocity in each 66-inch turnout for the hydroelectric plant is assumed to be 30 ft/sec (712 cfs).
- No additional demands beyond stated SDS, Pueblo West, and redundant flows were considered.
- The minimum streamflow in the Arkansas River below Pueblo Dam is 20 cfs to meet the demands of the State Fishery. Typically, flow is maintained above 50 cfs during low flow months. Design of the fixed cone valve constructed in 2012 assumed a minimum release 50 cfs throughout the year. Preliminary tailwater elevation is based upon this 50 cfs figure.

Available Net Head

Quantification and qualification of available net head at the PDHP turbines is based on:

- Historical daily Pueblo Reservoir Forebay Elevations from Reclamation's Great Plains Region Hydromet, Station PUER – October 1, 1983 through December 31, 2013
- SDS Environmental Impact Statement (EIS) discussion of effects to future Pueblo Dam Forebay levels projected the following: 1) Existing to No Action, the reservoir level would be reduced an average 3.8 ft, and 2) No Action to Proposed Action, the reservoir level would be reduced an additional 2.6 ft between 2016 and 2050. Overall, the proposed action will result in an average reduction of reservoir water surface levels of 6.4 ft between 2016 and 2050 (Reference: Final EIS, Appendix E - Simulated Hydrology Results, page E-38; Monthly WSEL Summary, Direct Effects, Location: Pueblo Reservoir). As a result, a

linearly decreasing correction factor is applied to historical reservoir elevations for use in projected energy production formulas.

- A constant tailwater water surface elevation (WSE) of 4744 ft is assumed, which is derived from Reclamation's Tailwater, Area, Capacity and Discharge Curves for Pueblo Dam. Tailwater appears relatively unaffected (less than a couple of ft) from river flows less than 10,000 cfs. A more precise quantification of tailrace WSE and outlet channel bathymetry should be determined during the preliminary design phase.
- The basis for system headlosses is presented in the Figures 1 through 4 and Tables 3 and 4. Headloss equations were developed from Computation Fluid Dynamic and U.S. Environmental Protection Agency Net Headloss models. Lookup Tables for bifurcation headlosses are derived from D.S. Miller's Internal Flow Systems Handbook.

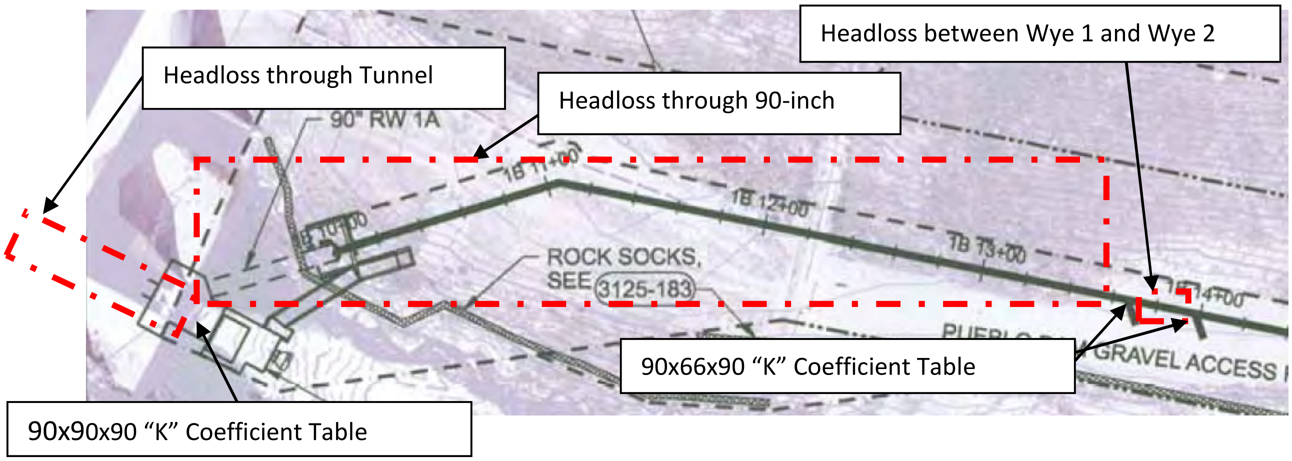


FIGURE 1: HEADLOSS MAP

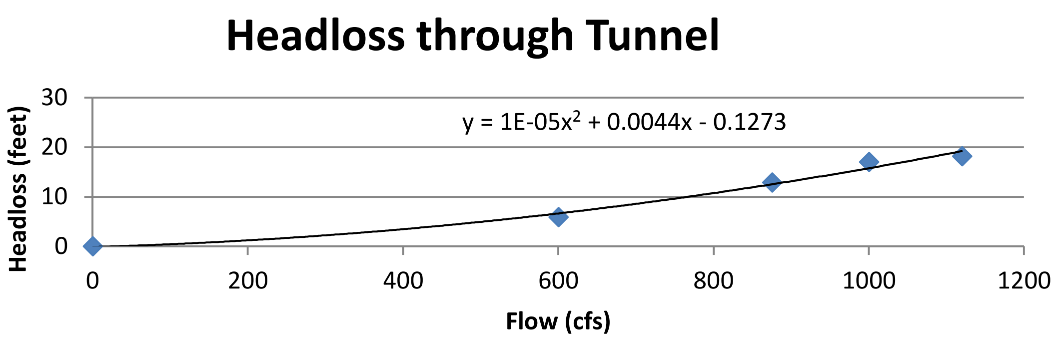


FIGURE 2: HEADLOSS THROUGH TUNNEL EQUATION

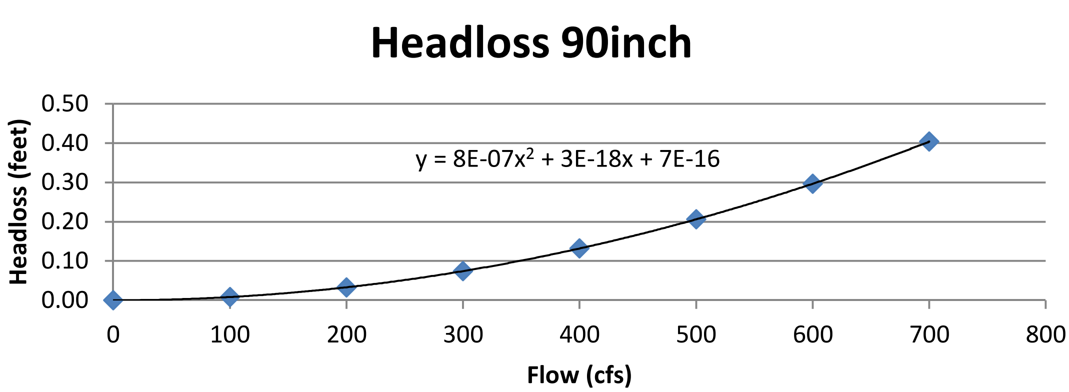


FIGURE 3: HEADLOSS IN 90-INCH EQUATION

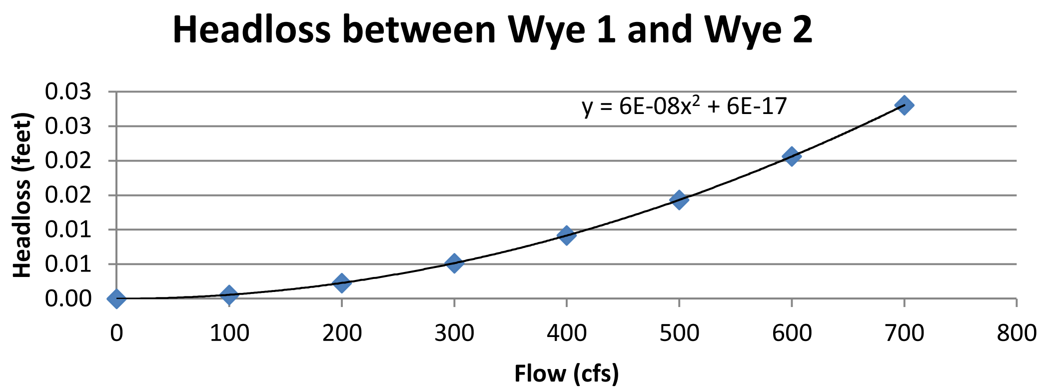


FIGURE 4: HEADLOSS BETWEEN WYE 1 AND WYE 2 EQUATION

TABLE 3

K Values for 90 x 90 x 90 Wye

Area Ratio	Flow Ratio ($Q_{90}/Q_{upstream}$)	K Value Wye Branch	K Value Through Branch
1.00	0.00	0.80	0.05
1.00	0.10	0.78	0.00
1.00	0.20	0.68	-0.03
1.00	0.30	0.60	-0.03
1.00	0.40	0.50	-0.01
1.00	0.50	0.43	0.03
1.00	0.60	0.40	0.08
1.00	0.70	0.40	0.15
1.00	0.80	0.40	0.22
1.00	0.90	0.40	0.30
1.00	1.00	0.40	0.40

TABLE 4
K Values for 90 x 90 x 90 Wye

Area Ratio	Flow Ratio ($Q_{66}/Q_{upstream}$)	K Value Wye Branch	K Value Through Branch
0.54	0.00	0.80	0.05
0.54	0.10	0.80	0.00
0.54	0.20	0.75	-0.03
0.54	0.30	0.72	-0.03
0.54	0.40	0.70	-0.01
0.54	0.50	0.72	0.03
0.54	0.60	0.78	0.08
0.54	0.70	0.85	0.15
0.54	0.80	0.90	0.22
0.54	0.90	1.00	0.30
0.54	1.00	1.50	0.40

Methodology for Turbine Flow, Net Head at Turbine, Power Generation, and Energy Production

Flow available for the turbines is based on the methodology featured in Table 5. Dates featured are “for example”. Condition statements are based on spreadsheet formula syntax.

TABLE 5
Flow Methodology

a) Capacity of Tunnel Works – 1,120 cfs
b) Maximum Flow in Reclamation Pipeline based on Velocity Constraints – 883.6 cfs
c) Ultimate Flow Reserves for SDS and Pueblo West – 148 cfs
d) Maximum Hydro plant total Flow – (E)+(G) < 883.6 cfs – 148 cfs
e) Turbine 1 Rated Flow
f) Turbine 1 Minimum Flow
g) Turbine 2 Rated Flow
h) Turbine 2 Minimum Flow

Label	(1F)	(2F)	(3F)	(4F)	(5F)	(6F)	(7F)	(8F)
Description	Historic Date	Projected Date in the Future	Historic Arkansas River Flow (cfs)	SDS Average Daily Flow (cfs)	Pueblo West Average Daily Flow (cfs)	Flow Available to Hydroelectric Plant (cfs)	Flow Through Turbine 1 to Determine Headlosses (cfs)	Flow through Turbine 2 to Determine Headlosses (cfs)
Formula	4/1/1984	4/1/2017	From Gauge based on 4/1/1984	From Table 2 Projections based on (2F)	From Table 2 Projections based on (2F)	(3F)-(4F)-(5F)	=IF[(6F)>(F),{IF(6F)<(E),(6F),(E)},0]	=IF[(6F)-(7F)>(H), IF{(6F)-(7F)<(G),(6F)-(7F),(G)},0]

Available net head at the turbines is based on the methodology featured in Table 6:

TABLE 6
Net Head Methodology

a) Rated Head Turbine 1
b) Maximum (Turbine Shutoff Head) Turbine 1
c) Minimum (Turbine Shutoff Head) Turbine 1
d) Rated Head Turbine 2
e) Maximum (Turbine Shutoff Head) Turbine 2
f) Minimum (Turbine Shutoff Head) Turbine 2

Label	(1H)	(2H)	(3H)	(4H)	(5H)	(6H)	(7H)
Description	Historic Pueblo Dam Forebay Elevation (ft)	Linear Decrease in Historic Reservoir Levels Due to EIS (ft)	Headloss to Turbine 1	Headloss to Turbine 2	Tailrace WSEL (ft)	Net Head @ Turbine 1	Net Head @ Turbine 2
Formula	From Gauge based on 4/1/1984	-5.15E-04@(2F) + 2.18E+01	Equations and Lookup Tables with applicable (4F) (5F) (7F) (8F)	Equations and Lookup Tables with applicable (4F) (5F) (7F) (8F)	4744	(1H)-(2H)-(3H)-(5H)	(1H)-(2H)-(4H)-(5H)

Energy produced by the hydroelectric equipment is based on the methodology featured in Table 7.

TABLE 7
Energy Methodology

a) Max Powerplant Output (kW) – (O) + (P)
b) Turbine 1 Rated Output (kW) – Max of Column (5E)
c) Turbine 2 Rated Output (kW) – Max of Column (6E)
d) Turbine 1 Average Annual Energy Production (kWh) – Sum Column (7E)/Data Count*365 Days
e) Turbine 2 Average Annual Energy Production (kWh) – Sum Column (8E)/Data Count*365 Days

Label	(1E)	(2E)	(3E)	(4E)	(5E)	(6E)	(7E)	(8E)
Description	Turbine 1 Flow used for Energy	Turbine 2 Flow used for Energy	Turbine 1 Efficiency	Turbine 2 Efficiency	Turbine 1 Power Output	Turbine 2 Power Output	Turbine 1 Daily Energy Projection	Turbine 2 Daily Energy Projection
Formula	=IF[(6H)<(K),0,IF{(6H)>(I),(7F),MIN(Manufacture provided flow curtailment equation due to reduced head based on (6H),(7F)}]	=IF[(7H)<(N),0,IF{(7H)>(L),(8F),MIN(Manufacture provided flow curtailment equation due to reduced head based on (7H),(8F)}]	=IF{(1E)>0,IF(6H)>(K),IF(6H<(J),lookup table of manufacturer provided efficiencies,0),0),0)*combined generator efficiency and line loss of 7 percent	=IF{(2E)>0,IF(7H)>(N),IF(7H<(M),lookup table of manufacturer provided efficiencies,0),0),0) *combined generator efficiency and line loss of 7 percent	(6H)*(1E)*(3E)/11.82	(7H)*(2E)*(4E)/11.82	(5E)*24	(7E)*24

Generating Equipment

This section is organized in three parts: Evaluating Various Equipment Selections, Equally-Sized Versus Unequally-Sized Units, and Preliminary Constant-Speed Equipment Selection. The approach used to determine a preferred equipment selection is discussed below.

Evaluating Various Equipment Selections

Hydropower turbine systems are specialized equipment and are most often of custom design. Their application requires close consultation with manufacturers. The selection and sizing of the hydropower equipment system is an iterative process. Site characteristics and general design concepts must be developed and analyzed with engineering judgment in order to provide a basis for manufacturer evaluation. In turn, a manufacturer's preliminary design typically requires the installation concept to be adapted to their equipment.

In order to optimize energy production, turbine-generator equipment is selected and sized according to the available hydraulic conditions, including variability in flow and head. In consultation with various turbine manufactures, coupled with an understanding for operating conditions, relative costs, installation requirements and equipment efficiency, it was determined that horizontal Francis–type turbines should be employed at the site. A Kaplan-type turbine was briefly considered because of the range of the site conditions. However, the Kaplan-type turbine presented challenges because of the following:

1. An upper head limit of approximately 140 ft suggesting a specialized Kaplan-type unit operating near the upper limits for propeller-type turbine applications
2. Higher runaway speed associated with the Kaplan, resulting in complications with, and adding cost to, the generator system
3. Physically larger vertical arrangement of the Kaplan requiring more extensive/expensive civil works
4. Requirement that the unit have runner centerline settings located well below tailwater (approximately 4-6 ft)
5. Greater control complexity and cost

The Kaplan-type unit would likely require a greater capital investment and incur more annual operation and maintenance (O&M) costs, greatly reducing the benefit received by a broader and more efficient use of the flow regime. As a result, a Kaplan-type unit was not considered further.

To arrive at a most advantageous Francis-type turbine selection, an iterative evaluation was conducted using methodology previously presented. Obtaining performance data for multiple equipment sizes from manufactures is time consuming and difficult. In order to simplify the process of determining the most effective turbine combination, CH2M HILL assumed that data could be scaled for various equipment sizes. As such, this assumption is not considered to adversely distort the results for determining the most advantageous equipment combination.

To determine the optimum equipment size and combination to maximize energy production, a number of different scenarios were developed and evaluated. The evaluations were conducted by developing multiple scenarios that employed either equally sized turbines (see Table 8) or unequally sized turbines (see Table 9).

Assumptions for the scenarios below are as follows:

- Energy production is based on historical Arkansas River flow and Pueblo Reservoir WSE data for the period January 1, 1984 – December 31, 2013, with applicable flow and head reductions, projected to analysis years (1984 equals 2017, 2013 equals 2046).
- The lower flow limit of the equipment is 35 percent of rated flow. Planning for hydroelectric projects using Francis-type units typically use a rule of thumb of 40 percent rated flow for the equipment's lower flow limit. However, given the site's hydrology and experience with similar equipment, 35 percent is

considered attainable. This more aggressive application of the lower flow limit is intended to portray project energy production more fairly with regard likely operation.

- A turbine with capacity greater than or equal to 450 cfs was assumed to have a rated head of 110 ft, with an upper head limit of 132 ft and a lower head limit of 88 ft. A turbine with capacity less than 450 cfs but greater than 250 cfs was assumed to have a rated head of 110 ft, with an upper head limit of 128 ft and a lower head limit of 89 ft. A turbine with capacity less than 250 cfs was assumed to have a rated head of 110 ft, with an upper head limit of 125 ft and a lower head limit of 90 ft. The differing head ranges are affected by a unit's rated flow and head and numerous other equipment design factors. The stated head ranges also represent a somewhat aggressive application of the limits of Francis-type units, but are deemed a fair approach for developing an economically viable project at this site. Certain manufacturers may be unable to produce equipment with such requirements. This is further discussed in the Summary of Assessment and Considerations section.
- Energy values presented in Tables 8 and 9 consider reductions for future flow demand of SDS and changes in Pueblo Reservoir operation

TABLE 8
Equally Sized Turbine Scenarios

Scenario	Turbine #1 Rated Flow/Lower Flow Limit	Turbine #2 Rated Flow/Lower Flow Limit	Average Annual Energy Production Turbine 1 (kWh)	Average Annual Energy Production Turbine 2 (kWh)	Maximum Power Output of Facility (kW)	Average Annual Total Energy Production (kWh)
1.	100 cfs /35 cfs	100 cfs/35 cfs	3,469,484	2,732,328	1,829	6,201,812
2.	150 cfs/53 cfs	150 cfs/53 cfs	4,858,547	3,604,906	2,744	8,463,453
3.	200 cfs/70fs	200 cfs/70fs	6,110,277	4,267,097	3,659	10,377,374
4.	250 cfs/88 cfs	250 cfs/88 cfs	7,983,389	5,266,051	4,710	13,249,440
5.	300 cfs/105 cfs	300 cfs/105 cfs	9,190,877	5,674,114	5,650	14,864,991
6.	320 cfs/112 cfs	320 cfs/112 cfs	9,638,869	5,798,221	6,028	15,437,090
7.	340 cfs/119 cfs	340 cfs/119 cfs	10,074,588	5,919,999	6,406	15,994,587
8.	360 cfs/126 cfs	360 cfs/126 cfs	10,473,823	5,995,619	6,778	16,469,442
9.	367 cfs/128 cfs	367 cfs/128 cfs	10,602,530	6,026,381	6,908	16,628,911

TABLE 9
Unequally Sized Turbine Scenarios

Scenario	Turbine #1 Rated Flow/Lower Flow Limit	Turbine #2 Rated Flow/Lower Flow Limit	Average Annual Energy Production Turbine 1 (kWh)	Average Annual Energy Production Turbine 2 (kWh)	Maximum Power Output of Facility (kW)	Average Annual Total Energy Production (kWh)
1.	734 cfs / 257 cfs	0 cfs / 0 cfs	17,045,051	0	7,093	17,045,051
2.	680 cfs/238 cfs	54 cfs/19 cfs	16,542,372	1,469,468	7,097	18,011,840
3.	650 cfs/228 cfs	84 cfs/29 cfs	16,255,786	2,129,528	7,078	18,385,314
4.	620 cfs/217 cfs	114 cfs/40 cfs	15,921,966	2,649,099	7,059	18,571,065
5.	590 cfs/207 cfs	144 cfs/50 cfs	15,555,227	3,117,909	7,040	18,673,136
6.	570 cfs/200 cfs	164 cfs/57 cfs	15,324,014	3,378,456	7,028	18,702,470
7.	560 cfs/199 cfs	174 cfs/61 cfs	15,191,121	3,510,835	7,021	18,701,956
8.	550 cfs/193 cfs	184 cfs/68 cfs	15,065,228	3,618,027	7,015	18,683,255
9.	545 cfs/191 cfs	189 cfs/66 cfs	14,989,571	3,687,137	7,013	18,676,708
10.	540 cfs/189 cfs	194 cfs/68 cfs	14,918,461	3,736,348	7,010	18,654,808
11.	535 cfs/187 cfs	199 cfs/70 cfs	14,857,435	3,761,329	7,006	18,618,764
12.	530 cfs/186 cfs	204 cfs/71 cfs	14,804,208	3,768,429	7,003	18,572,637
13.	520 cfs/500 cfs	214 cfs/75 cfs	14,672,043	3,845,415	6,996	18,517,458
14.	500 cfs/1 75 cfs	234 cfs/82 cfs	14,379,561	4,009,500	6,983	18,389,061
15.	470 cfs/1 65 cfs	264 cfs/92 cfs	13,915,034	4,473,144	7,053	18,388,178
16.	440 cfs/1 54 cfs	294 cfs/103 cfs	11,922,800	4,889,309	6,913	16,812,104
17.	410 cfs/1 44 cfs	324 cfs/113 cfs	11,398,516	5,349,394	6,914	16,747,910
18.	380 cfs/133 cfs	354 cfs/124 cfs	10,847,330	5,816,548	6,909	16,663,878

Equally Sized Versus Unequally Sized Units

Certain disadvantages are typically associated with selecting equipment of unequal size. The advantage of selecting unequally sized units is the ability to more effectively capitalize on a variable hydrograph by employing the lower flow reach of a smaller unit while covering the same total rated flow range as two equally sized machines. If the added energy production from reaching lower into a site's hydrograph compensates for certain disadvantages of employing unequal size units, such an installation can be preferred. Disadvantages of employing unequally sized units include:

- Different spare parts and tools to operate and maintain the equipment.
- Varying maximum and minimum head requirements causing more complex management of the facility.
- Civil works are designed to accommodate the larger unit, typically causing a lower turbine and draft tube floor (i.e., deeper excavation, taller building, longer and deeper tailrace, etc.) as compared to equally sized units of the same total rated flow capacity.

- Certain mechanical systems, such as the bridge crane, will be sized to handle the larger unit.
- Annual unit shutdown for inspection and maintenance must be coordinated with the hydrograph. Employing a smaller unit may reduce the period during which maintenance downtime is available, as certain years may allow for the smaller unit to operate continuously.

The disadvantages presented above appear manageable for the Pueblo Hydroelectric Project and are offset by the estimated energy benefit (2,000,000 kWh/year) of selecting an unequally sized unit combination over an equally sized unit combination (see Table 8 and Table 9).

Preliminary Constant-Speed Equipment Selection

As discussed above, unequally sized units appear to provide the higher energy benefit. Inspection of Table 9 suggests that Scenario 6, a combination of Turbine No. 1 at 570 cfs /200 cfs (rated/lower limit) and Turbine No. 2 at 164 cfs /57 cfs (rated/lower limit), will produce the maximum possible average annual energy (18, 702, 470 kWh). However, this flow split has a technical drawback—there is a gap between the flow ranges, as the lower flow limit of Turbine No. 1 is 200 cfs where Turbine No. 2's upper limit is 164 cfs.

Scenario 10 is similar to Scenario 6 but it adjusts the ranges to provide continuous flow coverage between the units. Scenario 10 indicates use of Turbine No. 1 at 540 cfs /189 cfs (rated/lower limit) and Turbine No. 2 at 194 cfs /68 cfs (rated/lower limit) would yield an estimated average annual energy production of 18,654,808. The difference of less than 50,000 kWh between Scenario 6 and Scenario 10 is likely within the range of accuracy in these estimates.

On this basis, the preliminary selection of Scenario 10 (Turbine No. 1: 540 cfs and Turbine No. 2: 194 cfs) is recommended. This selection was confirmed in consultation with a supplier and a budgetary quotation was obtained, as follows:

Turbine 1:

- Turbine type: Horizontal Francis, fixed-geometry.
- Runner Diameter: 4.92 ft
- Highest Permissible Centerline Setting: 4.3 ft (above T.W.)
- Rated Turbine Flow: 540 cfs
- Rated Turbine head: 110 ft
- Speed: 300 revolutions per minute (rpm)
- Maximum Turbine rated efficiency: 94 Percent
- Operating flow range: 189 to 540 cfs
- Operating head range: 88 to 132 ft
- Nominal generator type and nominal rating: Synchronous, 5,500 kW, 4160V, 3-phase.

Turbine 2:

- Turbine type: Horizontal Francis, fixed-geometry.
- Runner Diameter: 2.79 ft
- Highest Permissible Centerline Setting: 4.3 ft (above T.W.)
- Rated Turbine Flow: 194 cfs
- Rated Turbine head: 110 ft
- Speed: 514 rpm
- Maximum Turbine rated efficiency: 94 Percent
- Operating flow range: 68 to 194 cfs
- Operating head range: 90 to 125 ft
- Nominal generator type and nominal rating: Synchronous, 1,500 kW, 4160V, 3-phase.

The estimated equipment package cost is $6,650,000. This is inclusive of the two turbine-generators, Hydraulic Power Units (HPUs) and controls, and switchgear package F.O.B Pueblo Dam. Delivery time for the proposed equipment would be approximately 16-20 months after contract award. The quotation and performance curves for the selected turbines are featured in Appendix C. Information from these performance curves was used to predict annual energy production for the proposed installation.

Energy Production

- Energy production of the hydroelectric facility will vary widely because of the projected variation in heads and flow at the site. Additionally, the future energy production is dependent on the application of certain projected reductions because of planned changes in Forebay operations and demands from SDS and Pueblo West. This section presents energy production results with various assumptions based on the methodology previously presented and preliminary equipment selection identified in Table 9, Scenario 10.
- Table 10 presents the annual energy production for each calendar year of record (1984 – 2013) without adjustment to both available flow because of future SDS and Pueblo West demands and Forebay levels because of future changes in operation of Pueblo Reservoir. This table therefore presents unaltered production, for the District to evaluate the implications of energy from year to year. Various sequences/combinations of low- and high-energy production years should be evaluated by the District as it pertains to the overall viability of developing the project.

TABLE 10
Annual Energy Production without Reductions for Future flow Demands of SDS and Changes to Pueblo Reservoir Operation

Year	Annual kWh Production
1984	31,809,843
1985	35,650,222
1986	35,006,884
1987	35,908,011
1988	28,058,480
1989	21,406,176
1990	8,150,507
1991	7,095,521
1992	11,023,869
1993	20,851,611
1994	20,651,167
1995	30,663,215
1996	25,863,137
1997	32,855,445
1998	25,303,015
1999	31,778,683
2000	24,108,734
2001	15,633,294
2002	6,101,146
2003	1,387,497
2004	5,474,853
2005	4,982,960

TABLE 10
Annual Energy Production without Reductions for Future flow Demands of SDS and Changes to Pueblo Reservoir Operation

Year	Annual kWh Production
2006	12,305,639
2007	23,453,414
2008	26,230,423
2009	22,877,153
2010	21,008,987
2011	21,514,283
2012	8,547,752
2013	9,128,947
Average	**20,161,029**

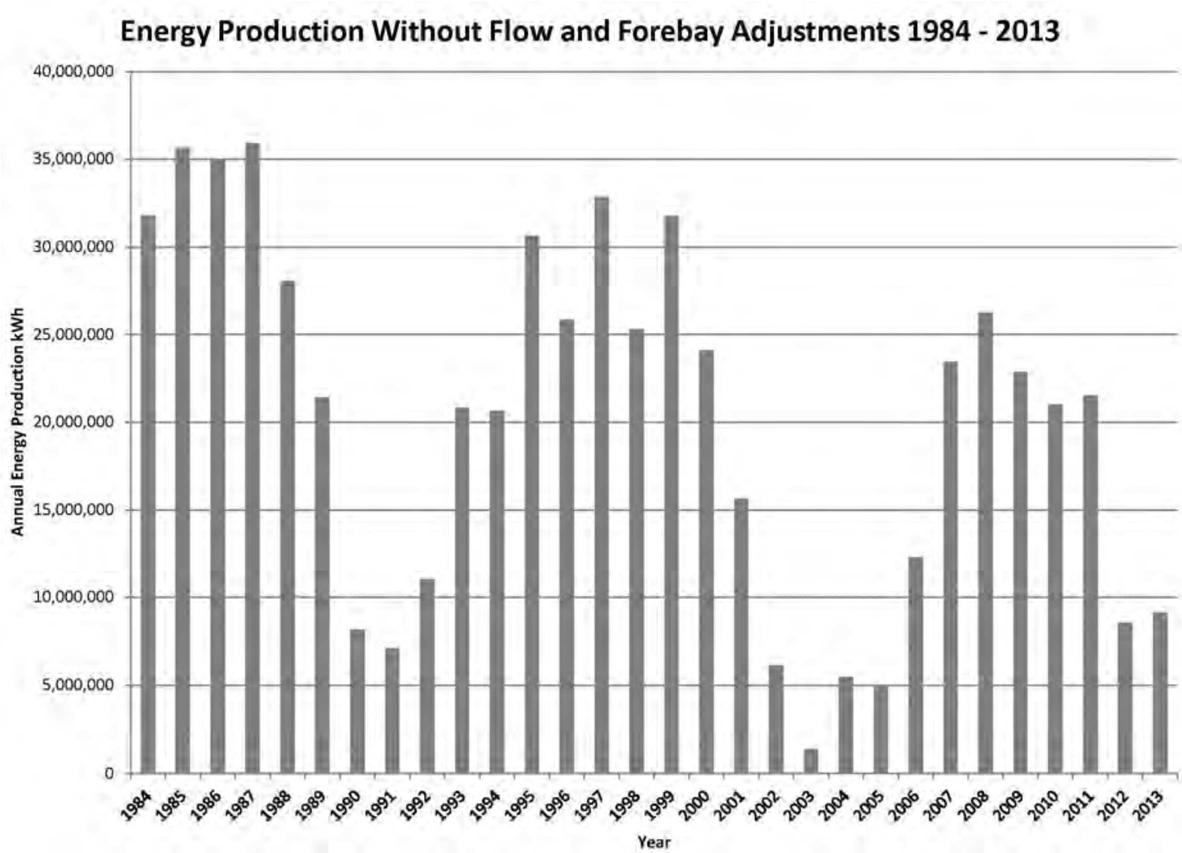


FIGURE 5: ANNUAL ENERGY PRODUCTION WITHOUT REDUCTIONS FOR FUTURE FLOW DEMANDS OF SDS AND CHANGES TO PUEBLO RESERVOIR OPERATION

Table 11 below presents the annual energy production for each calendar year of record (1984 – 2013) with adjustment to both available flow because of future SDS and Pueblo West demands and Forebay levels because of future changes in operation of Pueblo Reservoir. The table below is based on the assumption that January 1, 1984, is projected to January 1, 2017. Certain high-energy production years, such as 1985/2018, have greater annual energy production than when reductions are not applied (comparing

Tables 10 and 11). This is because of an operating condition where historical Forebay data indicates a net head condition just above 132 ft. When applying a reservoir-level reduction to historical data, net head is reduced below the upper shutoff limit of the turbine, thereby generating power. These head boundaries are real, but their exact definition is artificial in the model, producing these small discrepancies. The significance of these discrepancies should be evaluated by the District in consultation with CH2M HILL. The slight variation between the average energy presented in Table 11 from that presented for Scenario 10 in Table 9 is a result of a minor change to the approach of summing and averaging energy production for the period of record considered.

