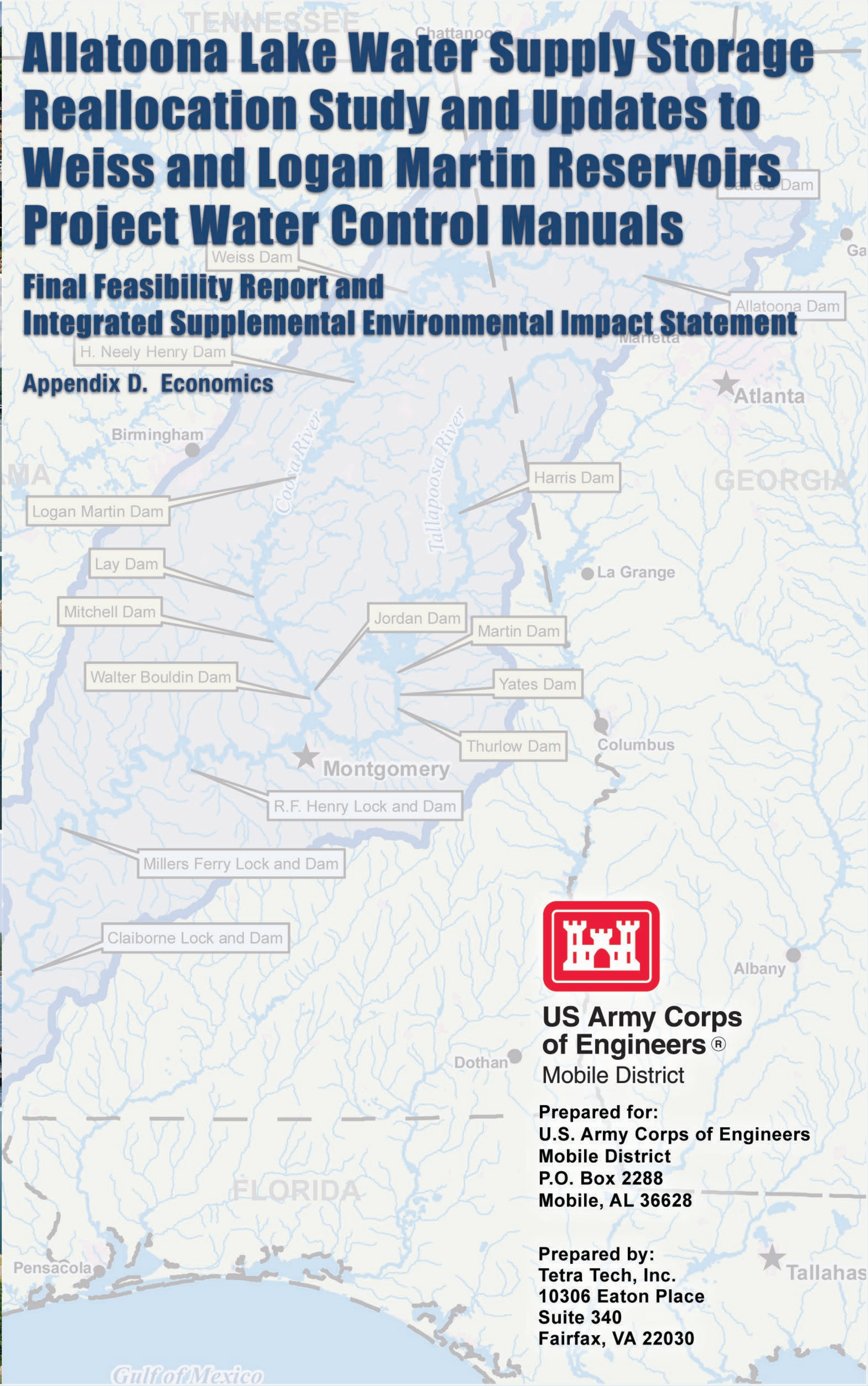
November 2020

Allatoona Lake Water Supply Storage Reallocation Study and Updates to Weiss and Logan Martin Reservoirs Project Water Control Manuals

Final Feasibility Report and Integrated Supplemental Environmental Impact Statement

Appendix D. Economics



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APPENDIX D

ECONOMICS APPENDIX

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APPENDIX D. ECONOMICS APPENDIX

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D.1 Purpose of Economic Evaluations in a Reallocation Study

As stated in the Institute for Water Resources (IWR) Water Supply Handbook (Revised IWR Report 96-PS-4):

> "U.S. Army Corps of Engineers and other Federal reservoirs represent a combination of large economic investments and commitments of valuable natural resources. These reservoirs can make important contributions to the nation's economy. Over time, as population shifts and growth and need changes, the purposes of some Federal reservoirs may no longer satisfy the original project priories. To meet these changing needs, the Corps is continually turning to reallocation. Reallocation of storage to municipal and industrial water supply has been considered in a number of different ways. However, any new reallocation agreement must provide the states or others with financial incentives not available elsewhere and the use of existing storage in Corps facilities must be cheaper for the potential user than the construction of new or additional facilities. Corps policy for reallocated storage is to charge the user the cost of the storage as if it were constructed today."

According to the same manual, there are three conditions that create an opportunity to reallocate flood control storage to water supply storage, which are:

- Where reallocated flood control storage volumes are small and do not affect flood protection. If the effect is large, Congressional action is required;
- Where the downstream floodplain has changed or supplemental protection has been provided; and
- Where reservoirs have been designed to a maximum site capacity that is larger than required by hydrologic analysis.

The purpose of this economic evaluation is to determine the impacts of reallocating water from the conservation pool and flood control pool at the USACE's Allatoona project and changing the operations of the Alabama Power Company's (APC) Logan Martin, and Weiss hydropower projects on the Coosa River. The proposed changes to the base condition (alternatives) are then compared to the base condition in order to determine their affects and aid the planning effort. For the Allatoona project specifically, this evaluation compares the increasing municipal and industrial (M&I) water supply needs, changes in downstream flood impacts, and hydropower benefits foregone to the next least costly and most likely alternative means of attaining the requested amount of water supply storage. USACE ER 1105-2-100 specifies the four pricing methods used to calculate the value of storage considered for reallocation (i.e., the price to be charged for the capital investment for the reallocated storage): benefits foregone, revenues foregone, replacement cost, and updated cost of storage. The value placed on the storage is the highest of the four methods, which in this case is the updated cost of storage. Unless otherwise stated all values are expressed in fiscal year 2021 (FY'21 values). Average annual dollars in this report are based on the FY'21 price levels, FY'21 discount rate of 2.5 percent and a period of analysis of 50 years.

D.2 Study Area

The study area is the Alabama-Coosa-Tallapoosa (ACT) River Basin. The ACT River Basin includes the Alabama, Coosa, and Tallapoosa rivers and all areas within the basin boundaries from the headwaters downstream to the mouth of the Alabama River, where it joins the Tombigbee River to form the Mobile River. The ACT River Basin at its confluence with the Tombigbee River has a drainage area of 22,739 square miles (sq mi) and covers portions of the states of Alabama, Georgia, and Tennessee. Further information regarding the study area can be found in Section 1.1 of the main report. For modeling purposes the study area is separated into two sections.

The Allatoona Lake section is composed of the following Georgia counties:

- Floyd
- Bartow
- Murray
- Gordon
- Carroll
- Catoosa
- Chattooga
- Cherokee
- Cobb
- Dade
- Dawson
- Fannin
- Forsyth
- Gilmer
- Haralson
- Heard
- Lumpkin
- Paulding
- Pickens
- Polk
- Walker
- Whitfield

The APC study area is composed of the following Alabama counties:

- Calhoun
- Cherokee
- Chilton
- Coosa
- Elmore
- Etowah
- Shelby
- St. Clair
- Talladega
- Autauga
- Baldwin
- Bibb
- Blount
- Bullock
- Butler
- Chambers
- Clarke
- Clay
- Cleburne
- Conecuh

- Crenshaw
- Dallas
- DeKalb
- Escambia
- Jefferson
- Lee
- Lowndes
- Macon
- Marengo
- Mobile
- Monroe
- Montgomery
- Perry
- Pike
- Randolph
- Russell
- Tallapoosa
- Tuscaloosa
- Washington
- Wilcox

D.3 Existing and Future Without Project Condition

D.3.1 Population

Due to the nature of reallocation, the existing and future without project (FWOP) conditions are assumed to be equal with the exception of population growth. The Allatoona section is composed of the study area's Georgia counties and has a total land area of 7,209 sq mi and a population of 2,121,165. The largest city within the Allatoona section is Rome, GA with a population of 36,340. Rome is in Floyd County at the confluence of the Oostanaula and Etowah Rivers, approximately 70 miles northwest of Atlanta.

The APC section is composed of the study area's Alabama counties and has a total land area of 31,501 sq mi and a population of 3,307,059. The largest city within the APC study area is Gadsden with a population of 36,235. Gadsden is in Etowah County on the Coosa River downstream of Weiss Lake, approximately 60 miles northeast of Birmingham.

The following tables display the basic population, population projections, demographic, and poverty statistics information for each portion of the study area as estimated by the Census Bureau 2016 American Community Survey 5 year estimates and Center for Disease Control 2016 Social Vulnerability Index.

Table D-1. ACT Population

Area	% of Basin	1960	1970	1980	1990	2000	2010	2016
ACT (AL)	60%	2,330,066	2,379,925	2,688,651	2,766,512	3,042,112	3,255,514	3,307,059
ACT (GA)	40%	484,100	636,681	854,126	1,153,046	1,594,408	2,019,492	2,200,123

ACT Basin		2,814,166	3,016,606	3,542,777	3,919,558	4,636,520	5,275,006	5,507,182

Table D-2. ACT Population Projections

	2030	2060
ACT (AL)	4,197,614	5,601,733
ACT (GA)	4,643,786	6,197,150
ACT Basin	8,841,400	11,798,883

Table D-3. ACT Demographics (2016)

Area	Minority (all persons except white, non-Hispanic)	Percentage minority (all persons except white, non-Hispanic)	Persons below poverty	Percentage of persons below poverty	Single parent household with children under 18	Percentage of single parent households with children	Percentage of persons aged 17 and younger
ACT (AL)	1,249,404	38.78	601,746	21.77	125,381	9.78	22.55
ACT (GA)	645,686	18.22	290,083	16.37	73,022	8.72	23.71
ACT Basin	1,895,090	28.50	891,829	19.07	198,403	9.25	23.13

D.3.2 Education

Table D-4 shows the percent of people over the age of 25 with no high school diploma. This is an important statistic due to its correlation with higher rates of unemployment and underemployment. Overall this percentage is greatest in the Alabama counties of the study area with 19% of people with no a high school diploma. The Georgia counties of the study area also have a higher percentage at 18.7% compared to the state overall at 14.2%. The overall study area percent of people with no high school diploma is 18.9%, which is higher than both the U.S. South Region, and the overall U.S. at 14.4% and 13% respectively.

Table D-4. ACT Persons with no High School Diploma (2016)

Area	Percentage of persons with no high school diploma (age 25+)
ACT (AL)	19.0
AL (Entire State)	16.2
ACT (GA)	18.7
GA (Entire State)	14.2
ACT Basin	18.9
US South Region	14.4
Entire US	13

D.3.3 Employment

As seen in Table D-5 below, the industry sector that accounts for the highest percentage of the labor force in the ACT Basin is educational services, and health care and social assistance (20.06%). The second largest is manufacturing with 18.35% followed by retail trade with 11.78%.

Table D-5. ACT Percent of Employees by Industry (2016)

Industry	Area		
	AL	GA	ACT Basin
Educational services, and health care and social assistance	21.32	18.80	20.06
Manufacturing	18.37	18.34	18.35
Retail trade	11.53	12.03	11.78
Arts, entertainment, and recreation, and accommodation and food services	7.41	8.13	7.77
Professional, scientific, and management, and administrative and waste management services	6.65	8.85	7.75
Construction	6.83	8.36	7.59
Transportation and warehousing, and utilities	5.75	5.23	5.49
Other services, except public administration	4.93	5.35	5.14
Finance and insurance, and real estate and rental and leasing	4.71	5.33	5.02
Public administration	6.07	3.83	4.95
Wholesale trade	2.21	2.73	2.47
Agriculture, forestry, fishing and hunting, and mining	2.94	1.24	2.09
Information	1.32	1.82	1.57

D.3.4 Income

Table D-6 and Table D-7 show income per capita and income growth rate for the study area. During the period from 2009 to 2016, the income growth rate for the study area has slowed compared to the previous 50 years. However, overall the areas income has grown at a rate of 3.11% since 1959.

Table D-6. ACT Income per Capita ($) (1959-2016)

Income Per Capita							
Area	**1959**	**1969**	**1979**	**1989**	**1999**	**2009**	**2016**
ACT(AL)	$3,824	$6,046	$8,514	$9,779	$15,738	$19,895	$21,125
ACT(GA)	$4,362	$7,234	$9,544	$11,709	$18,841	$22,174	$24,850
ACT Basin	$4,009	$6,455	$8,868	$10,444	$16,806	$20,679	$22,988

Table D-7. ACT Income per Capita Growth Rate (1959-2016)

Income Per Capita Annual Growth Rate							
Area	**1959-1969**	**1969-1979**	**1979-1989**	**1989-1999**	**1999-2009**	**2009-2016**	**1959–2016**
ACT(AL)	4.69%	3.48%	1.40%	4.87%	2.37%	0.86%	3.04%
ACT(GA)	5.19%	2.81%	2.07%	4.87%	1.64%	1.64%	3.10%
ACT Basin	4.88%	3.23%	1.65%	4.87%	2.10%	1.52%	3.11%

D.3.5 Housing

The following tables display the number of housing units for the study area as well as annual growth rate for houses and mobile home. Overall, the number of housing units has grown at a rate of 1.90% since the 1940s to a total of 2,391,261 in 2016 of which 259,744 are mobile homes.

Table D-8. ACT Total Housing Units (1940-2016)

Total Housing Units									
Area	**1940**	**1950**	**1960**	**1970**	**1980**	**1990**	**2000**	**2010**	**2016**
ACT (AL)	487,000	598,041	691,644	773,949	1,010,899	1,141,341	1,336,384	1,530,108	1,510,687
ACT (GA)	86,556	112,995	144,153	204,074	318,845	471,315	627,987	819,161	880,574
ACT Basin	573,556	711,036	835,797	978,023	1,329,744	1,612,656	1,964,371	2,349,269	2,391,261

Table D-9. ACT Housing Annual Growth Rate (1940-2016)

Housing Annual Growth Rates									
Area	**1940-1950**	**1950-1960**	**1960-1970**	**1970-1980**	**1980-1990**	**1990-2000**	**2000-2010**	**2010-2016**	**1940-2016**
ACT (AL)	2.08%	1.46%	1.13%	2.71%	1.22%	1.59%	1.36%	-0.21%	1.50%
ACT (GA)	2.70%	2.47%	3.54%	4.56%	3.99%	2.91%	2.69%	1.21%	3.10%
ACT Basin	2.17%	1.63%	1.58%	3.12%	1.95%	1.99%	1.81%	0.30%	1.90%

Table D-10. ACT Mobile Homes (2000-2016)

Housing units mobile homes			Annual growth rate
Area	**2000**	**2016**	**2000–2016**
ACT(AL)	199,445	190,445	-6.41%
ACT(GA)	68,950	69,141	0.02%
ACT Basin	268,395	268,395	-0.20%

D.4 Water Supply Demand

D.4.1 Summary of Water Supply Demand Forecast

The Metropolitan North Georgia Water Planning District provided a future water supply demand forecast for the demands at Allatoona Lake. The analysis forecasted future water supply demand through 2050 based on population and employment forecasts. The 2050 forecasts used the Demand Side Management Least Cost Planning Decision Support System (DSS) Model developed by Maddaus Water Management (Maddaus Water Management, Inc. and CH2M Hill 2011).In 2050, the demand forecast estimates that the Cobb County-Marietta Water Authority will require 57 million gallons per day (MGD), and the City of Cartersville will require 37 MGD for a total of 94 MGD. Further information regarding the water supply demand analysis can be found in Section B.2 of Appendix B.

Table D-11. Water Supply Demand

Water Provider	Average Annual Day – Million Gallons per Day (AAD-MGD)
Cobb County-Marietta Water Authority	57
City of Cartersville / Bartow County	37
Total Demand	**94**

D.5 Navigation

The federally authorized Alabama River navigation project in southwest Alabama stretches 289 miles from its confluence with the Mobile River upstream to Montgomery, AL. The authorization provides for a 9-ft by 200-ft navigation channel from its junction with the Mobile River upstream to Montgomery and includes three lock and dams: Claiborne, Millers Ferry, and Robert F. Henry. No alternatives resulted in a reduction in channel availability of 1%. Due to the nature of the proposed alternatives, and the low amount of navigation that takes place on the ACT below Claiborne lock and dam an in-depth analysis of navigation was not conducted. Additional information about navigation on the ACT system can be found in Section E.1.7.2 of the main report.

D.6 Recreation Analysis

D.6.1 Summary of Recreation Analysis

This section summarizes the objectives, methods, and results of the recreation analysis performed for the Allatoona Lake Water Supply Storage Reallocation Study and Updates to Weiss and Logan Martin Reservoirs Water Control Manuals Feasibility Report and Integrated Supplemental Environmental Impact Statement (FR/SEIS). The analysis estimates National Economic Development (NED) recreation benefits for the final array of alternatives using the Unit Day Value (UDV) methodology. The full recreation analysis can be found in Attachment 1 of this appendix.

Per the UDV methodology, project visitation was forecasted for each project over the period of analysis, and UDV scores were generated for each project and recreation impact zone. UDV scores were converted to value-per-visit in accordance with the FY20 guidance, and total annual recreation value was estimated by project and alternative. FY21 guidance was not available at the time of this report, and values have been adjusted to FY21 dollars using a 2.5% interest rate.

Scores generated for the UDV analysis were a function of reservoir pool level. For each project, several recreation impact zones (pool level ranges) were defined in a way that is consistent with existing information regarding the effects of decreasing pool elevation on recreation. The results from the detailed engineering modeling of the alternatives in the FR/SEIS were queried to tabulate the amount of time during the year that the reservoirs would remain within recreation impact zone under each alternative. This allowed estimation of the proportion of annual visitation that would occur within the recreation impact zone and application of the UDV methodology for the FWOP and the alternatives.

Based on modeling of reservoir levels documented in the main FR/SEIS, alternatives were categorized into two recreation impact scenarios:

• No Change Scenario – Consisting of the alternatives that would have negligible effects on recreation relative to the FWOP.

• With Change Scenario – Consisting of the alternatives that would affect recreation at the projects.

Table D-12 displays, alternatives included in the With Change Scenario would result in positive net benefits to recreation at all three of reservoirs ranging from about 1to 3% net gains compared to the FWOP.