TABLE 11
Annual Energy Production with Reductions for Future flow Demands of SDS and Changes to Pueblo Reservoir Operation

Year	Analysis Year	Annual kWh Production
1984	2017	31,708,976
1985	2018	36,937,840
1986	2019	35,528,928
1987	2020	36,934,708
1988	2021	27,216,132
1989	2022	19,458,194
1990	2023	6,609,917
1991	2024	6,266,804
1992	2025	8,743,286
1993	2026	18,248,452
1994	2027	16,806,236
1995	2028	30,251,783
1996	2029	25,833,980
1997	2030	32,315,849
1998	2031	24,277,270
1999	2032	30,091,813
2000	2033	25,886,483
2001	2034	12,407,496
2002	2035	3,581,273
2003	2036	469,668
2004	2037	1,966,076
2005	2038	2,466,908
2006	2039	6,949,754
2007	2040	20,356,517
2008	2041	23,528,015
2009	2042	20,276,536

TABLE 11
Annual Energy Production with Reductions for Future flow Demands of SDS and Changes to Pueblo Reservoir Operation

Year	Analysis Year	Annual kWh Production
2010	2043	19,783,019
2011	2044	19,353,773
2012	2045	6,321,349
2013	2046	4,825,165
Average		**18,513,407**

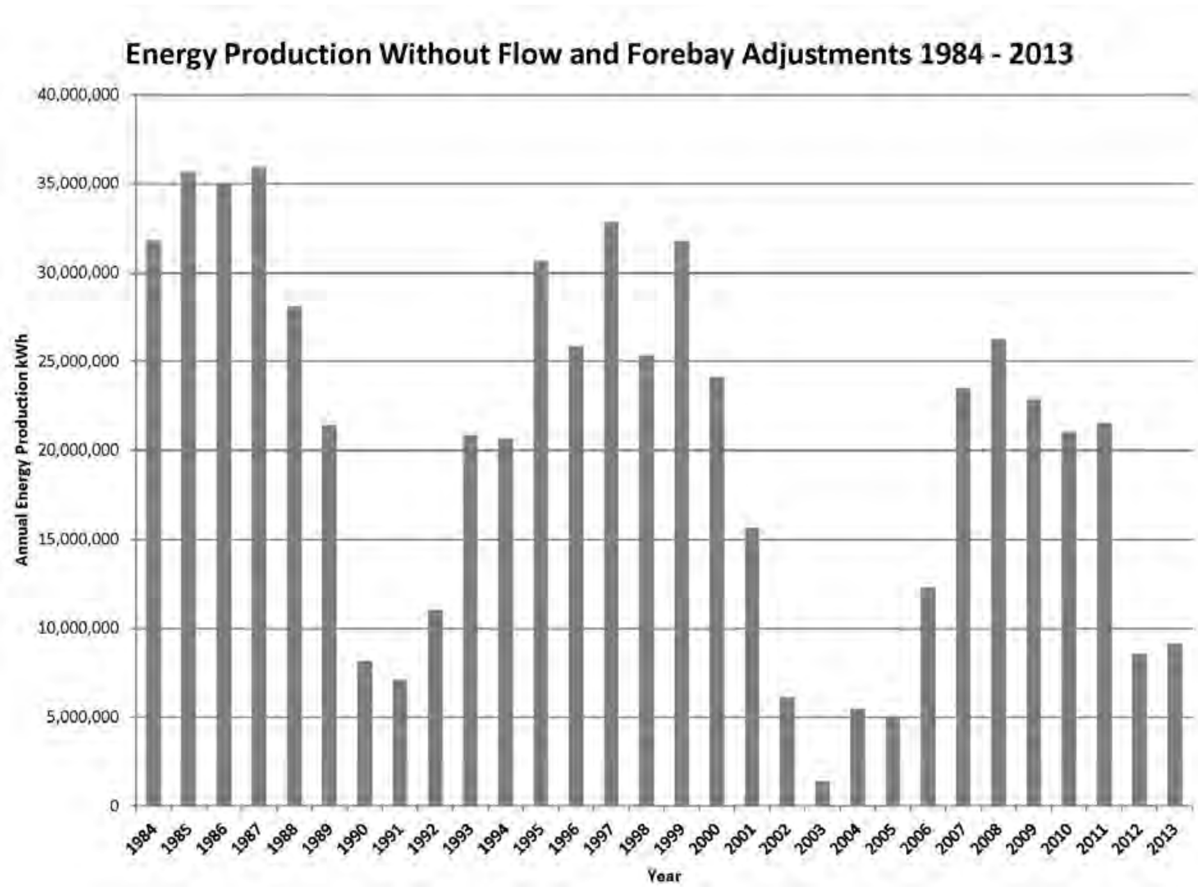


FIGURE 6: ANNUAL ENERGY PRODUCTION WITH REDUCTIONS FOR FUTURE FLOW DEMANDS OF SDS AND CHANGES TO PUEBLO RESERVOIR OPERATION

Increased demands on Arkansas River water because of future SDS and Pueblo West account for approximately 65 percent of the total effects of the adjustments. This is primarily because of the flow reductions altering a 66 cfs flow exceedance (lower flow limit of Turbine #2) from a less than 6 percent occurrence to a 20 percent occurrence when SDS and Pueblo West flow demand increases to an average of 56 cfs between 2045 and 2050. The reality of SDS and Pueblo West flow demands affecting the flow exceedance to this degree is probably quite uncertain since it is more likely flow will be managed differently in the summer months (curtail peak releases) to maintain higher base flows in the Arkansas River during low-flow months to achieve the minimum design flow of the fixed cone valve facility. This should be noted by the District and discussed with CH2M HILL.

Power Plant Arrangement and Electrical Interconnection

The powerhouse would be a two-level cast-in-place concrete and metal structure located approximately 500 ft downstream from the fixed cone valve facility. Exterior architectural treatment will be consistent with that approved by Reclamation, State Parks, and Pueblo County for the Juniper Pump Station. Water supply to the turbines will be from two separate 66-inch (nominal) turnouts from the 90-inch Reclamation pipeline. The 66-inch turnouts were determined during the summer of 2013. Pipeline shop drawings actually indicate a 67-inch ID for these turnouts. Flow to Turbine #1 will be 540 cfs, suggesting a 67-inch x 72-inch enlargement on the tap to connect with the 72-inch Inlet Valve No. 1. Turbine #2 will require a 67x48 reducer for to the 48-inch Turbine Inlet Valve No. 2.

The turbines and generators will be located below grade. A maintenance and control room will be located approximately 3 ft below the existing dam access road elevation of 4766 ft. The runner centerline of Turbine No. 1 will be approximately 4 ft above the minimum tailwater elevation of 4744, which is approximately 18 ft below the existing Pueblo Dam access road. To provide a uniform turbine room floor elevation of 4739.5 ft, the runner centerline of Turbine No. 2 will be approximately 1 foot above the minimum tailwater elevation, though a higher setting could be employed.

The building will have lighting, heating, cooling, and drainage systems and an overhead crane to remove the generator and turbine runner for maintenance. Protective relay cabinets, metering, and the remote control (SCADA) system will be installed in the control room area. Low voltage motor control center and power distribution panels will be provided for AC station service, along with a station battery and inverter to provide an uninterruptible power supply for the controls and computer equipment.

The turbines will be horizontal shaft Francis type with synchronous generators. The generator will be rated 3-phase, 60 hertz (Hz) at 4160 volts (V). The mechanical equipment will include dedicated hydraulic power units. The generator will include a brushless excitation system and neutral grounding equipment. Both the turbine and the generator will have complete instrumentation installed to allow monitoring of critical machine operating parameters, including lube oil temperature and level, hydraulic power system status, speed, generator stator and bearing temperatures, and unit out voltage, amperage, and kilowatts. A butterfly-type inlet valve and ultrasonic flow meter will be installed in each penstock to allow for unit isolation and metering, respectively.

Interconnection of the power plant to the transmission/distribution system will be through a 4160-volt (V) to 12.47-kilovolt (kV) transformer located adjacent to the power plant and a 12.47-kV underground transmission line to interconnect with the 15-kV switchgear of the Juniper Pump Station. The underground line is required because of overhead lines being prohibited by State Parks though it will be more expensive than overhead. The hydroelectric facility will use the substation and distribution system of the Juniper Pump Station for interconnection with the power grid. A backup generator will not be provided at the powerplant. 480-V backup power will be provided from Juniper Pump Station.

Conceptual drawings for the project are included in Appendix D. These drawings were used as a basis for the development of cost estimates for infrastructure associated with the proposed hydropower facility.

Order-of-Magnitude Cost

An opinion of probable construction cost consistent with the level required for a feasibility-level design was performed. A Class 4 Cost Estimate per the Association for the Advancement of Cost Engineering (AACE) International was prepared to show the construction costs for the hydropower system.

A Class 4 Cost Estimate is defined as an estimate that is prepared to form the basis for the project authorization and/or funding. Typically, engineering is from 1 to 5 percent complete. Detailed strategic planning, business development, project screening, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval are needed to proceed. The accuracy range for this class of estimate should be expected between –30 percent and +50 percent.

Table 12 presents estimated costs for significant project elements: Detailed opinion of probable construction costs for the project can be found in Appendix E.

TABLE 12
Summary of development costs

Item	Cost
Total Construction Costs	$10,292,162
Owner Furnished Products and Project Interconnection Costs	$7,320,000
Project Administration Costs	$2,050,000
Estimated Total Capital Cost of Development	**$19,662,162**

Economic Feasibility

The conventional economic feasibility for developing a project is determined by comparing the present value of benefits (i.e., revenue from the sale of energy or monies saved by offsetting consumption) with the present value of costs (such as the capital cost for development or O&M costs). This comparison can also take the form of the net present value (benefits minus costs) or Benefit/Cost (B/C) ratio. A basic financial-economic evaluation, illustrating the costs, benefits, and economic feasibility of developing the site, is presented in Appendix F.

Costs

Four primary costs are associated with development of the site:

- Total Development Cost – $19,401,926, major development cost elements include rock excavation ($2.9M, 15 percent of the total cost) and Turbine/Generator costs ($6.65M, 34 percent of the total cost). Rock excavation costs are based on using rock trenchers and excavation equipment (unit price of $300 per yard) as blasting will not be permitted at the site. A rock excavation contractor who has performed work at Pueblo Dam suggested that the proposed excavation could be accomplished for approximately $100 per yard. CH2M HILL is currently soliciting budgetary estimates from other contractors for the rock excavation. Budgetary construction costs featured in Appendix E include a 20 percent contingency. Further refinement and opportunities to reduce costs will be considered during preliminary design.
- Annual O&M costs – $168,466 in 2017 based on an average cost per kWh of $0.0085 and an average annual energy production associated with the Economic Evaluation attachment. The O&M costs were escalated 3.5 percent annually from the 2017 value. This is based on investigations performed by Colorado Springs Utilities during the 2011 LoPP Application efforts.
- Transmission and Wheeling – $3.75/MWh as indicated by Colorado Springs Utilities during the 2011 LoPP Application efforts. Transmission and Wheeling costs to the project are carried by the project through 2027, at which time this cost ceases when Pueblo West and Juniper Pump Stations consume all energy produced by the hydropower plant. This cost approach was provided by the District.
- Payments to the United States – Assumed to be at 3 mills/kWh for duration of evaluation.

Any other costs not specifically stated, such as monthly or annual fees charged by the interconnecting utility for interconnection facilities, are not included. These costs, if any, will be determined by the District during the LoPP permitting process.

Benefits

In the absence of a District preferred value of energy to be used in this Feasibility Update, CH2M HILL has assumed an energy value of $55/MWh in 2017, escalating at 3 percent annually for the 25 year operation period evaluated. This assumption must be verified by the District. Based on the benefit cost ratio determined for this feasibility update, initial energy values in the $50 to $55/MWh, including any potential renewable energy credits, should be the minimum target range for this project to be feasible, assuming all other factors (capital costs, financing rates, escalation rates, energy generation) stated in this TM remain constant.

Present Value of Benefits and Costs

Monies spent or accrued at different times or over a period must be discounted or escalated to a single point in time in order to be compared properly. For development of the PDHP the recurring benefits (annual energy savings) and costs (capital and O&M) that occur throughout the life of the project are discounted to a 2014 Present Value for determination of a B/C ratio. The period of analysis extends from 2014 to 2041 (25-year operating period, 2017-2041) and assumes a discount rate (cost of money) of 2.0 percent, as provided by the District.

Table 13 summarizes basic project operation and financial performance over the period of analysis, 2017 to 2041. The actual project development and funding approach of the District will dictate how such data must be applied to actual project financial scenarios. It is assumed that the District will complete such additional analyses in its final determinations of project funding and feasibility. The table summarizes the conventional feasibility of developing the site based on the financial-economic evaluation presented in Appendix F.

TABLE 13
B/C Ratio for Hydropower Development of the Site

Item	Value
2014 Total PV of Costs	$26,580,537
2014 Total PV of Revenue/Benefit	$28,334,187
2014 Net Present Value	$1,753,650
Overall PV B/C Ratio	1.07

Summary of Assessment and Considerations

This TM presents a basis for assessment of the PDHP’s feasibility. The final assessment of feasibility should include a variety of consideration including the following:

- Historic reservoir levels and flows in the Arkansas River from 1983 to 2013 appear to have an overall downward trend. Although 30 years of record is not an extensive period to evaluate hydrologic climate change in the drainage basin or predict the future, this general trend and its potential long-term effect on the proposed hydroelectric facility should be evaluated by the District.
- The basis for equipment selection and sizing, power plant arrangement, projected operations, and energy production estimates is the historical hydrology for Pueblo Dam and its releases, adjusted for projected operation of the SDS. To date, these patterns of flow and available head have been endorsed by the Partnership as the basis for project feasibility assessment and planning. They have been averaged or otherwise analyzed to select equipment and estimate average energy production. The projected annual production is tabulated in Tables 10 and 11. Production, revenue, and project cash flow can vary widely with hydrologic conditions. As presented in Table 13 and attached financial-economic evaluation, the sequence of those conditions is simply based upon the historical record, and does not reflect possible future trends. The District should consider whatever additional assessments may be necessary to understand the risks associated with the hydrologic uncertainty and to establish that possible cash flow scenarios are incorporated into the project development and funding plans.
- The project development plan and energy production estimates prepared in 2011 during the LoPP application process were very preliminary. Equipment selection and sizing reflected the preliminary data

on flow and head provided at that time, resulting in the twin 300 cfs turbine-generators. The final data for available head and flow, provided in late 2012, have indicated that 1) wide variation in reservoir pool level is typical, 2) low available flows from 50 to 100 cfs are typically present for long periods, and 3) maximum available flow to the hydroelectric plant have increased. These conditions have increased the range of flows that should be used for the most economical project development. This result has, in turn, suggested that two unequally sized units best capture these low and high flows.

- Effective use of constant speed Horizontal Francis Units at this site will require aggressive equipment operation somewhat outside the zone with which manufacturers would typically be comfortable. The estimates of energy production are based upon discussions with equipment manufacturers and reflect a somewhat "aggressive" range of operation in relation to net head. This consists of allowing operation at heads that extend about 3 ft above and below the ideal range quoted by the manufacturers. The risks associated with such operation are an increased possibility of cavitation or hydraulic vibration. However, the likelihood of conditions that would actually dictate limiting operation is small. Such increase in cavitation pitting might require periodic repairs, but their expected cost is small in relation to the energy production benefit.
- To illustrate importance of a broader head operating head range at the site:
  - For Turbine No. 1, rated at 540 cfs and 110 ft, the upper head limit is analyzed at 132 ft versus manufacturer-recommended 128.6 ft. This produces an additional average 1,200,000 kWh/year. The lower limit was analyzed at 87 ft versus manufacturer-recommended 89.9 ft producing an average additional 450,000 kWh/year.
  - For Turbine No. 2, rated at 190 cfs and 110 ft, the upper head limit is analyzed at 125 ft versus manufacturer-recommended 121.7 ft. This produces an additional average 150,000 kWh/year. The lower limit was analyzed at 90 ft versus manufacturer-recommended 93.5 ft producing an average additional 250,000 kWh/year.
  - During procurement of the equipment, the desired operating ranges could be incorporated into a manufacturer's bid or the District may be required to push the equipment past the guaranteed operating ranges in efforts to capture additional kWhs.
- Several manufacturers might be considered for providing equipment for this project, including Voith, Andritz, Alstom, Canyon Hydro, Gilkes, and Mavel. However, because of the operation requirements of the Francis units installed at the site, some of these manufacturers will likely be unable to provide equipment because of an inability to offer more specialized machines from both an engineering and manufacturing standpoint.
- The preliminary equipment selection in this TM utilizes the remaining flow capacity of the Reclamations Pipeline beyond that reserved for Pueblo West and SDS. The District should verify that this is acceptable to project stakeholders.
- The significantly varying net head at the site suggests investigation of variable speed controls based on power electronics apparatus. This approach is "cutting edge" in the industry, but would allow the units to operate at consistent efficiencies across the entire range of heads. Such equipment will increase the capital and O&M costs, which will need to be compared to the energy benefit of this approach. Costs are still being compiled to assist the District in assessing the viability of this approach. Evaluation of this approach will be performed during preliminary design.
- Integration of Powerplant operation with the Reclamation Pipeline, Forebay levels, fixed cone valve, and spillway gates is yet to be determined. Most effective operation of the hydropower facility will require an ability to work "hand-in-hand" with the various facility operators of the integrated conveyance systems. It is recommended that the District understand the latitude which will be allowed to plan for

and dictate reservoir, fixed cone valve, and other facility operation in efforts to maximize energy production.

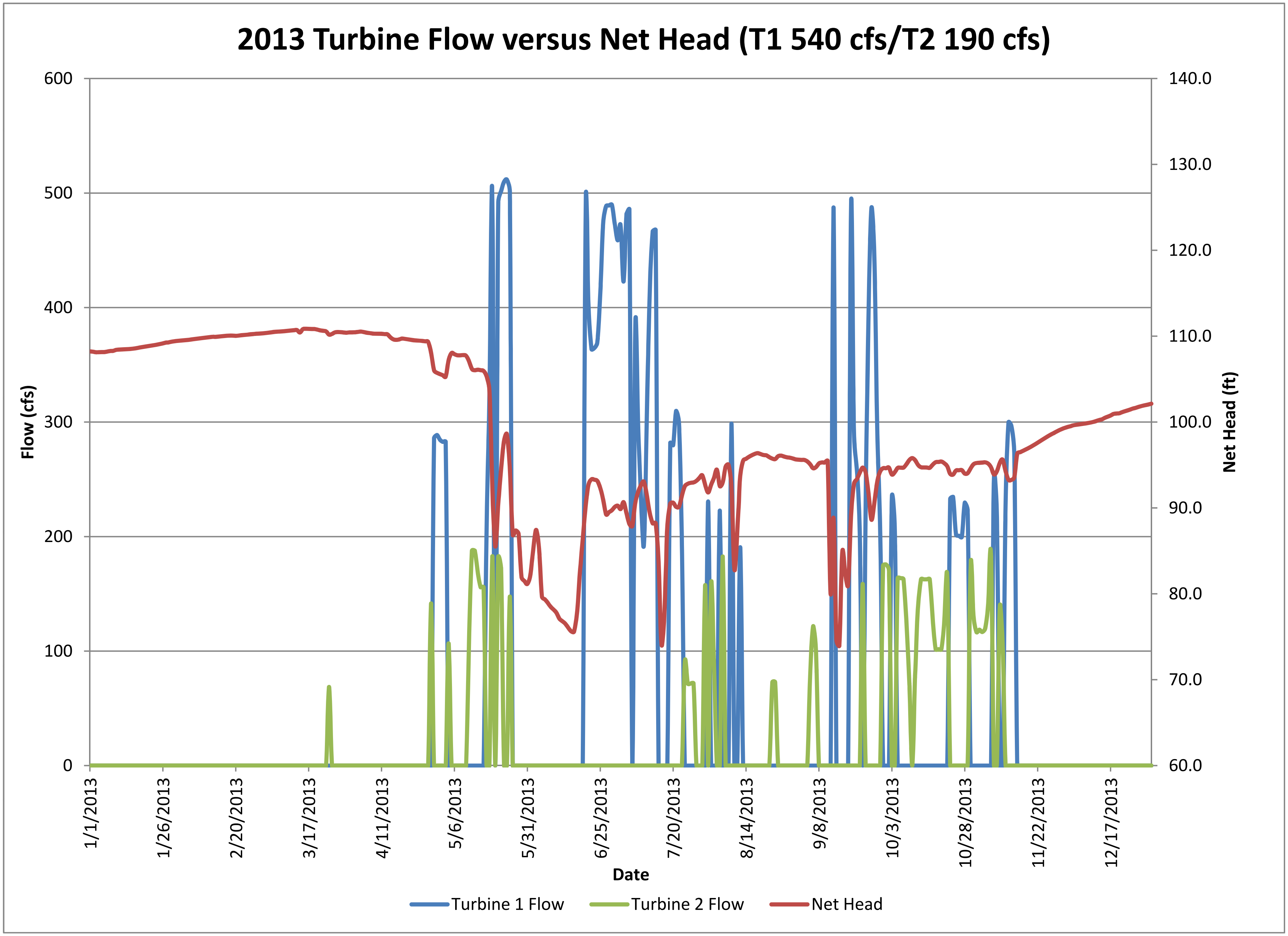
- Total Development Costs for the project are estimated to be $19.7M. A conventional economic feasibility analysis suggests that development of the project has a B/C ratio of 1.07 or a net present value of $1.8M, considering a 25-year analysis period and assumptions presented in this TM.

District Action Items

- The general trend of decreasing average Forebay levels and its potential long-term effect on the proposed hydroelectric facility should be evaluated by the District.
- The significance of head and flow operating boundaries of the hydroelectric equipment should be evaluated by the District in consultation with CH2M HILL.
- The reality of SDS and Pueblo West flow demands affecting the low flow exceedance to the degree quantified by this feasibility update is probably quite uncertain. This should be noted by the District and discussed with CH2M HILL.
- The preliminary equipment selection in this TM utilizes the remaining flow capacity of the Reclamations Pipeline beyond that reserved for Pueblo West and SDS. The District should verify that this is acceptable to project stakeholders.
- The District has yet to establish the value of energy. As a result, CH2M HILL has assumed an energy value of $55/MWh in 2017, escalating at 3 percent annually for the 25-year operation period evaluated. This assumption must be verified by the District.
- The actual project development and funding approach of the District will dictate how data must be applied to actual project financial scenarios. The District should complete such additional analyses in its final determinations of project funding and feasibility.
- The District should consider whether additional assessments may be necessary to establish that possible cash flow scenarios are incorporated into the project development and funding plans.
- It is recommended that the District understand the latitude that they will be allowed to plan for and dictate reservoir, fixed cone valve, and other facility operation in efforts to maximize energy production.

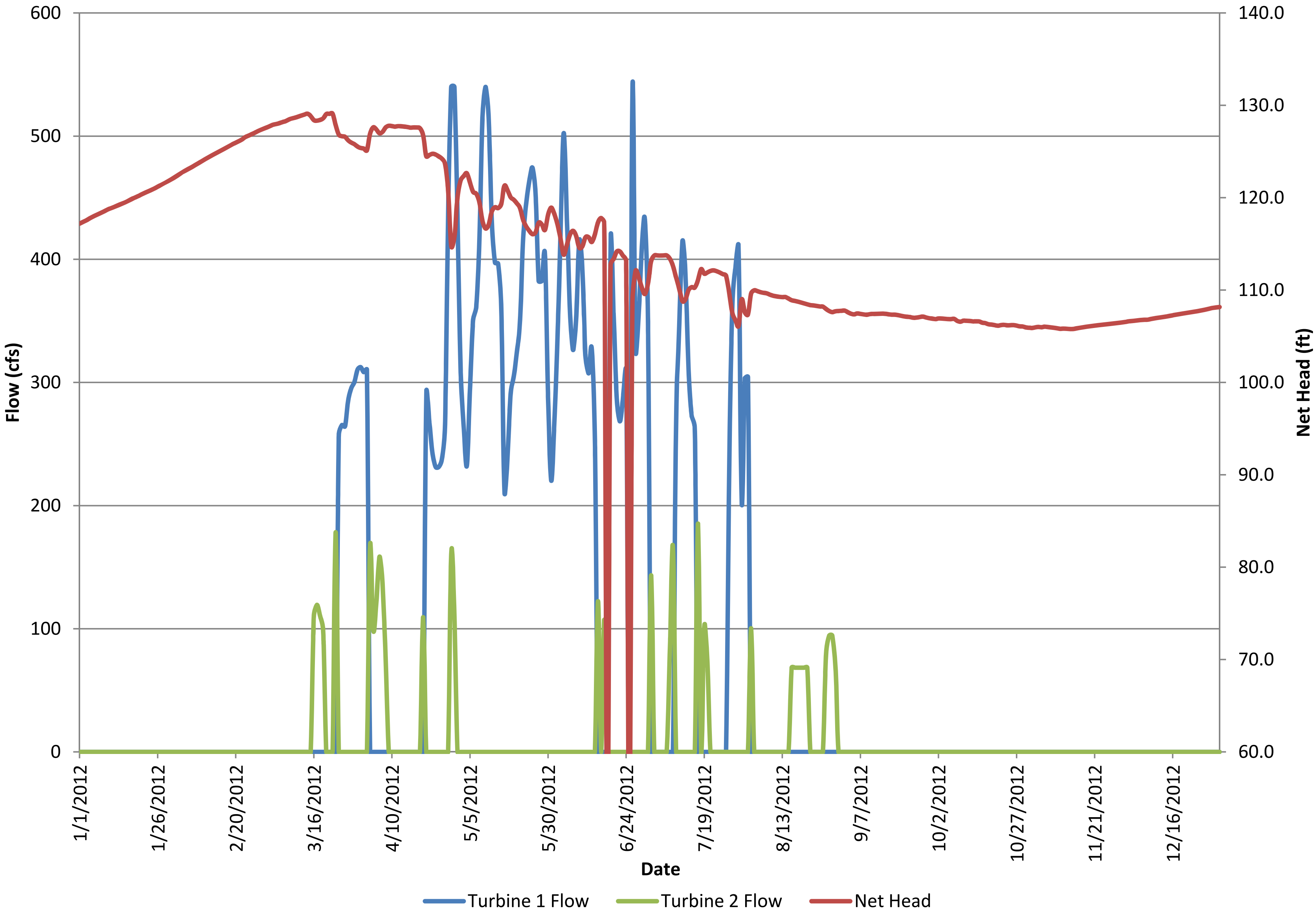
APPENDIX A

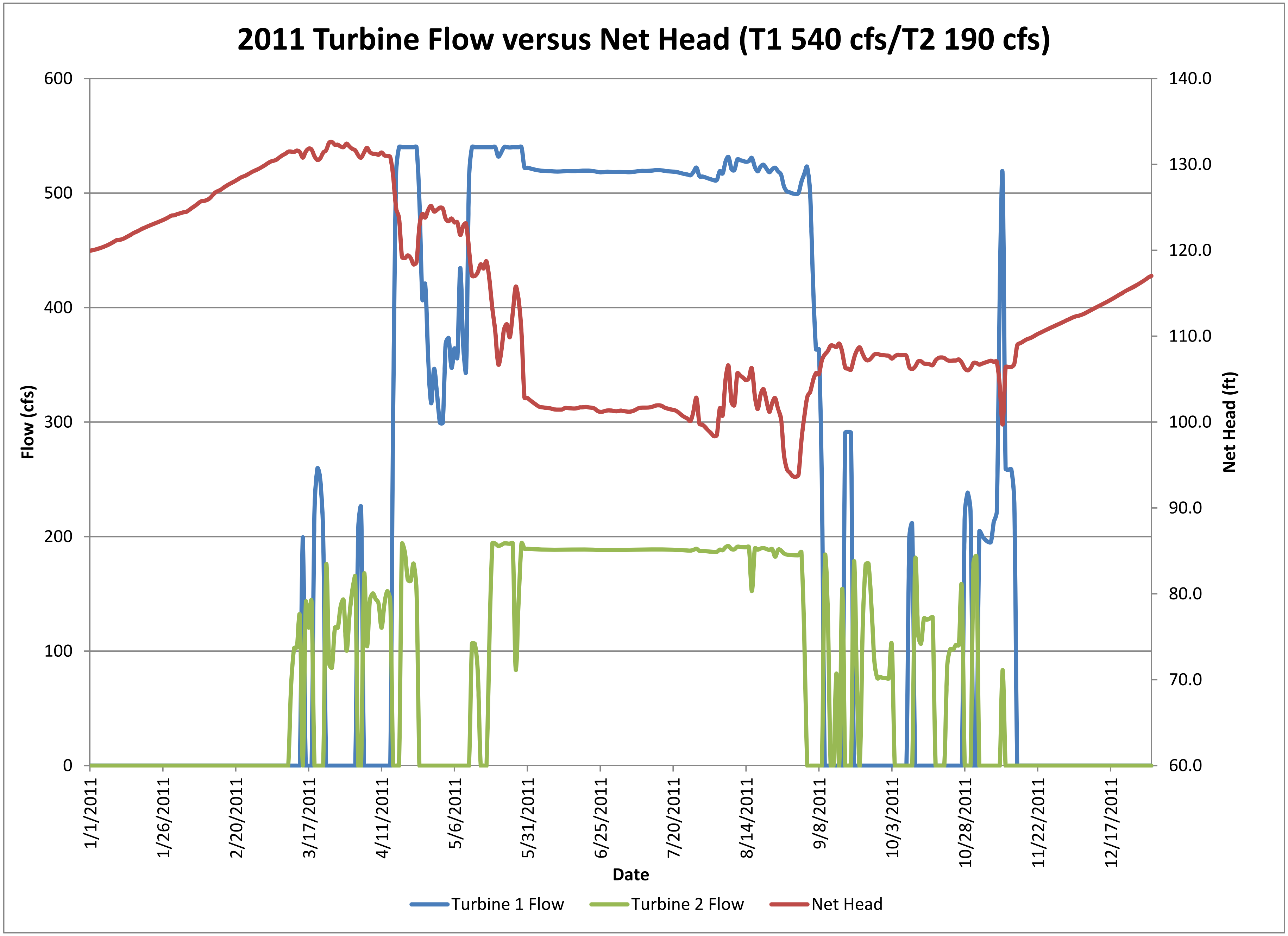
Net Head/Turbine Flow Comparisons 1984-2013



2013 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
0
100
200
300
400
500
600
60.0
70.0
80.0
90.0
100.0
110.0
120.0
130.0
140.0
1/1/2013
1/26/2013
2/20/2013
3/17/2013
4/11/2013
5/6/2013
5/31/2013
6/25/2013
7/20/2013
8/14/2013
9/8/2013
10/3/2013
10/28/2013
11/22/2013
12/17/2013
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head

2012 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)




2011 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
600
500
400
300
200
100
0
Net Head (ft)
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/2011
1/26/2011
2/20/2011
3/17/2011
4/11/2011
5/6/2011
5/31/2011
6/25/2011
7/20/2011
8/14/2011
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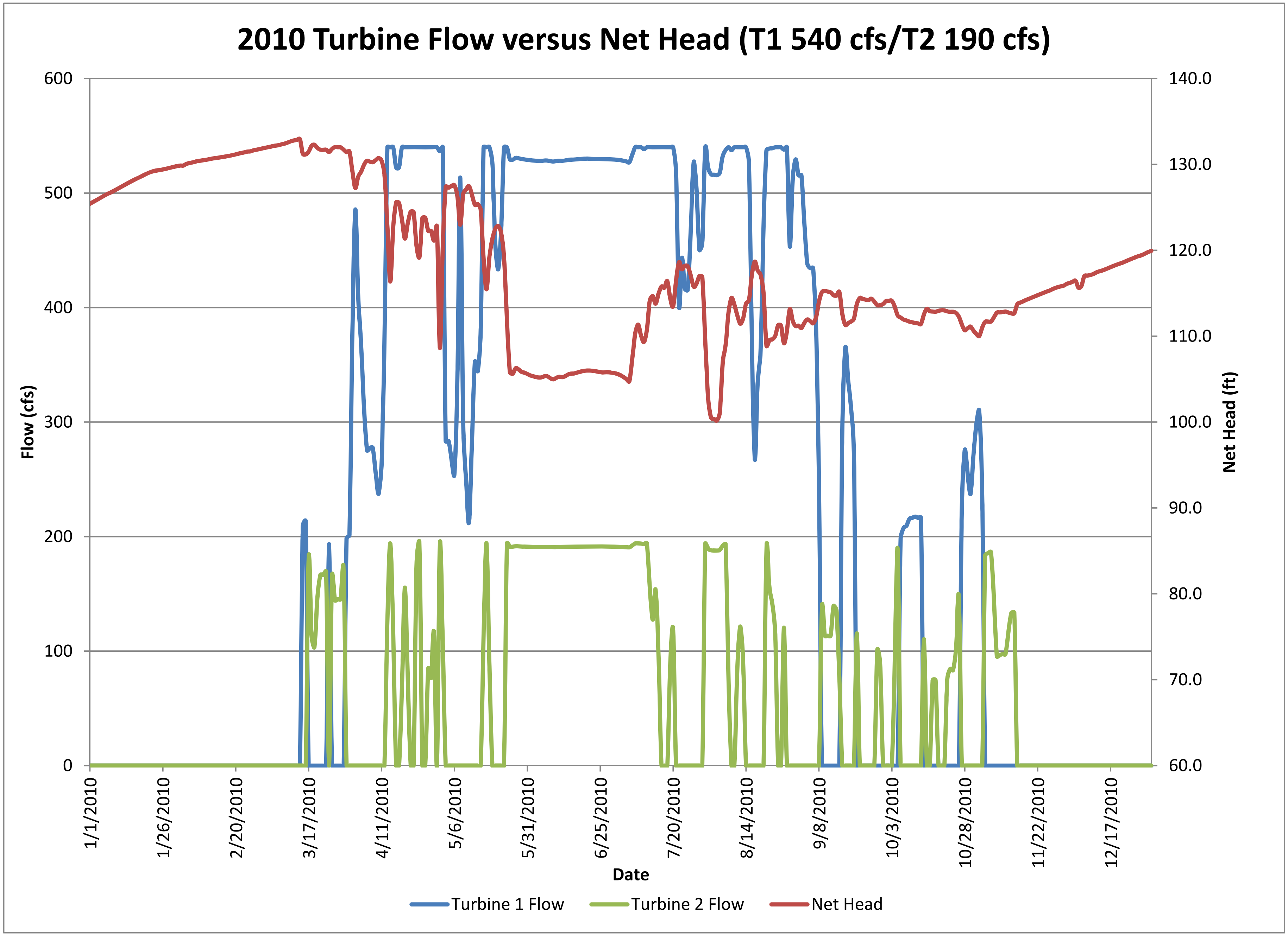
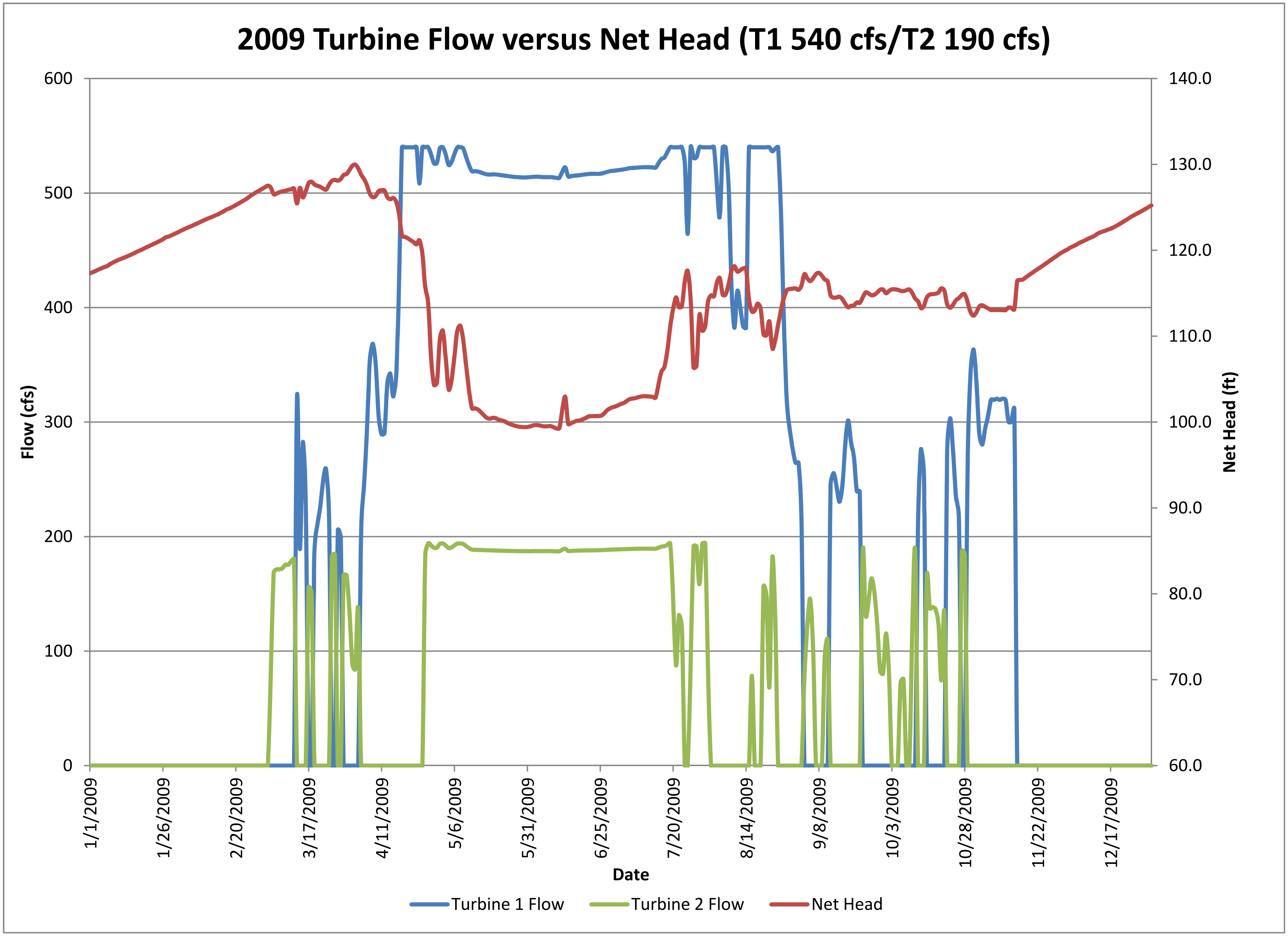
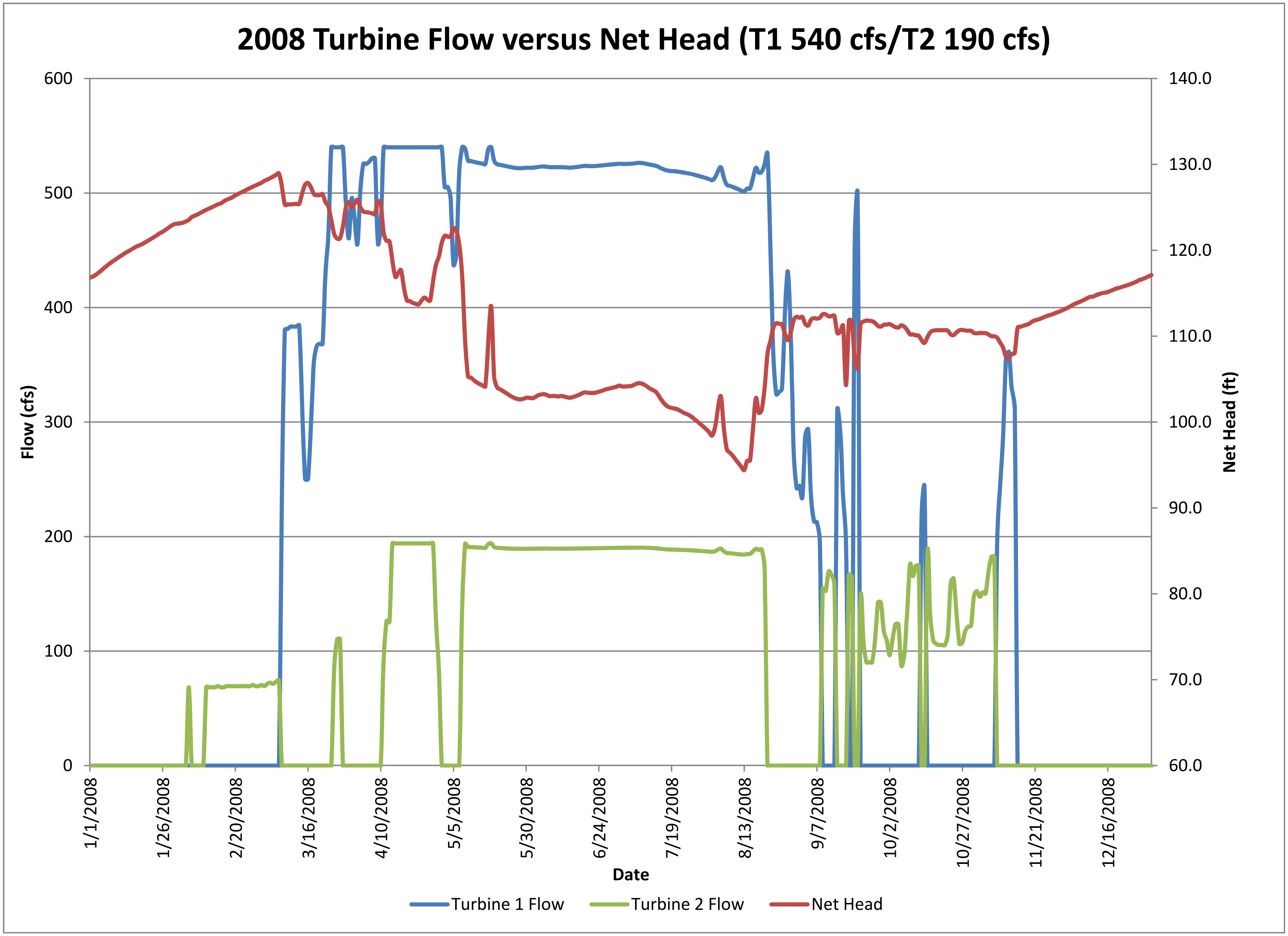
10/3/2011
10/28/2011
11/22/2011
12/17/2011
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head

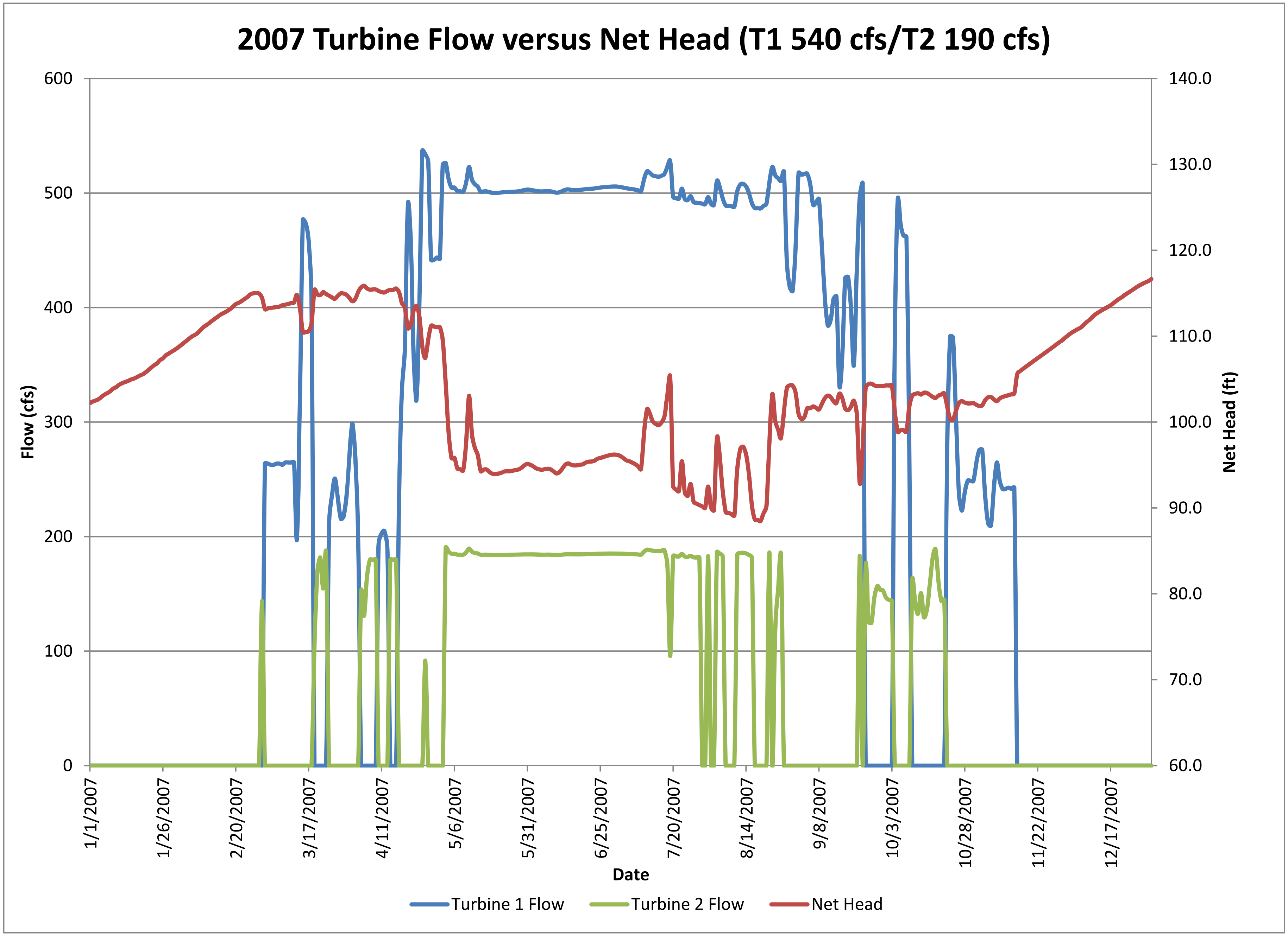


2010 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
600
500
400
300
200
100
0
Net Head (ft)
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/2010
1/26/2010
2/20/2010
3/17/2010
4/11/2010
5/6/2010
5/31/2010
6/25/2010
7/20/2010
8/14/2010
9/8/2010
10/3/2010
10/28/2010
11/22/2010
12/17/2010
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head

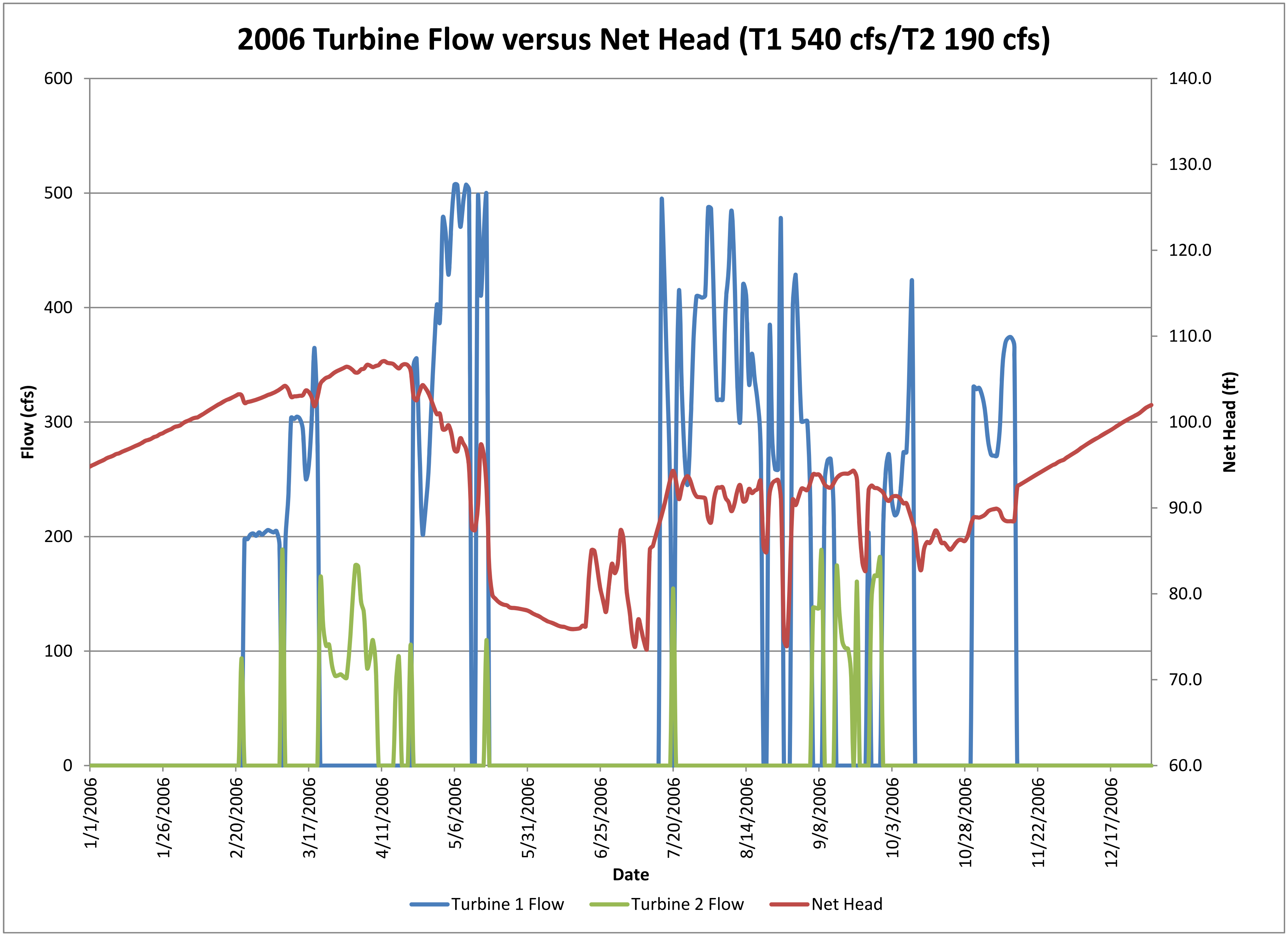


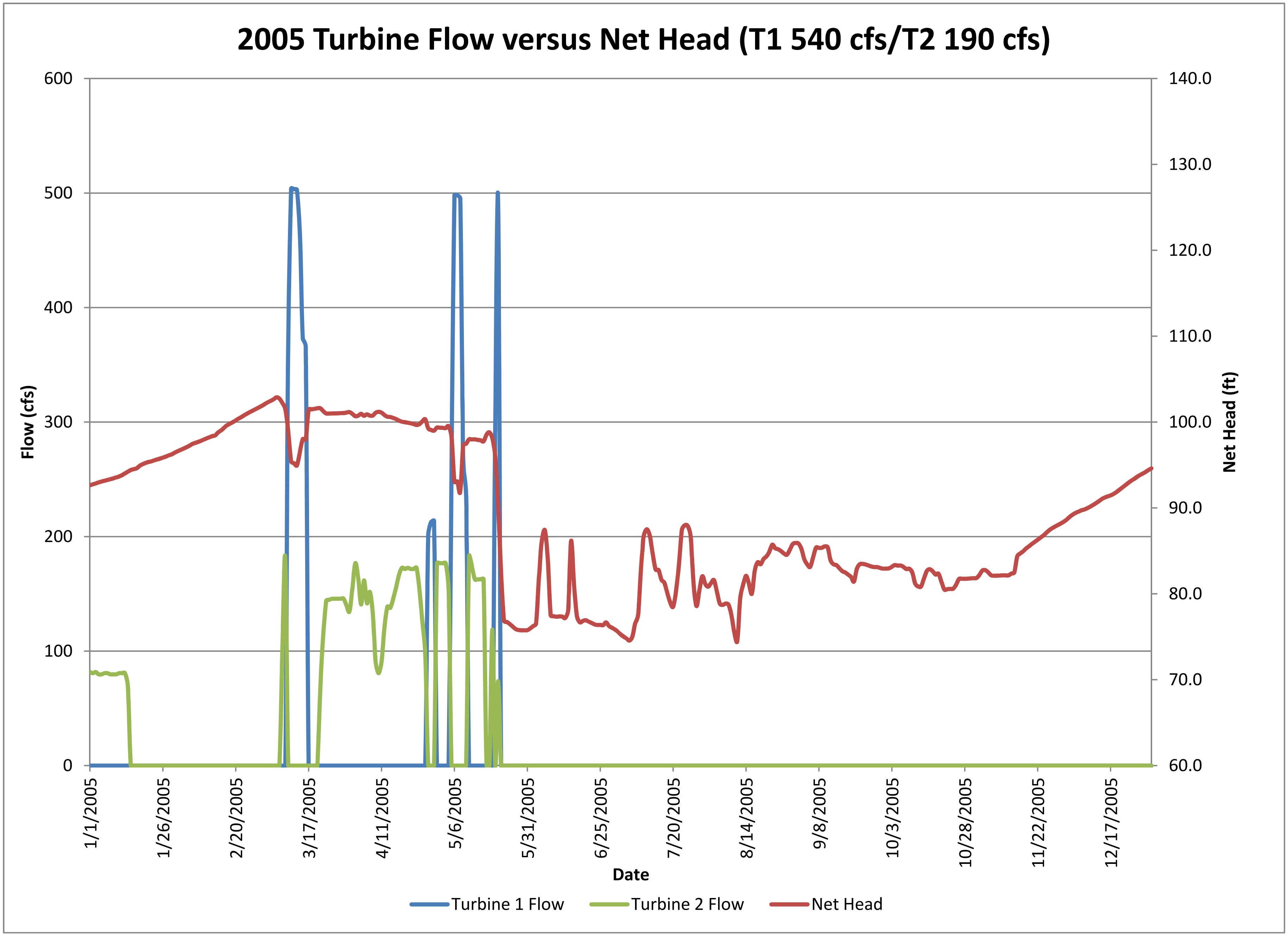
2009 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/2009
1/26/2009
2/20/2009
3/17/2009
4/11/2009
5/6/2009
5/31/2009
6/25/2009
7/20/2009
8/14/2009
9/8/2009
10/3/2009
10/28/2009
11/22/2009
12/17/2009
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head

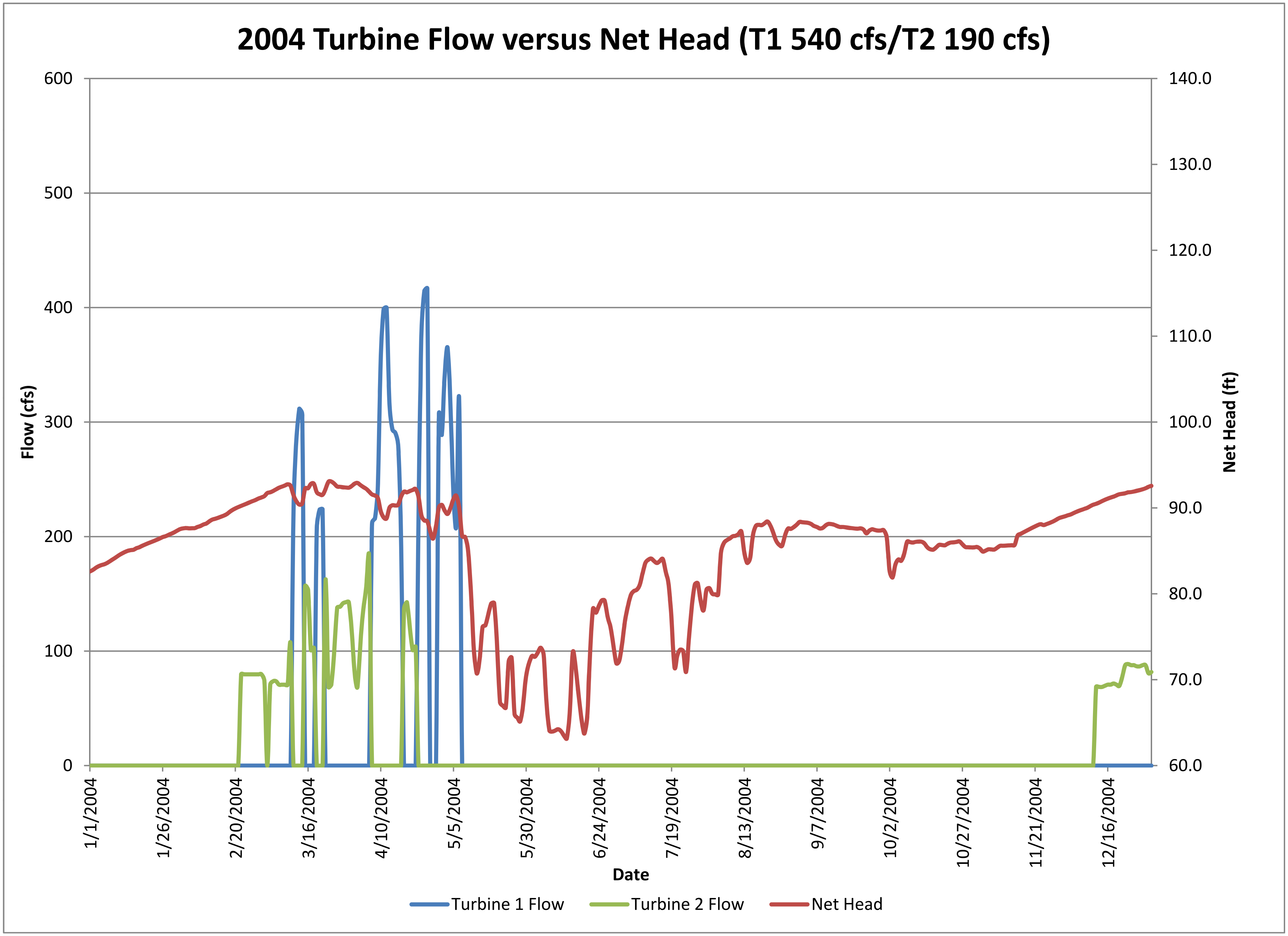

2008 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
600
500
400
300
200
100
0
Net Head (ft)
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/2008
1/26/2008
2/20/2008
3/16/2008
4/10/2008
5/5/2008
5/30/2008
6/24/2008
7/19/2008
8/13/2008
9/7/2008
10/2/2008
10/27/2008
11/21/2008
12/16/2008
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head



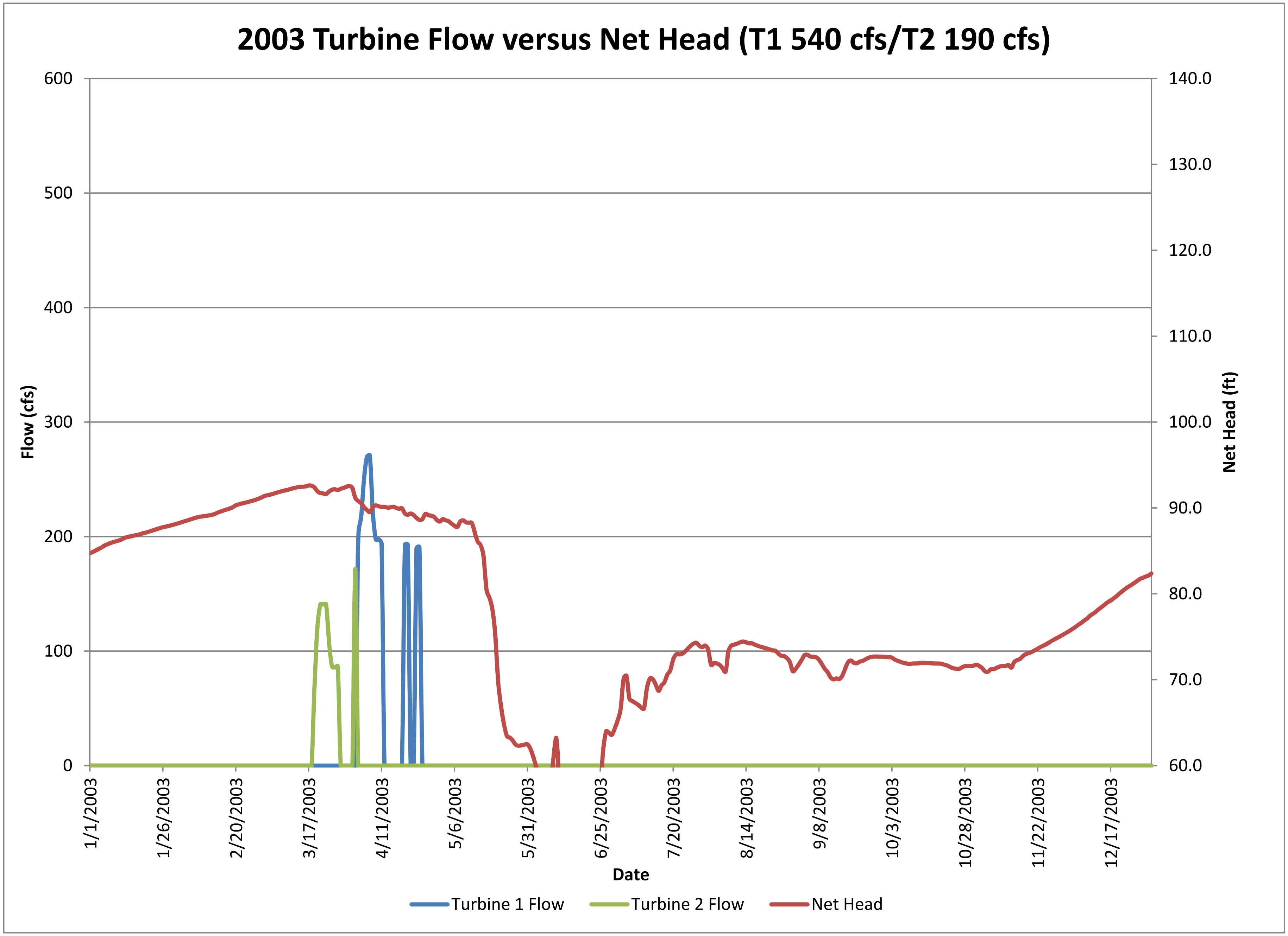
2007 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
Date
0
100
200
300
400
500
600
60.0
70.0
80.0
90.0
100.0
110.0
120.0
130.0
140.0
1/1/2007
1/26/2007
2/20/2007
3/17/2007
4/11/2007
5/6/2007
5/31/2007
6/25/2007
7/20/2007
8/14/2007
9/8/2007
10/3/2007
10/28/2007
11/22/2007
12/17/2007
Turbine 1 Flow
Turbine 2 Flow
Net Head