Table D-12. Summary of Recreation Analysis ($)

Project and Scenario	Annualized Recreation Value ($)	Present Value ($)	Annualized Change vs. Without Project	Percent Change
Allatoona				
No Change Scenario	$75,076,600	$2,129,345,000	$0	0%
With Change Scenario [1]	$75,785,400	$2,149,450,000	$708,800	0.90%
Weiss				
No Change Scenario	$16,159,200	$458,312,000	$0	0%
With Change Scenario [2]	$16,492,500	$467,766,000	$333,300	2.10%
Logan Martin				
No Change Scenario	$16,449,700	$466,551,000	$0	0%
With Change Scenario [2]	$16,957,700	$480,959,000	$508,000	3.10%

[1] Allatoona WCS alternatives: 5, 8, 11, 13

[2] Weiss and Logan Martin WCS alternatives: 9, 10, 11, 12, 13

D.7 Hydropower Analysis

This section presents an abbreviated report of the full analysis of the effects on hydropower and the monetary value hydropower that are expected to result from proposed changes to system water control operations within the Alabama-Coosa-Tallapoosa (ACT) River Basin. The system hydropower values for energy and capacity were computed for the baseline condition, representing current water control operations, and for alternative flow scenarios associated with these studies. The full detailed hydropower analysis is found in the attached addendum prepared by the USACE Hydropower Analysis Center (HAC).

D.7.1 General methodology Discussion

D.7.1.1 Calculation of Hydropower

The calculations of hydropower energy and capacity values are based on seventy-three years of historic hydrology (1939-2011) using the HEC-ResSim model.

To understand how system operations can effect hydropower generation we will first consider the mathematics used to approximate the amount of power produced from a hydropower facility. The power equation, seen below, shows that power is directly proportional to three variables; the efficiency of the plant turbines, the amount of flow going through the turbines, and the head, the height of the water in the reservoir relative to its height after discharge.

$$P = e * g * Q * H$$

Where; P=power (kW),
e=turbine efficiency,
g = gravitational constant (ft/sec2),
Q-flow (cfs),
H=head (ft).

Reservoir operations can affect all three of these variables. Higher or lower operational reservoir elevations change the head. Maximum or minimum flow requirements used for flood risk management and environmental purpose can affect the flow. Although power is linear in both head and flow, this relationship quickly becomes non-linear with the inclusion of efficiency which is a non-linear function of both head and flow.

D.7.2 Summary of Results

D.7.2.1 Value of Hydropower

The following tables present a summary of the total hydropower value for the alternatives of this study. Hydropower Value is the sum of energy value and capacity value. Information concerning each alternative can be found in Table 4-5 of the main report document.

Table D-13. Value of Individual Plant Dependable Capacity – Water Supply Alternatives ($)

Alternatives > Projects V		Base2018	BaseCap	FWOP	A03_WS1	A04_WS2	A05_WS3	A06_WS4
ALLATOONA	Federal	$9,725,232	$9,750,813	$9,733,881	$9,621,229	$9,609,987	$9,785,481	$10,002,355
CARTERS	Federal	$75,489,581	$75,489,396	$75,489,396	$75,489,396	$75,489,396	$75,489,396	$75,489,396
MILLERS FERRY	Federal	$11,205,660	$11,206,806	$11,205,615	$11,409,319	$11,206,965	$11,412,005	$11,222,559
RF HENRY	Federal	$9,763,461	$9,764,596	$9,762,725	$10,203,925	$9,763,825	$10,203,984	$9,783,323
Federal	**subtotal**	**$106,183,933**	**$106,211,611**	**$106,191,617**	**$106,723,868**	**$106,070,173**	**$106,890,866**	**$106,497,633**
HARRIS	non-Federal	$16,080,059	$16,079,814	$16,081,757	$16,946,663	$16,086,307	$16,948,631	$16,069,046
HN HENRY	non-Federal	$7,304,157	$7,306,859	$7,305,711	$7,301,512	$7,300,602	$7,309,369	$7,330,374
JORDAN	non-Federal	$13,481,412	$13,481,587	$13,481,187	$13,479,699	$13,479,677	$13,483,649	$13,479,996
LAY	non-Federal	$20,495,364	$20,501,629	$20,497,842	$20,490,832	$20,488,332	$20,510,876	$20,552,264
LOGAN MARTIN	non-Federal	$16,377,419	$16,382,708	$16,376,792	$16,371,576	$16,368,396	$16,393,319	$16,457,463
MARTIN	non-Federal	$23,239,618	$23,228,766	$23,239,618	$23,244,096	$23,245,711	$23,252,374	$23,221,667
MITCHELL	non-Federal	$20,496,844	$20,502,136	$20,497,100	$20,491,009	$20,488,606	$20,512,492	$20,572,127
THURLOW	non-Federal	$9,878,252	$9,876,189	$9,878,696	$9,883,591	$9,884,950	$9,883,235	$9,867,405
WALTER-BOULDIN	non-Federal	$26,988,635	$27,002,847	$26,988,669	$26,972,926	$26,966,317	$27,028,399	$27,186,145
WEISS	non-Federal	$9,165,574	$9,168,753	$9,163,821	$9,159,464	$9,158,136	$9,177,001	$9,237,515
YATES	non-Federal	$5,890,338	$5,775,052	$5,776,102	$5,778,594	$5,779,478	$5,780,229	$5,772,178
non-Federal	**subtotal**	**$169,397,672**	**$169,306,340**	**$169,287,294**	**$170,119,963**	**$169,246,512**	**$170,279,573**	**$169,746,180**
System	**TOTAL**	**$275,581,606**	**$275,517,951**	**$275,478,911**	**$276,843,831**	**$275,316,685**	**$277,170,438**	**$276,243,812**

Table D-14. Value of Individual Plant Dependable Capacity – Water Supply Alternatives ($)

Alternatives > Projects V		A08_WS6	A09_FWOPMF	A10_WS2MF	A11_WS6MF	A12_WS1MF	A13_WS3MF
ALLATOONA	Federal	$9,777,113	$9,733,848	$9,609,996	$9,777,061	$9,621,185	$9,785,420
CARTERS	Federal	$75,489,396	$75,489,440	$75,489,440	$75,489,440	$75,489,440	$75,489,440
MILLERS FERRY	Federal	$11,412,024	$11,410,022	$11,407,964	$11,411,051	$11,408,479	$11,410,665
RF HENRY	Federal	$10,203,984	$10,205,718	$10,205,847	$10,205,847	$10,205,847	$10,205,847
Federal	**subtotal**	**$106,882,517**	**$106,839,028**	**$106,713,247**	**$106,883,398**	**$106,724,951**	**$106,891,372**
HARRIS	non-Federal	$16,948,897	$16,945,782	$16,944,882	$16,947,326	$16,944,753	$16,945,525
HN HENRY	non-Federal	$7,308,743	$7,300,418	$7,294,245	$7,302,476	$7,294,759	$7,303,633
JORDAN	non-Federal	$13,484,178	$13,484,115	$13,482,444	$13,486,688	$13,482,058	$13,486,816
LAY	non-Federal	$20,509,446	$20,489,374	$20,476,255	$20,477,799	$20,477,799	$20,496,061
LOGAN MARTIN	non-Federal	$16,392,400	$16,366,523	$16,354,176	$16,356,748	$16,356,748	$16,377,197
MARTIN	non-Federal	$23,252,068	$23,237,126	$23,235,969	$23,248,701	$23,235,969	$23,245,229
MITCHELL	non-Federal	$20,511,280	$20,486,030	$20,473,940	$20,495,161	$20,475,741	$20,496,061
THURLOW	non-Federal	$9,883,842	$9,889,723	$9,883,293	$9,885,222	$9,883,164	$9,883,164
WALTER-BOULDIN	non-Federal	$27,024,870	$26,950,740	$26,919,488	$26,974,404	$26,924,246	$26,976,719
WEISS	non-Federal	$9,175,829	$9,147,643	$9,140,699	$9,159,604	$9,141,856	$9,161,148
YATES	non-Federal	$5,780,280	$5,781,663	$5,777,804	$5,779,733	$5,777,676	$5,778,833
non-Federal	**subtotal**	**$170,271,833**	**$170,079,137**	**$169,983,194**	**$170,113,862**	**$169,994,769**	**$170,150,387**
System	**TOTAL**	**$277,154,349**	**$276,918,165**	**$276,696,441**	**$276,997,260**	**$276,719,720**	**$277,041,759**

D.7.3 Summary of Benefits Foregone

Benefits forgone are calculated for the Allatoona project in accordance with guidance in the ER 1105-2-100. No NED benefits of navigation were evaluated due to the lack of consistent commodity movements over the last decade. Benefits forgone are calculated for the hydropower project purpose, flood risk management (FRM) and for recreation. A full description of the methodology for NED hydropower impacts is contained in Attachment 4 of Appendix C. Hydropower, FRM, and recreation benefits forgone are summarized in Table D-15.

Table D-15. Benefits Foregone ($)

Account	Total Benefits (Federal System)		Benefits/Revenues Foregone
	FWOP	Reallocation	
Hydropower	$106,183,933	$106,882,517	$698,584
FRM	$6,467,600	$6,556,078	($88,478)
Recreation	$75,076,600	$75,785,400	$708,800
Total	$187,728,133	$189,223,995	$1,318,906

D.8 Flood Damage Analysis

To determine the acceptability of a reallocation from the flood control pool at the Allatoona project, and a change in operations at the APC's Logan Martin and Weiss projects, a flood impacts analysis was conducted to show any possible areas of increased flood risk.

D.8.1 Methodology

The model used to evaluate the existing and proposed flood damages in the ACT basin is the USACE Hydrologic Engineering Center's (HEC) Flood Impact Analysis (HEC-FIA) model software which is a tool to help identify the consequences from a single event. HEC-FIA was developed by HEC in collaboration with the Risk Management Center (RMC) and the Engineering Research and Design Center (ERDC). HEC-FIA evaluates consequences from events defined by hydraulic model output such as gridded data (e.g., depth and arrival time Grids) or HEC's Data Storage System (HEC-DSS) Stage Hydrographs. The consequences HEC-FIA computes include economic losses (losses to structures and their contents), agricultural losses, and expected life loss from these hydraulic events.

D.8.1.1 HEC-FIA Inputs

HEC-FIA requires external inputs, which are developed by the USACE economics branch and by the USACE Hydrologic and Hydraulic (H&H) branch.

D.8.1.1.1 H&H Inputs:

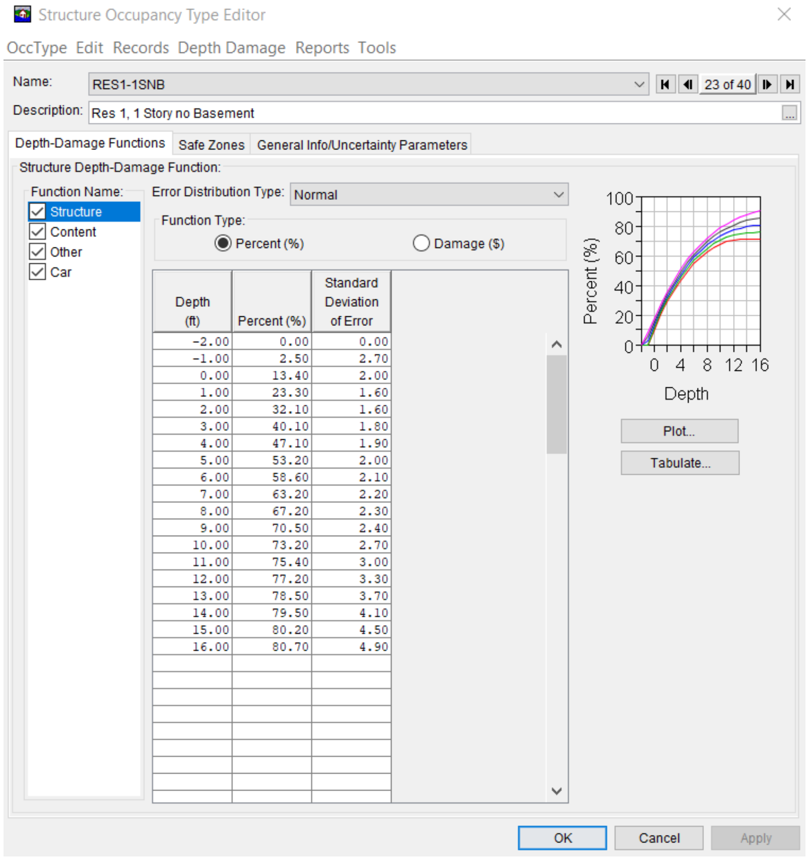
- Watershed Boundary
  - A geospatial boundary that contains the entire area which is to be considered.
- Terrain Grid
  - LiDAR data which established the ground elevation in raster format.
- Depth Grids
  - A raster dataset grid that contains the water depth with reference to the terrain grid. A depth grid is developed through the HEC-RAS model for each event/scenario that is to be evaluated in HEC-FIA.

D.8.1.1.2 Economic Inputs:

- Impact Areas
  - A set of boundaries that differentiate regions within the watershed. Impact areas for this study are the counties within the Watershed Boundary.
- Structure Inventory

A GIS point shapefile that contains the location and information of each structure within the study area. The dataset used for the study structure inventory is the National Structure Inventory (NSI) version 2. The NSI version 1 was initially developed to simplify the workflow for the GIS pre-processing for the USACE Modeling Mapping and Consequence center. Within a given layer of the NSI data, each point is represented by a geospatial location, and a series of required attributes. These attributes can then be used to inform consequence calculations in modeling frameworks such as LifeSim, HEC-FIA, and HEC-FDA. The NSI version 2 improves upon the NSI version 1 with increased accuracy by incorporating additional layers of location and value precision at the parcel level. Examples of the increased accuracy of the NSI 2 are found in Figure D-2 and Figure D-3. The data within the structure inventory is based on Hazus census block data and increasing accuracy for the structure inventory is possible through acquiring individual parcel data from Tax Assessor's Offices.

- Depth Damage Functions
    - Depth Damage Functions are a component of the structure inventory and report the amount of damage that a specific category of structures can expect to receive at certain depths of flooding. This study incorporated the same damage functions that were used in a 2014 ACT watershed CWMS report. The CWMS report utilized Hazus depth damage functions which are designed to be applied across the nation. Additional accuracy can be achieved through development of area specific depth damage functions via conducting surveys and interviews of local home and business owners.



Name: RES1-1SNB

Description: Res 1, 1 Story no Basement

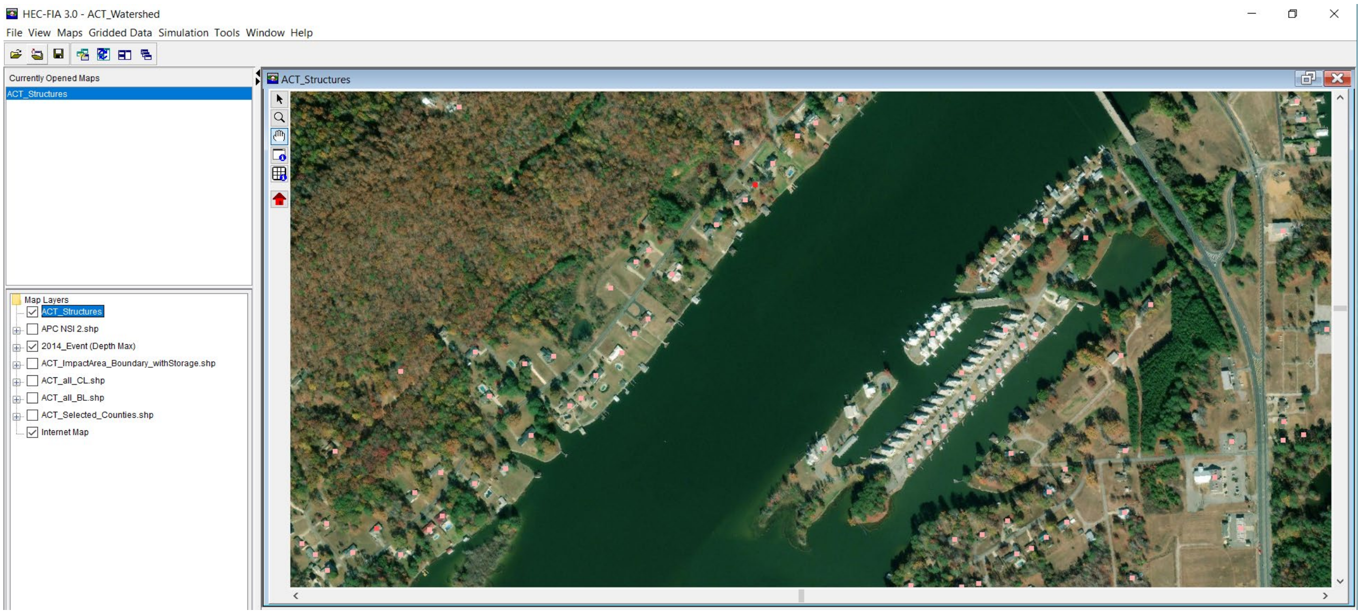
Function Name:
☑ Structure
☑ Content
☑ Other
☑ Car

Error Distribution Type: Normal

Function Type: ● Percent (%) ○ Damage ($)

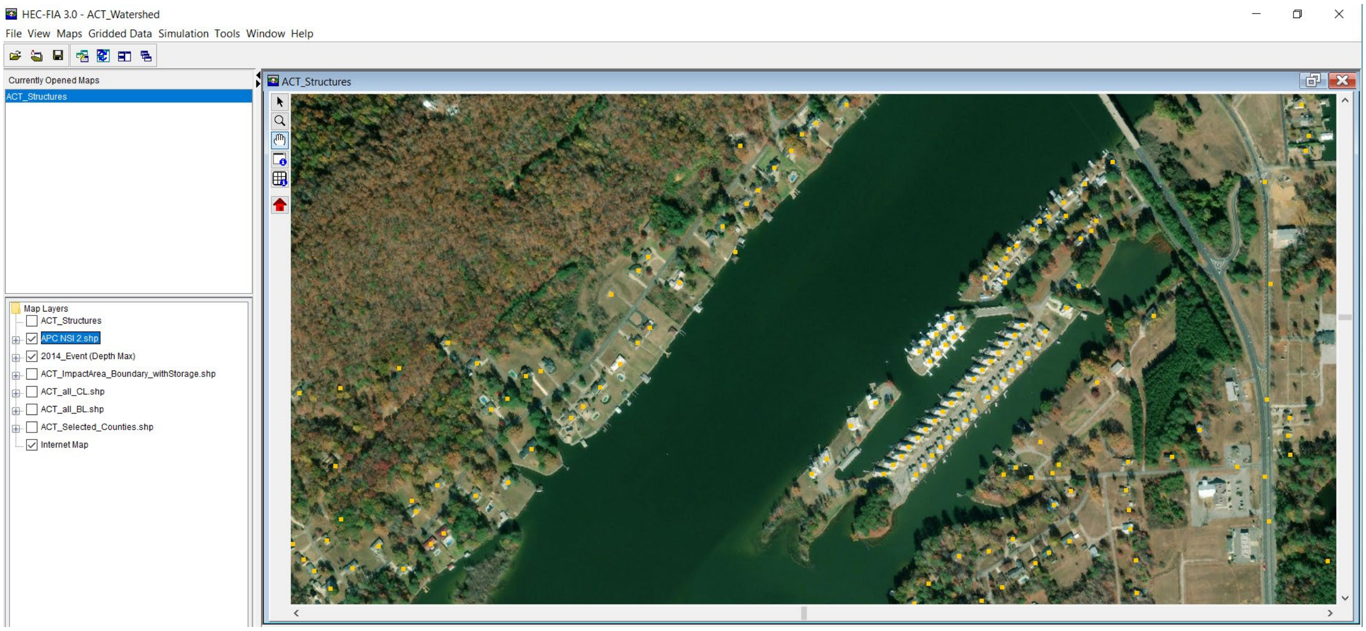
Depth (ft)	Percent (%)	Standard Deviation of Error
-2.00	0.00	0.00
-1.00	2.50	2.70
0.00	13.40	2.00
1.00	23.30	1.60
2.00	32.10	1.60
3.00	40.10	1.80
4.00	47.10	1.90
5.00	53.20	2.00
6.00	58.60	2.10
7.00	63.20	2.20
8.00	67.20	2.30
9.00	70.50	2.40
10.00	73.20	2.70
11.00	75.40	3.00
12.00	77.20	3.30
13.00	78.50	3.70
14.00	79.50	4.10
15.00	80.20	4.50
16.00	80.70	4.90