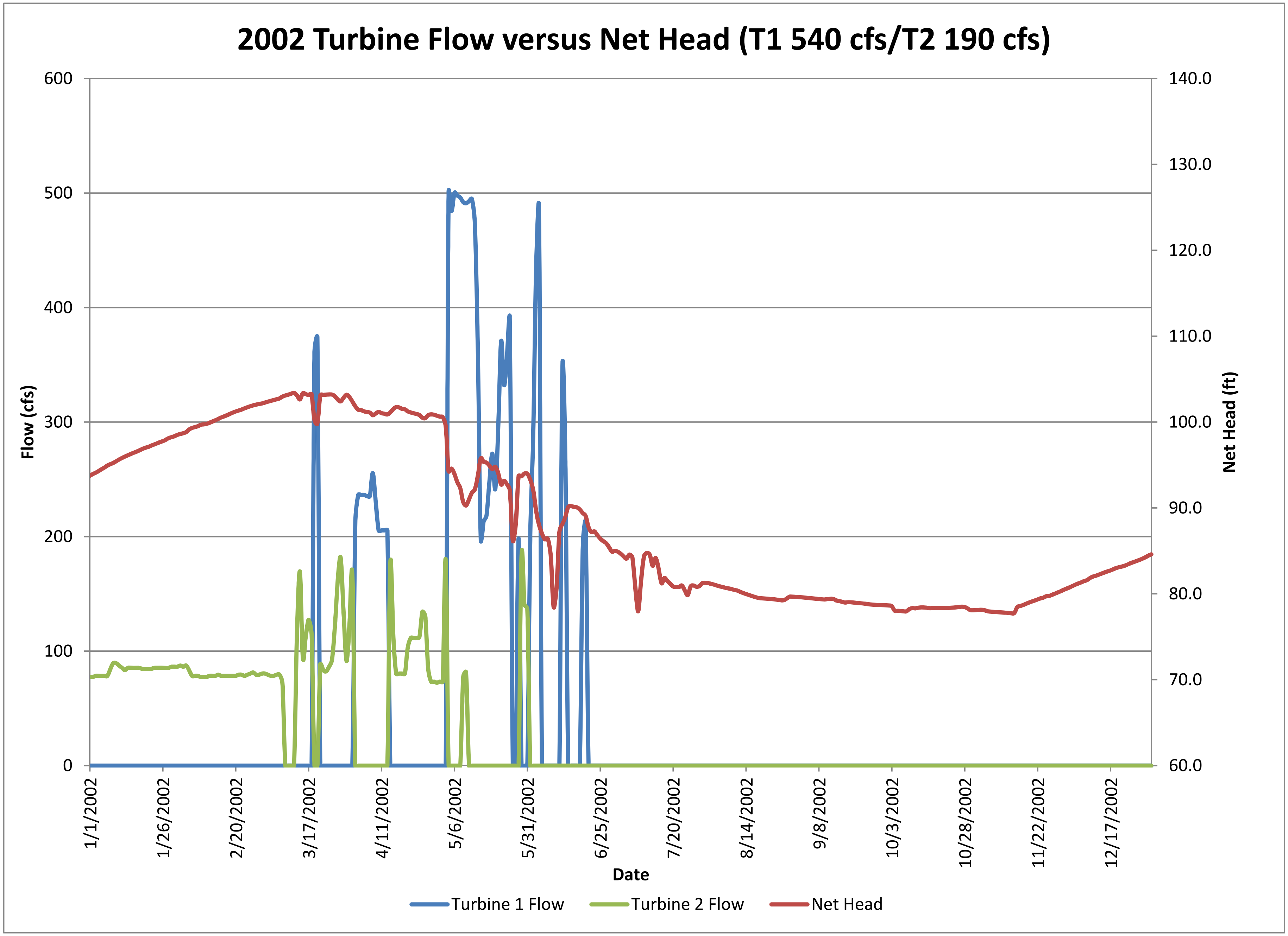

2006 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/2006
1/26/2006
2/20/2006
3/17/2006
4/11/2006
5/6/2006
5/31/2006
6/25/2006
7/20/2006
8/14/2006
9/8/2006
10/3/2006
10/28/2006
11/22/2006
12/17/2006
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head


2005 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
Date
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/2005
1/26/2005
2/20/2005
3/17/2005
4/11/2005
5/6/2005
5/31/2005
6/25/2005
7/20/2005
8/14/2005
9/8/2005
10/3/2005
10/28/2005
11/22/2005
12/17/2005
Turbine 1 Flow
Turbine 2 Flow
Net Head

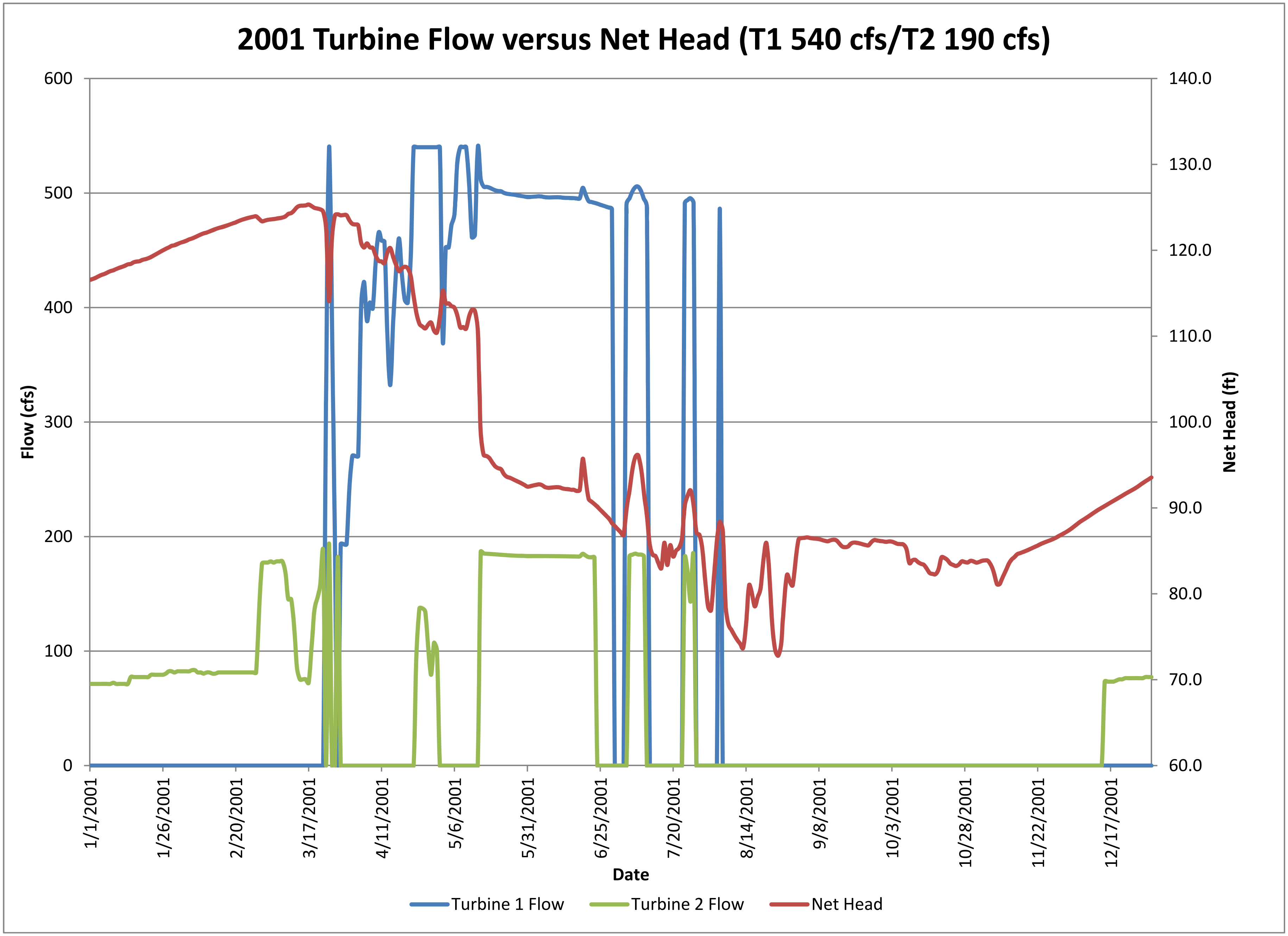


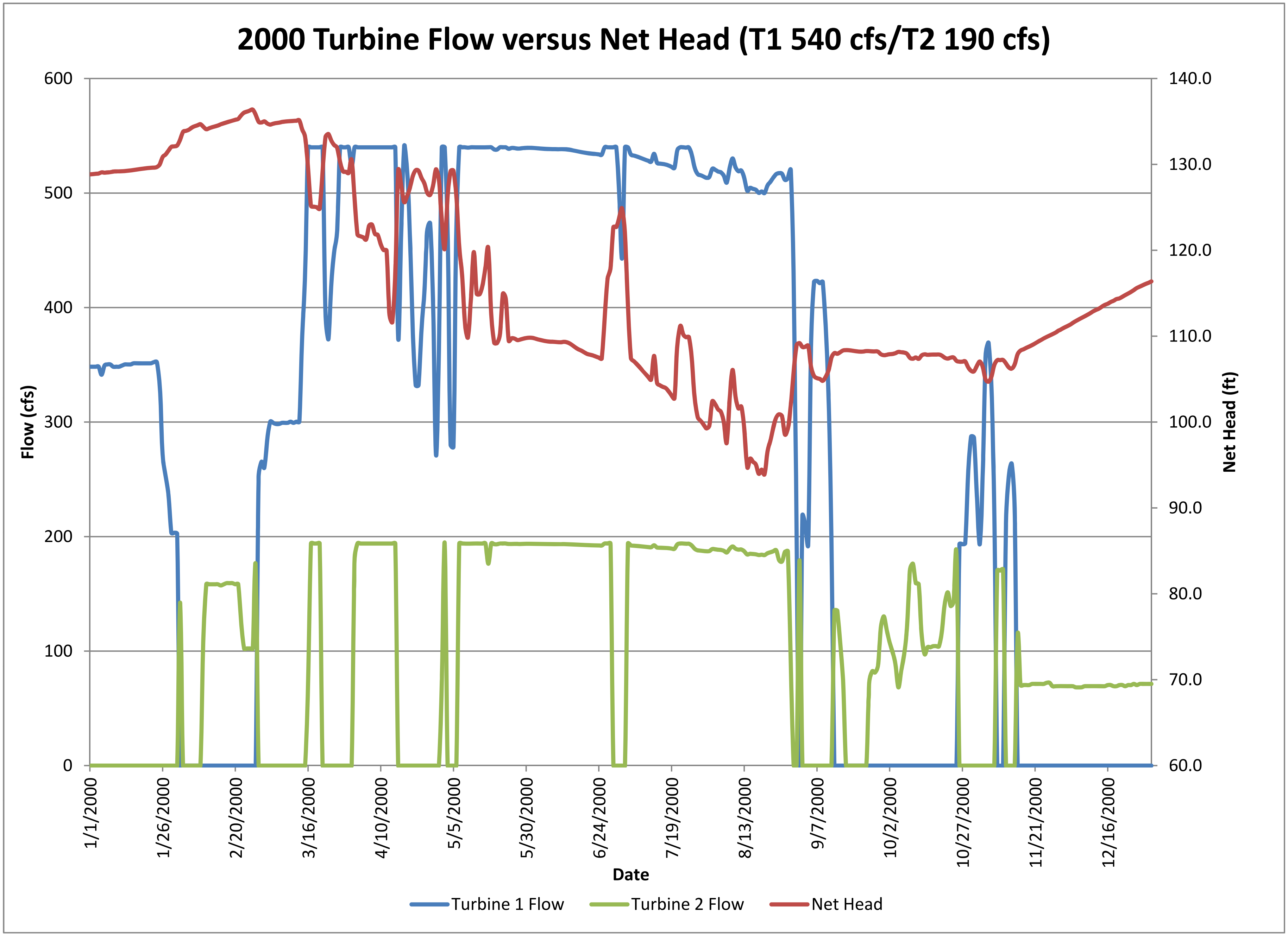
2004 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
600
500
400
300
200
100
0
Flow (cfs)
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
Net Head (ft)
1/1/2004
1/26/2004
2/20/2004
3/16/2004
4/10/2004
5/5/2004
5/30/2004
6/24/2004
7/19/2004
8/13/2004
9/7/2004
10/2/2004
10/27/2004
11/21/2004
12/16/2004
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head

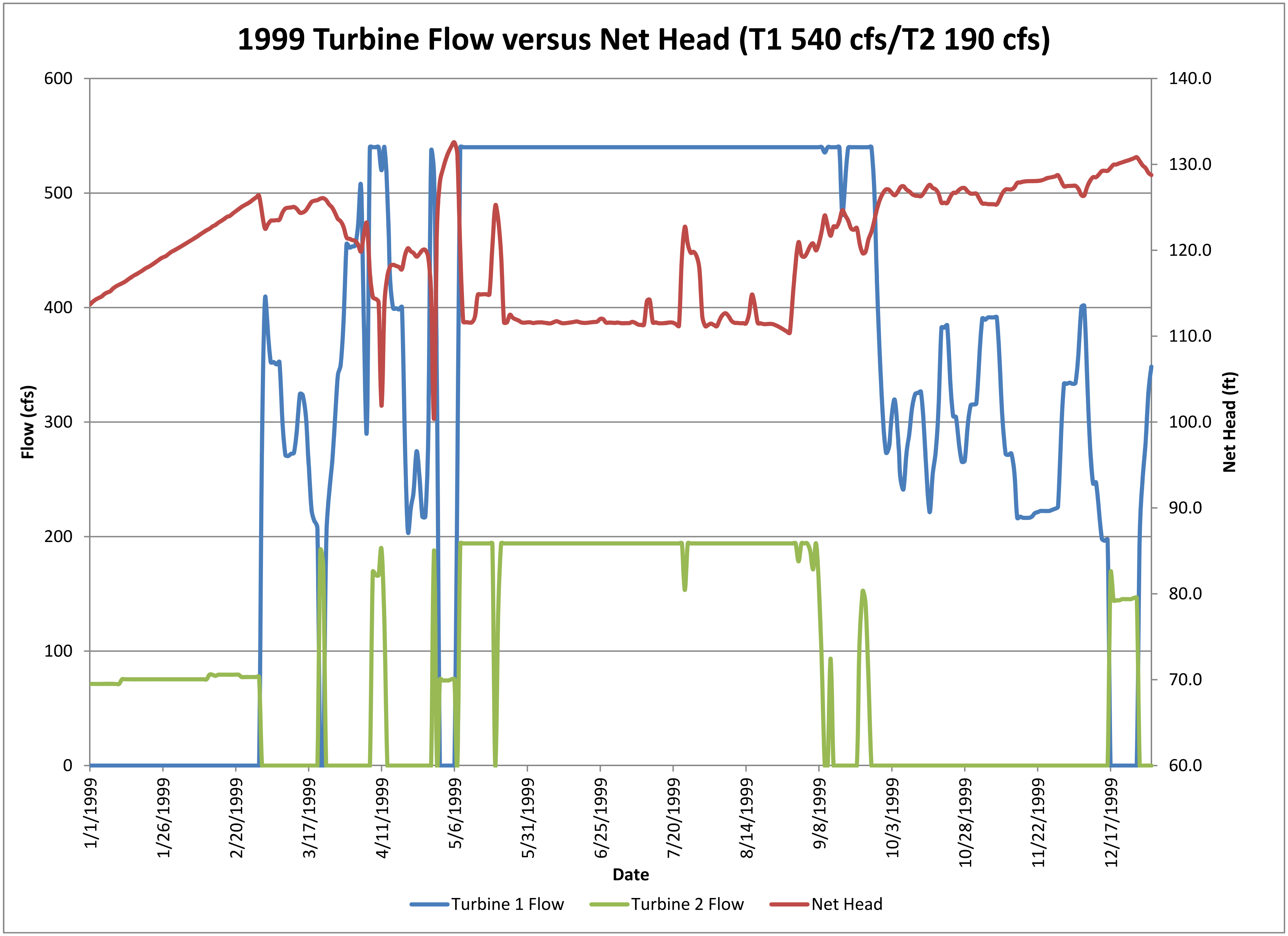

2003 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
600
500
400
300
200
100
0
Net Head (ft)
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/2003
1/26/2003
2/20/2003
3/17/2003
4/11/2003
5/6/2003
5/31/2003
6/25/2003
7/20/2003
8/14/2003
9/8/2003
10/3/2003
10/28/2003
11/22/2003
12/17/2003
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head

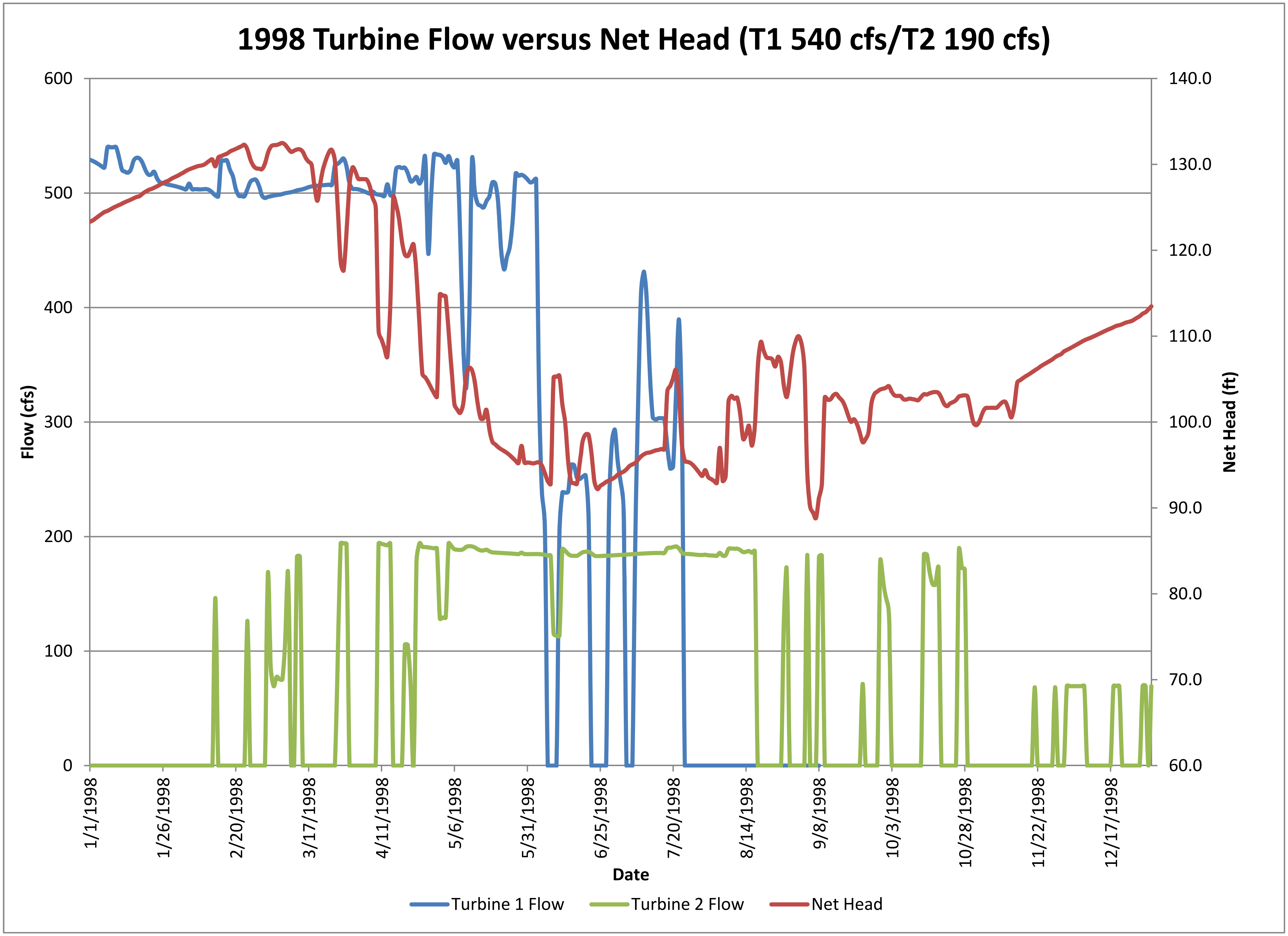


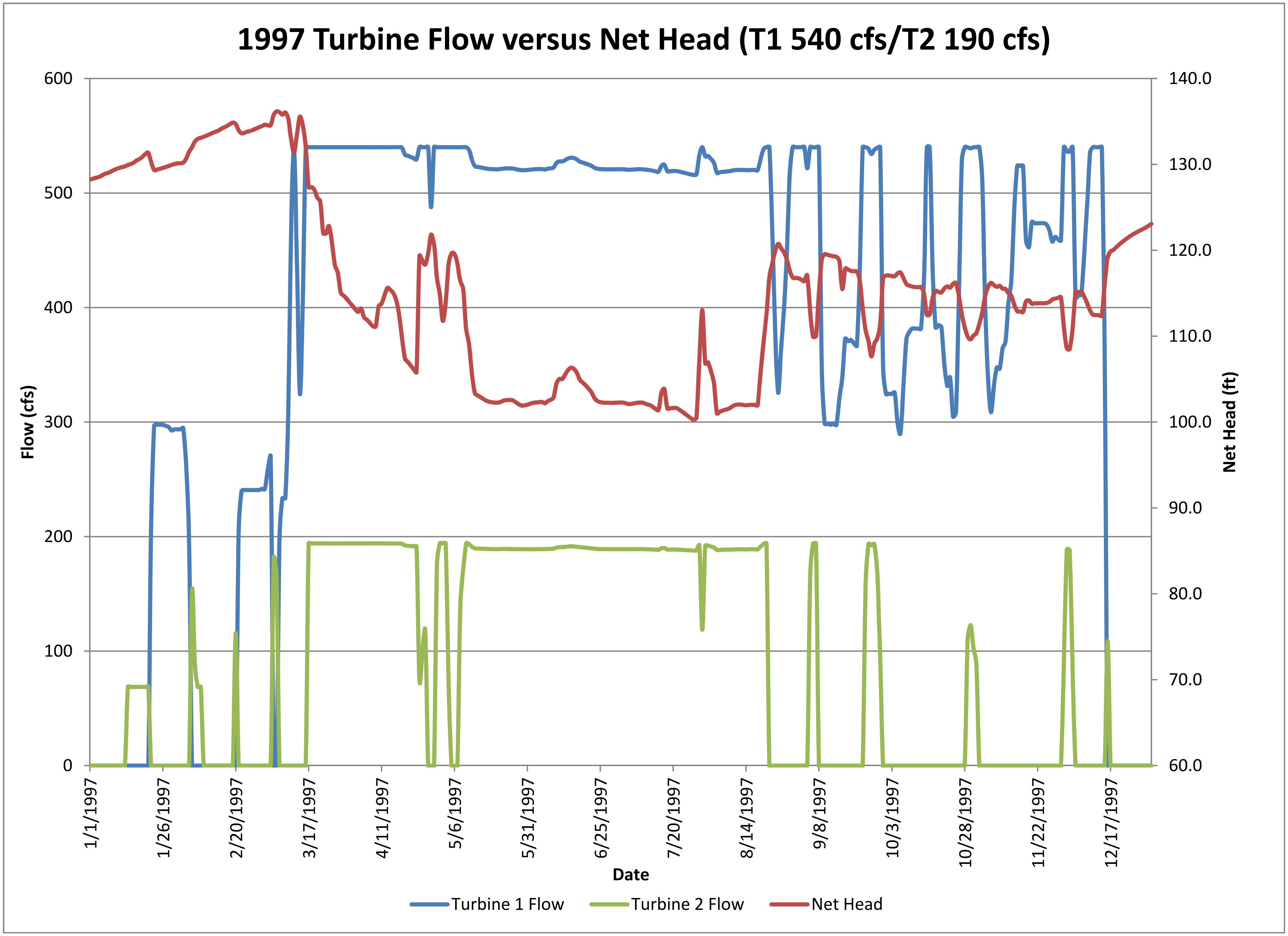
2002 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/2002
1/26/2002
2/20/2002
3/17/2002
4/11/2002
5/6/2002
5/31/2002
6/25/2002
7/20/2002
8/14/2002
9/8/2002
10/3/2002
10/28/2002
11/22/2002
12/17/2002
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head


2001 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
0
100
200
300
400
500
600
Net Head (ft)
60.0
70.0
80.0
90.0
100.0
110.0
120.0
130.0
140.0
1/1/2001
1/26/2001
2/20/2001
3/17/2001
4/11/2001
5/6/2001
5/31/2001
6/25/2001
7/20/2001
8/14/2001
9/8/2001
10/3/2001
10/28/2001
11/22/2001
12/17/2001
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head

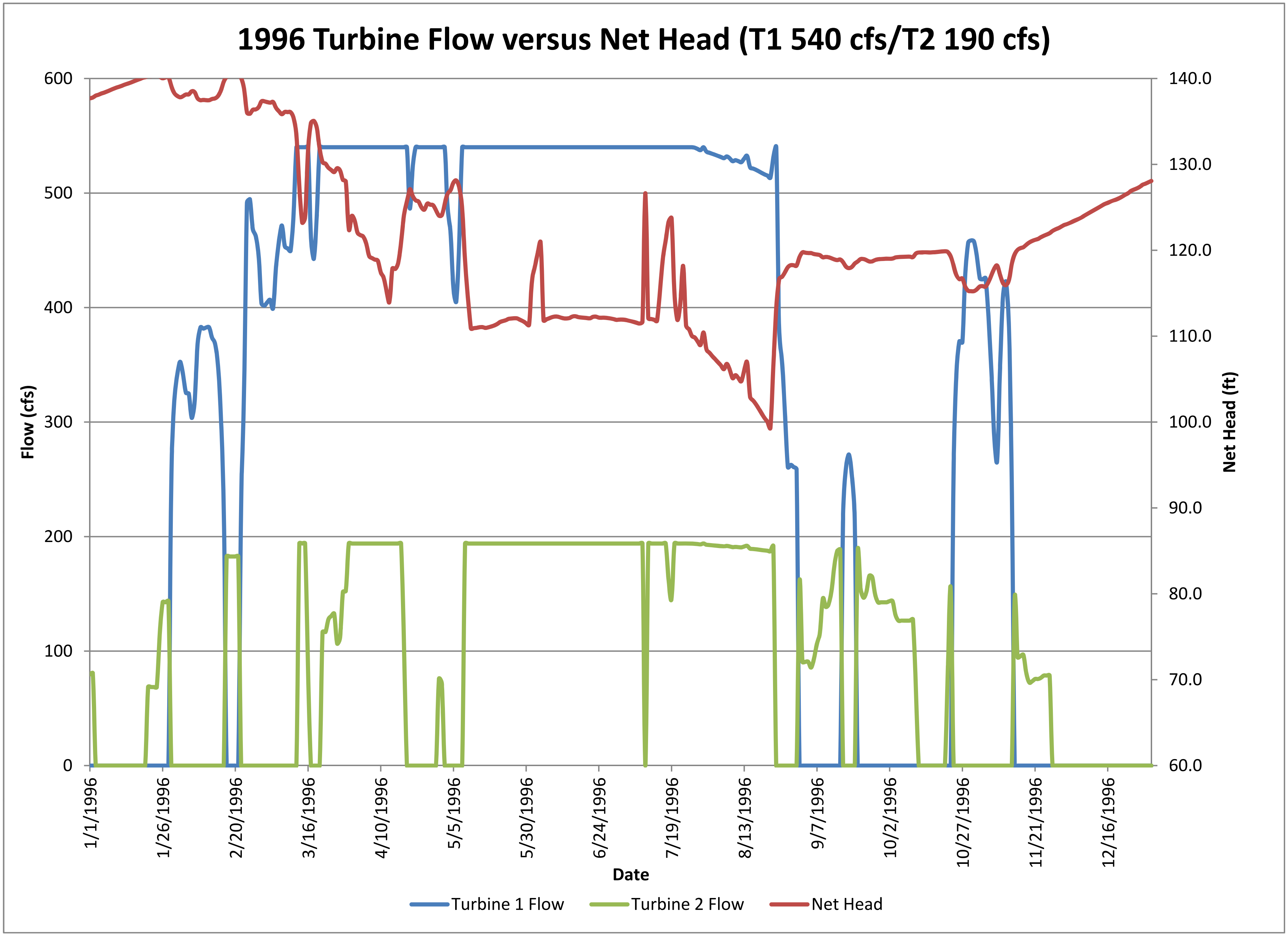

2000 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
Date
0
100
200
300
400
500
600
60.0
70.0
80.0
90.0
100.0
110.0
120.0
130.0
140.0
1/1/2000
1/26/2000
2/20/2000
3/16/2000
4/10/2000
5/5/2000
5/30/2000
6/24/2000
7/19/2000
8/13/2000
9/7/2000
10/2/2000
10/27/2000
11/21/2000
12/16/2000
Turbine 1 Flow
Turbine 2 Flow
Net Head