Figure D-1. Example of Depth Damage Function



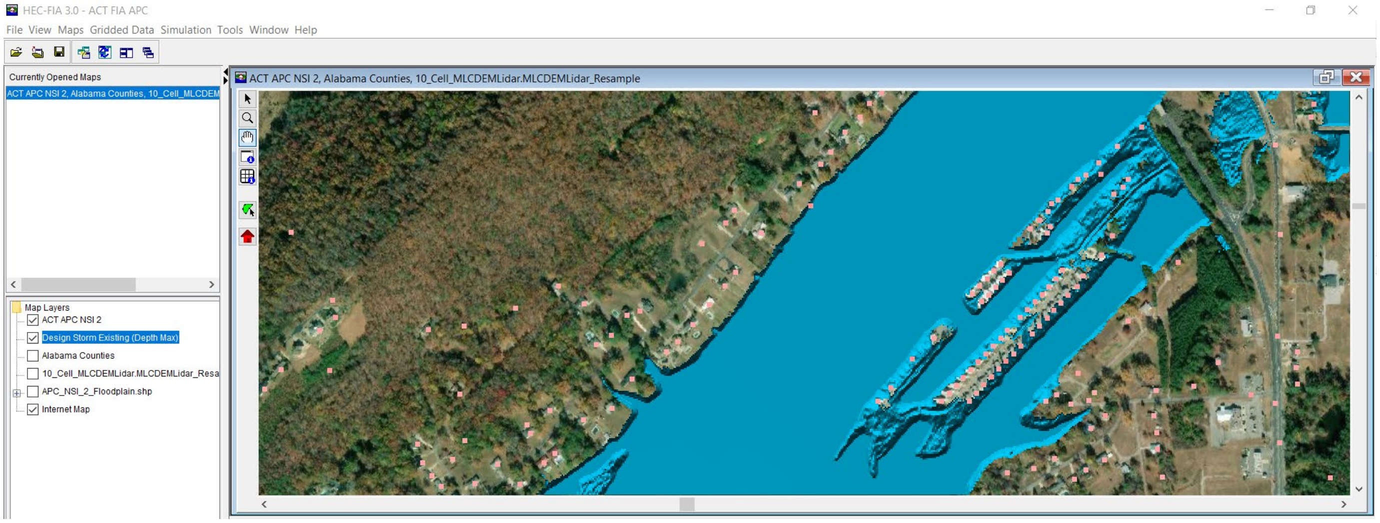
Map Layers
☑ ACT_Structures
☐ APC NSI 2.shp
☑ 2014_Event (Depth Max)
☐ ACT_ImpactArea_Boundary_withStorage.shp
☐ ACT_all_CL.shp
☐ ACT_all_BL.shp
☐ ACT_Selected_Counties.shp
☑ Internet Map

Figure D-2. NSI 1 Structure locations example near Rainbow City, AL



Map Layers
☐ ACT_Structures
☑ APC NSI 2.shp
☑ 2014_Event (Depth Max)
☐ ACT_ImpactArea_Boundary_withStorage.shp
☐ ACT_all_CL.shp
☐ ACT_all_BL.shp
☐ ACT_Selected_Counties.shp
☑ Internet Map

Figure D-3. NSI 2 Structure locations example near Rainbow City, AL



Map Layers
☑ ACT APC NSI 2
☑ Design Storm Existing (Depth Max)
☐ Alabama Counties
☐ 10_Cell_MLCDEMLidar.MLCDEMLidar_Resa
☐ APC_NSI_2_Floodplain.shp
☑ Internet Map

Figure D-4. NSI 2 Structure locations example near Rainbow City, AL with Existing Condition Design Storm Inundation

With all required data inputs, the HEC-FIA model then shows the depth of flooding and reported damages at each individual structure for a specific flood event. The results are then compared to show any flood impact increases or decreases across the modeled scenarios.

D.8.1.2 Assumptions

Assumptions for the HEC-FIA model development for this study include:

- Floodplain residents react to a floodplain management plan in a rational manner.
- Real property continues to be repaired to pre-flood conditions subsequent to each flood event.
- The NSI 2 is an accurate representation of the structure value and content.
- The depth damage functions developed by the FEMA Hazus program are applicable to structures within the floodplain.
- All values are equivalent to FY’21 dollars.
- Any new property development will occur outside of the modeled flood areas.
- The proposed operational changes are the only changes incorporated at each individual project over the analysis period.
- The inundation scenarios and data provided by APC and H&H accurately represent the extent and depth of flooding on the ground.

D.8.1.3 Risk and Uncertainty Factors

Risk and uncertainty are inherent in water resources planning and analysis. These factors arise due to errors in measurement and from the innate variability of complex physical, social, and economic situations. The measured or estimated values of key planning and design variables are rarely known with certainty and can take on a range of possible values. The model results depict the most accurate picture of the study area and the conditions which occur under the given scenarios. In order to further reduce uncertainty, additional time and resources would be needed that do not adhere to this study's mandated completion date.

D.8.2 Discussion of HEC-RAS Outputs

The HEC produces a suite of models and tools that USACE uses to conduct analysis. Many of these models have output data that feeds directly into another HEC model which requires a very specific data structure. The HEC-FIA model uses data produced by the HEC-HAS model to conduct a flood impacts analysis. Further information regarding the HEC-RAS model is discussed in Attachment 1 of Appendix C.

D.8.3 Event Selection and Descriptions

D.8.3.1 Allatoona Events

The USACE H&H branch provided HEC-RAS inputs for the Allatoona section analysis. A total of 3 Historical storms with 5 associated frequency based events each were analyzed to show any potential differences between the base operations of the Allatoona project and the operations due to the proposed reallocation from the conservation and flood control pools. These inputs translate to a total of 30 modeled flood scenarios, which include a base and proposed condition for 15 storm events. Table D-16 displays the events with the associated frequencies. Additional information concerning the methodology and descriptions of the modeled events is found in Attachment 1 of Appendix C.

Table D-16. Flood Frequencies for Allatoona Project Modeled Scenarios

Dam/Event	1961	1979	1990
Allatoona Base	0.20%	0.20%	0.20%
Allatoona Base	0.50%	0.50%	0.50%
Allatoona Base	1.00%	1.00%	1.00%
Allatoona Base	2.00%	2.00%	2.00%
Allatoona Base	5.00%	5.00%	5.00%
Allatoona Proposed	0.20%	0.20%	0.20%
Allatoona Proposed	0.50%	0.50%	0.50%
Allatoona Proposed	1.00%	1.00%	1.00%
Allatoona Proposed	2.00%	2.00%	2.00%
Allatoona Proposed	5.00%	5.00%	5.00%

D.8.3.2 APC Events

The USACE H&H branch provided HEC-FIA inputs for the APC Projects section analysis. A total of 5 Historical storms and 2 designed storms were analyzed to show any potential differences between the base operations of the APC projects and the operations due to the proposed change in operations. These inputs translate to a total of 14 modeled flood scenarios; a base and proposed condition for 7 storm events. Table D-17 describes the modeled flood scenarios. Additional information concerning the methodology and descriptions of the modeled events is found in Attachment 1 of Appendix C.

Table D-17. APC Projects Modeled Scenarios

Dam/City	Apr-79	Feb-90	Design Flood	Oct-95	May-03
Jordan	250-yr < X < 500-yr	25-yr	Unregulated 100-yr	5-yr	5-yr
Mitchell	250-yr < X < 500-yr	25-yr	Unregulated 100-yr	5-yr	8-yr
Childersburg, AL		33-yr		5-yr	16-yr
Lay	250-yr	33-yr	Unregulated 100-yr	5-yr	13-yr
Logan Martin	250-yr	25-yr < X < 50-yr	Unregulated 100-yr		20-yr
Gadsden, AL		90-yr		5-yr	10-yr
Henry	100-yr < X < 250-yr	75-yr	Unregulated 100-yr	5-yr	15-yr
Weiss	50-yr	100-yr	Unregulated 100-yr	5-yr	8-yr

D.8.4 Summary of Results

For organizational purposes, the watershed was separated into 2 individual areas, each with its own complete HEC-FIA model and analysis. The first modeled area was for the Allatoona portion of the study and contains the areas from Rome, GA upstream along the Oostanaula River to the Carters Reservoir and areas along the Etowah River to Allatoona Lake. The second modeled area was for the APC projects and follows the Coosa River from Weiss Lake in Cherokee County, AL to Lake Jordan in Elmore County, AL. Estimated FRM impacts for each are discussed below. Overall, under the proposed conditions, an acceptable level of flood risk is maintained, and the areas that may have never developed under an unregulated Oostanaula, Etowah, or Coosa river continue to receive flood risk management (FRM) benefits provided by the USACE project at Allatoona and the APC projects along the Coosa River. Any increases in water surface elevations seen downstream are in fractions of a foot and, except for in events above the 1.0% annual chance exceedance (ACE), do not appear to expand the extent of flooding to previously unaffected structures beyond marginal amounts. Additional information regarding the changes to impacts downstream of Allatoona Lake can be found in section D.8.4.2.

D.8.4.1 Analysis of Allatoona

D.8.4.1.1 Proposed Changes to Water Supply Storage at Allatoona Lake

For detailed information regarding the proposed changes to water supply storage at Allatoona Lake, refer to Section 2.4 of the Main Report. In summary, the State of Georgia has requested that USACE enter into a storage contract to provide sufficient storage to sustain annual average withdrawals of 94 mgd in the year 2050. This section of the Economic Appendix provides analysis of the downstream impacts of the proposed reallocations to Allatoona Lake flood pool incorporated into study alternatives All permutations of alternatives with a flood pool reallocation would reduce the flood pool by the same amount.

D.8.4.1.2 Allatoona Flood Impact Analysis

From a total impacts perspective, the modeled events/frequencies that impacted the largest number of structures was the Base and Proposed 1979 0.2% ACE scenario (500 year event). These scenarios produced impacts to 509 structures at base conditions, and 514 structures at proposed conditions along the Etowah, Oostanaula, and Coosa Rivers. The majority of impacts occur in Rome, GA within Floyd County. Details of impacts are found in the following figures and descriptions.

Table D-18. Allatoona Project Summary of Impacts

Impacts								
Base				Proposed				
Storm	Frequency	Structures Impacted		Storm	Frequency	Structures Impacted		% Change from Base
1961	0.002	418		1961	0.002	418		0.00%
1961	0.005	350		1961	0.005	350		0.00%
1961	0.01	315		1961	0.01	315		0.00%
1961	0.02	271		1961	0.02	271		0.00%
1961	0.05	87		1961	0.05	87		0.00%
1979	0.002	509		1979	0.002	514		0.97%
1979	0.005	362		1979	0.005	369		1.90%

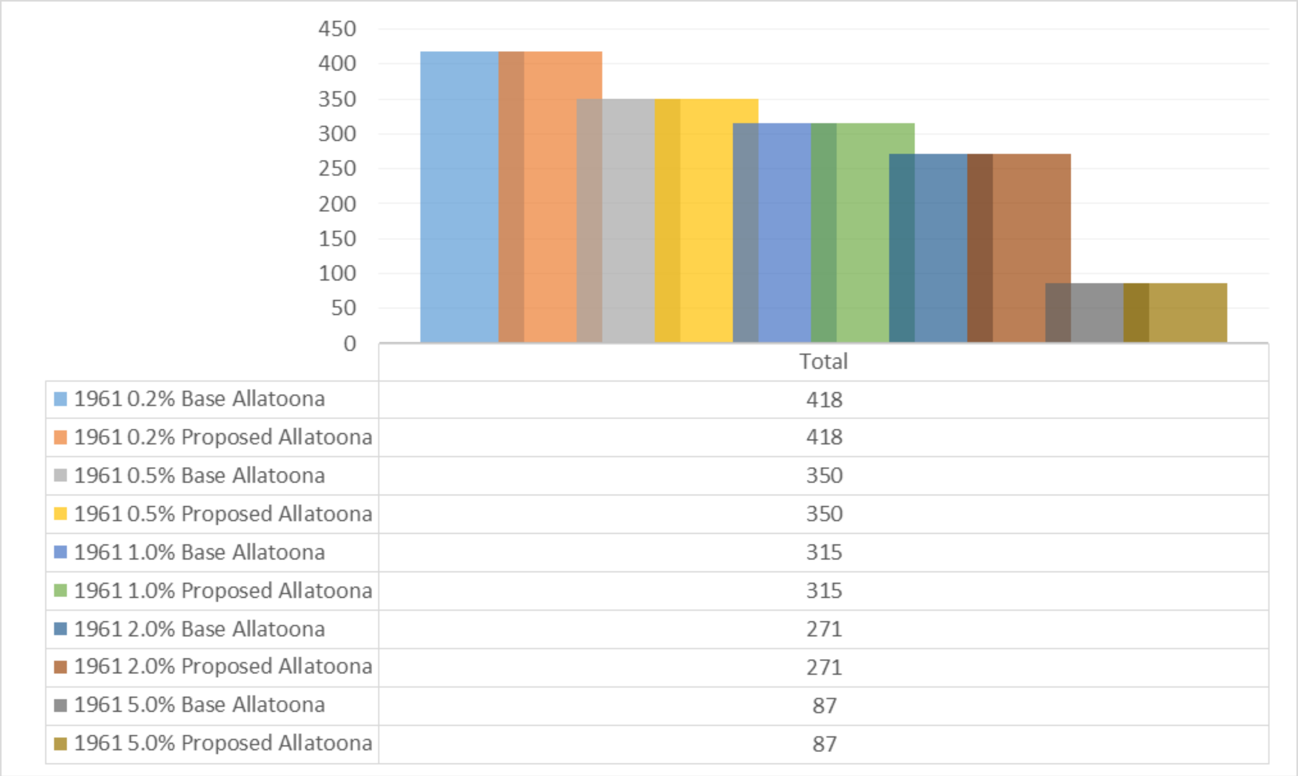
Impacts								
1979	0.01	251		1979	0.01	251		0.00%
1979	0.02	184		1979	0.02	184		0.00%
1979	0.05	159		1979	0.05	159		0.00%
1990	0.002	328		1990	0.002	328		0.00%
1990	0.005	263		1990	0.005	263		0.00%
1990	0.01	203		1990	0.01	203		0.00%
1990	0.02	177		1990	0.02	177		0.00%
1990	0.05	158		1990	0.05	158		0.00%

Table D-19. Allatoona Project Summary of Damages ($)

Damages								
Base				Proposed				
Storm	Frequency	Structure Damages		Storm	Frequency	Structure Damages		% Change from Base
1961	0.002	$184,263,968		1961	0.002	$184,337,425		0.04%
1961	0.005	$149,342,255		1961	0.005	$149,395,790		0.04%
1961	0.01	$136,706,588		1961	0.01	$136,706,431		0.00%
1961	0.02	$122,477,595		1961	0.02	$122,514,216		0.03%
1961	0.05	$15,005,491		1961	0.05	$15,089,047		0.55%
1979	0.002	$186,086,367		1979	0.002	$186,086,367		0.00%
1979	0.005	$134,210,201		1979	0.005	$134,210,201		0.00%
1979	0.01	$109,473,795		1979	0.01	$109,472,927		0.00%
1979	0.02	$88,235,892		1979	0.02	$88,212,326		-0.03%
1979	0.05	$67,342,136		1979	0.05	$68,578,803		1.80%
1990	0.002	$135,416,987		1990	0.002	$135,432,160		0.01%
1990	0.005	$121,029,960		1990	0.005	$121,057,034		0.02%
1990	0.01	$106,969,300		1990	0.01	$106,996,607		0.03%
1990	0.02	$95,726,553		1990	0.02	$95,764,229		0.04%
1990	0.05	$76,237,342		1990	0.05	$76,491,145		0.33%

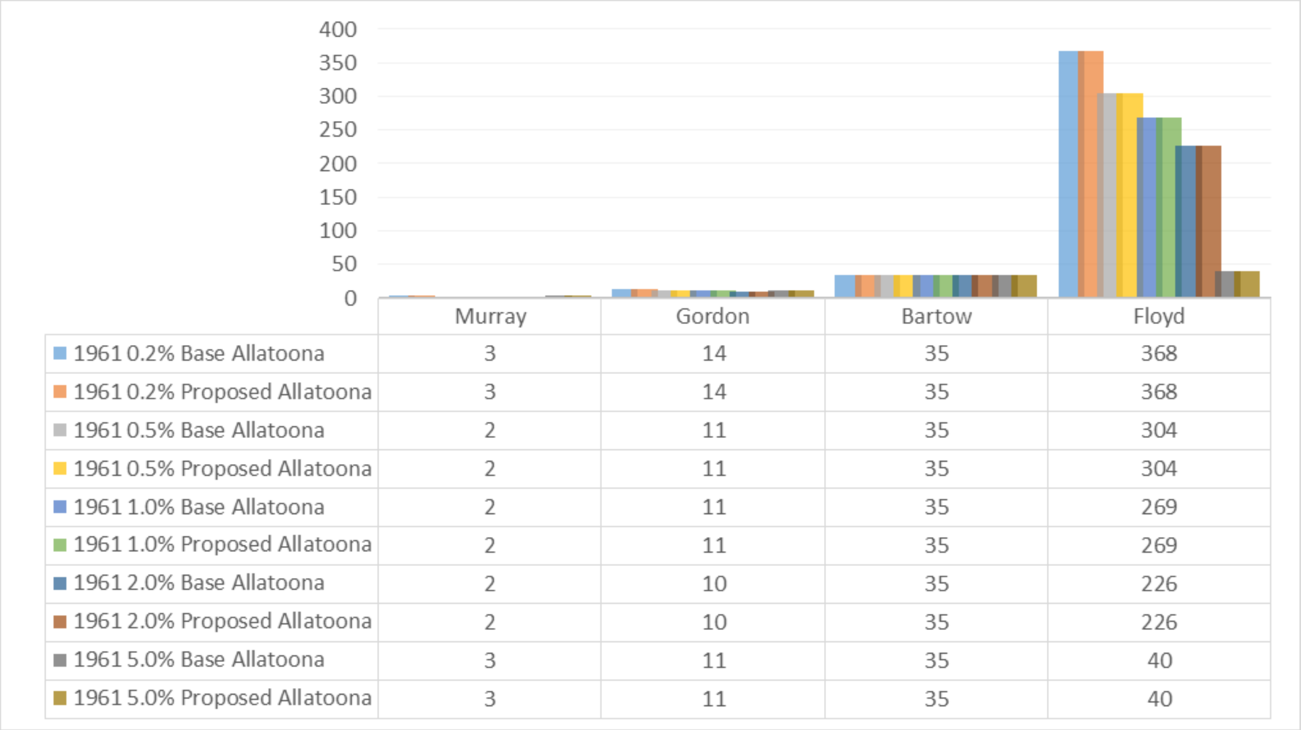
D.8.4.1.2.1 1961 Storm

Figure D-5 and Figure D-6 display the number of structures impacted downstream of Allatoona Lake under the base and proposed conditions for the 1961 Storm frequencies. This storm showed no additional impacts under the proposed condition.