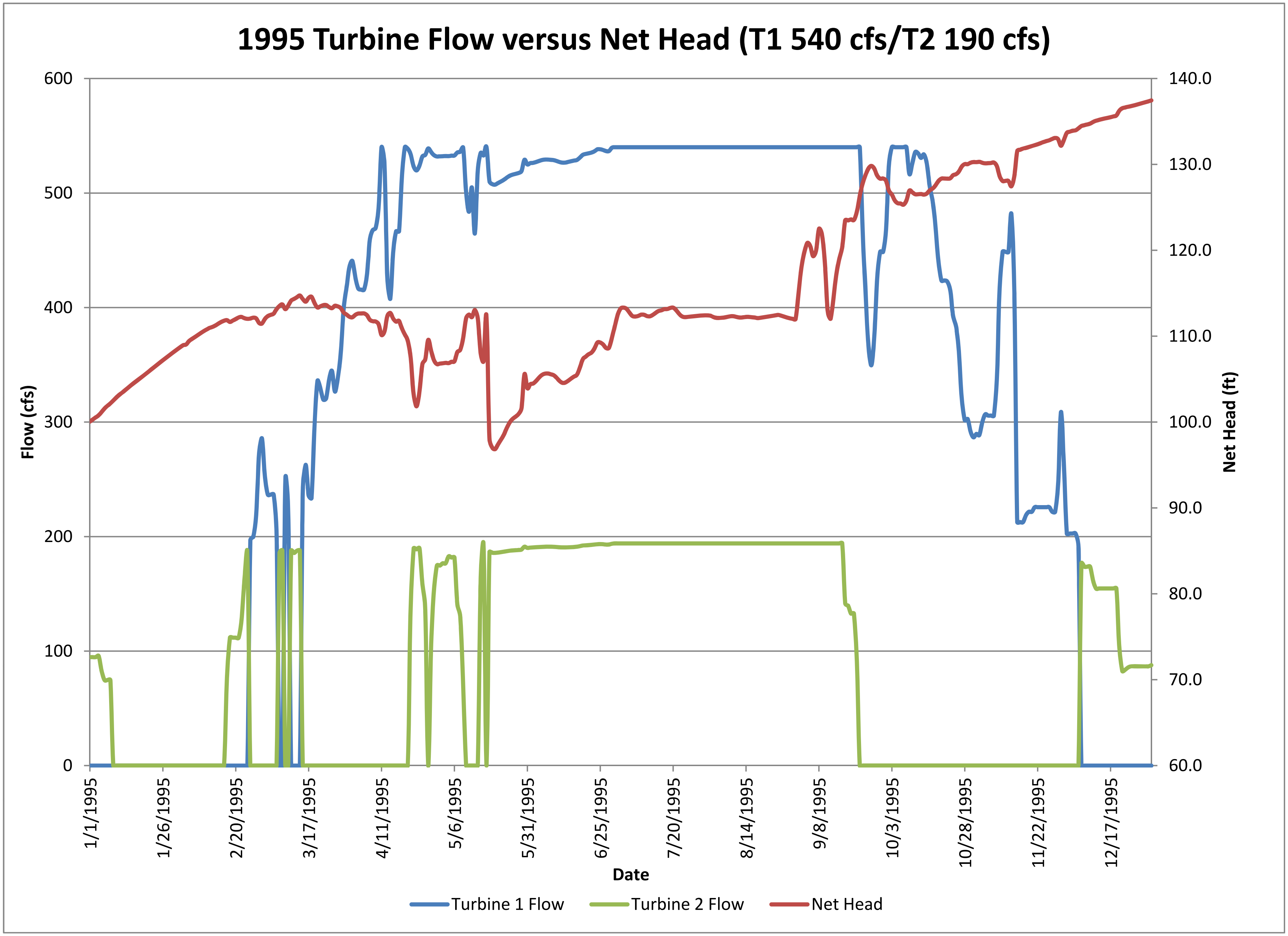

1999 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
Date
0
100
200
300
400
500
600
60.0
70.0
80.0
90.0
100.0
110.0
120.0
130.0
140.0
1/1/1999
1/26/1999
2/20/1999
3/17/1999
4/11/1999
5/6/1999
5/31/1999
6/25/1999
7/20/1999
8/14/1999
9/8/1999
10/3/1999
10/28/1999
11/22/1999
12/17/1999
Turbine 1 Flow
Turbine 2 Flow
Net Head

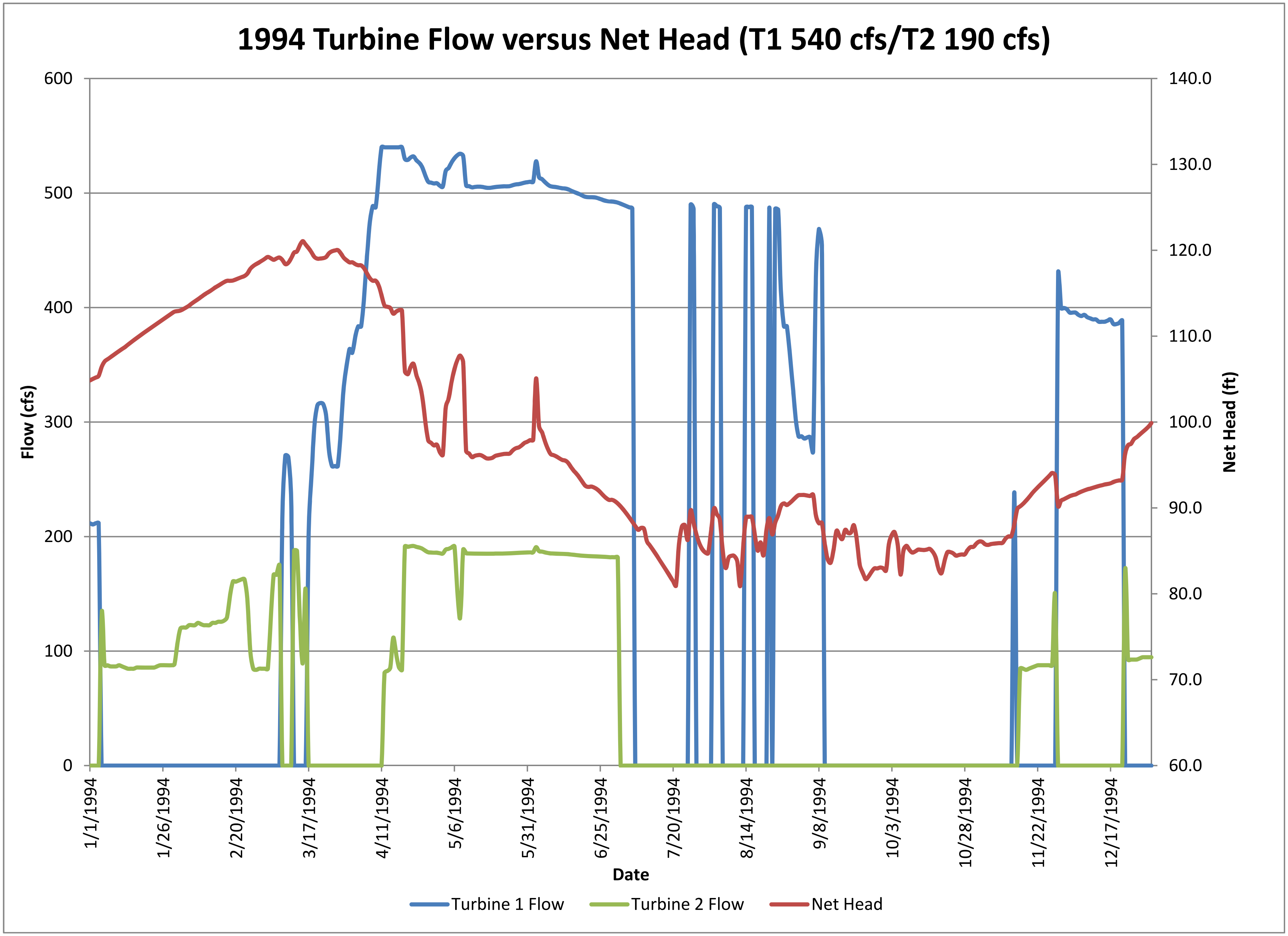

1998 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1998
1/26/1998
2/20/1998
3/17/1998
4/11/1998
5/6/1998
5/31/1998
6/25/1998
7/20/1998
8/14/1998
9/8/1998
10/3/1998
10/28/1998
11/22/1998
12/17/1998
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head



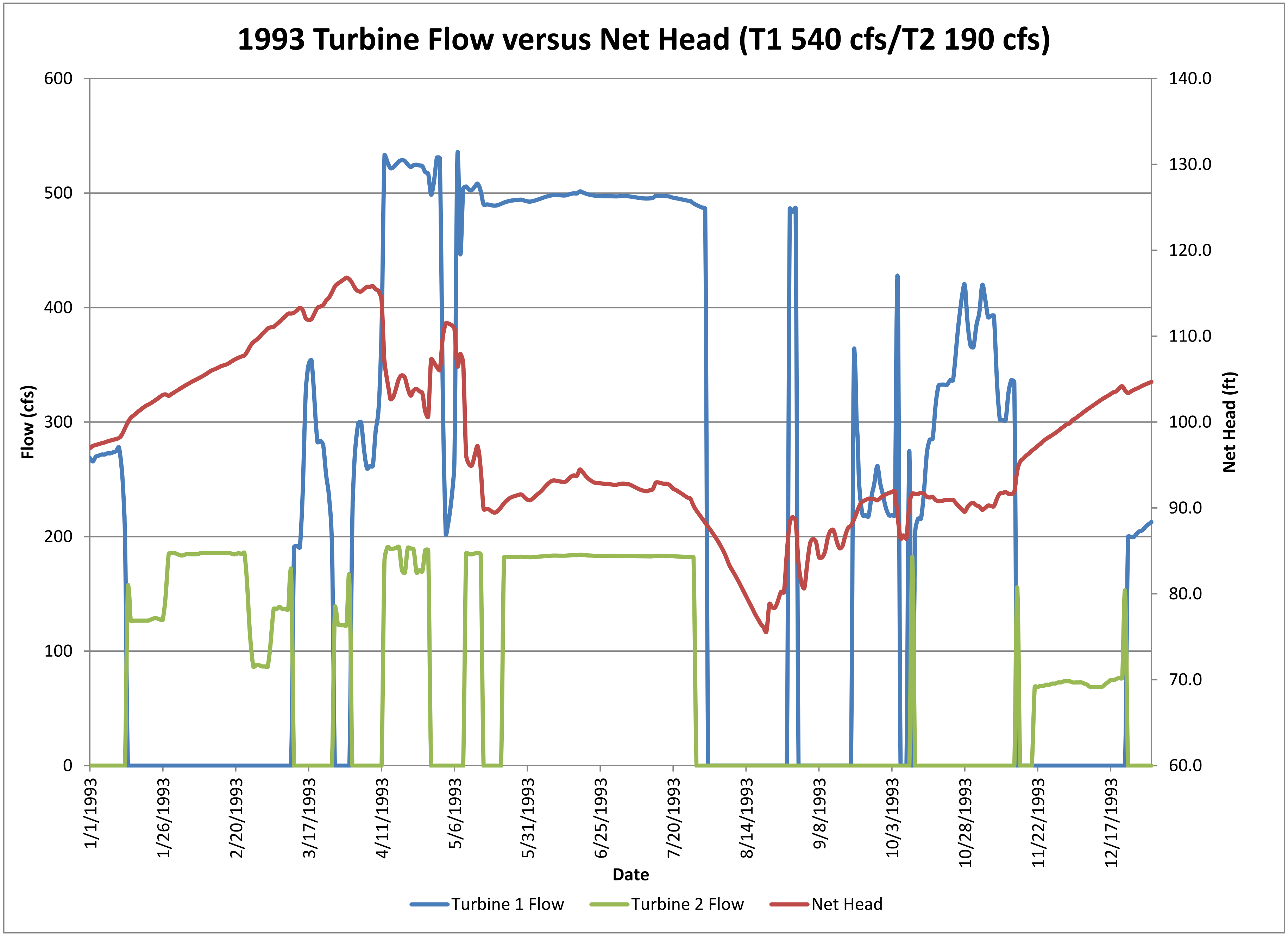
1997 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
600
500
400
300
200
100
0
Flow (cfs)
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
Net Head (ft)
1/1/1997
1/26/1997
2/20/1997
3/17/1997
4/11/1997
5/6/1997
5/31/1997
6/25/1997
7/20/1997
8/14/1997
9/8/1997
10/3/1997
10/28/1997
11/22/1997
12/17/1997
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head


1996 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
Date
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1996
1/26/1996
2/20/1996
3/16/1996
4/10/1996
5/5/1996
5/30/1996
6/24/1996
7/19/1996
8/13/1996
9/7/1996
10/2/1996
10/27/1996
11/21/1996
12/16/1996
Turbine 1 Flow
Turbine 2 Flow
Net Head

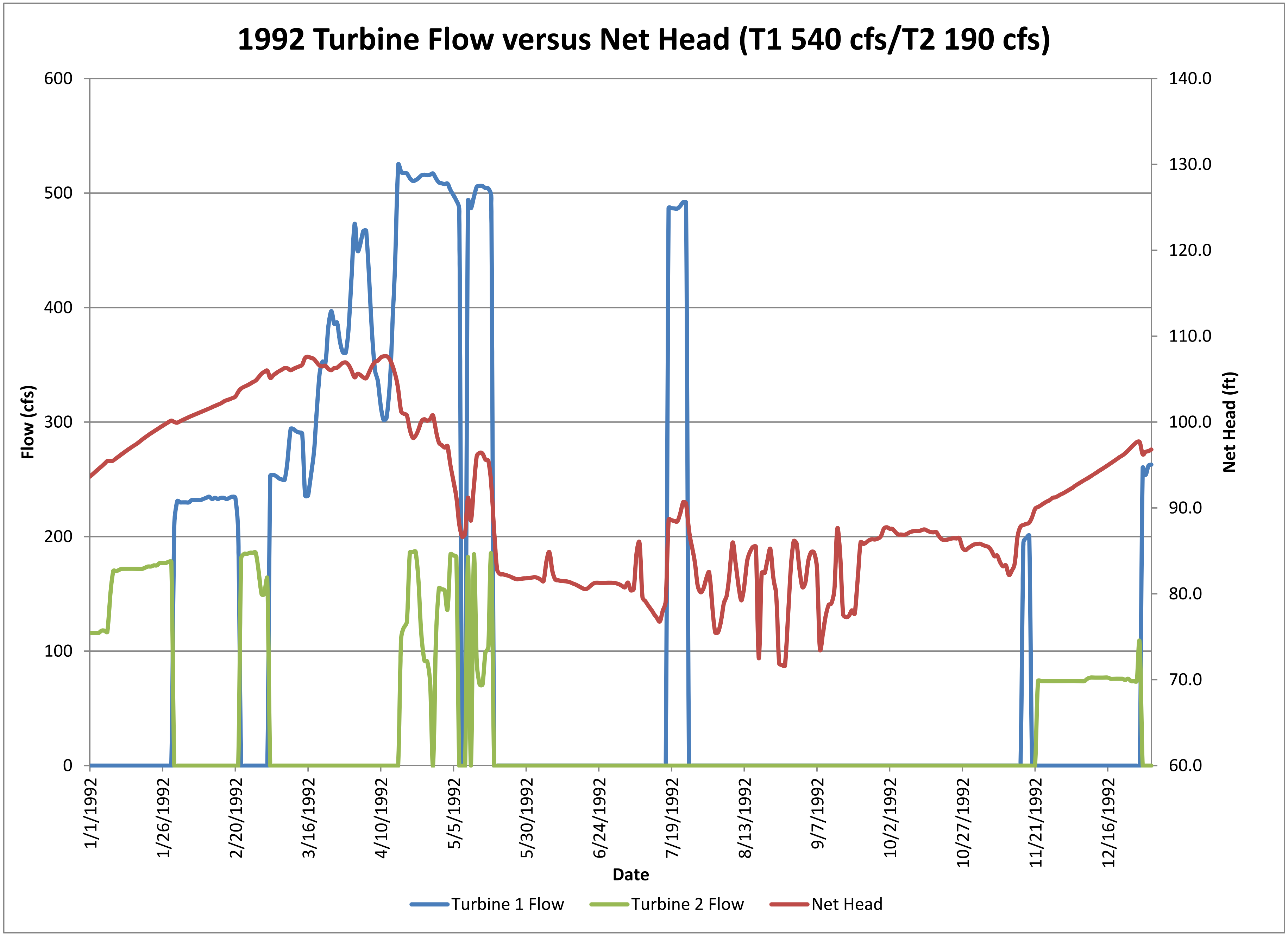

1995 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
Date
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1995
1/26/1995
2/20/1995
3/17/1995
4/11/1995
5/6/1995
5/31/1995
6/25/1995
7/20/1995
8/14/1995
9/8/1995
10/3/1995
10/28/1995
11/22/1995
12/17/1995
Turbine 1 Flow
Turbine 2 Flow
Net Head

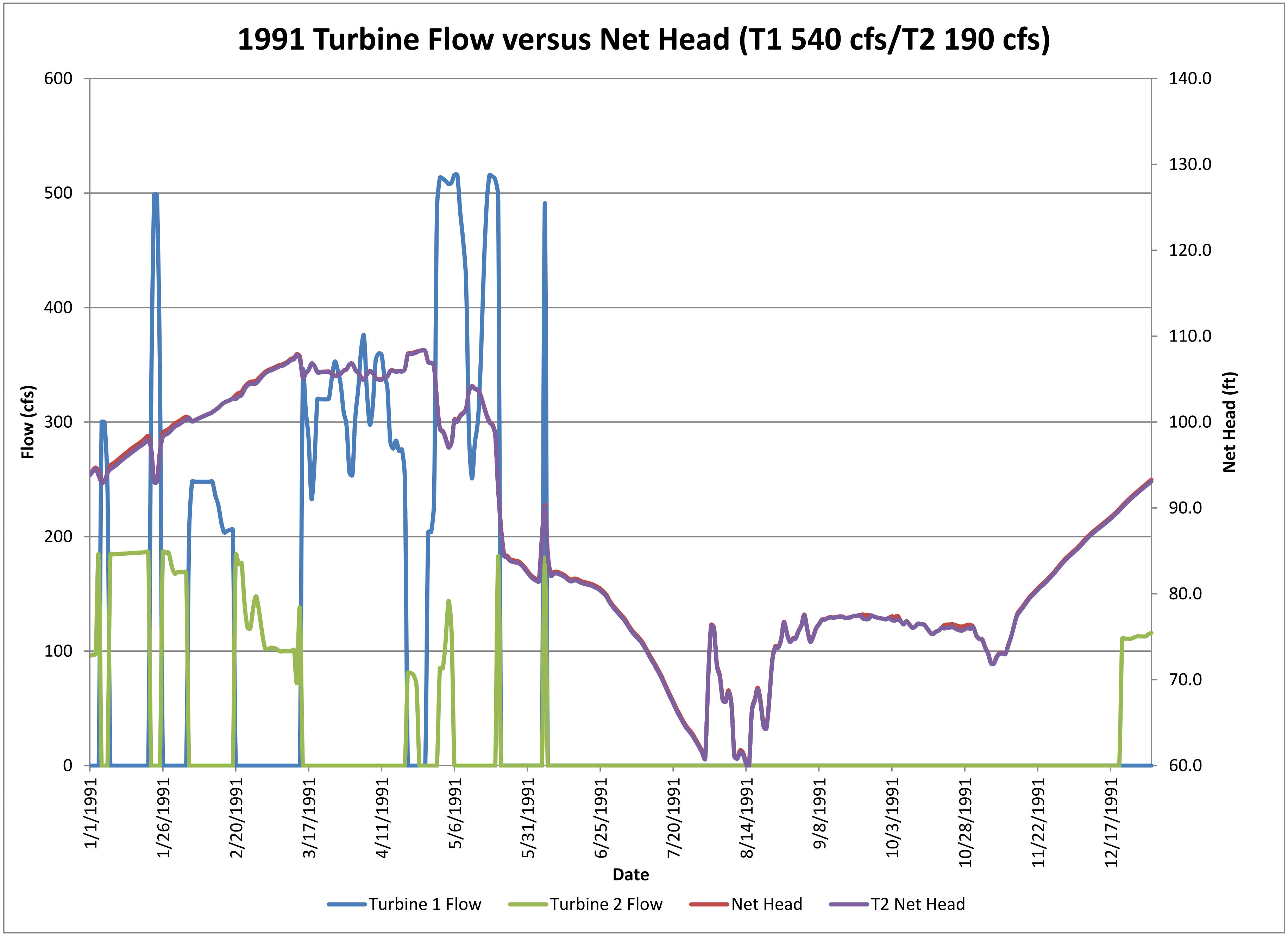


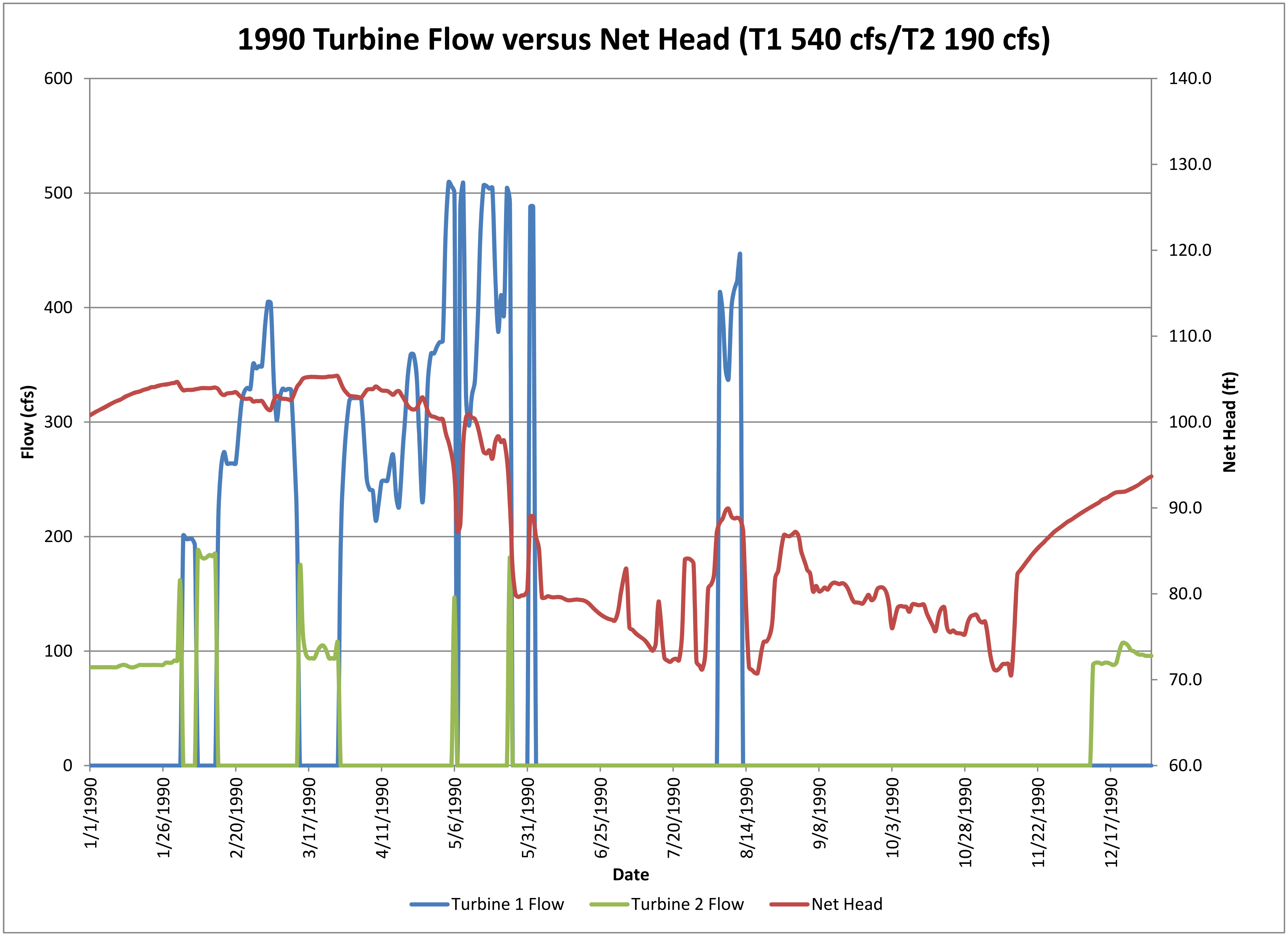
1994 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
Date
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1994
1/26/1994
2/20/1994
3/17/1994
4/11/1994
5/6/1994
5/31/1994
6/25/1994
7/20/1994
8/14/1994
9/8/1994
10/3/1994
10/28/1994
11/22/1994
12/17/1994
Turbine 1 Flow
Turbine 2 Flow
Net Head



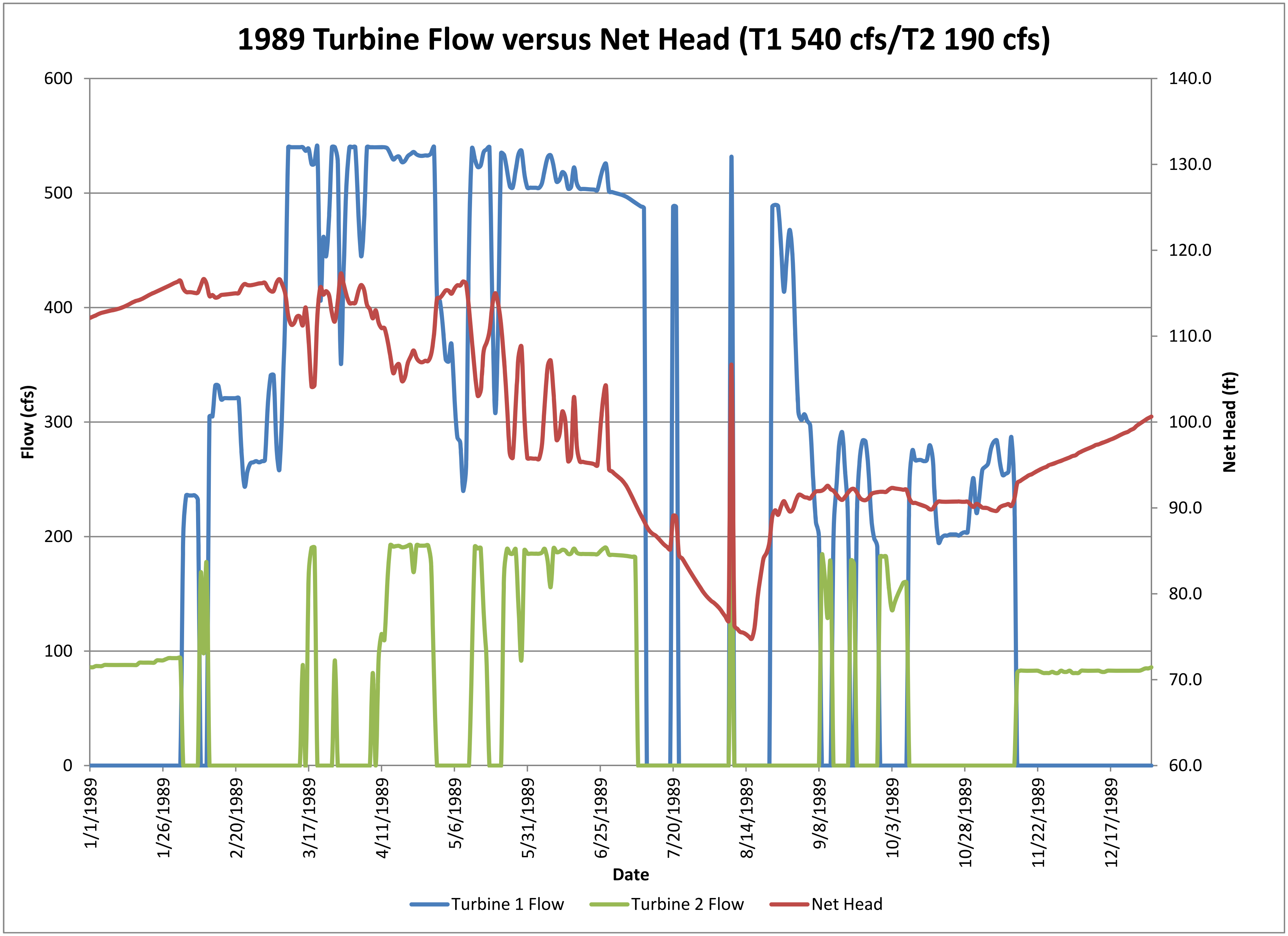
1993 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
600
500
400
300
200
100
0
Net Head (ft)
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1993
1/26/1993
2/20/1993
3/17/1993
4/11/1993
5/6/1993
5/31/1993
6/25/1993
7/20/1993
8/14/1993
9/8/1993
10/3/1993
10/28/1993
11/22/1993
12/17/1993
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head


1992 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
Date
0
100
200
300
400
500
600
60.0
70.0
80.0
90.0
100.0
110.0
120.0
130.0
140.0
1/1/1992
1/26/1992
2/20/1992
3/16/1992
4/10/1992
5/5/1992
5/30/1992
6/24/1992
7/19/1992
8/13/1992
9/7/1992
10/2/1992
10/27/1992
11/21/1992
12/16/1992
Turbine 1 Flow
Turbine 2 Flow
Net Head

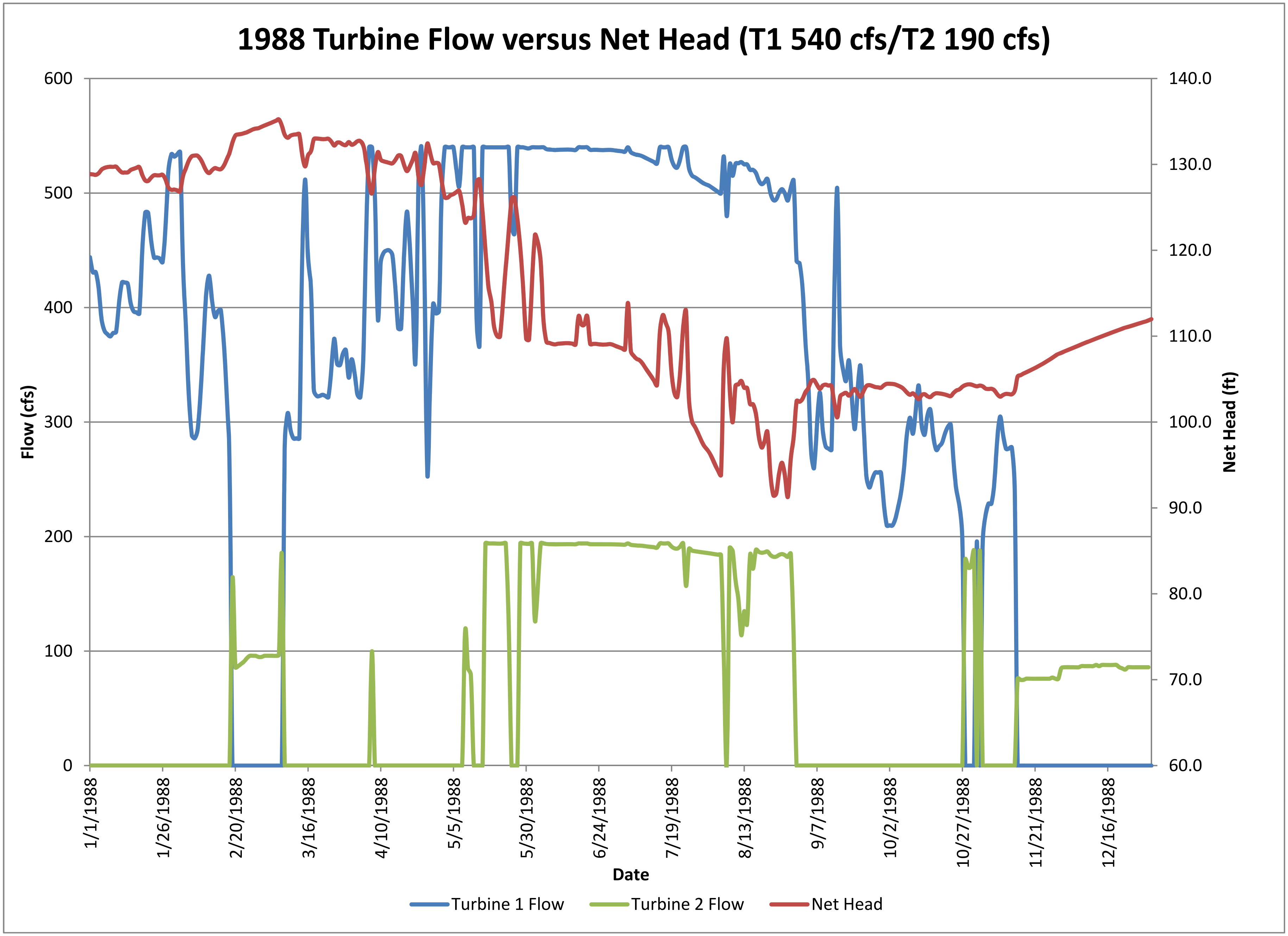

1991 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1991
1/26/1991
2/20/1991
3/17/1991
4/11/1991
5/6/1991
5/31/1991
6/25/1991
7/20/1991
8/14/1991
9/8/1991
10/3/1991
10/28/1991
11/22/1991
12/17/1991
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head
T2 Net Head