	Total
■ 1961 0.2% Base Allatoona	418
■ 1961 0.2% Proposed Allatoona	418
■ 1961 0.5% Base Allatoona	350
■ 1961 0.5% Proposed Allatoona	350
■ 1961 1.0% Base Allatoona	315
■ 1961 1.0% Proposed Allatoona	315
■ 1961 2.0% Base Allatoona	271
■ 1961 2.0% Proposed Allatoona	271
■ 1961 5.0% Base Allatoona	87
■ 1961 5.0% Proposed Allatoona	87

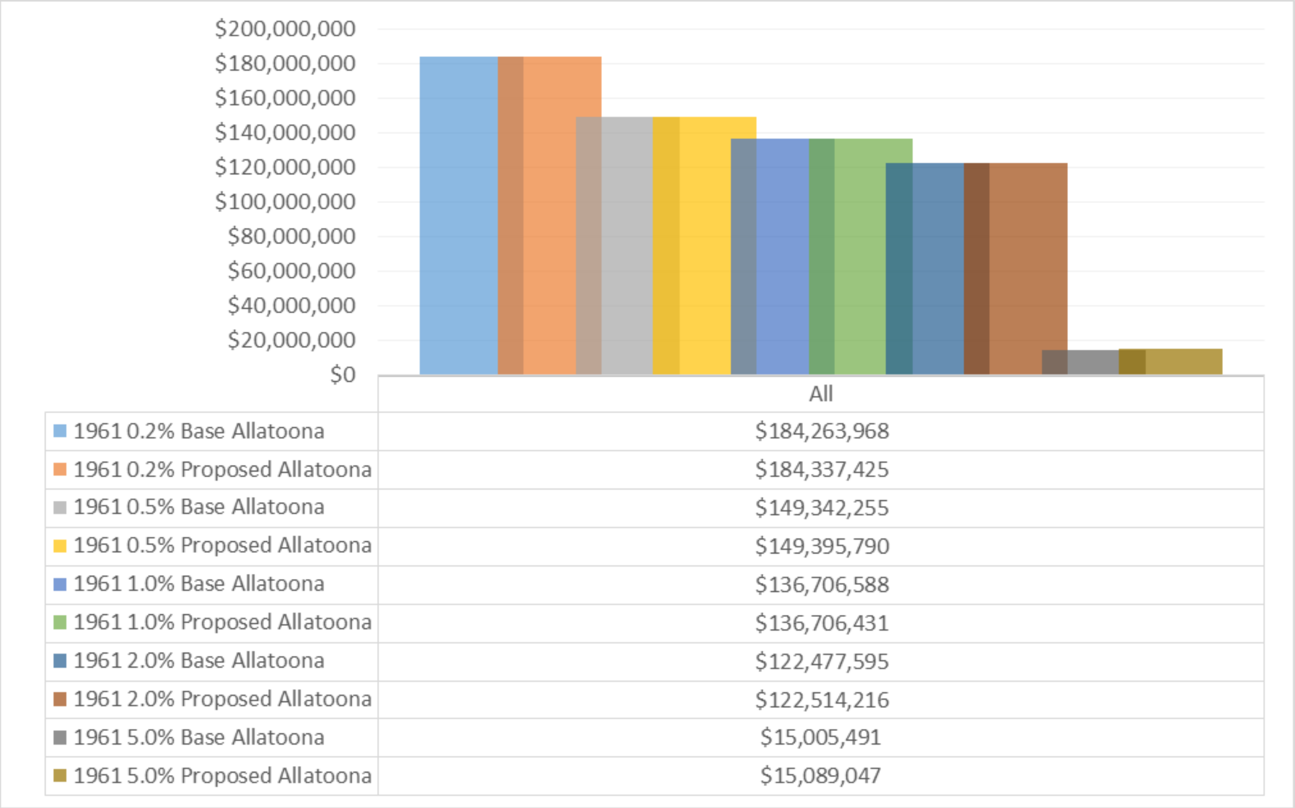
Figure D-5. 1961 Storm Allatoona Project Total of Downstream Structures Impacted (Count)



	Murray	Gordon	Bartow	Floyd
1961 0.2% Base Allatoona	3	14	35	368
1961 0.2% Proposed Allatoona	3	14	35	368
1961 0.5% Base Allatoona	2	11	35	304
1961 0.5% Proposed Allatoona	2	11	35	304
1961 1.0% Base Allatoona	2	11	35	269
1961 1.0% Proposed Allatoona	2	11	35	269
1961 2.0% Base Allatoona	2	10	35	226
1961 2.0% Proposed Allatoona	2	10	35	226
1961 5.0% Base Allatoona	3	11	35	40
1961 5.0% Proposed Allatoona	3	11	35	40

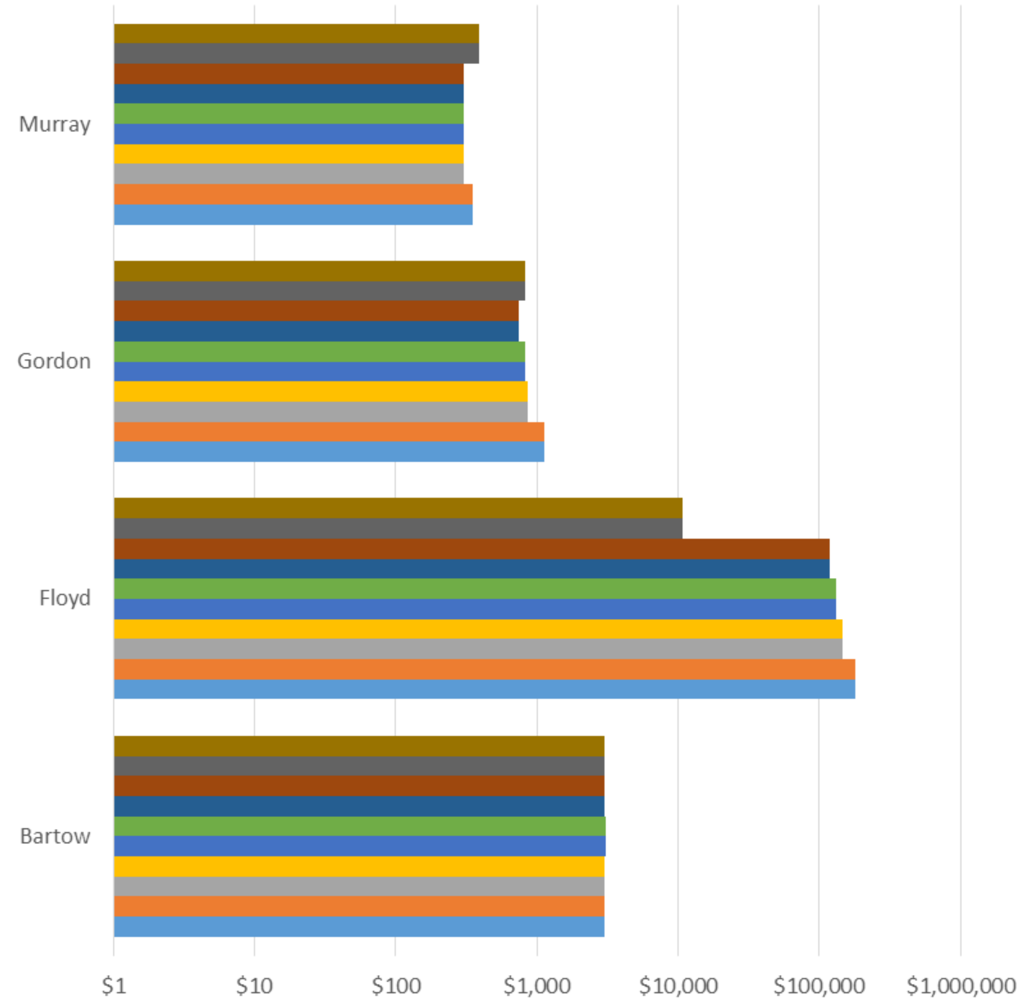
Figure D-6. 1961 Storm Allatoona Project Total of Downstream Structures Impacted by County (Count)

Figure D-7 and Figure D-8 display the amount of flood damages expected at each frequency of the 1961 modeled storm. Additional damages in the proposed events are less than a 1% increase from base conditions.



	All
■ 1961 0.2% Base Allatoona	$184,263,968
■ 1961 0.2% Proposed Allatoona	$184,337,425
■ 1961 0.5% Base Allatoona	$149,342,255
■ 1961 0.5% Proposed Allatoona	$149,395,790
■ 1961 1.0% Base Allatoona	$136,706,588
■ 1961 1.0% Proposed Allatoona	$136,706,431
■ 1961 2.0% Base Allatoona	$122,477,595
■ 1961 2.0% Proposed Allatoona	$122,514,216
■ 1961 5.0% Base Allatoona	$15,005,491
■ 1961 5.0% Proposed Allatoona	$15,089,047

Figure D-7. 1961 Storm Allatoona Project Total Downstream Flood Damages ($)



	Bartow	Floyd	Gordon	Murray
■ 1961 5.0% Proposed Allatoona	3031.315781	10848.69071	819.6661063	389.3721313
■ 1961 5.0% Base Allatoona	3030.044525	10766.42678	819.6556	389.3721313
■ 1961 2.0% Proposed Allatoona	3025.831519	118436.4099	748.4442375	303.5255625
■ 1961 2.0% Base Allatoona	3025.821013	118399.8167	748.423225	303.5255625
■ 1961 1.0% Proposed Allatoona	3052.8641	132518.336	831.716775	303.5255625
■ 1961 1.0% Base Allatoona	3052.8641	132518.4726	831.716775	303.5255625
■ 1961 0.5% Proposed Allatoona	3029.435163	145196.8583	866.0512	303.4415125
■ 1961 0.5% Base Allatoona	3029.130481	145143.6546	866.0301875	303.4415125
■ 1961 0.2% Proposed Allatoona	3032.797163	179817.9358	1137.490675	349.2067375
■ 1961 0.2% Base Allatoona	3032.765644	179744.5392	1137.459156	349.2067375

Figure D-8. 1961 Storm Allatoona Project Total Downstream Flood Damages by County ($1,000)

Table D-20. Allatoona Project 1961 Storm Base Average Annual Damages ($)

Base Condition Damages 1961					
Frequency (Year Storm)	***Frequency***	***Incremental Probability***	***Incremental Damage***	***Average Damage***	***Incremental Average Annual***
		0.002		$184,263,968	$368,528
500	0.002		$184,263,968		
		0.003		$166,803,111	$500,409
200	0.005		$149,342,255		
		0.005		$143,024,421	$715,122
100	0.010		$136,706,588		
		0.010		$129,592,091	$1,295,921
50	0.020		$122,477,595		
		0.030		$68,741,543	$2,062,246
20	0.050		$15,005,491		
		0.050		$7,502,745	$375,137
10	0.100		$ -		
Without Project Average Annual Damages					**$5,321,909**

Table D-20 displays the Average Annual Damages expected under the 1961 storm base conditions.

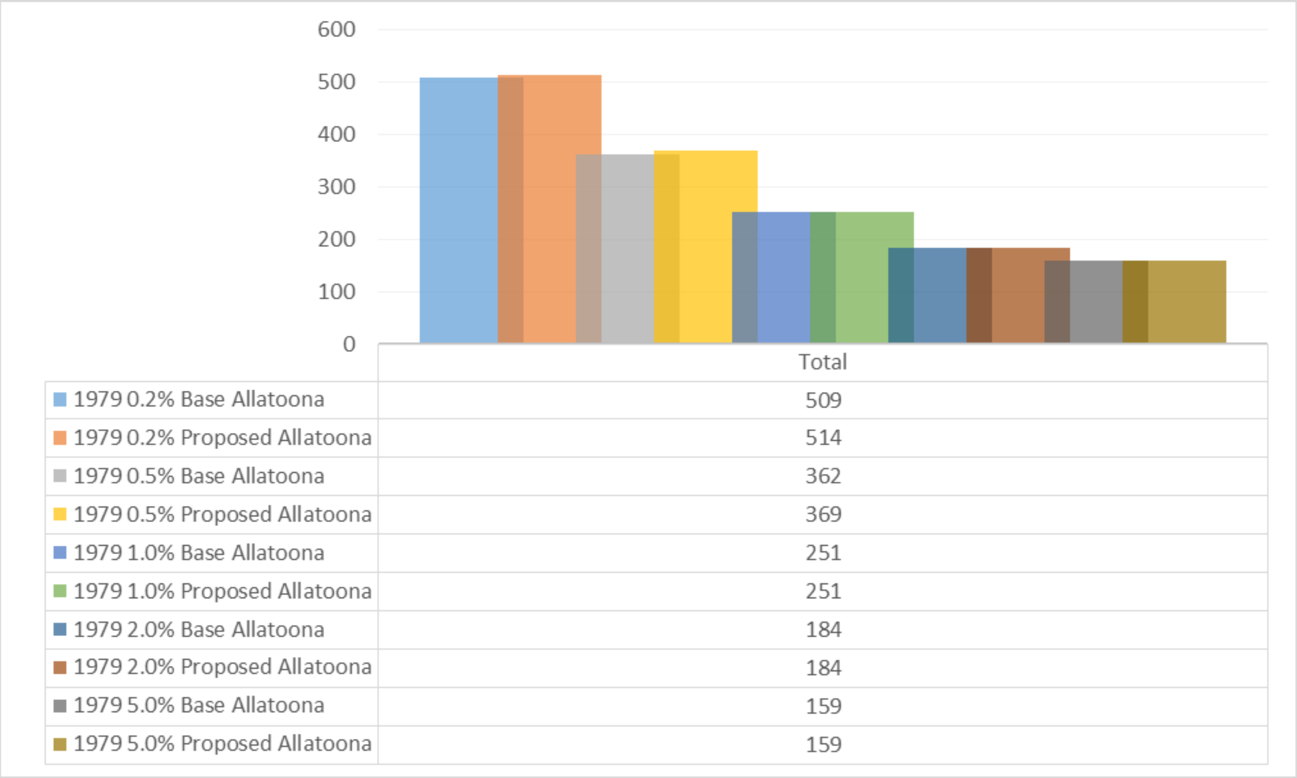
Table D-21 shows the 1961 storm proposed conditions average annual damages. The base conditions average annual damages are $5,317,364, and the proposed average annual damages are $5,321,909 with a difference of an additional $4,545 or 0.085% increase in damages under the proposed condition.

Table D-21. Allatoona Project 1961 Storm Proposed Average Annual Damages ($)

Proposed Condition Damages 1961					
Frequency (Year Storm)	***Frequency***	***Incremental Probability***	***Incremental Damage***	***Average Damage***	***Incremental Average Annual***
		0.002		$184,337,425	$368,675
500	0.002		$184,337,425		
		0.003		$166,866,607	$500,600
200	0.005		$149,395,790		
		0.005		$143,051,110	$715,256
100	0.010		$136,706,431		
		0.010		$129,610,323	$1,296,103
50	0.020		$122,514,216		
		0.030		$68,801,631	$2,064,049
20	0.050		$15,089,047		
		0.050		$7,544,523	$377,226
10	0.100				
With Project Average Annual Damages					**$ 5,321,909**
Damage Reductions					**$ (4,545)**

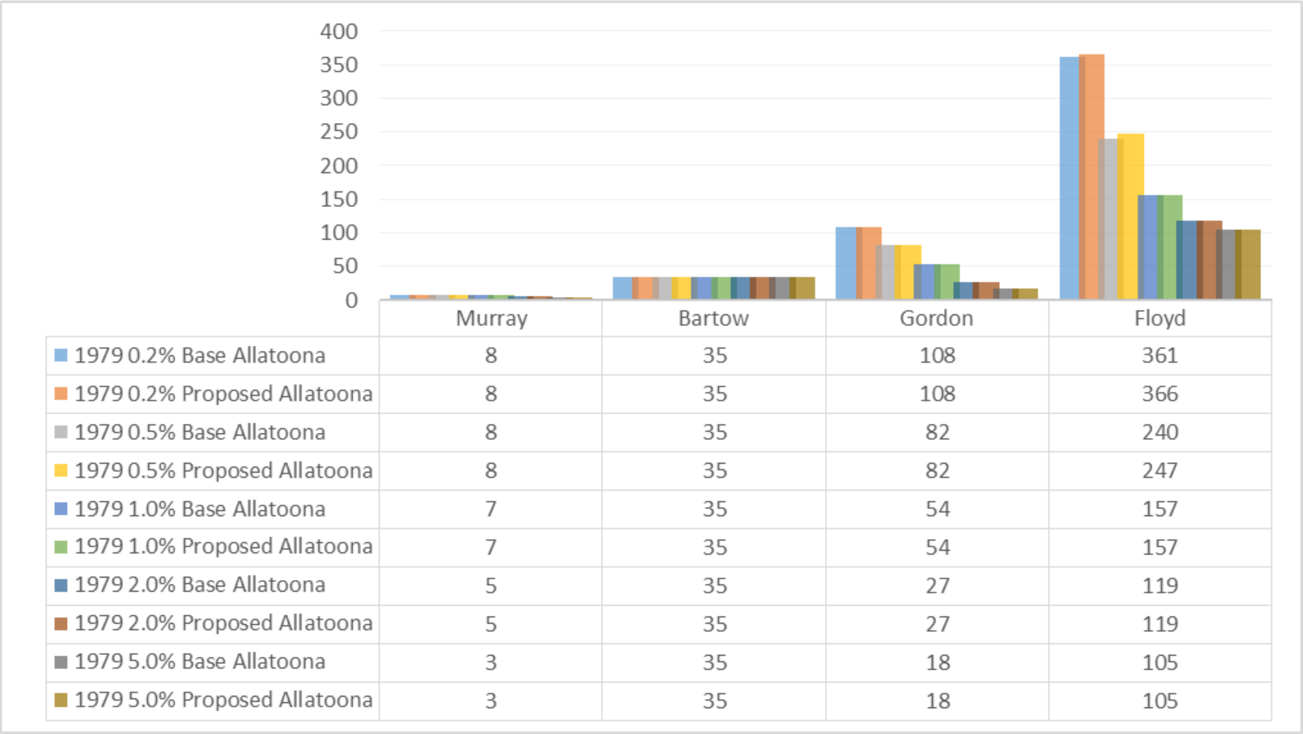
D.8.4.1.2.2 1979 Storm

Figure D-9 and Figure D-10 display the number of structures impacted downstream of Allatoona Lake under the base and proposed conditions for the 1979 Storm frequencies. The 0.5% ACE event showed an additional 7 structures impacted under the proposed condition and the 0.2% ACE event reported an additional 5 structures impacted under the proposed event. These increases represent a 1.90% increase at the 0.5% ACE and a 0.97% increase at the 0.2% ACE.