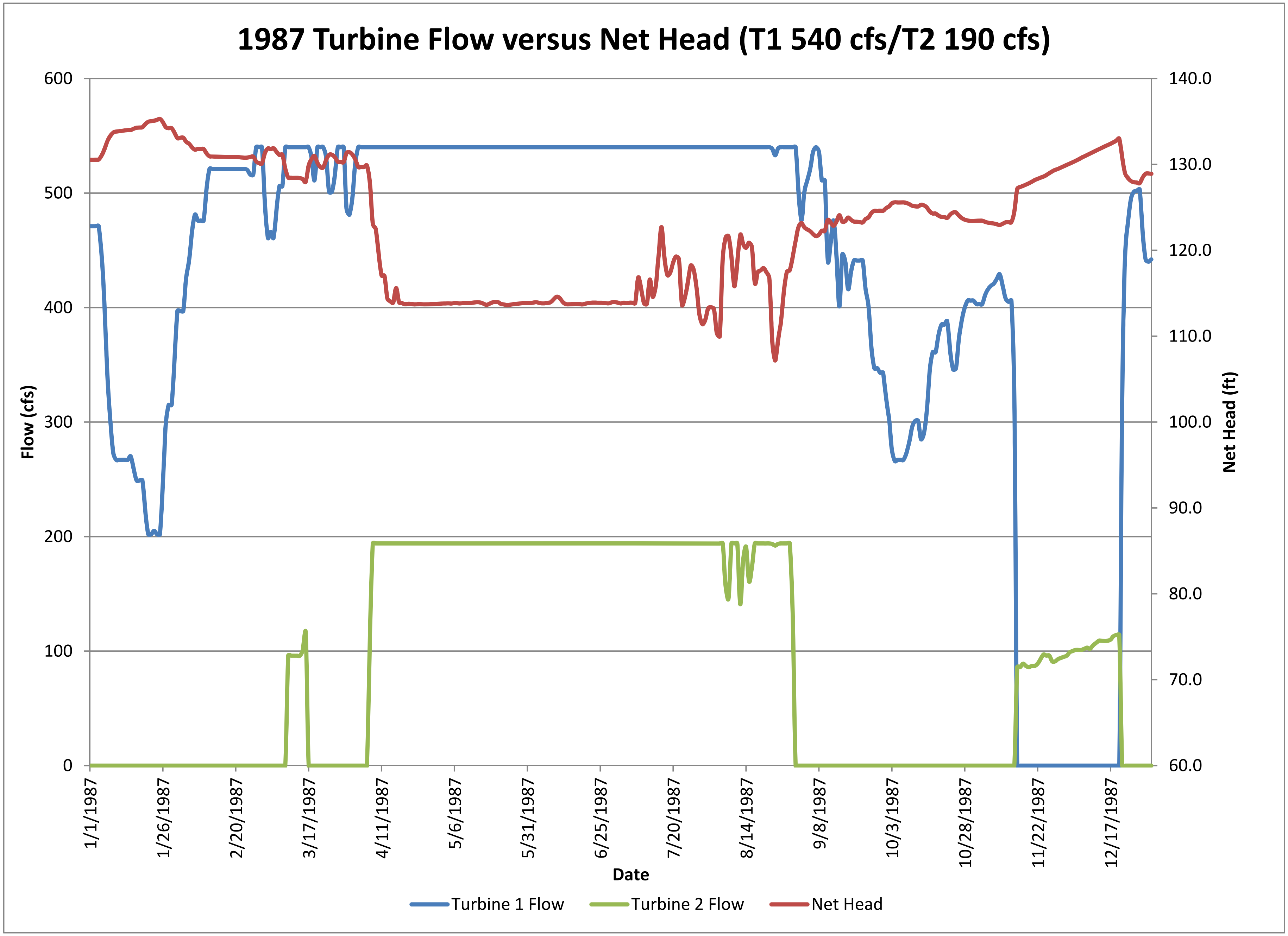
1990 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1990
1/26/1990
2/20/1990
3/17/1990
4/11/1990
5/6/1990
5/31/1990
6/25/1990
7/20/1990
8/14/1990
9/8/1990
10/3/1990
10/28/1990
11/22/1990
12/17/1990
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head

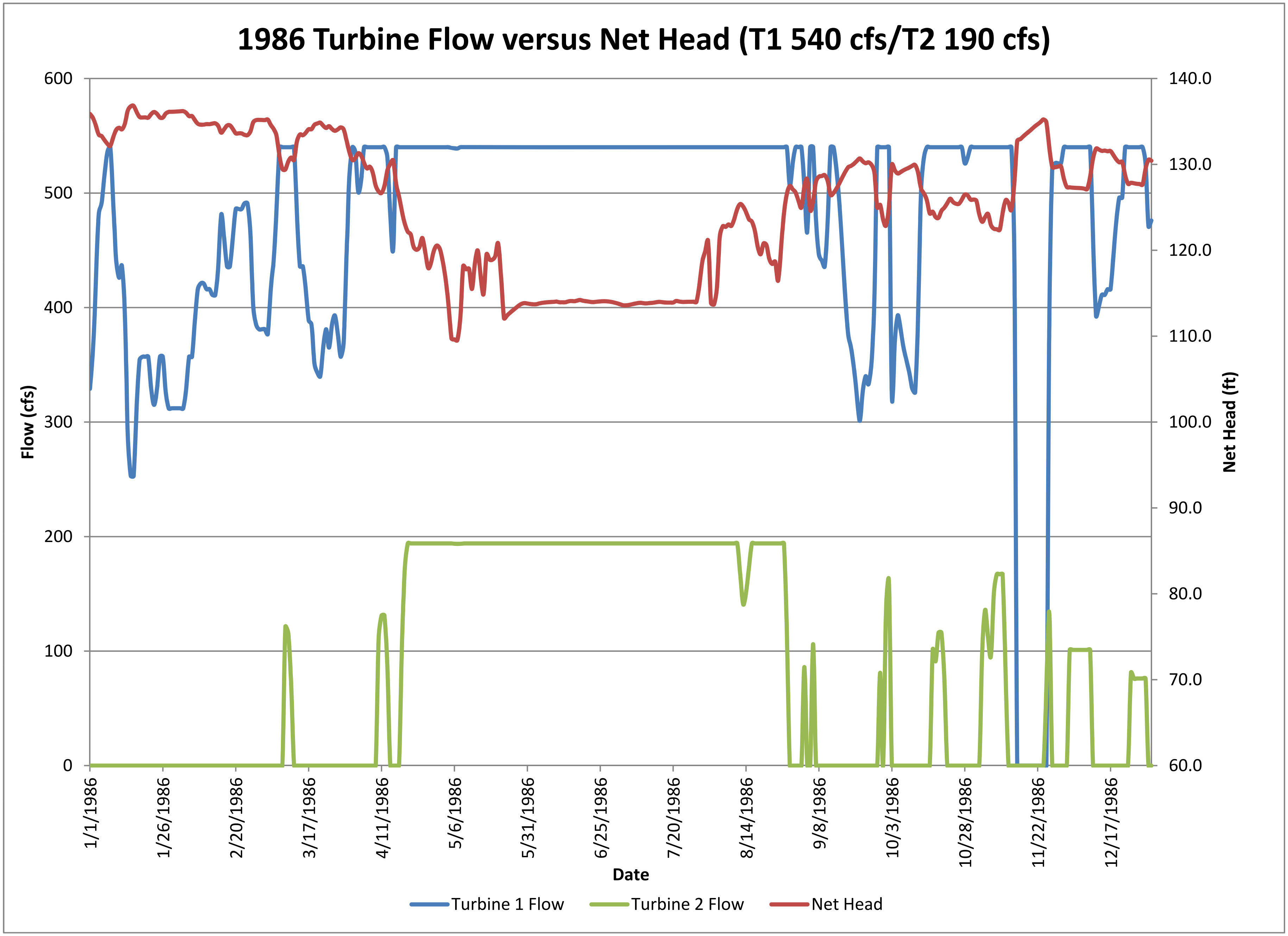


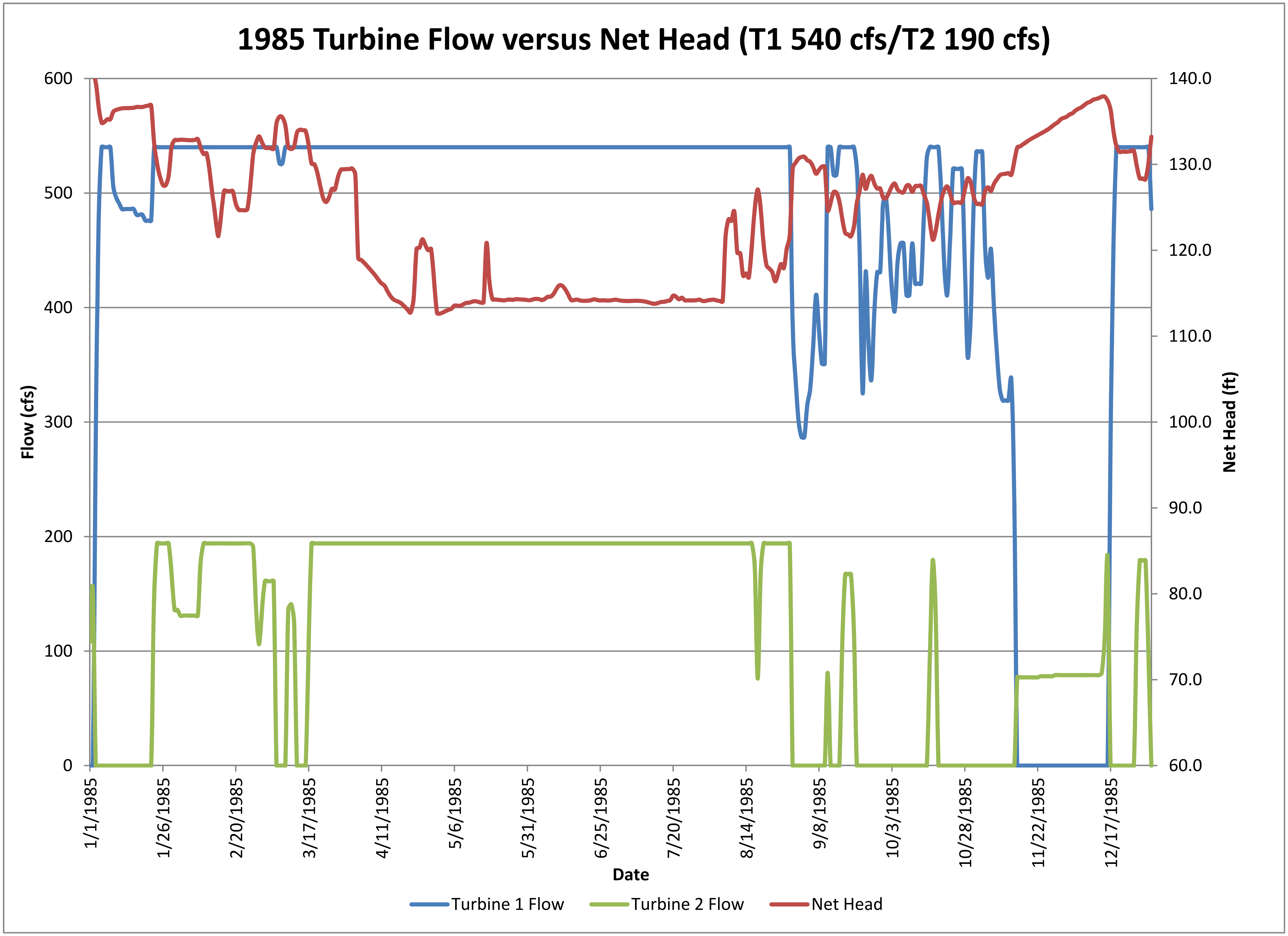
1989 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
600
500
400
300
200
100
0
Flow (cfs)
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
Net Head (ft)
1/1/1989
1/26/1989
2/20/1989
3/17/1989
4/11/1989
5/6/1989
5/31/1989
6/25/1989
7/20/1989
8/14/1989
9/8/1989
10/3/1989
10/28/1989
11/22/1989
12/17/1989
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head



1988 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
600
500
400
300
200
100
0
Net Head (ft)
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1988
1/26/1988
2/20/1988
3/16/1988
4/10/1988
5/5/1988
5/30/1988
6/24/1988
7/19/1988
8/13/1988
9/7/1988
10/2/1988
10/27/1988
11/21/1988
12/16/1988
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head


1987 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
600
500
400
300
200
100
0
Net Head (ft)
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1987
1/26/1987
2/20/1987
3/17/1987
4/11/1987
5/6/1987
5/31/1987
6/25/1987
7/20/1987
8/14/1987
9/8/1987
10/3/1987
10/28/1987
11/22/1987
12/17/1987
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head

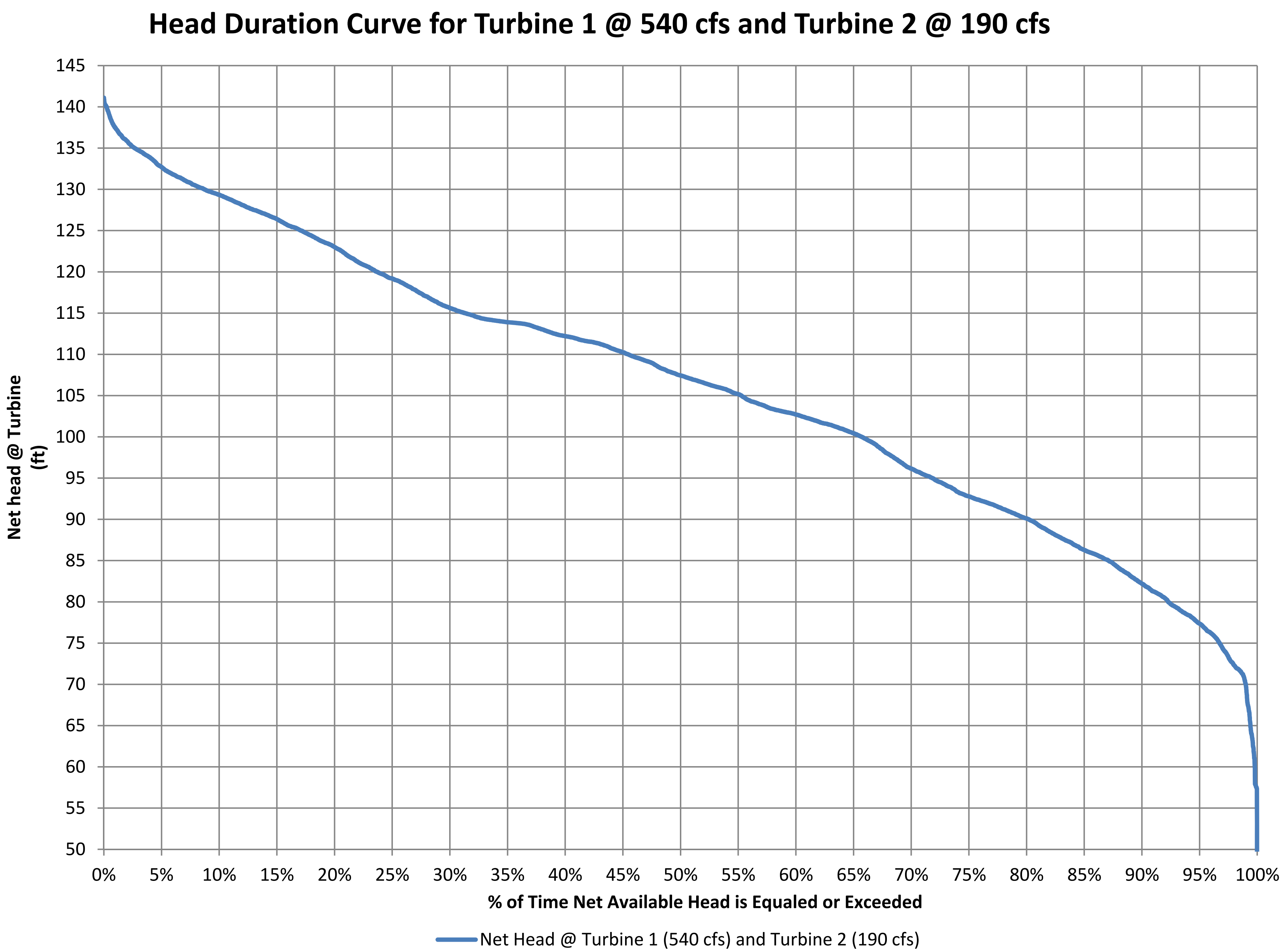

1986 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1986
1/26/1986
2/20/1986
3/17/1986
4/11/1986
5/6/1986
5/31/1986
6/25/1986
7/20/1986
8/14/1986
9/8/1986
10/3/1986
10/28/1986
11/22/1986
12/17/1986
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head



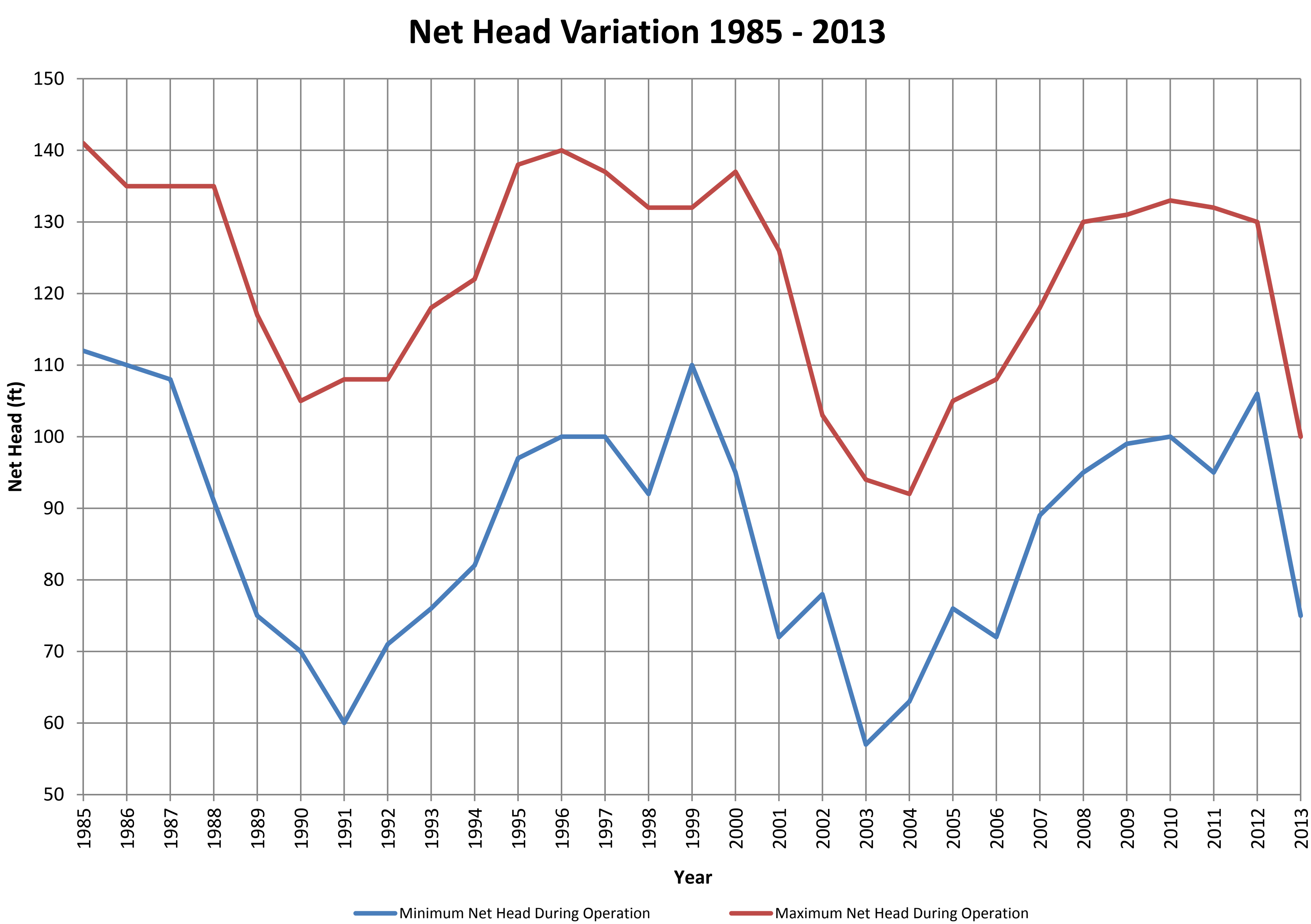
1985 Turbine Flow versus Net Head (T1 540 cfs/T2 190 cfs)
Flow (cfs)
Net Head (ft)
600
500
400
300
200
100
0
140.0
130.0
120.0
110.0
100.0
90.0
80.0
70.0
60.0
1/1/1985
1/26/1985
2/20/1985
3/17/1985
4/11/1985
5/6/1985
5/31/1985
6/25/1985
7/20/1985
8/14/1985
9/8/1985
10/3/1985
10/28/1985
11/22/1985
12/17/1985
Date
Turbine 1 Flow
Turbine 2 Flow
Net Head

APPENDIX B

Net Head Exceedance and Variability Curves



Head Duration Curve for Turbine 1 @ 540 cfs and Turbine 2 @ 190 cfs
Net head @ Turbine (ft)
145
140
135
130
125
120
115
110
105
100
95
90
85
80
75
70
65
60
55
50
0%
5%
10%
15%
20%
25%
30%
35%
40%
45%
50%
55%
60%
65%
70%
75%
80%
85%
90%
95%
100%
% of Time Net Available Head is Equaled or Exceeded
Net Head @ Turbine 1 (540 cfs) and Turbine 2 (190 cfs)


Net Head Variation 1985 - 2013
Net Head (ft)
150
140
130
120
110
100
90
80
70
60
50
1985
1986
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Year
Minimum Net Head During Operation
Maximum Net Head During Operation

APPENDIX C

Equipment Quotation and Performance Curve

January 20, 2014

CH2M HILL
322 East Front Street, Suite 200
Boise, ID 83702

Attention: Mr. Dan Murrer

Subject: Pueblo Dam Hydro Project

Dear Sir:

Thank you for your recent inquiry requesting budgetary price and technical information on hydroturbine equipment for the subject application. Based on our discussions of January 17, 2014 and the net head and discharge information you submitted in your subsequent e-mail, we are proposing two horizontal Francis type turbines each including a synchronous generator and hydraulic pressure system (HPU) for operation of the wicket gates.

The turbine configuration proposed has the turbine runner mounted directly onto an extended generator shaft resulting in a compact arrangement. The size and speed were selected to maximize performance over a wide flow and head range and to permit a unit setting above tailwater.

Also proposed is a controls/switchgear package which will have full manual and automatic operation capability and include limited DC backup equipment and station service equipment. Note that the equipment proposed is not designed to operate off the utility grid (speed governing, isolated operation). Main power transformer and high voltage switchyard are not included.

Attached is a technical data and price sheet covering our recommended equipment solutions. Also included for your reference are turbine performance curves and a preliminary general arrangement drawing.

Price quoted is F.O.B. jobsite (assuming easy access to site via commercial carrier) and includes any applicable import duties. Delivery time for the proposed equipment is approximately 14 to 17 months after contract award.

ANDRITZ HYDRO Corp.
23 Colonial Drive
Morristown, NJ 07960 USA

Tel.: (973) 403-8210

E-mail: mark.barandy@andritz.com

The turbine equipment is proposed to be designed by ANDRITZ HYDRO S.A.S. in Fontaine, France. ANDRITZ HYDRO will make use of its global network of production facilities to source the manufacturing of the turbine equipment.

Should you have any questions or wish to discuss this or other possible unit arrangements, please contact me at:

ANDRITZ HYDRO Corp.
23 Colonial Drive
Morristown, NJ 07960

Tel. No.: 973 403 8210
e-mail: mark.barandy@andritz.com

Very truly yours,

ANDRITZ HYDRO Corp.

Mark Barandy
enc.

Project: Pueblo Dam Hydro Project – Large Unit

Turbine Quantity/Type	-	1 - Horizontal Francis
Runner Diameter	-	1500 mm
Speed	-	300 rpm
Intake Type	-	Spiral Case
Draft Tube Type	-	Elbow
Runner Material	-	Stainless Steel
Highest Permissible Centerline Setting	-	+1.3m (above T.W. elev.)
Rated Turbine Output	-	4,853 KW at 15.9 m^3/s and 33.5m Net Hd
Max Turbine Output (at Max Hd)	-	5,722 KW at 15.9 m^3/s and 39.2m Net Hd
Max Turbine Output (at Min Hd)	-	3,591 KW at 14.3 m^3/s and 27.4m Net Hd
Generator Type	-	Horizontal Synchronous
Generator Rating	-	5,500 KW (Nominal)
Speed	-	300 rpm (60 Hz)
Voltage	-	4160 V
Temperature Rise	-	80^{o}C over 40^{o}C Ambient
Excitation	-	Brushless
Power Factor	-	0.90

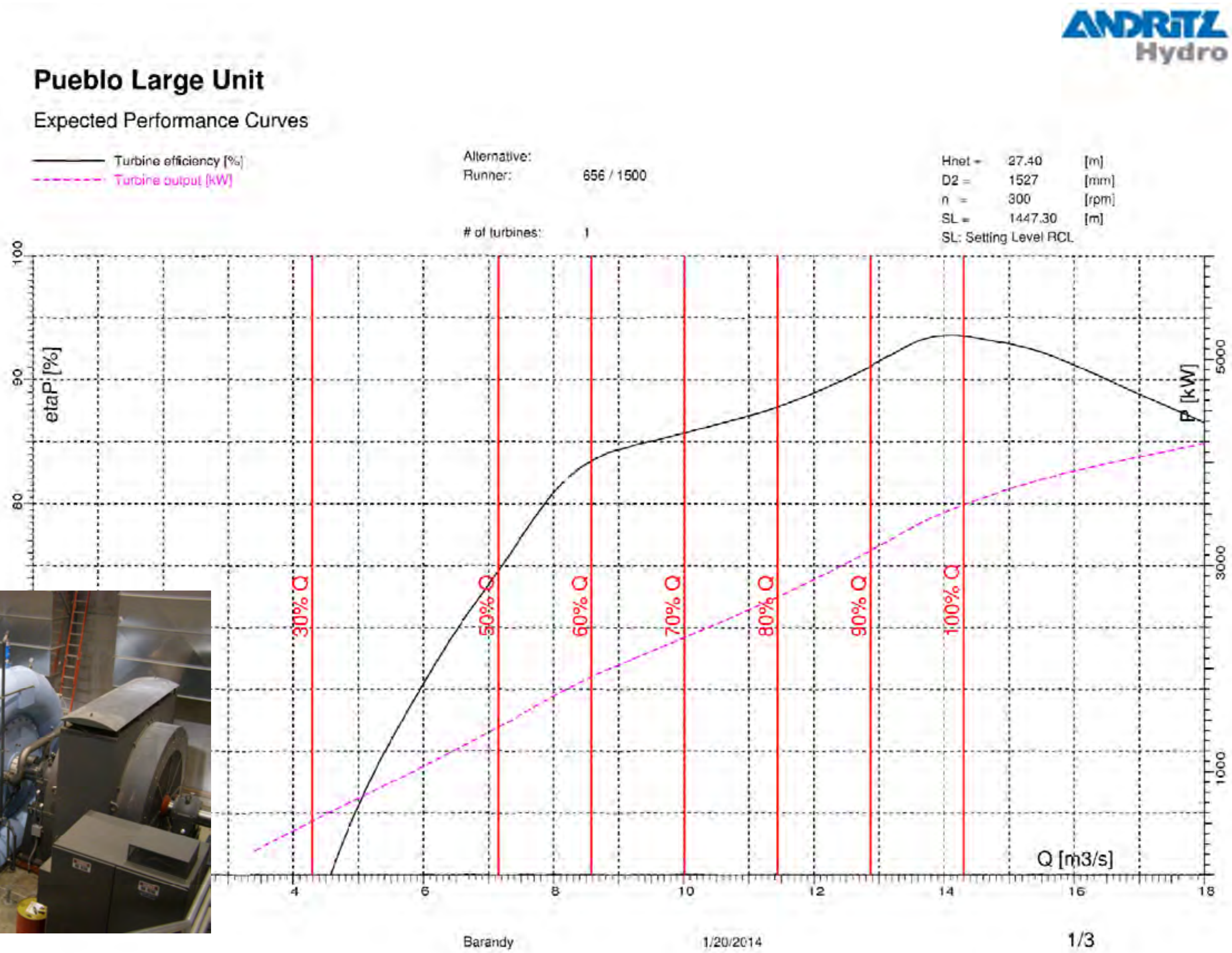
Project: Pueblo Dam Hydro Project – Small Unit