	Total
■ 1979 0.2% Base Allatoona	509
■ 1979 0.2% Proposed Allatoona	514
■ 1979 0.5% Base Allatoona	362
■ 1979 0.5% Proposed Allatoona	369
■ 1979 1.0% Base Allatoona	251
■ 1979 1.0% Proposed Allatoona	251
■ 1979 2.0% Base Allatoona	184
■ 1979 2.0% Proposed Allatoona	184
■ 1979 5.0% Base Allatoona	159
■ 1979 5.0% Proposed Allatoona	159

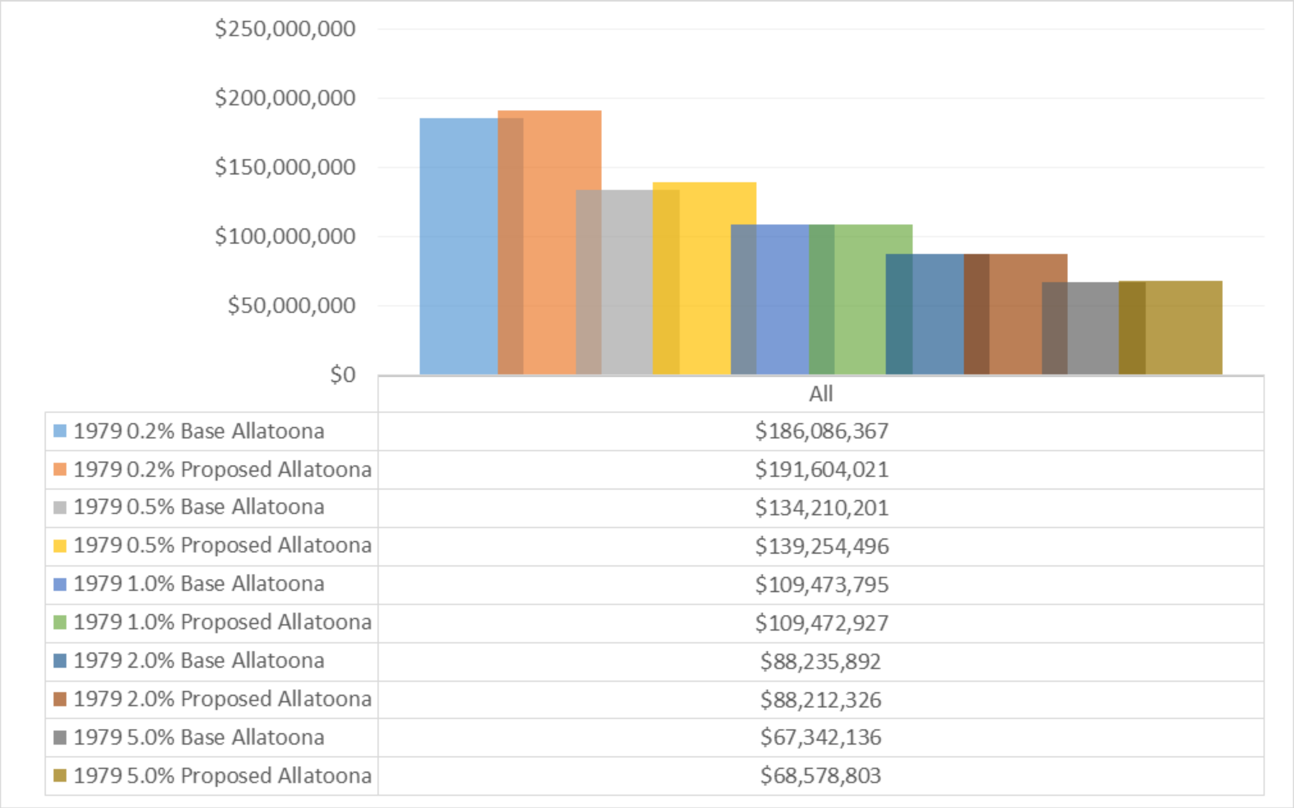
Figure D-9. 1979 Storm Allatoona Project Total of Downstream Structures Impacted (Count)



	Murray	Bartow	Gordon	Floyd
■ 1979 0.2% Base Allatoona	8	35	108	361
■ 1979 0.2% Proposed Allatoona	8	35	108	366
■ 1979 0.5% Base Allatoona	8	35	82	240
■ 1979 0.5% Proposed Allatoona	8	35	82	247
■ 1979 1.0% Base Allatoona	7	35	54	157
■ 1979 1.0% Proposed Allatoona	7	35	54	157
■ 1979 2.0% Base Allatoona	5	35	27	119
■ 1979 2.0% Proposed Allatoona	5	35	27	119
■ 1979 5.0% Base Allatoona	3	35	18	105
■ 1979 5.0% Proposed Allatoona	3	35	18	105

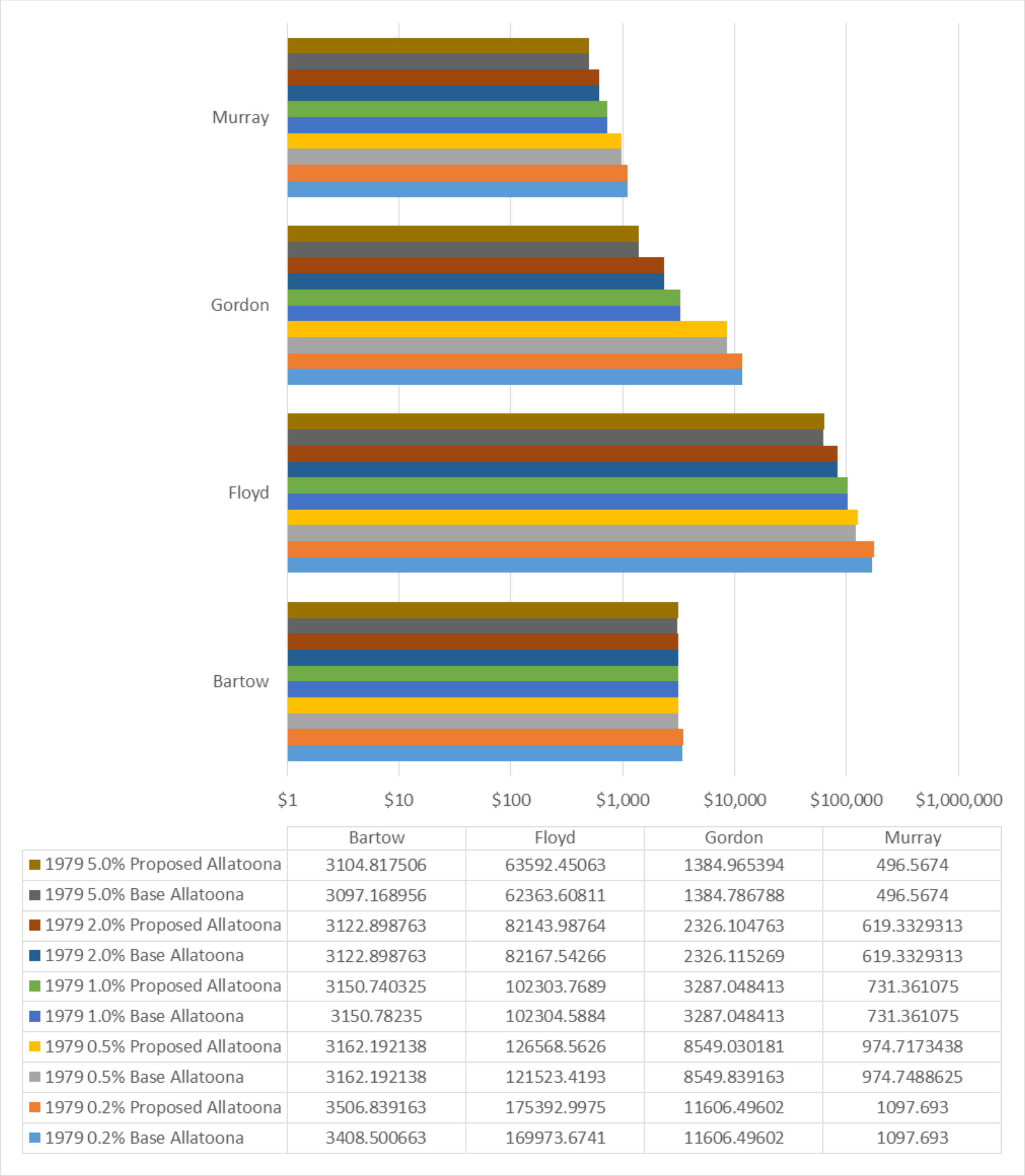
Figure D-10. 1979 Storm Allatoona Project Total of Downstream Structures Impacted by County (Count)

Figure D-11 and Figure D-12 display the amount of flood damages expected at each frequency of the 1979 modeled storm. All additional damages in the proposed events are less than a 4% increase from base conditions.



	All
1979 0.2% Base Allatoona	$186,086,367
1979 0.2% Proposed Allatoona	$191,604,021
1979 0.5% Base Allatoona	$134,210,201
1979 0.5% Proposed Allatoona	$139,254,496
1979 1.0% Base Allatoona	$109,473,795
1979 1.0% Proposed Allatoona	$109,472,927
1979 2.0% Base Allatoona	$88,235,892
1979 2.0% Proposed Allatoona	$88,212,326
1979 5.0% Base Allatoona	$67,342,136
1979 5.0% Proposed Allatoona	$68,578,803

Figure D-11. 1979 Storm Allatoona Project Total Downstream Flood Damages ($)



	Bartow	Floyd	Gordon	Murray
■ 1979 5.0% Proposed Allatoona	3104.817506	63592.45063	1384.965394	496.5674
■ 1979 5.0% Base Allatoona	3097.168956	62363.60811	1384.786788	496.5674
■ 1979 2.0% Proposed Allatoona	3122.898763	82143.98764	2326.104763	619.3329313
■ 1979 2.0% Base Allatoona	3122.898763	82167.54266	2326.115269	619.3329313
■ 1979 1.0% Proposed Allatoona	3150.740325	102303.7689	3287.048413	731.361075
■ 1979 1.0% Base Allatoona	3150.78235	102304.5884	3287.048413	731.361075
■ 1979 0.5% Proposed Allatoona	3162.192138	126568.5626	8549.030181	974.7173438
■ 1979 0.5% Base Allatoona	3162.192138	121523.4193	8549.839163	974.7488625
■ 1979 0.2% Proposed Allatoona	3506.839163	175392.9975	11606.49602	1097.693
■ 1979 0.2% Base Allatoona	3408.500663	169973.6741	11606.49602	1097.693

Figure D-12. 1979 Storm Allatoona Project Total Downstream Flood Damages by County ($1,000)

Table D-22 displays the Average Annual Damages expected under the base conditions of the 1979 storm.

Table D-22. Allatoona Project 1979 Storm Base Average Annual Damages ($)

Base Condition Damages 1979					
Frequency (Year Storm)	*1/Frequency*	*Incremental Probability*	*Incremental Damage*	*Average Damage*	*Incremental Average Annual*
		0.002		$186,086,367	$372,173
500	0.002		$186,086,367		
		0.003		$160,148,284	$480,445
200	0.005		$134,210,201		
		0.005		$121,841,998	$609,210
100	0.010		$109,473,795		
		0.010		$98,854,843	$988,548
50	0.020		$88,235,892		
		0.030		$77,789,014	$2,333,670
20	0.050		$67,342,136		
		0.050		$33,671,068	$1,683,553
10	0.100				
Without Project Average Annual Damages					**$6,467,600**

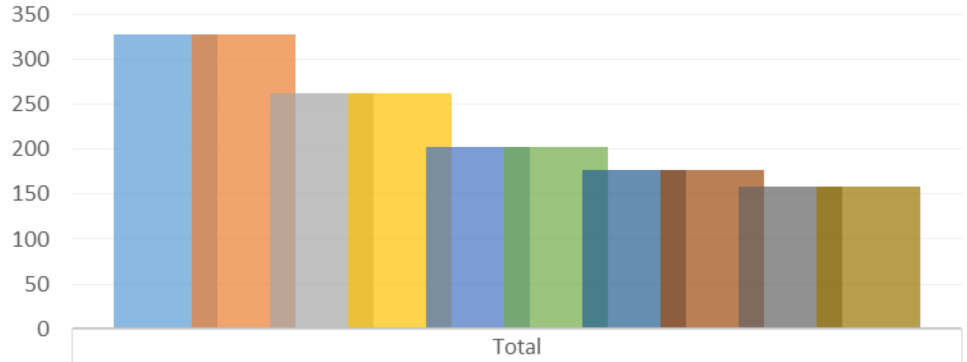
Table D-23 shows the 1979 storm proposed conditions average annual damages. The results reported the largest increase seen below Allatoona Lake. The base conditions average annual damages are $6,467,600, and the proposed average annual damages are $6,556,078 with a difference of an additional $88,478 or 1.35% increase in average annual damages under the proposed condition.

Table D-23. Allatoona Project 1979 Storm Proposed Average Annual Damages ($)

Proposed Condition Damages 1979					
Frequency (Year Storm)	***1/Frequency***	***Incremental Probability***	***Incremental Damage***	***Average Damage***	***Incremental Average Annual***
		0.002		$191,604,021	$383,208
500	0.002		$191,604,021		
		0.003		$165,429,258	$496,288
200	0.005		$139,254,496		
		0.005		$124,363,711	$621,819
100	0.010		$109,472,927		
		0.010		$98,842,627	$988,426
50	0.020		$88,212,326		
		0.030		$78,395,565	$2,351,867
20	0.050		$68,578,803		
		0.050		$34,289,402	$1,714,470
10	0.100				
				With Project Average Annual Damages	**$6,556,078**
				Damage Reductions	**$ (88,478)**

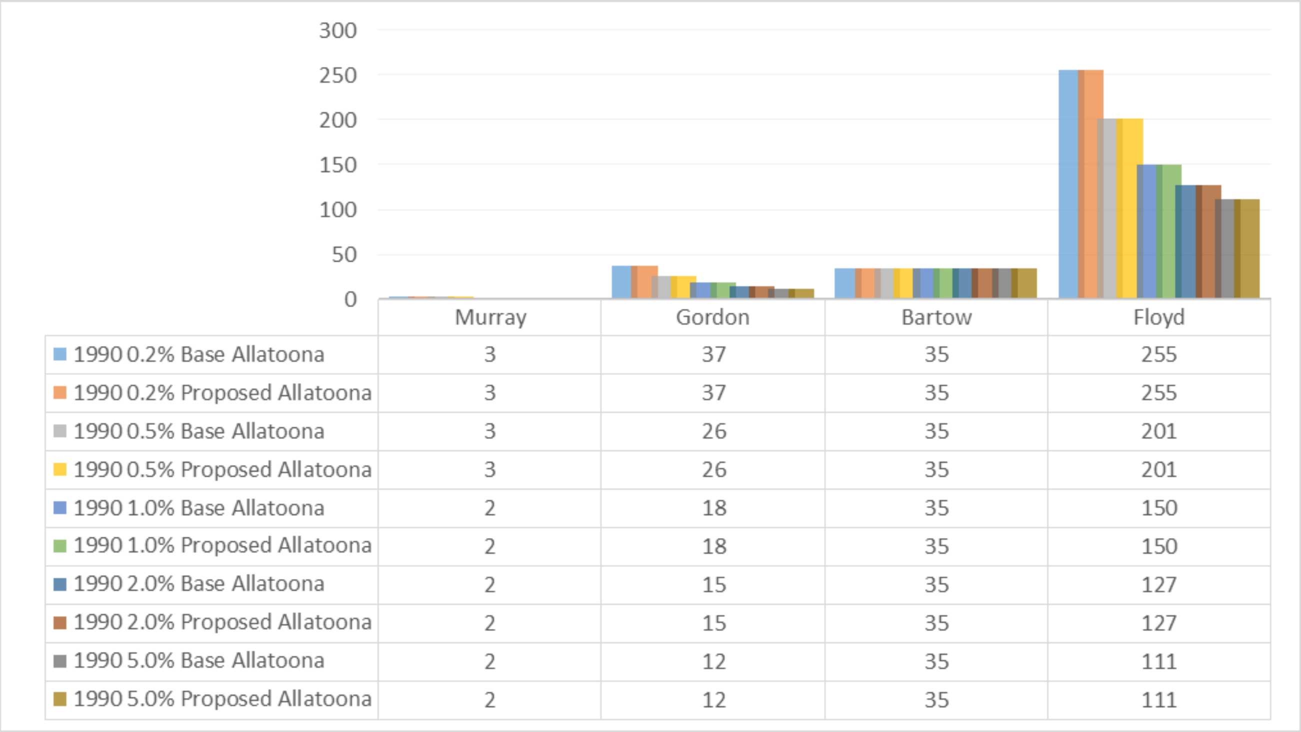
D.8.4.1.2.3 1990 Storm

Figure D-13 and Figure D-14 display the number of structures impacted downstream of Allatoona Lake under the base and proposed conditions for the 1990 Storm frequencies. This storm showed no additional impacts under the proposed condition.