Turbine Quantity/Type	-	1 - Horizontal Francis
Runner Diameter	-	850 mm
Speed	-	514 rpm
Intake Type	-	Spiral Case
Draft Tube Type	-	Elbow
Runner Material	-	Stainless Steel
Highest Permissible Centerline Setting	-	+1.3m (above T.W. elev.)
Rated Turbine Output	-	1,512 KW at 5.0 m^3/s and 33.5m Net Hd
Max Turbine Output (at Max Hd)	-	1,685 KW at 5.0 m^3/s and 37.1m Net Hd
Max Turbine Output (at Min Hd)	-	1,215 KW at 4.7 m^3/s and 28.51m Net Hd
Generator Type	-	Horizontal Synchronous
Generator Rating	-	1,500 KW (Nominal)
Speed	-	514 rpm (60 Hz)
Voltage	-	4160 V
Temperature Rise	-	80^{o}C over 40^{o}C Ambient
Excitation	-	Brushless
Power Factor	-	0.90

Budget Price for Turbines, Generators, HPUs and Controls/switchgear	-	US$ 6,650,000 (total for the Large and Small units proposed)

Note: speed governing is not included

Preliminary Turbine Performance Curves



ANDRITZ HYDRO Corp.
23 Colonial Drive
Morristown, NJ 07960 USA

Tel.: (973) 403-8210

E-mail: mark.barandy@andritz.com

Preliminary Turbine Performance Curves

Pueblo Large Unit

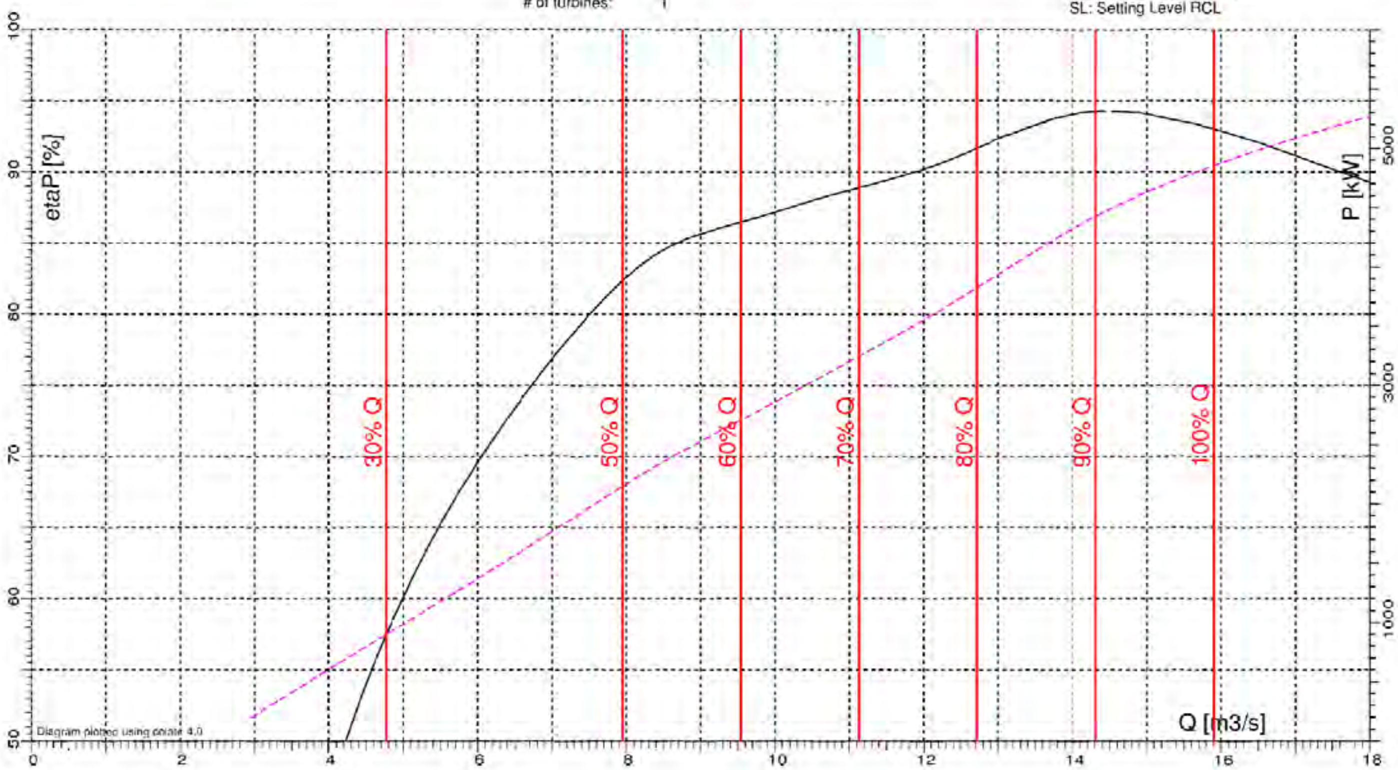
Expected Performance Curves

Turbine efficiency [%]
Turbine output [kW]

Alternative:
Runner: 656 / 1500

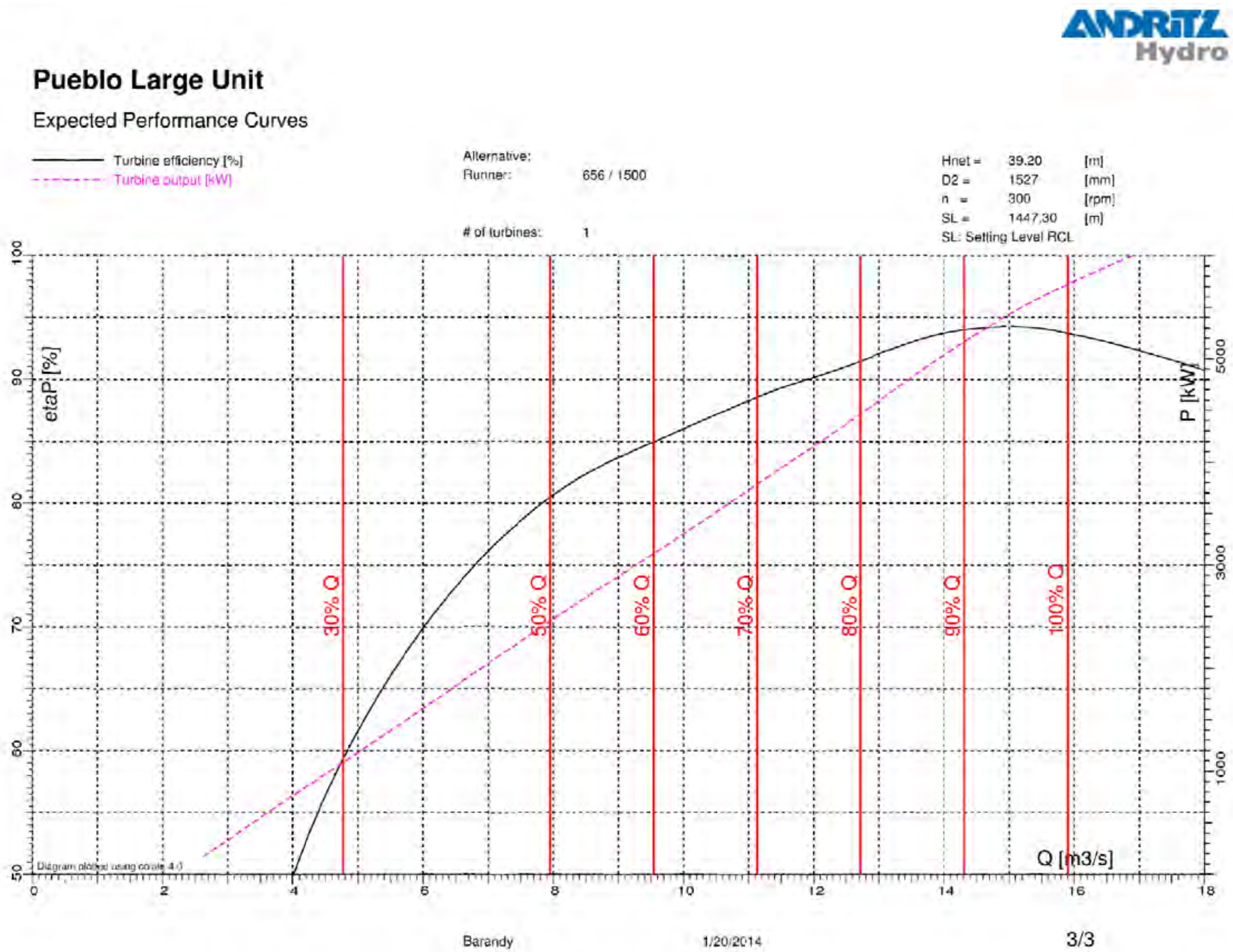
# of turbines: 1

Hnet = 33.50 [m]
D2 = 1527 [mm]
n = 300 [rpm]
SL = 1447.30 [m]
SL: Setting Level RCL

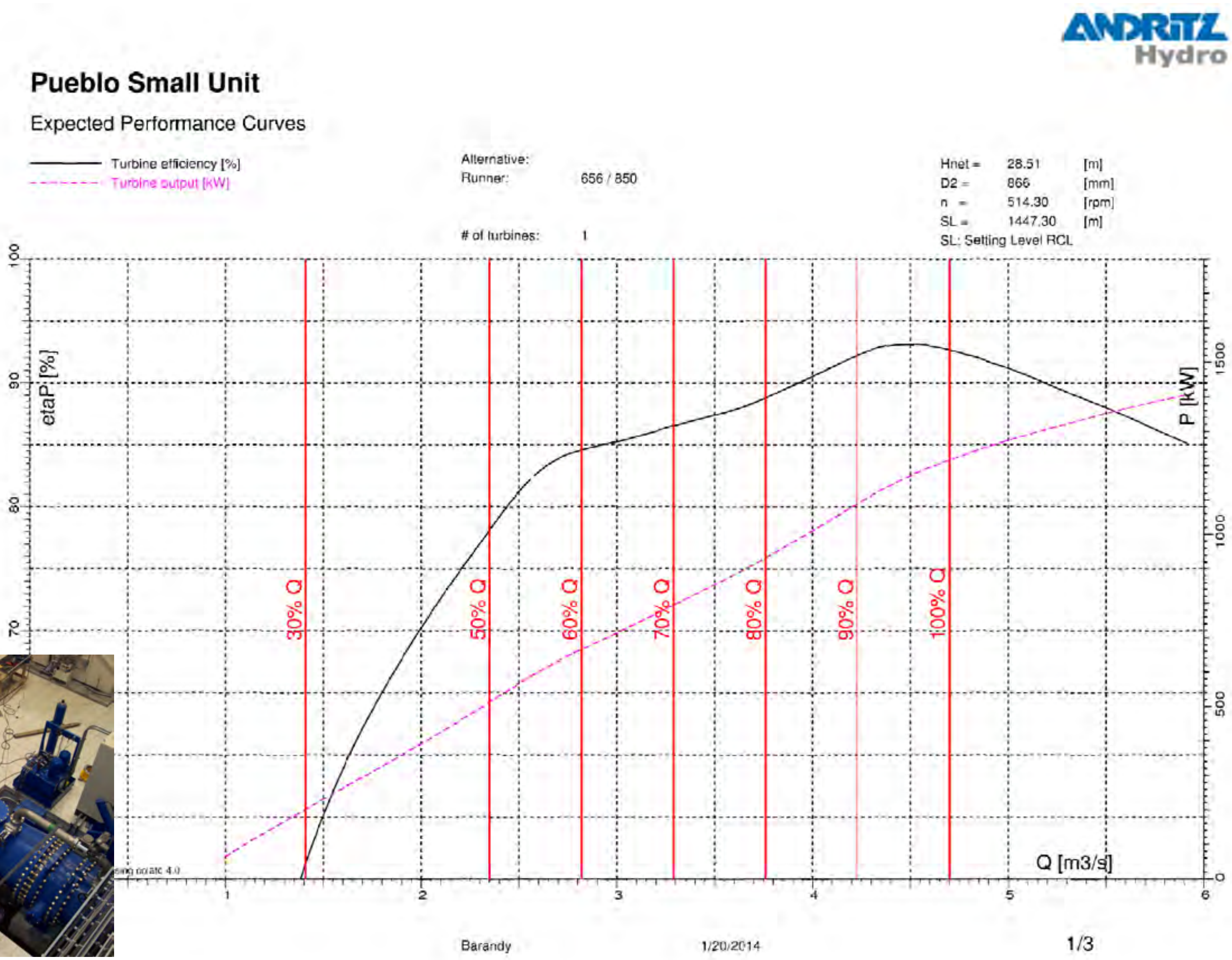


Barandy 1/20/2014

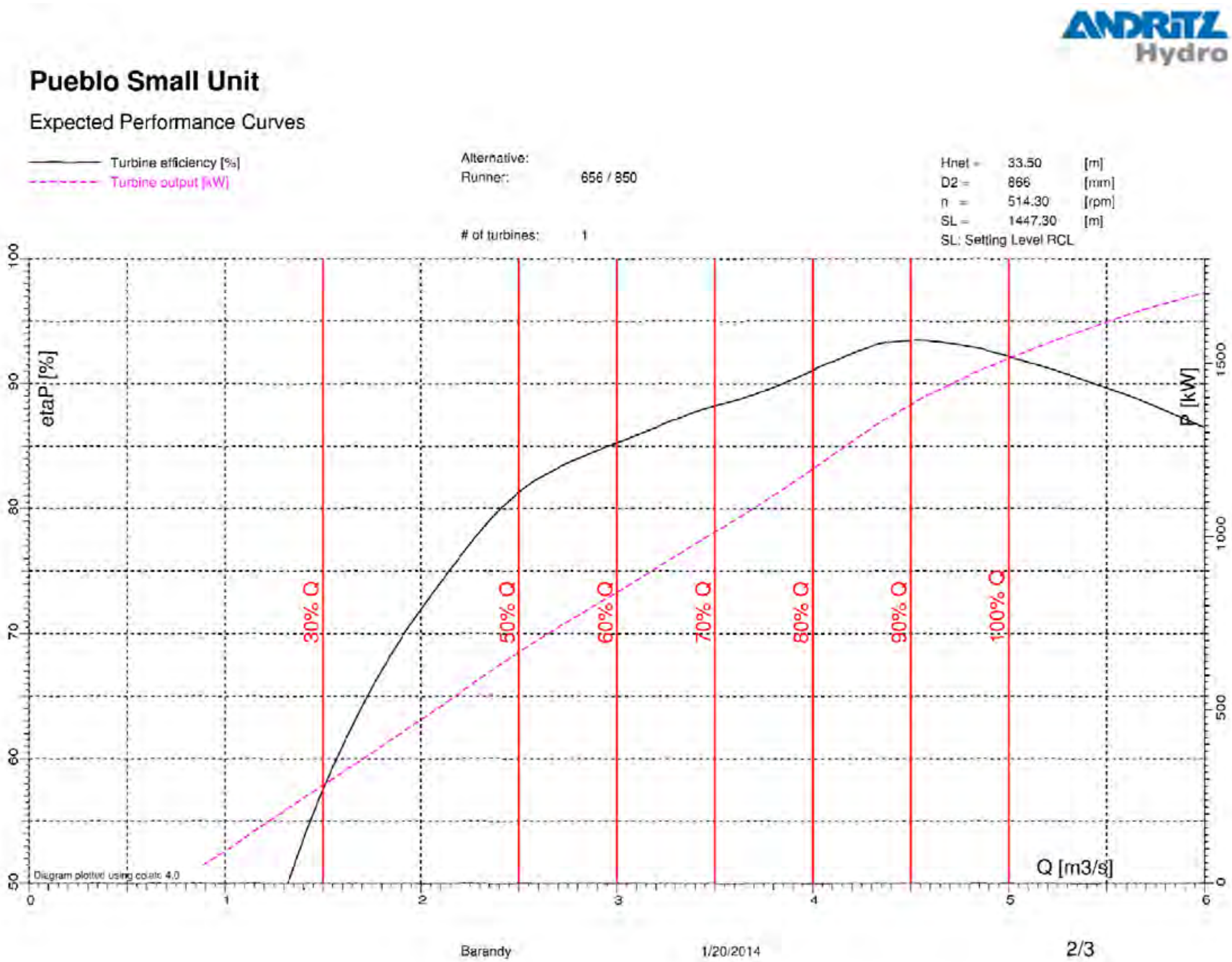
Preliminary Turbine Performance Curves



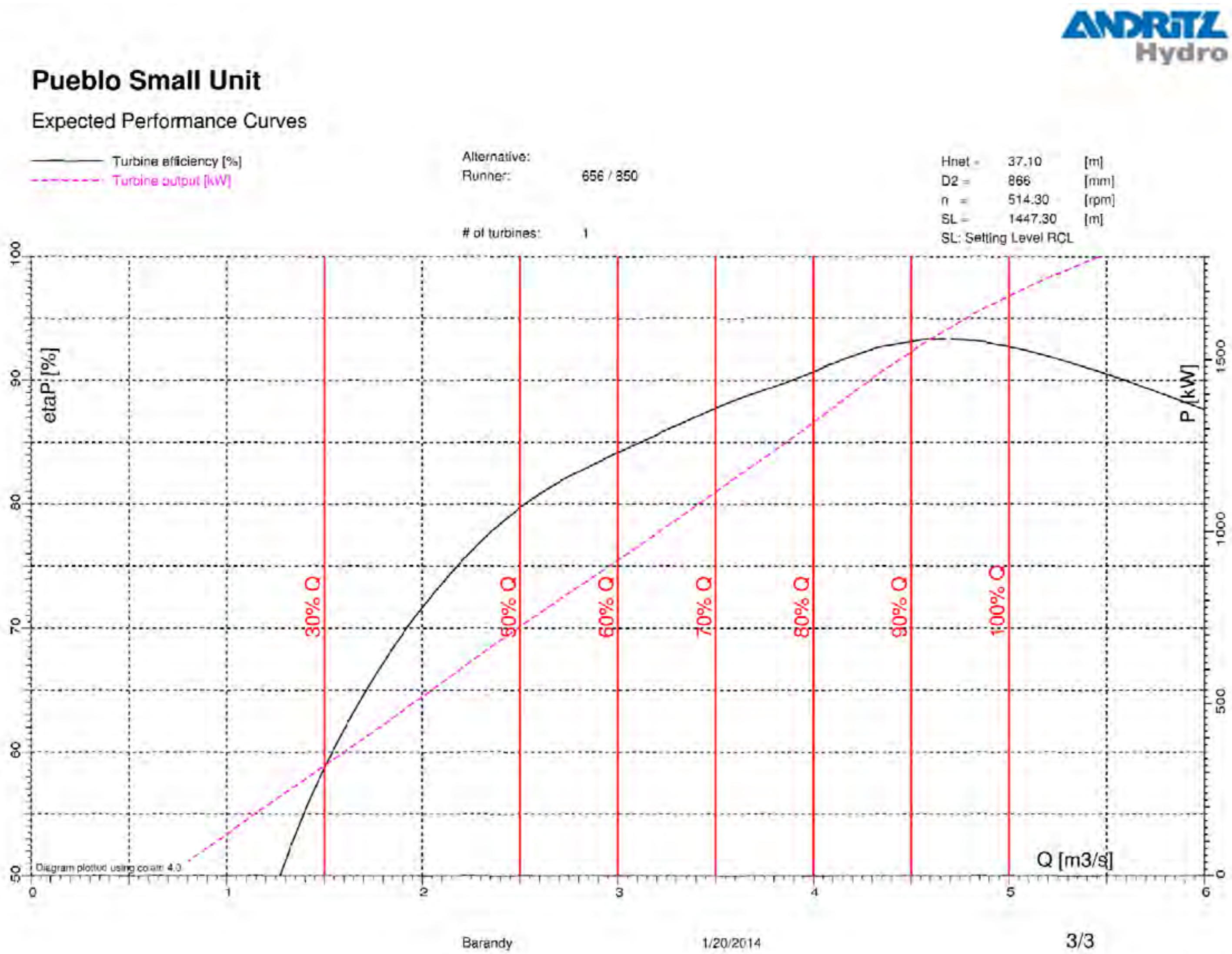
Preliminary Turbine Performance Curves



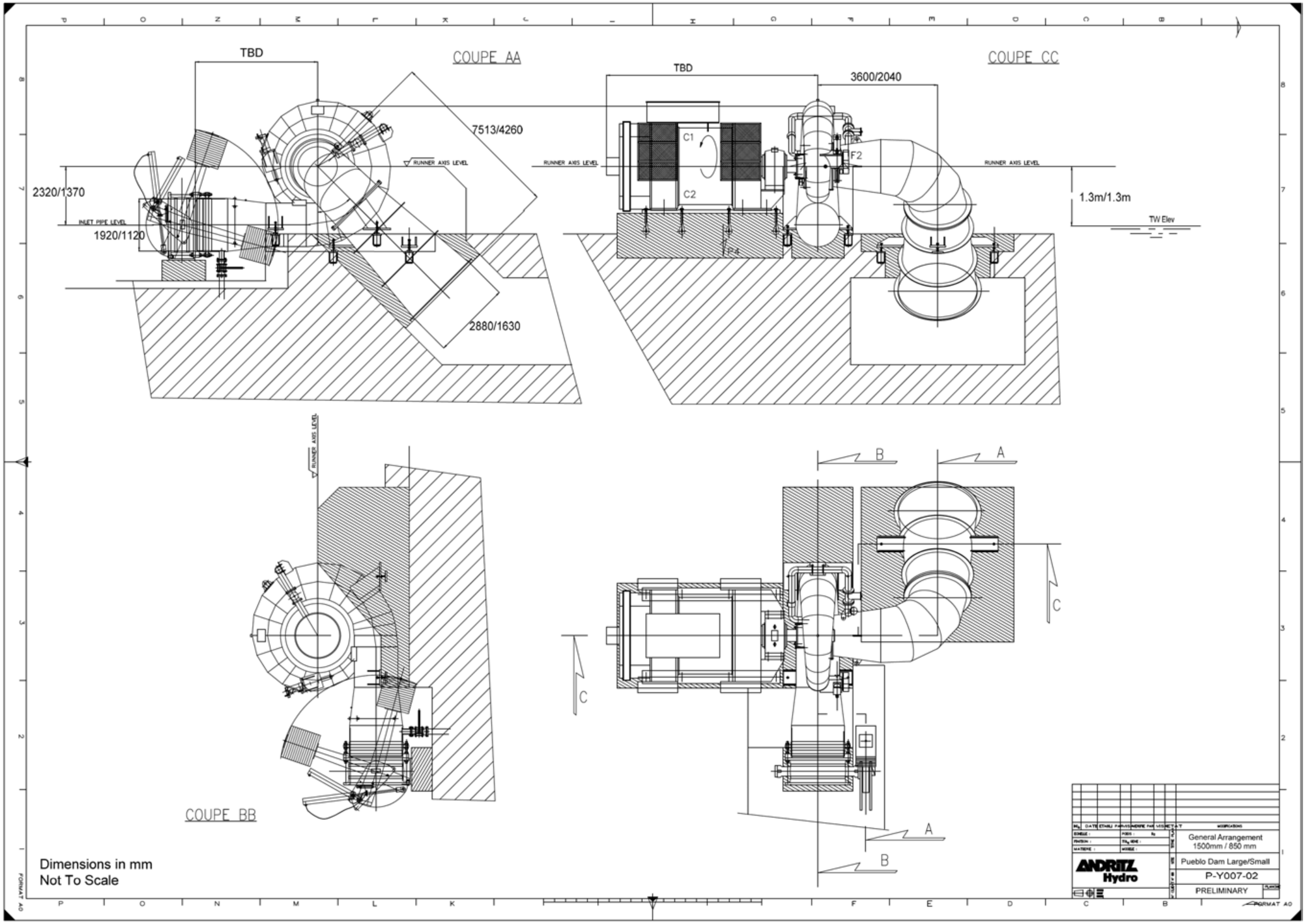
Preliminary Turbine Performance Curves



Preliminary Turbine Performance Curves



Preliminary General Arrangement



APPENDIX D

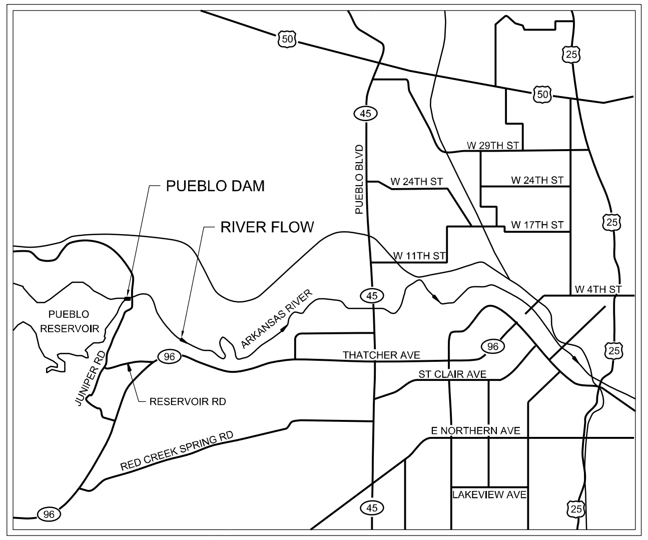
Feasibility Level Drawings

PUEBLO DAM HYDROELECTRIC PROJECT
FEASIBILITY LEVEL DRAWINGS

SOUTHEASTERN COLORADO WATER CONSERVANCY DISTRICT
PUEBLO, COLORADO

JANUARY 2014

INDEX TO DRAWINGS



N

SITE MAP
NTS

PRELIMINARY NOT FOR CONSTRUCTION

NO.	DATE	REVISION	BY	APVD

DSGN M RARDIN | DR M RARDIN | CHK E SCHULZ | APVD D MURRER

PUEBLO DAM HYDROELECTRIC PROJECT
PUEBLO, COLORADO
SOUTHEASTERN COLORADO WATER CONSERVANCY DISTRICT
PUEBLO, COLORADO

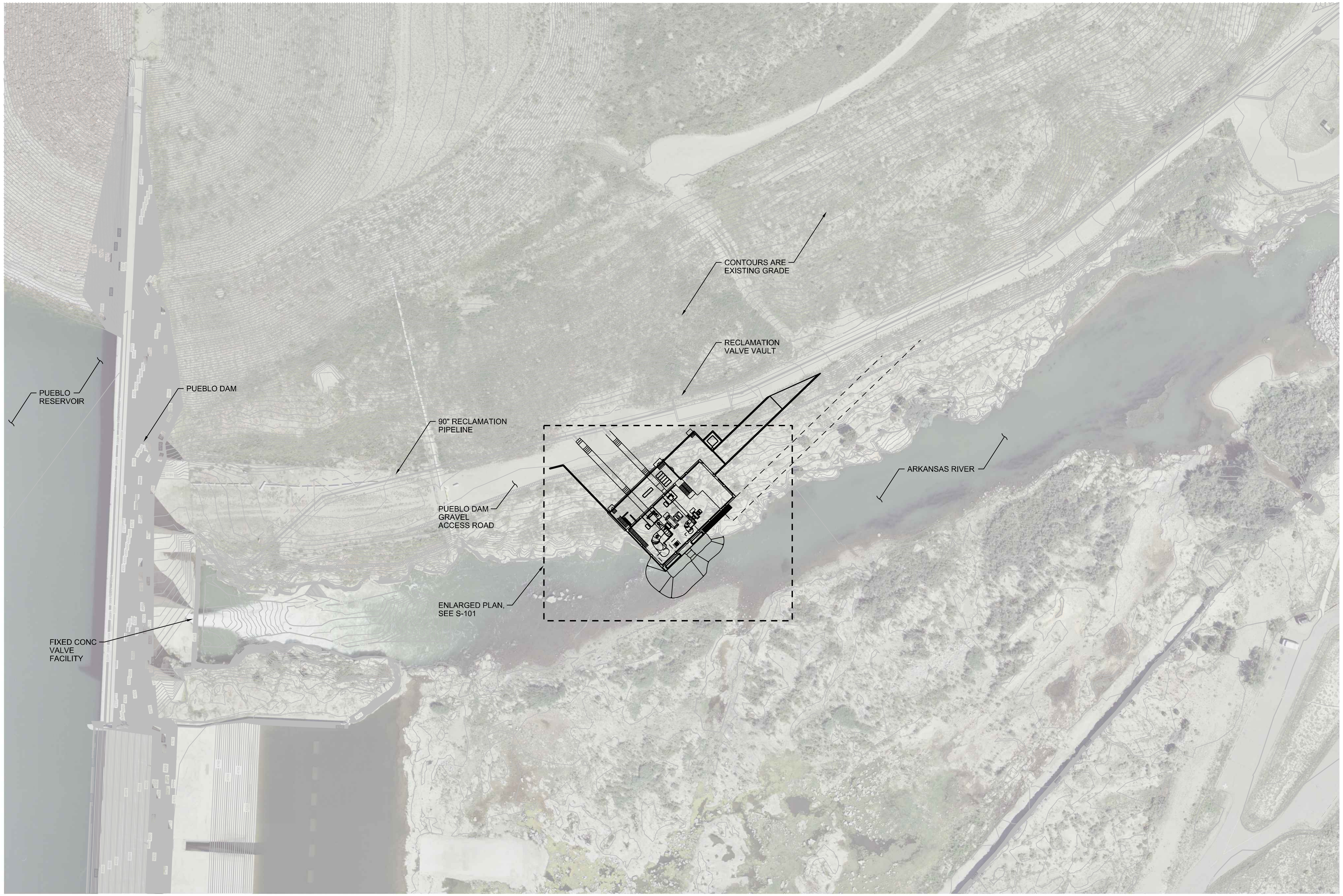
CH2MHILL®

GENERAL
COVER SHEET AND INDEX

AS SHOWN
VERIFY SCALE
BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

DATE	2014/01/24
PROJ	481454
DWG	G-001
SHEET	1 of 5

1 2 3 4 5 6



N

SITE PLAN

1"=50'-0"