	Total
🟦 1990 0.2% Base Allatoona	328
🟧 1990 0.2% Proposed Allatoona	328
⬜ 1990 0.5% Base Allatoona	263
🟨 1990 0.5% Proposed Allatoona	263
🟦 1990 1.0% Base Allatoona	203
🟩 1990 1.0% Proposed Allatoona	203
🟦 1990 2.0% Base Allatoona	177
🟫 1990 2.0% Proposed Allatoona	177
⬛ 1990 5.0% Base Allatoona	158
🟨 1990 5.0% Proposed Allatoona	158

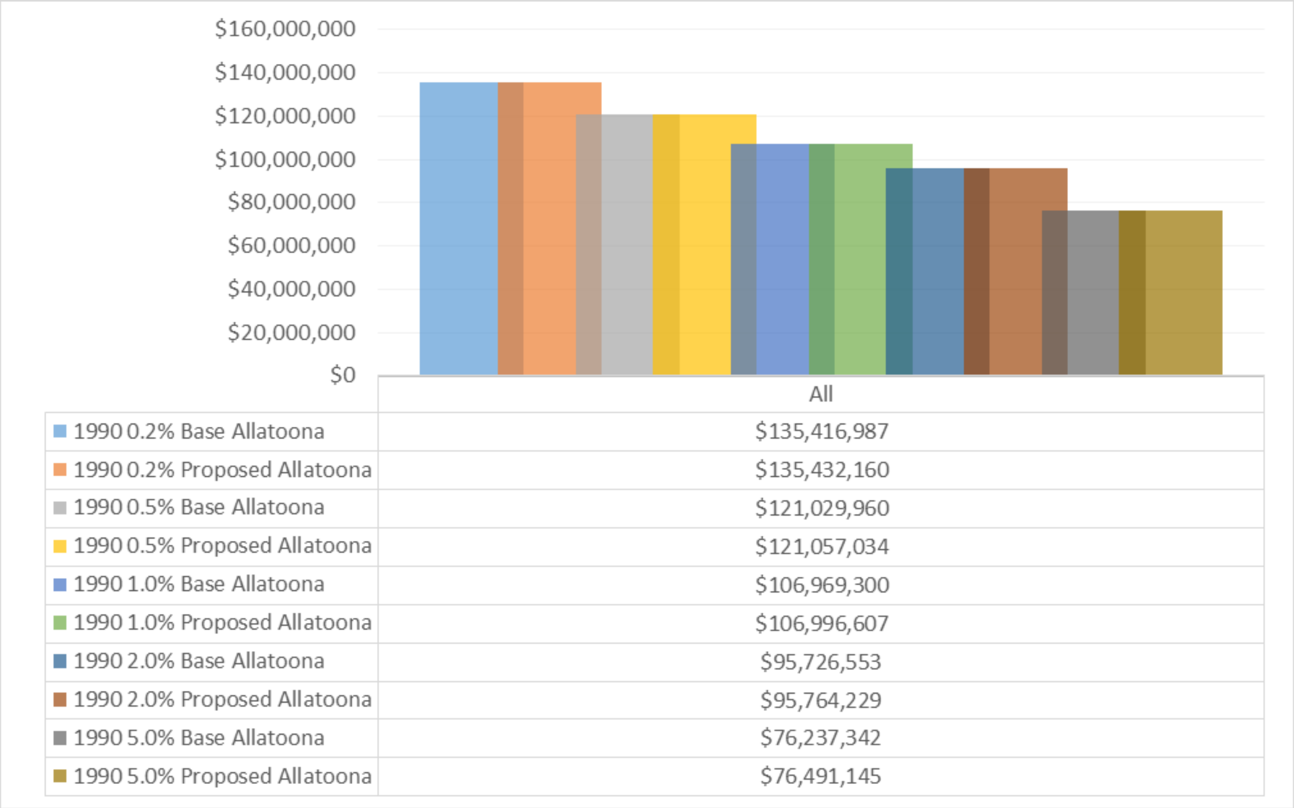
Figure D-13. 1990 Storm Allatoona Project Total of Downstream Structures Impacted (Count)



	Murray	Gordon	Bartow	Floyd
■ 1990 0.2% Base Allatoona	3	37	35	255
■ 1990 0.2% Proposed Allatoona	3	37	35	255
■ 1990 0.5% Base Allatoona	3	26	35	201
■ 1990 0.5% Proposed Allatoona	3	26	35	201
■ 1990 1.0% Base Allatoona	2	18	35	150
■ 1990 1.0% Proposed Allatoona	2	18	35	150
■ 1990 2.0% Base Allatoona	2	15	35	127
■ 1990 2.0% Proposed Allatoona	2	15	35	127
■ 1990 5.0% Base Allatoona	2	12	35	111
■ 1990 5.0% Proposed Allatoona	2	12	35	111

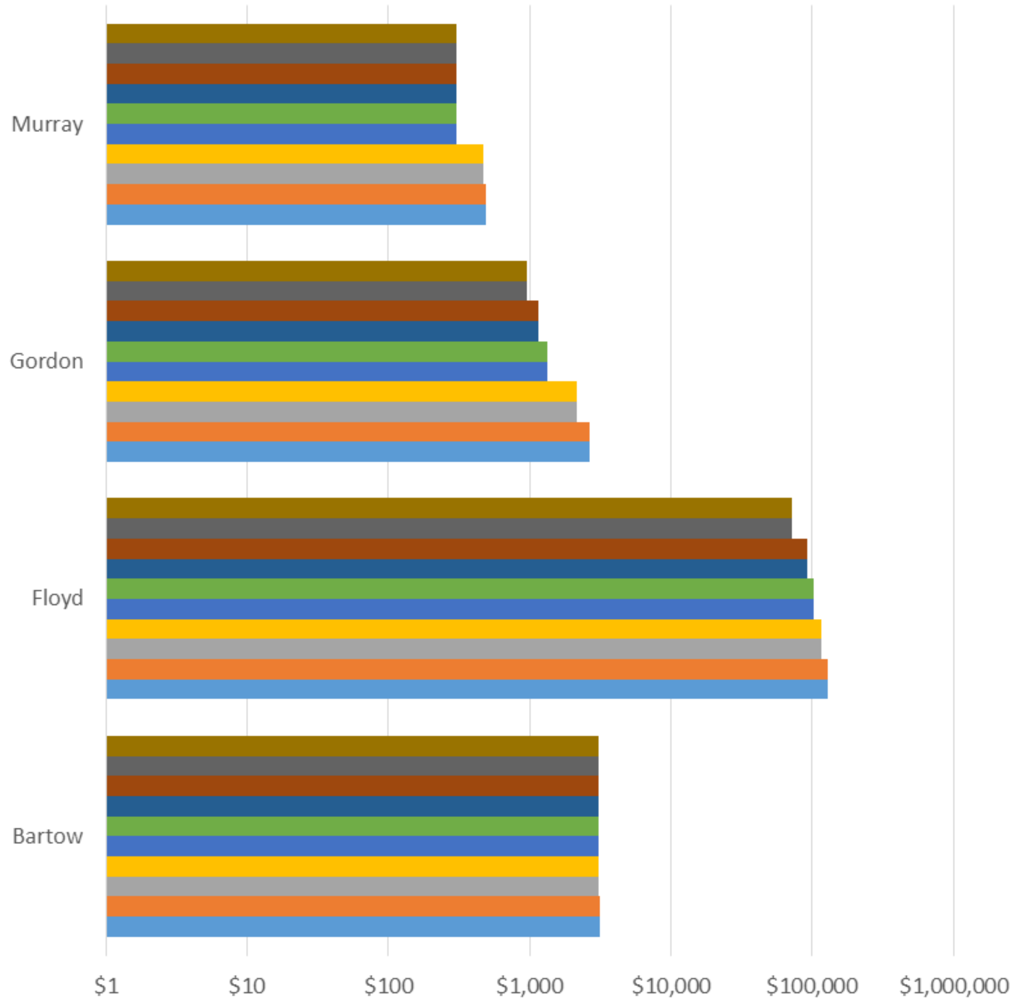
Figure D-14. 1990 Storm Allatoona Project Total of Downstream Structures Impacted by County (Count)

Figure D-15 and Figure D-16 display the amount of flood damages expected at each frequency of the 1990 modeled storm. All additional damages in the proposed events are less than a 1% increase from base conditions.



	All
1990 0.2% Base Allatoona	$135,416,987
1990 0.2% Proposed Allatoona	$135,432,160
1990 0.5% Base Allatoona	$121,029,960
1990 0.5% Proposed Allatoona	$121,057,034
1990 1.0% Base Allatoona	$106,969,300
1990 1.0% Proposed Allatoona	$106,996,607
1990 2.0% Base Allatoona	$95,726,553
1990 2.0% Proposed Allatoona	$95,764,229
1990 5.0% Base Allatoona	$76,237,342
1990 5.0% Proposed Allatoona	$76,491,145

Figure D-15. 1990 Storm Allatoona Project Total Downstream Flood Damages ($)



	Bartow	Floyd	Gordon	Murray
■ 1990 5.0% Proposed Allatoona	3059.398988	72165.70823	962.5406	303.4940438
■ 1990 5.0% Base Allatoona	3052.244231	71919.70438	961.8892125	303.4940438
■ 1990 2.0% Proposed Allatoona	3073.939638	91243.40874	1143.384681	303.4940438
■ 1990 2.0% Base Allatoona	3069.989288	91210.12494	1142.953925	303.4940438
■ 1990 1.0% Proposed Allatoona	3086.137394	102280.2139	1326.760769	303.4940438
■ 1990 1.0% Base Allatoona	3082.838431	102256.5013	1326.4771	303.4940438
■ 1990 0.5% Proposed Allatoona	3094.059106	115331.4138	2165.38015	466.183325
■ 1990 0.5% Base Allatoona	3091.5271	115306.8817	2165.369644	466.183325
■ 1990 0.2% Proposed Allatoona	3162.959094	129107.9127	2666.969538	494.3295688
■ 1990 0.2% Base Allatoona	3161.803406	129093.9079	2666.948525	494.3295688

Figure D-16. 1990 Storm Allatoona Project Total Downstream Flood Damages by County ($1,000)

Table D-24 displays the Average Annual Damages expected under the base conditions of the 1990 storm.

Table D-24. Allatoona Project 1990 Storm Base Average Annual Damages ($)

Base Condition Damages 1990					
Frequency (Year Storm)	1/Frequency	Incremental Probability	Incremental Damage	Average Damage	Incremental Average Annual
		0.002		$135,416,987	$270,834
500	0.002		$135,416,987		
		0.003		$128,237,011	$384,711
200	0.005		$121,057,034		
		0.005		$114,013,167	$570,066
100	0.010		$106,969,300		
		0.010		$101,347,926	$1,013,479
50	0.020		$95,726,553		
		0.030		$85,981,947	$2,579,458
20	0.050		$76,237,342		
		0.050		$38,118,671	$1,905,934
10	0.100				
				Without Project Average Annual Damages	**$ 6,724,482**

Table D-25 shows the 1990 storm proposed conditions average annual damages. The base conditions average annual damages are $6,724,482, and the proposed average annual damages are $6,735,646 with a difference of an additional $11,11,164 or 0.17% increase in average damages under the proposed condition.

Table D-25. Allatoona Project 1990 Storm Proposed Average Annual Damages ($)

Proposed Condition Damages 1990					
Frequency (Year Storm)	***1/Frequency***	***Incremental Probability***	***Incremental Damage***	***Average Damage***	***Incremental Average Annual***
		0.002		$135,432,160	$270,864
500	0.002		$135,432,160		
		0.003		$128,244,597	$384,734
200	0.005		$121,057,034		
		0.005		$114,026,821	$570,134
100	0.010		$106,996,607		
		0.010		$101,380,418	$1,013,804
50	0.020		$95,764,229		
		0.030		$86,127,687	$2,583,831
20	0.050		$76,491,145		
		0.050		$38,245,572	$1,912,279
10	0.100				
With Project Average Annual Damages					**$ 6,735,646**
Damage Reductions					**$ (11,164)**

D.8.4.2 Changes to Flood Risk Management

In all but 2 proposed scenarios, the total number of structures impacted was equal between the base case and with proposed reallocations from flood storage pools. The 2 scenarios in which very small increases occurred were at very low frequency flood events (0.2% chance exceedance and 0.5% chance exceedance) for the 1979 storm. In flood damages terms, the largest increase in flood damages under the proposed conditions cause an increase of 1.35% from the base average annual damages.

For the 1979 storm (0.2% chance exceedance) assuming reallocations , there were an additional 5 structures impacted in Floyd County, GA., of which 2 were residential along the Oostanaula River to the north of Rome, GA receiving -1.92 and -2.0 feet of flooding. Within the city of Rome, GA., one additional residential structure received -1.92 feet of flooding, and 2 commercial buildings received -0.95 and -0.94 feet of flooding. Negative depths of flooding result from flooding at the structure's foundation, below the elevation of the first finished floor. Using the assumption that residential structures are elevated 2 feet above the ground elevation and commercial structures are elevated 1 foot above the ground elevation, these results state that the structures are receiving less than 0.1 feet of flooding at the foundation. Details pertaining to the additional structures are found in Table D-26.

Table D-26. Allatoona Project 1979 Storm 0.2% Chance Exceedance Additional Structures

Structure Type	Foundation Height (FT)	Depth of Flooding (FT)	Notes
Residential	2.00	-2.00 (0.00)	Residential Structure near the Oostanaula River between Rome, GA and Carters Lake
Residential	2.00	-1.92 (+0.08)	Residential Structure in Rome, GA
Residential	2.00	-1.92 (+0.08)	Residential Structure near the Oostanaula River between Rome, GA and Carters Lake
Commercial	1.00	-0.95 (+0.05)	Commercial Structure in Rome, GA
Commercial	1.00	-0.94 (+0.06)	Commercial Structure in Rome, GA

Similarly, for the 1979 storm 0.5% chance exceedance proposed event there were and an additional 7 structures impacted in Floyd County. Details pertaining to these structures can be found in Table D-27.

Table D-27. Allatoona Project 1979 Storm 0.5% Chance Exceedance Additional Structures

Structure Type	Foundation Height (FT)	Depth of Flooding (FT)	Notes
Residential	2.00	-1.92 (+0.08)	Residential Structure in Rome, GA
Residential	2.00	-1.98 (+0.02)	Residential Structure in Rome, GA
Residential	2.00	-1.86 (+0.14)	Residential Structure in Rome, GA
Residential	2.00	-1.85 (+0.15)	Residential Structure in Rome, GA
Commercial	1.00	-0.78 (+0.22)	Commercial Structure in Rome, GA
Commercial	1.00	-0.73 (+0.27)	Commercial Structure in Rome, GA
Commercial	1.00	-0.99 (+0.01)	Commercial Structure in Rome, GA

D.8.5 Analysis of APC Projects

D.8.5.1 Proposed Changes to APC Projects

For detailed descriptions of the proposed reallocations to the APC projects, refer to section 2.6 of the main report. In summary, APC proposes revisions to flood operation plans for the Weiss and Logan Martin projects. At Weiss Lake and Dam the proposed changes include a 30% reduction in the flood storage during winter and a 24% reduction in flood storage during summer. At Logan Martin Dam and Lake the proposed changes include a 35% reduction in flood storage during the winter months as well as a 35% reduction in the summer months. To account for the reduction in flood storage, APC proposes to modify the current Flood Regulation Schedules for Weiss and Logan Martin Dams.

D.8.5.2 Model Results

Model results show that there is an overall decrease in flood impacts under the proposed operations of the Logan Martin and Weiss APC Projects. Flooding occurs in some areas; however, these increases in flooding extent are mostly in uninhabited rural areas directly downstream of the projects.

Table D-28. APC Projects Summary of Impacts

Impacts			
Storm	Existing	Proposed	% Change from Existing
	Structures Impacted		
Design	1,142	847	-25.83%
Back to Back	495	419	-15.35%
April 1979	796	757	-4.90%
February 1990	1,008	445	-55.85%
March 1990	457	424	-7.22%
May 2003	361	316	-12.47%
October 1995	393	383	-2.54%

Table D-29. APC Projects Summary of Damages ($)

Damages			
Storm	Existing	Proposed	% Change from Existing
	Structure Damages		
Design	$49,734,218	$36,507,766	-26.59%
Back to Back	$23,305,895	$19,334,049	-17.04%
April-79	$38,717,563	$36,724,324	-5.15%
February-90	$42,421,189	$17,989,152	-57.59%
March-90	$18,748,315	$17,740,564	-5.38%
May-03	$15,971,455	$13,079,966	-18.10%
October-95	$12,939,940	$15,370,944	18.79%

D.8.5.2.1 APC Projects Impacts Analysis

Across the basin, counties that benefited the most from the proposed operations are Etowah (Gadsden), Talladega (Childersburg), and St. Clair (Pell City, Ragland, Riverside).

D.8.5.2.1.1 Design Storm

Figure D-17 and Figure D-18 display the number of structures impacted along the Coosa River under the base and proposed conditions for the Design Storm scenario. This storm showed a net reduction of structures impacted under the proposed condition.