PRELIMINARY NOT FOR CONSTRUCTION

NO.	DATE	REVISION	BY	APVD

DSGN D MURRER | DR T STIMPSON | CHK E SCHULZ | APVD D MURRER

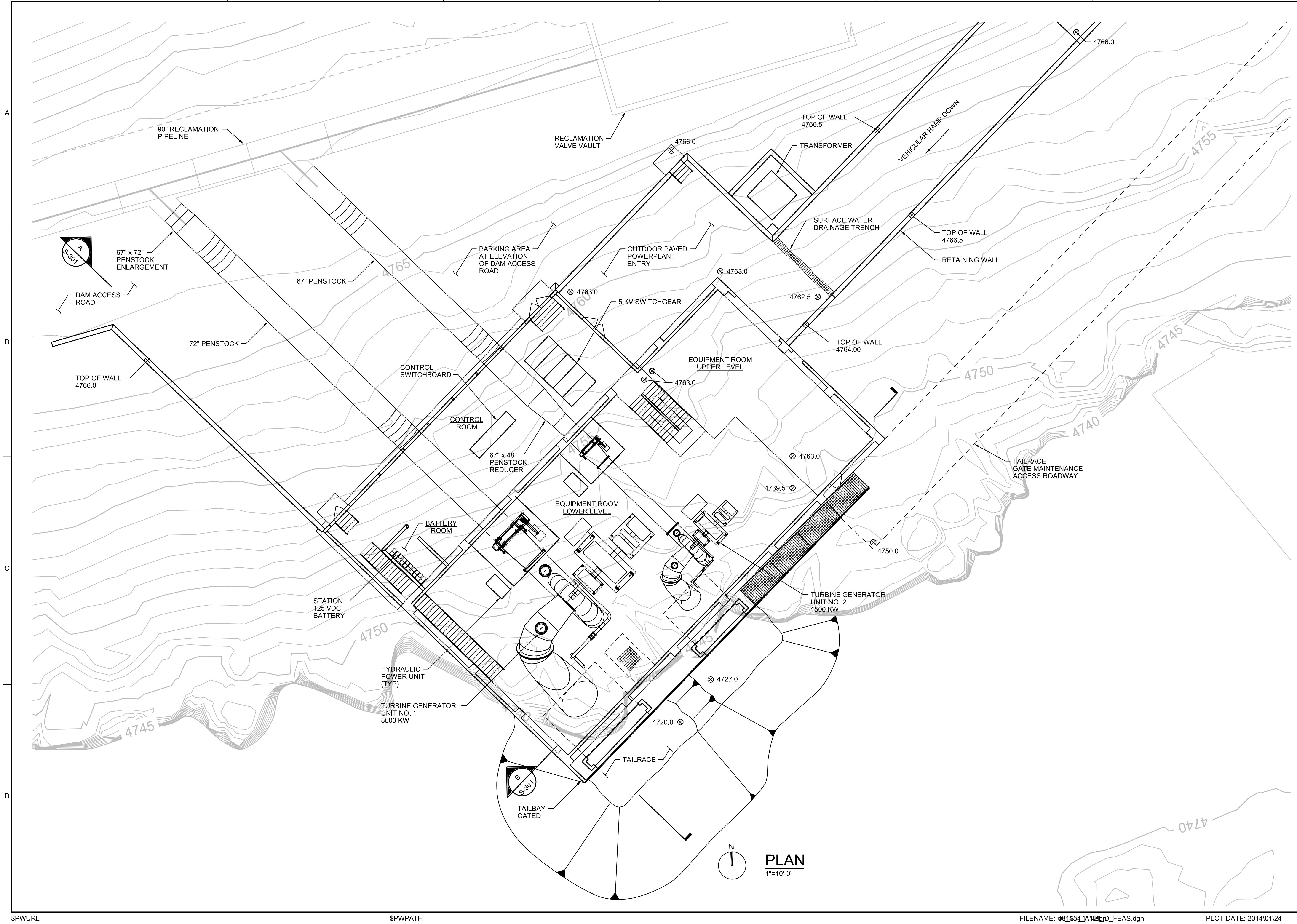
PUEBLO DAM HYDROELECTRIC PROJECT
PUEBLO, COLORADO
SOUTHEASTERN COLORADO WATER CONSERVANCY DISTRICT
PUEBLO, COLORADO

CH2MHILL®

CIVIL
OVERALL SITE PLAN

VERIFY SCALE
BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

DATE	2014/01/24
PROJ	481454
DWG	C-101
SHEET	2 of 5



PRELIMINARY NOT FOR CONSTRUCTION

NO.	DATE	REVISION	BY	APVD

DSGN D MURRER | DR T STIMPSON | CHK E SCHULZ | APVD D MURRER

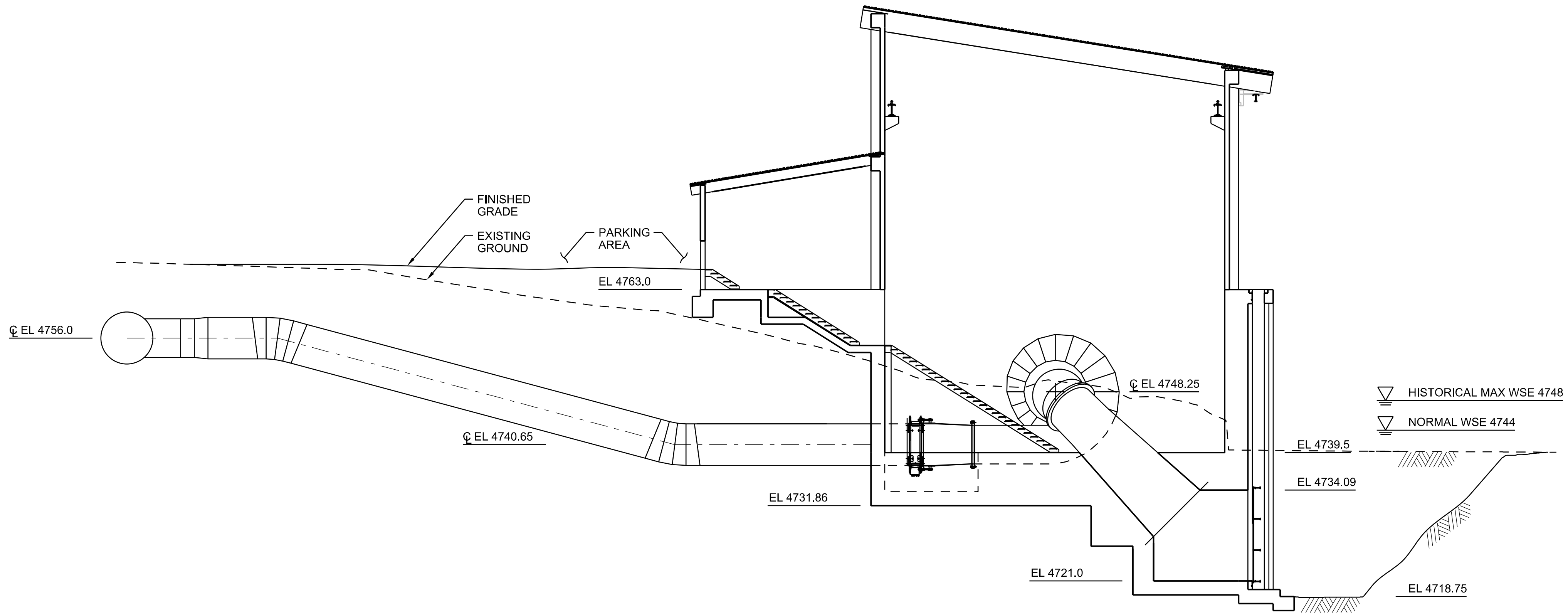
PUEBLO DAM HYDROELECTRIC PROJECT
PUEBLO, COLORADO
SOUTHEASTERN COLORADO
WATER CONSERVANCY DISTRICT
PUEBLO, COLORADO

CH2MHILL®

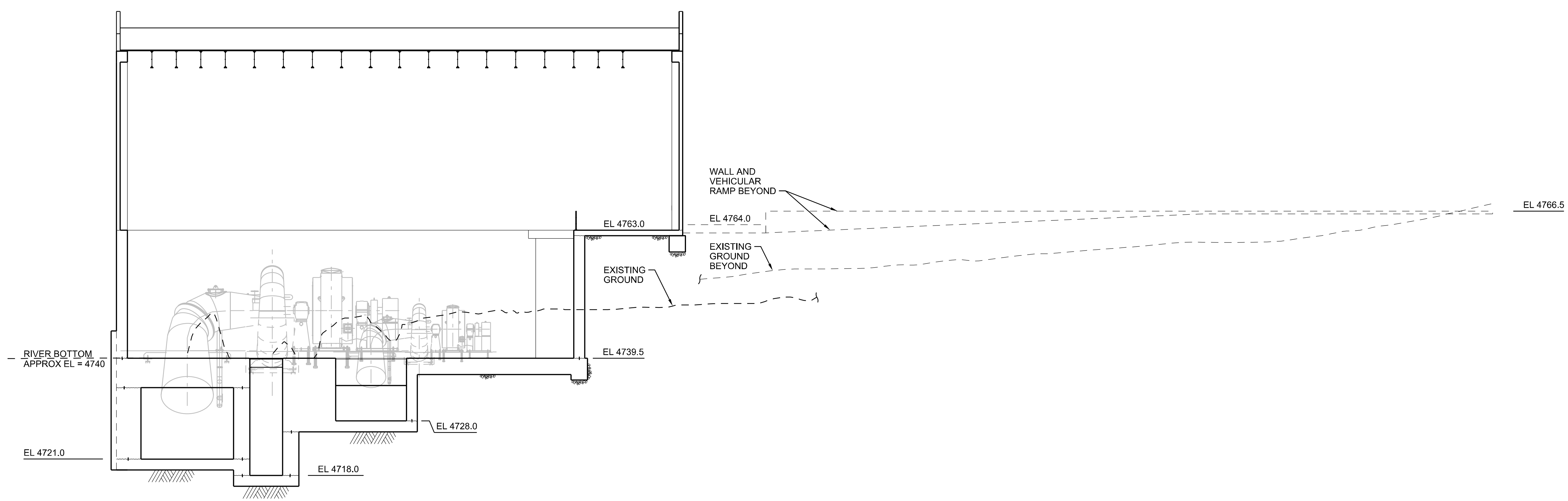
STRUCTURAL
POWER HOUSE
ENLARGED
SITE PLAN

VERIFY SCALE
BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

DATE	2014/01/24
PROJ	481454
DWG	S-101
SHEET	3 of 5



(A) SECTION
3/32"=1'-0"



(B) SECTION
3/32"=1'-0"

PRELIMINARY NOT FOR CONSTRUCTION

NO.	DATE	REVISION	BY	APVD

DSGN	DR	CHK	APVD
D MURRER	T STIMPSON	E SCHULZ	D MURRER

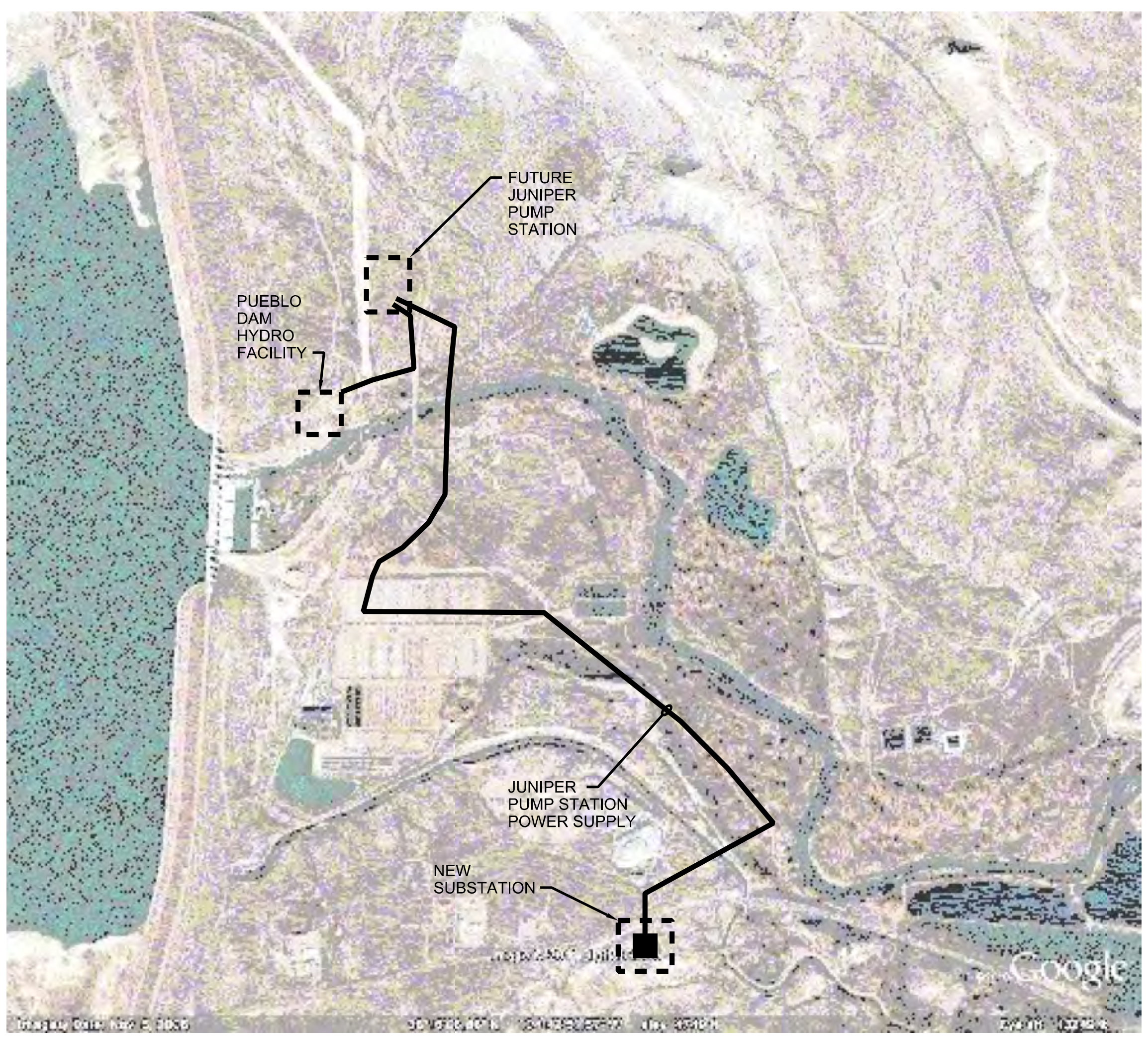
PUEBLO DAM HYDROELECTRIC PROJECT
PUEBLO, COLORADO
SOUTHEASTERN COLORADO
WATER CONSERVANCY DISTRICT
PUEBLO, COLORADO

CH2MHILL®

STRUCTURAL
POWER HOUSE
SECTIONS

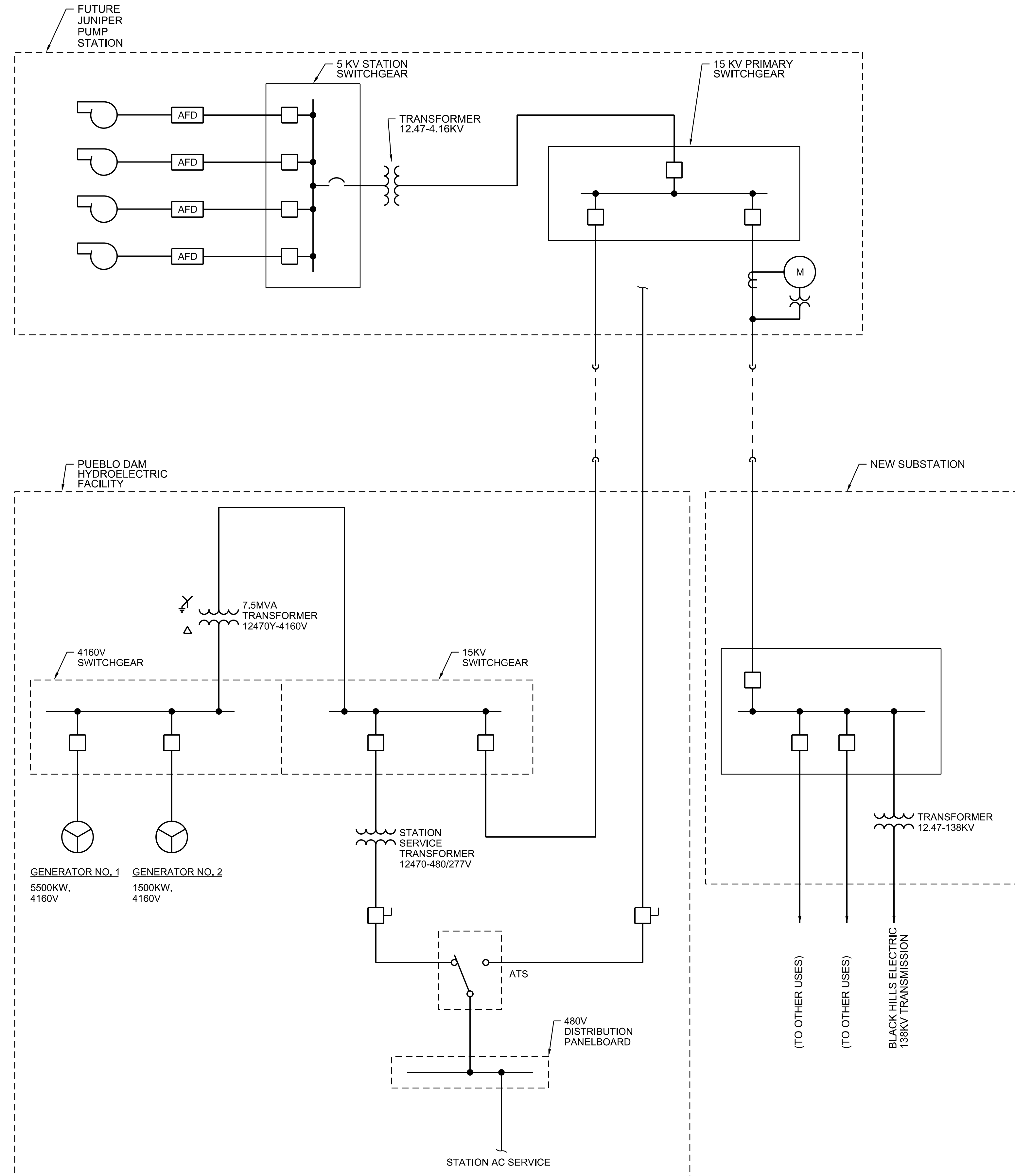
VERIFY SCALE
BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

DATE	2014/01/24
PROJ	481454
DWG	S-301
SHEET	4 of 5



INTERCONNECTION PLAN

NTS



SINGLE LINE DIAGRAM

NTS

PRELIMINARY NOT FOR CONSTRUCTION

NO.	DATE	REVISION	BY	APVD

DSGN C CURTIS | DR M RARDIN | CHK E SCHULZ | APVD D MURRER

PUEBLO DAM HYDROELECTRIC PROJECT
PUEBLO, COLORADO
SOUTHEASTERN COLORADO WATER CONSERVANCY DISTRICT
PUEBLO, COLORADO

CH2MHILL®

ELECTRICAL
SINGLE LINE DIAGRAM AND INTERCONNECTION PLAN

VERIFY SCALE
BAR IS ONE INCH ON ORIGINAL DRAWING.
0 1"

DATE	2014/01/24
PROJ	481454
DWG	E-001
SHEET	5 of 5

APPENDIX E

Order-of-Magnitude Cost Estimate

FEASIBILITY STUDY ORDER-OF-MAGNITUDE COST ESTIMATE

PUEBLO DAM HYDROELECTRIC PROJECT, PUEBLO, CO
SOUTHEASTERN COLORADO WATER CONSERVANCY DISTRICT

CONSTRUCTION COSTS

Item (Major cost elements)	Unit	Unit Cost	Quantity	Extended Cost	Remarks
Initial/Misc Sitework	LS	$ 40,000	1	40,000	SWPPP, Staging, Clearing/Grubbing
Final Grading	LS	$ 40,000	1	40,000	Parking Lot Surfacing etc.
Dewatering	LS	$ 100,000	1	100,000	Supersacks, Membrane, pumping
66-inch penstock sections	LF	$ 800	90	72,000	.375" thick pipe, $3/LB
72-inch penstock sections	LF	$ 1,000	105	105,000	.375" thick pipe, $3/LB
Rock excavation	CY	$ 300	8000	2,400,000	Rock Excavation, no blasting
Tailrace excavation	CY	$ 300	1200	360,000	Rock Excavation, no blasting
Common backfill	CY	$ 10	1000	10,000	Beneath Parking lot
Structural backfill	CY	$ 30	4000	120,000	Beneath Control Room and other Misc areas
Structural Concrete (building and substructure)	CY	$ 500	3500	1,750,000	All site concrete
Metals	LS	$ 100,000	1	100,000	Allowance
Doors	LS	$ 20,000	1	20,000	Allowance
Finishes	LS	$ 50,000	1	50,000	Allowance
Thermal/Roofing	LS	$ 100,000	1	100,000	Allowance
SUBTOTAL - CIVIL WORKS, PIPELINES, AND STRUCTURES				*$ 5,267,000*	
Power distribution equipment - MCCs, panelboards, disconnects	LS	$ 60,000	1	60,000	
125 Vdc battery, dc panelboard, 2 chargers	LS	$ 50,000	1	50,000	
Interior conductors and raceways	LS	$ 350,000	1	350,000	
Plant Instrumentation and Controls	LS	$ 100,000	1	100,000	Includes turbine flowmeters
Miscellaneous site and underground electrical	LS	$ 100,000	1	100,000	
Lighting	LS	$ 90,000	1	90,000	
Grounding system	LS	$ 70,000	1	70,000	
Security and communication	LS	$ 15,000	1	15,000	
SUBTOTAL - ELECTRICAL				*$ 835,000*	
Plumbing - miscellaneous	LS	$ 10,000	1	10,000	
Equipment room unit heaters	LS	$ 20,000	1	20,000	
Equipment room ventilation fans and ductwork	LS	$ 160,000	1	160,000	
Control room HVAC	LS	$ 20,000	1	20,000	
Bridge crane	LS	$ 100,000	1	100,000	
Pumps	LS	$ 20,000	1	20,000	
Valves	LS	$ 15,000	1	15,000	
Piping - water	LS	$ 40,000	1	40,000	
Piping - hydraulics	LS	$ 20,000	1	20,000	
Tailbay monorail	LS	$ 20,000	1	20,000	
Tailbay gates	EA	$ 20,000	2	40,000	
Installation of Owner-furnished products:	**%**	$ 6,500,000	10%	650,000	Allowance
SUBTOTAL - MECHANICAL AND MISCELLANEOUS				*$ 1,115,000*	
12.47 kV primary and secondary circuiting, underground ducts.	LS	$ 60,000	1	60,000	
12.47 kV outgoing utility circuiting, underground ducts.	LS	$ 50,000	1	50,000	
Containment pad for substation transformer	CY	$ 180	20	3,600	
SUBTOTAL - PLANT SUBSTATION FACILITIES				*$ 113,600*	
General Requirements, including supervision, temporary facilities, testing, etc.	**%**	$ 7,330,600	3%	219,918	
Mobilization / Demobilization	**%**	$ 7,330,600	5%	366,530	
Contractor bonds	**%**	$ 7,330,600	2%	146,612	
Contractor insurance	**%**	$ 7,330,600	1%	73,306	
Contractor overhead and profit	**%**	$ 7,330,600	6%	439,836	
SUBTOTAL - CONTRACTOR CONSTRUCTION ADMINISTRATION AND OVERHEAD/PROFIT				*$ 1,246,202*	
SUBTOTAL - CONSTRUCTION SUBTOTAL				**$ 8,576,802**	
Construction Contingency	%	$ 8,576,802	20%	1,715,360	Allowance
TOTAL - POWERHOUSE CONSTRUCTION TOTAL				**$ 10,292,162**	

OWNER FURNISHED PRODUCTS AND PROJECT INTERCONNECTION COSTS

Item (Major cost elements)				Extended Cost	Remarks
Generating equipment package - Turbines, Generators, TIVs, HPCUs, Controls, Switchgear	LS	$ 6,500,000	1	6,500,000	
Field Services	DAYS	$ 2,500	60	150,000	
SUBTOTAL - PLANT EQUIPMENT				*$ 6,650,000*	
Transformer	LS	$ 300,000	1	300,000	
SUBTOTAL - MAIN POWER				*$ 300,000*	
480V backup power from JPS	Mile	$ 120,000	0.33	40,000	
New 12.47 kV underground line from Hydro Facility to interconnection at Pump Station	Mile	$ 1,000,000	0.33	330,000	
SUBTOTAL - DISTRIBUTION FACILITIES				*$ 370,000*	
TOTAL - PROJECT CONSTRUCTION TOTAL				**$ 7,320,000**	

PROJECT ADMINSTRATION COSTS

Item (Major cost elements)	Extended Cost	Remarks
Engineering	1,500,000	Allowance
Environmental Assessment	50,000	Allowance
SDC	500,000	Allowance
TOTAL - PROJECT ENGINEERING AND ADMINISTRATION	**$ 2,050,000**	

ESTIMATED TOTAL CAPITAL COST	**$ 19,662,162**	

APPENDIX F

Basic Economic-Feasibility Evaluation

Basic Financial-Economic Evaluation

Pueblo Dam Hydroelectric Project		
Item	**Summary**	
Total Development Cost	$19,662,162	
Utilities Initial Investment	$2,000,000	
Funding Entity	CWCB #1	SCWCD #1
Finance Rate on Debt	2.0%	2.0%
Principal Borrowed	$12,800,000	$4,862,162
Bond Origination Fees	1%	1%
Total Bond Amount	$12,928,000	$4,910,784
Bond Term (Years)	20	20
Total Repaid	$15,812,681	$6,006,548
Total Interest Paid	$2,884,681	$1,095,765
Annual Payment	($790,634)	($300,327)

Annual Costs	
Item	**Cost**
2017 O&M Costs	$168,446
Escalation of O&M	3.5%
Payments to the US (mills/kWh)	3.00
Transmission and Wheeling ($/MWh	$3.75

Cash Flow and IRR Summary	
Item	**50 Year Period**
Total Gross Revenue	$37,288,336
Total Costs	($32,807,974)
Total Net Revenue	$4,480,361

Internal Rate of Return (IRR)	
Item	**Rate**
IRR 2014-2041	**4.09%**

Value of Energy	
Item	**Rate**
2017 Value of Energy (per MWh)	**$55.00**
Annual energy Escalation	**3.0%**

Benefit Cost Summary 2014- 2041	
Discount Rate	2.0%
Total PV of Costs	$26,580,537
Total PV of Revenue/Benefit	$28,334,187
Net Present Value	**$1,753,650**
Overall PV Benefit/Cost Ratio	**1.07**

Cash Flow Breakdown During a 25 Year Operation Period

Year	Data Year	Loan Year	Operation Year	Annual Energy Production kWh	Sale Price of Energy	Total Annual Revenue	Present Value of Revenue	Initial Investment	Annual Bond Payment	Payments to the United States	Transmission and Wheeling	Operating and Maintenance Costs	Total Annual Costs	Present Value of Costs	Net Revenue
2014				0	N/A	$0	$0	($2,000,000)	N/A			N/A	($2,000,000)	($2,000,000)	($2,000,000)
2015		1		0	N/A	$0	$0		($1,090,961)			N/A	($1,090,961)	($1,069,570)	($1,090,961)
2016		2		0	N/A	$0	$0		($1,090,961)			N/A	($1,090,961)	($1,048,598)	($1,090,961)
2017	1984	3	1	31,701,217	$55.00	$1,743,567	$1,643,002		($1,090,961)	($95,104)	($118,880)	($168,446)	($1,473,391)	($1,388,409)	$270,176
2018	1985	4	2	36,949,087	$56.65	$2,093,166	$1,933,762		($1,090,961)	($110,847)	($138,559)	($174,342)	($1,514,710)	($1,399,358)	$578,456
2019	1986	5	3	35,536,085	$58.35	$2,073,513	$1,878,044		($1,090,961)	($106,608)	($133,260)	($180,444)	($1,511,274)	($1,368,807)	$562,239
2020	1987	6	4	36,961,181	$60.10	$2,221,366	$1,972,510		($1,090,961)	($110,884)	($138,604)	($186,759)	($1,527,209)	($1,356,118)	$694,157
2021	1988	7	5	27,144,694	$61.90	$1,680,338	$1,462,835		($1,090,961)	($81,434)	($101,793)	($193,296)	($1,467,484)	($1,277,533)	$212,853
2022	1989	8	6	19,878,481	$63.76	$1,267,453	$1,081,759		($1,090,961)	($59,635)	($74,544)	($200,061)	($1,425,203)	($1,216,397)	($157,749)
2023	1990	9	7	7,106,205	$65.67	$466,685	$390,501		($1,090,961)	($21,319)	($26,648)	($207,064)	($1,345,992)	($1,126,266)	($879,307)
2024	1991	10	8	6,323,477	$67.64	$427,739	$350,895		($1,090,961)	($18,970)	($23,713)	($214,311)	($1,347,956)	($1,105,793)	($920,216)
2025	1992	11	9	10,681,297	$69.67	$744,191	$598,525		($1,090,961)	($32,044)	($40,055)	($221,812)	($1,384,872)	($1,113,801)	($640,681)
2026	1993	12	10	19,012,762	$71.76	$1,364,404	$1,075,823		($1,090,961)	($57,038)	($71,298)	($229,575)	($1,448,873)	($1,142,426)	($84,469)
2027	1994	13	11	19,770,041	$73.92	$1,461,311	$1,129,641		($1,090,961)	($59,310)	($74,138)	($237,610)	($1,462,019)	($1,130,189)	($709)
2028	1995	14	12	30,236,599	$76.13	$2,301,999	$1,744,627		($1,090,961)	($90,710)		($245,927)	($1,427,598)	($1,081,941)	$874,401
2029	1996	15	13	25,845,389	$78.42	$2,026,714	$1,505,878		($1,090,961)	($77,536)		($254,534)	($1,423,032)	($1,057,333)	$603,682
2030	1997	16	14	32,424,806	$80.77	$2,618,931	$1,907,749		($1,090,961)	($97,274)		($263,443)	($1,451,679)	($1,057,469)	$1,167,252
2031	1998	17	15	24,096,326	$83.19	$2,004,632	$1,431,633		($1,090,961)	($72,289)		($272,663)	($1,435,914)	($1,025,476)	$568,718
2032	1999	18	16	30,137,472	$85.69	$2,582,426	$1,808,110		($1,090,961)	($90,412)		($282,206)	($1,463,580)	($1,024,739)	$1,118,846
2033	2000	19	17	25,868,894	$88.26	$2,283,159	$1,567,231		($1,090,961)	($77,607)		($292,084)	($1,460,652)	($1,002,636)	$822,507
2034	2001	20	18	13,382,969	$90.91	$1,216,600	$818,737		($1,090,961)	($40,149)		($302,307)	($1,433,417)	($964,649)	($216,816)
2035	2002		19	4,192,995	$93.63	$392,606	$259,032			($12,579)		($312,887)	($325,466)	($214,735)	$67,140
2036	2003		20	478,375	$96.44	$46,136	$29,842			($1,435)		($323,838)	($325,273)	($210,400)	($279,138)
2037	2004		21	2,398,790	$99.34	$238,286	$151,111			($7,196)		($335,173)	($342,369)	($217,115)	($104,083)
2038	2005		22	3,123,768	$102.32	$319,612	$198,710			($9,371)		($346,904)	($356,275)	($221,504)	($36,663)
2039	2006		23	8,628,044	$105.39	$909,272	$554,230			($25,884)		($359,045)	($384,929)	($234,626)	$524,343
2040	2007		24	19,957,639	$108.55	$2,166,347	$1,294,564			($59,873)		($371,612)	($431,485)	($257,846)	$1,734,862
2041	2008		25	23,593,878	$111.80	$2,637,882	$1,545,435			($70,782)		($384,618)	($455,400)	($266,802)	$2,182,482
						$37,288,336	**$28,334,187**	**($2,000,000)**	**($21,819,229)**	**($1,486,291)**	**($941,492)**	**($6,560,962)**	**($32,807,974)**	**($26,580,537)**	**$4,480,361**

1. O&M Costs Based on Colorado Springs Utilities investigations suggesting a current estimation of $0.0085/kWh.
2. Energy in 2017 begins on April 1, the current target date for start-up
3. Transmission and Wheeling Ends in Year 2027 per SEWCD direction