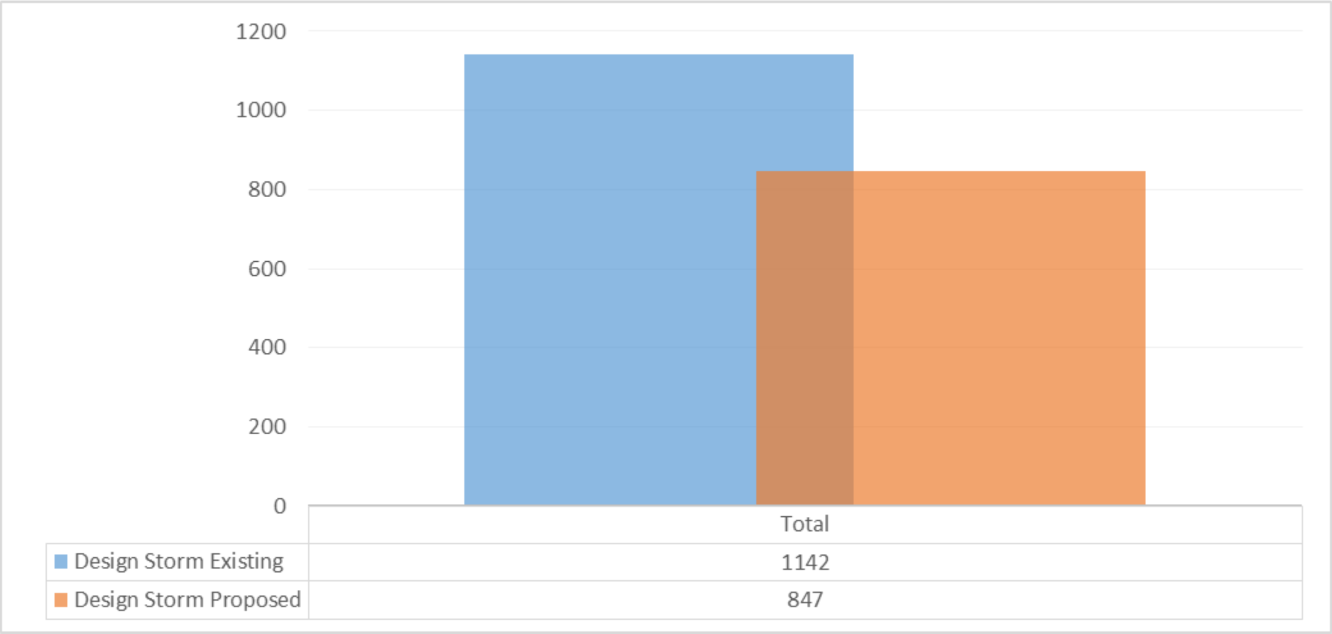
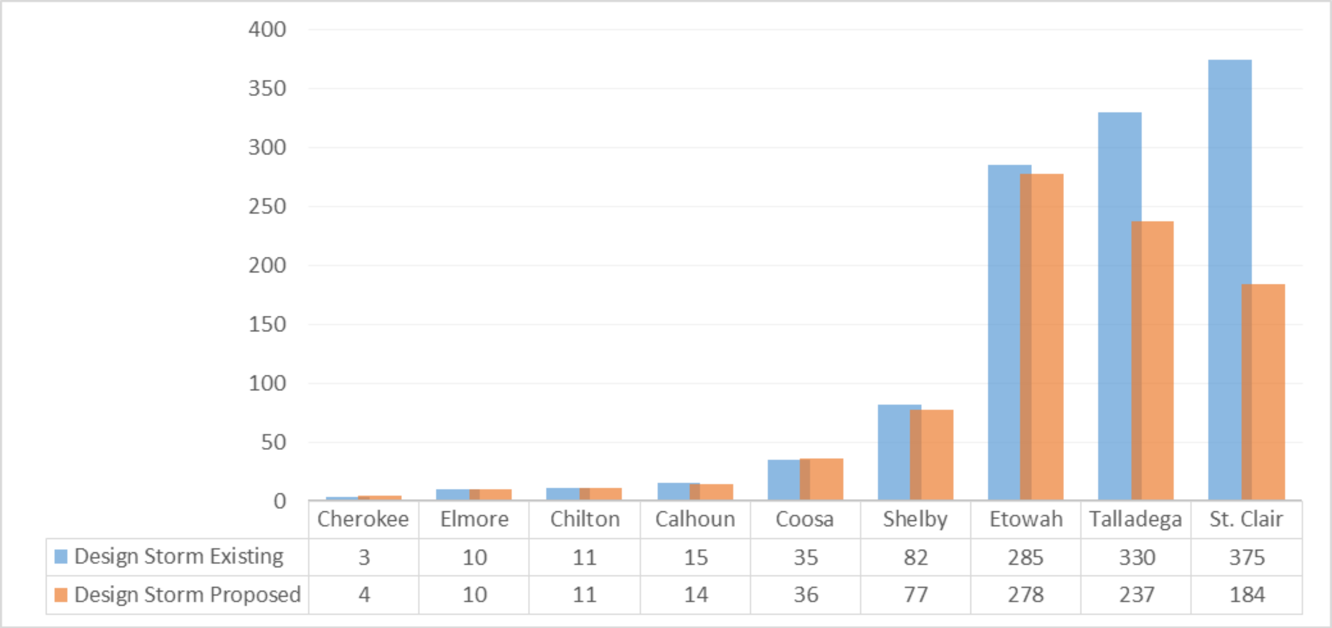


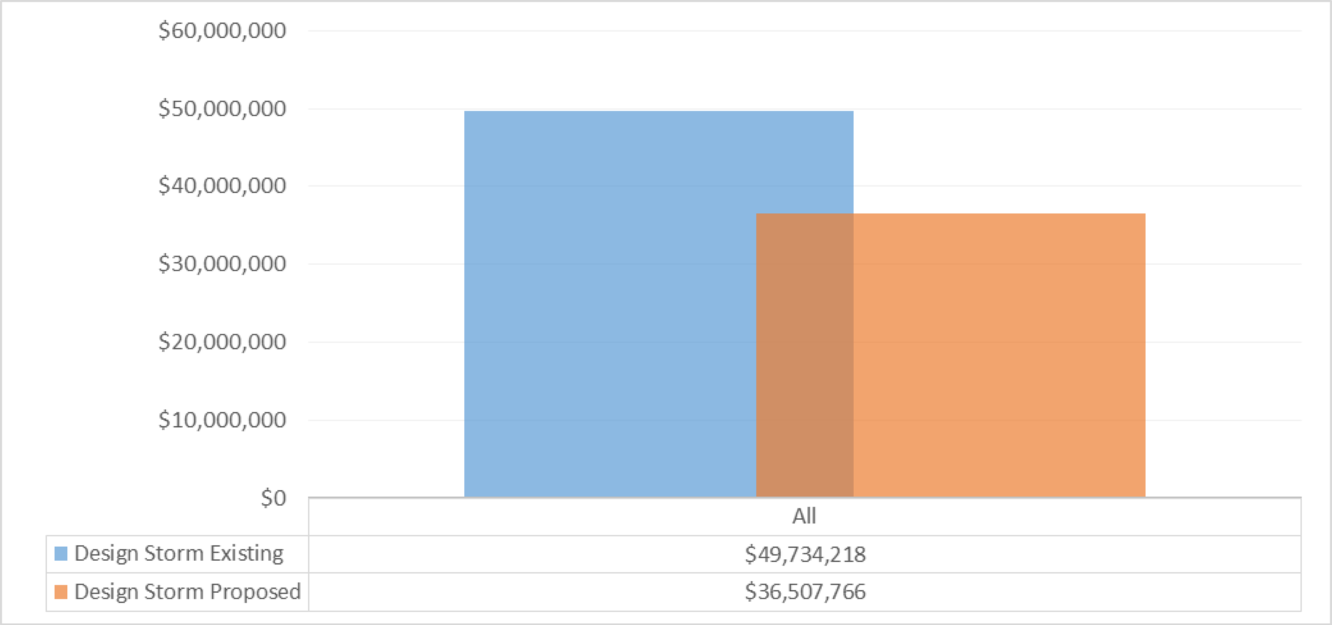
Figure D-17. Design Storm APC Area Total of Downstream Structures Impacted (Count)



	Cherokee	Elmore	Chilton	Calhoun	Coosa	Shelby	Etowah	Talladega	St. Clair
🟦 Design Storm Existing	3	10	11	15	35	82	285	330	375
🟧 Design Storm Proposed	4	10	11	14	36	77	278	237	184

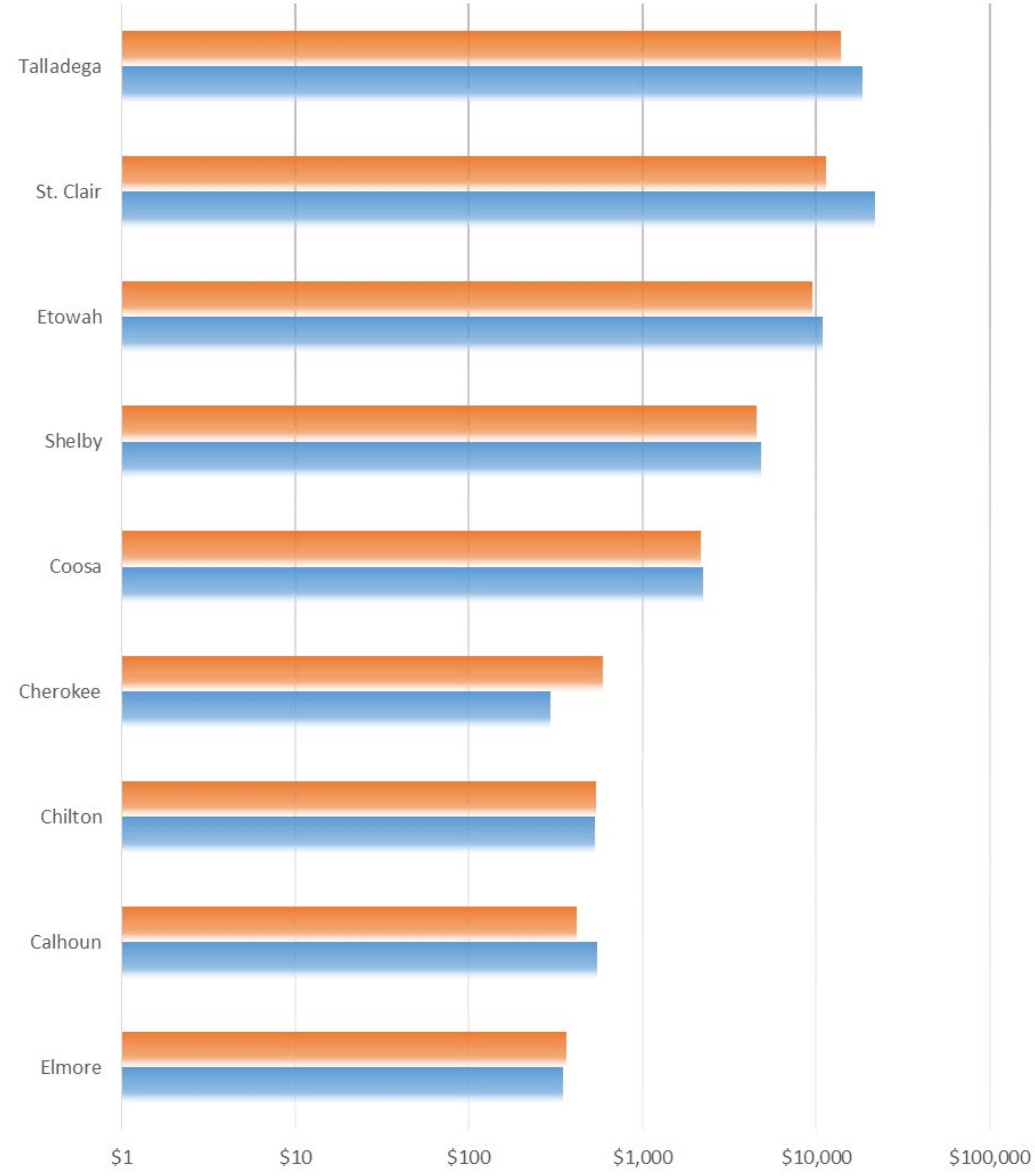
Figure D-18. Design Storm APC Area Total of Downstream Structures Impacted by County (Count)

Figure D-19 and Figure D-20 display the amount of flood damages expected at the Design Storm existing and proposed conditions. Overall, damages are reduced under the proposed condition.



	All
🟦 Design Storm Existing	$49,734,218
🟧 Design Storm Proposed	$36,507,766

Figure D-19. Design Storm APC Area Total Downstream Flood Damages ($)

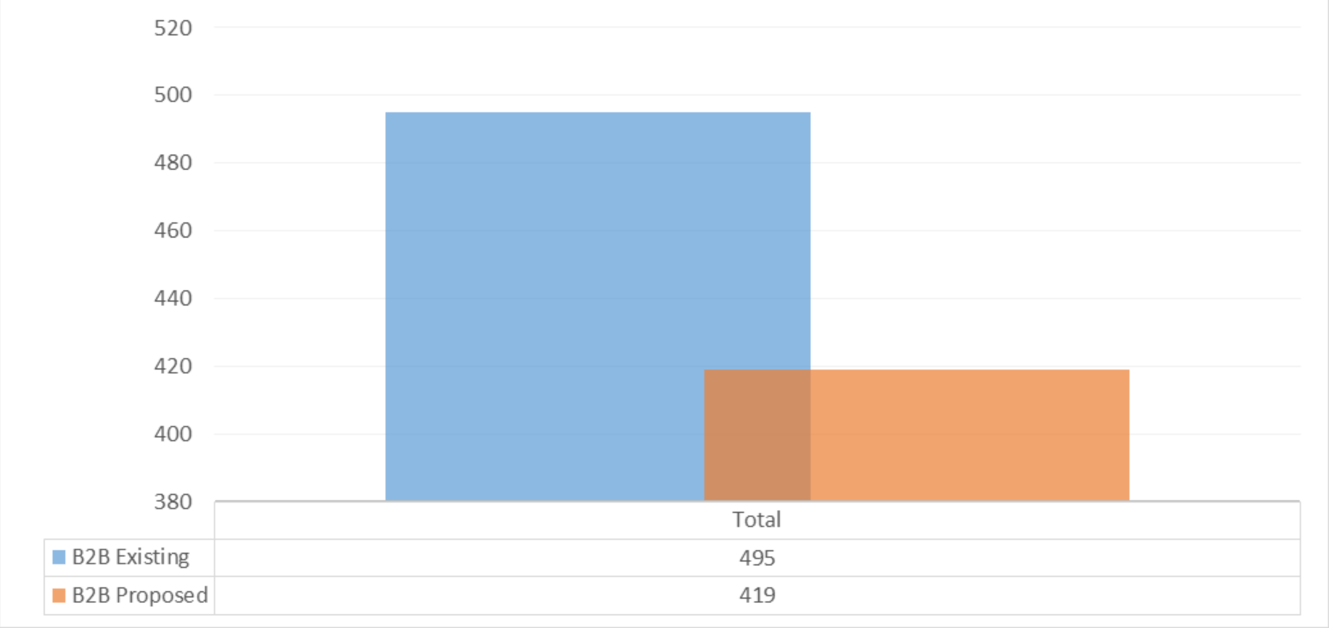


	Elmore	Calhoun	Chilton	Cherokee	Coosa	Shelby	Etowah	St. Clair	Talladega
🟧 Design Storm Proposed	$364	$415	$536	$590	$2,152	$4,547	$9,562	$11,369	$13,852
🟦 Design Storm Existing	$347	$544	$530	$294	$2,223	$4,779	$10,841	$21,658	$18,573

Figure D-20. Design Storm APC Area Total Downstream Flood Damages by County ($)

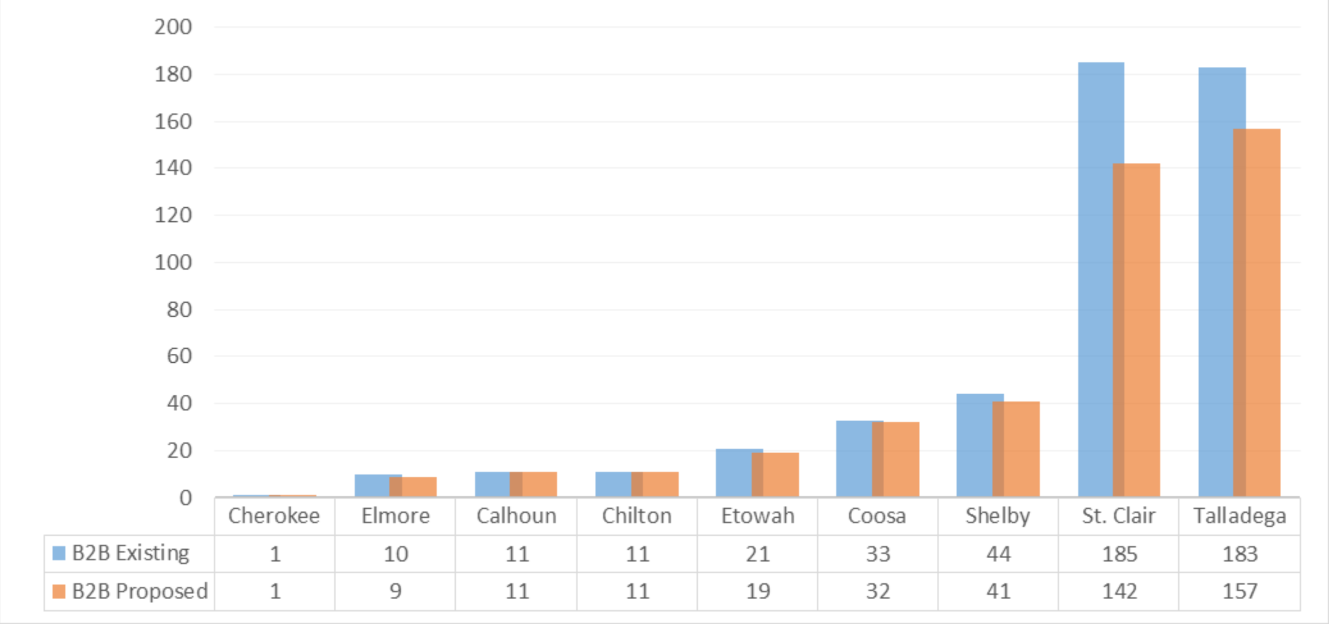
D.8.5.2.1.2 Back to Back Storm

Figure D-21 and Figure D-22 display the number of structures impacted along the Coosa River under the base and proposed conditions for the Back to Back Storm scenario. This storm showed a net reduction of structures impacted under the proposed condition.



	Total
■ B2B Existing	495
■ B2B Proposed	419

Figure D-21. APC Area Total of Downstream Structures Impacted (Count)



	Cherokee	Elmore	Calhoun	Chilton	Etowah	Coosa	Shelby	St. Clair	Talladega
■ B2B Existing	1	10	11	11	21	33	44	185	183
■ B2B Proposed	1	9	11	11	19	32	41	142	157

Figure D-22. APC Area Total of Downstream Structures Impacted by County (Count)

Figure D-23 and Figure D-24 display the amount of flood damages expected at the Back to Back Storm existing and proposed conditions. Overall, damages are reduced under the proposed condition.

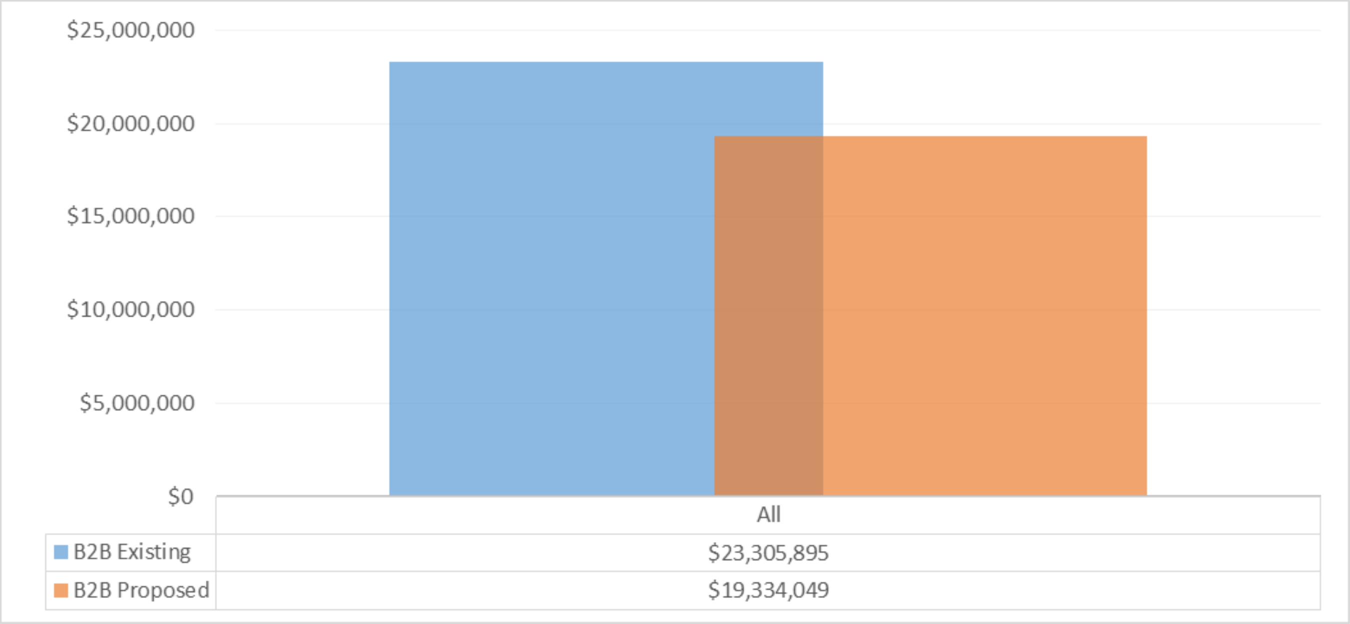
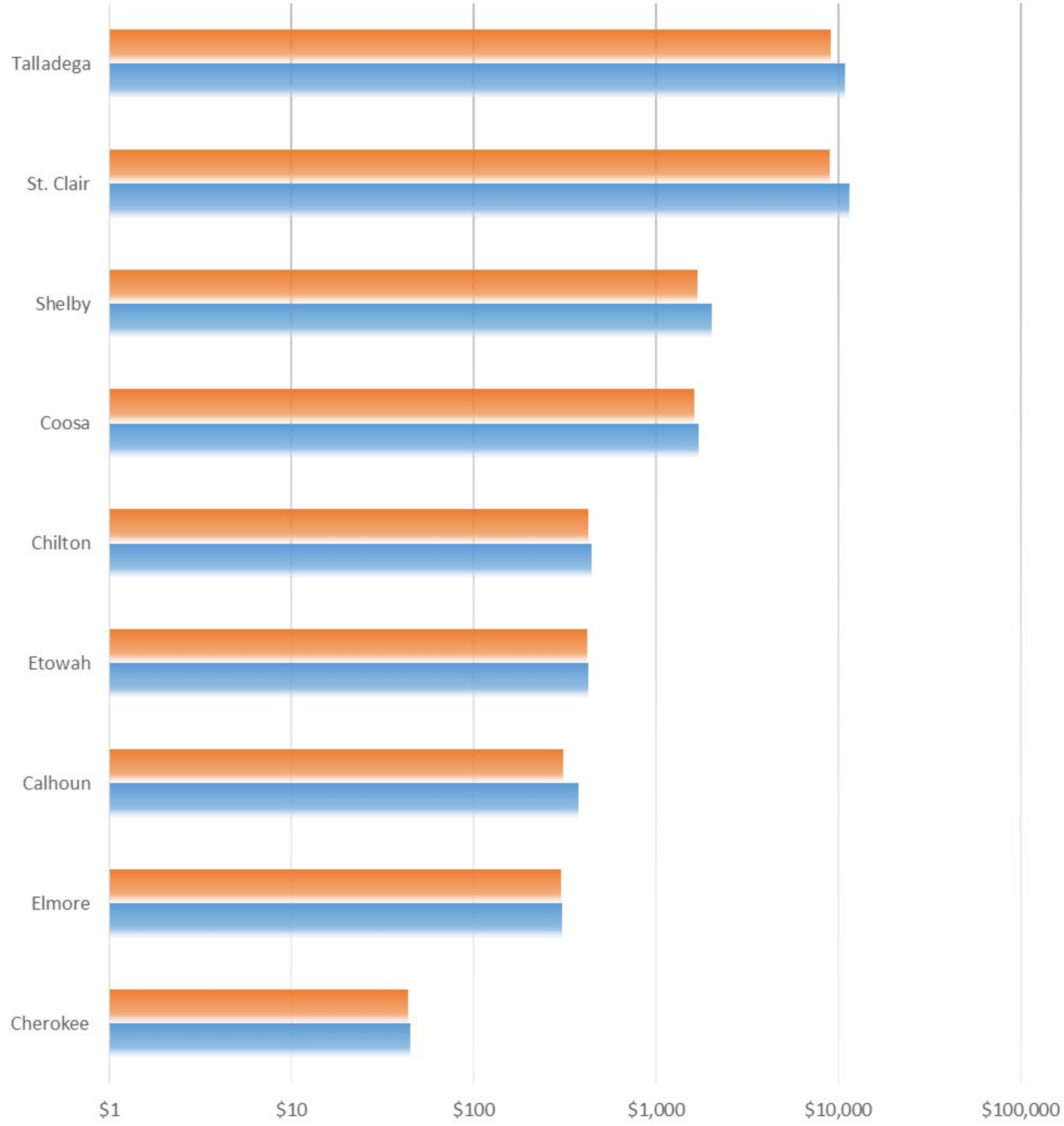


Figure D-23. APC Area Total Downstream Flood Damages ($)

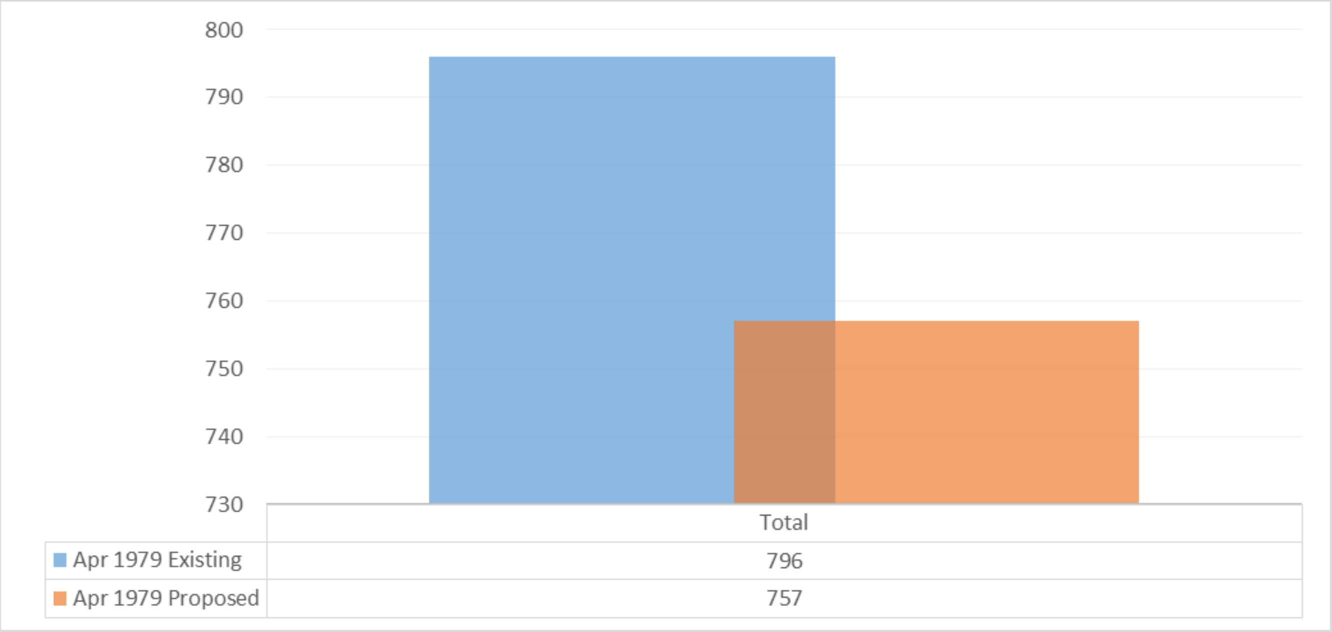


	Cherokee	Elmore	Calhoun	Etowah	Chilton	Coosa	Shelby	St. Clair	Talladega
🟧 B2B Proposed	$44	$300	$310	$421	$426	$1,624	$1,684	$8,886	$9,046
🟦 B2B Existing	$45	$303	$372	$423	$443	$1,717	$2,017	$11,500	$10,782

Figure D-24. Back to Back Storms APC Area Total Downstream Flood Damages by County ($1,000)

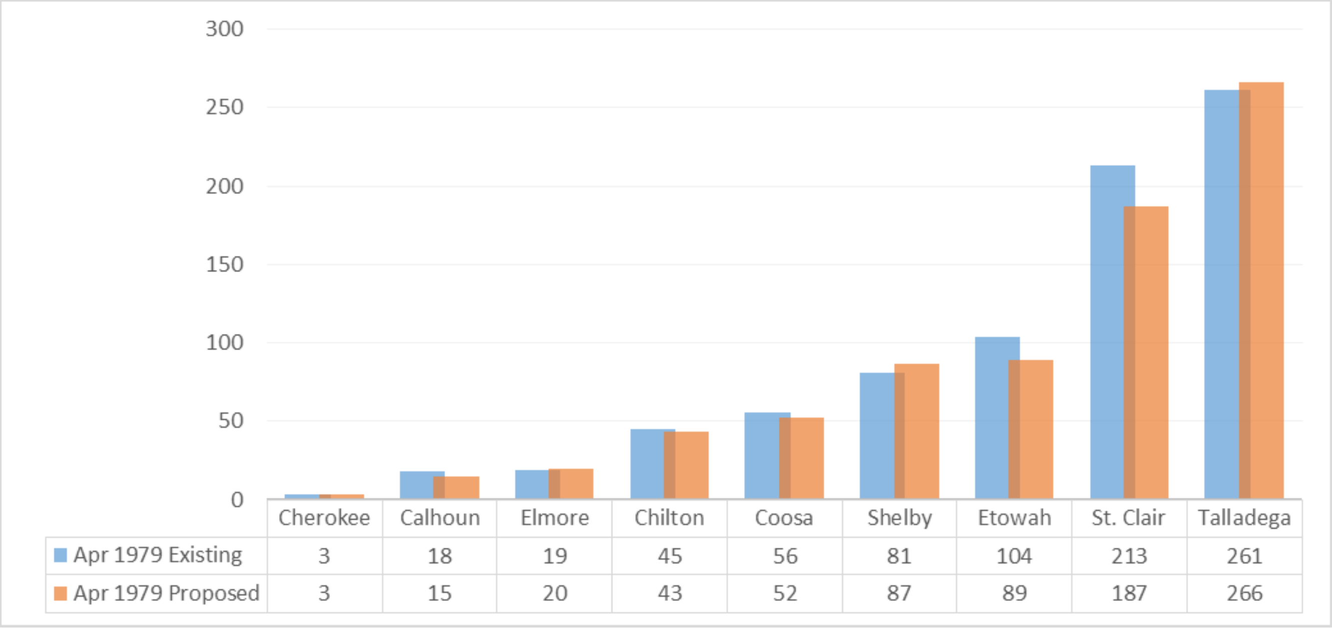
D.8.5.2.1.3 April 1979 Storm

Figure D-25 and Figure D-26 display the number of structures impacted along the Coosa River under the base and proposed conditions for the April 1979 Storm scenario. This storm showed a net reduction of structures impacted under the proposed condition.



	Total
Apr 1979 Existing	796
Apr 1979 Proposed	757

Figure D-25. April 1979 APC Area Total of Downstream Structures Impacted (Count)



	Cherokee	Calhoun	Elmore	Chilton	Coosa	Shelby	Etowah	St. Clair	Talladega
Apr 1979 Existing	3	18	19	45	56	81	104	213	261
Apr 1979 Proposed	3	15	20	43	52	87	89	187	266

Figure D-26. April 1979 APC Area Total of Downstream Structures Impacted by County (Count)

Figure D-27 and Figure D-28 display the amount of flood damages expected at the April 1979 Storm existing and proposed conditions. Overall, damages are reduced under the proposed condition.

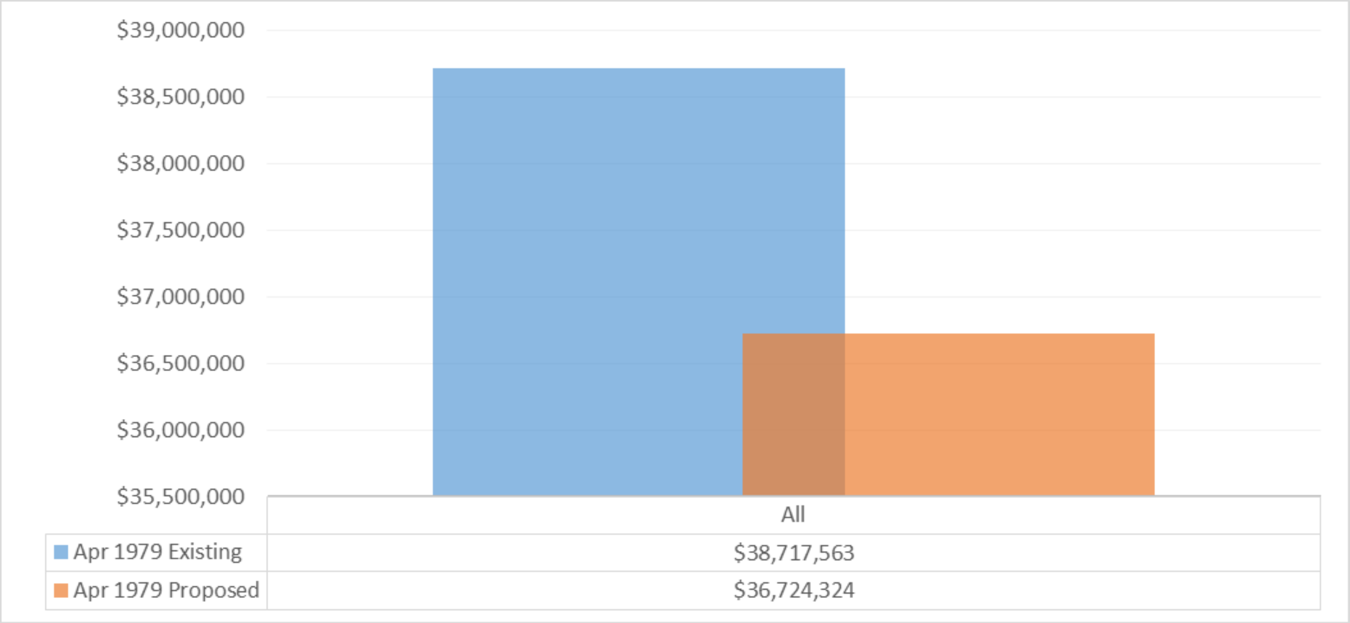
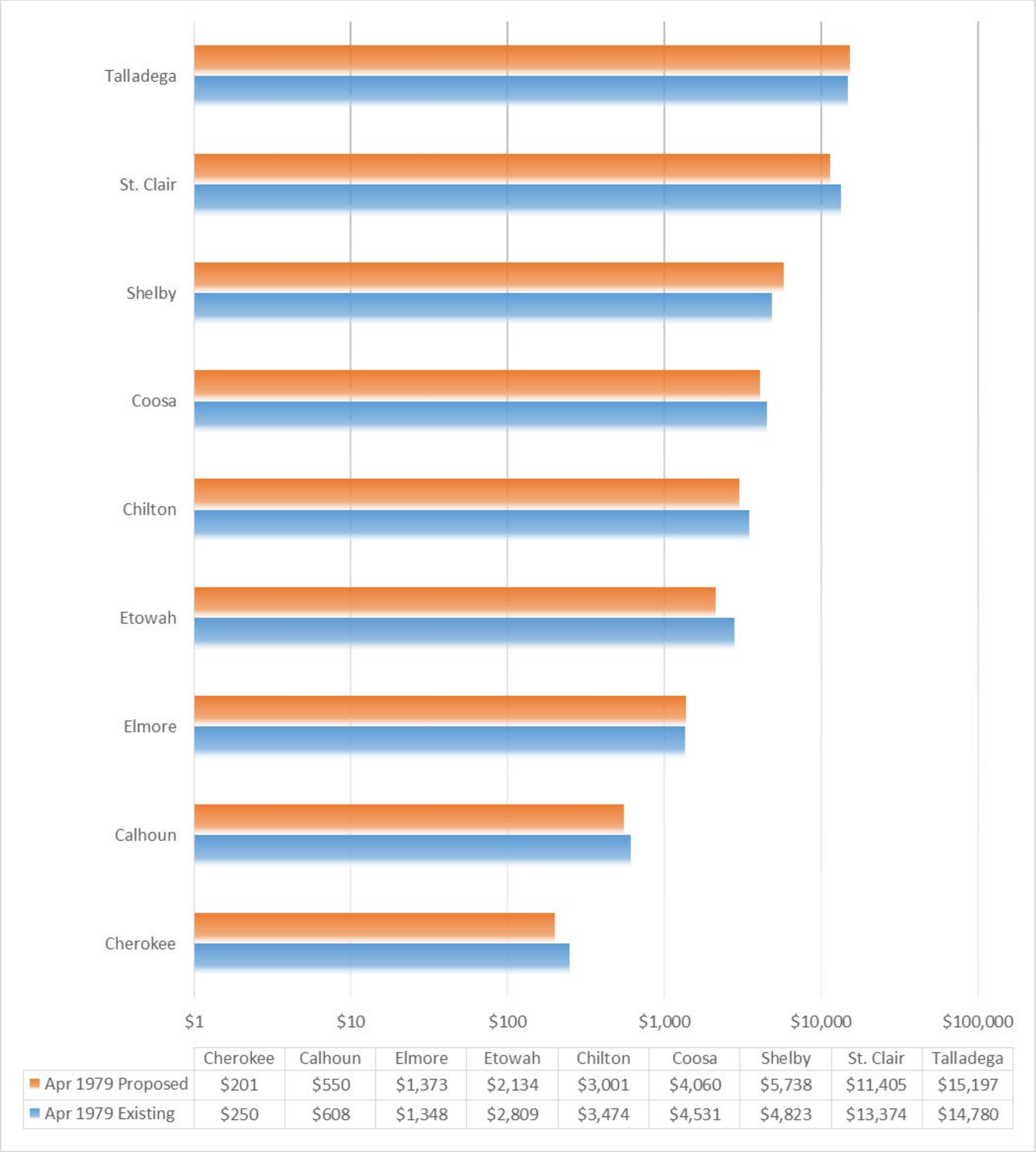


Figure D-27. April 1979 APC Area Total Downstream Flood Damages ($)



	Cherokee	Calhoun	Elmore	Etowah	Chilton	Coosa	Shelby	St. Clair	Talladega
🟧 Apr 1979 Proposed	$201	$550	$1,373	$2,134	$3,001	$4,060	$5,738	$11,405	$15,197
🟦 Apr 1979 Existing	$250	$608	$1,348	$2,809	$3,474	$4,531	$4,823	$13,374	$14,780

Figure D-28. April 1979 Storm APC Area Downstream Flood Damages by County ($1,000)

D.8.5.2.1.4 February 1990 Storm

Figure D-29 and Figure D-30 display the number of structures impacted along the Coosa River under the base and proposed conditions for the February 1990 Storm scenario. This storm showed a net reduction of structures impacted under the proposed condition.

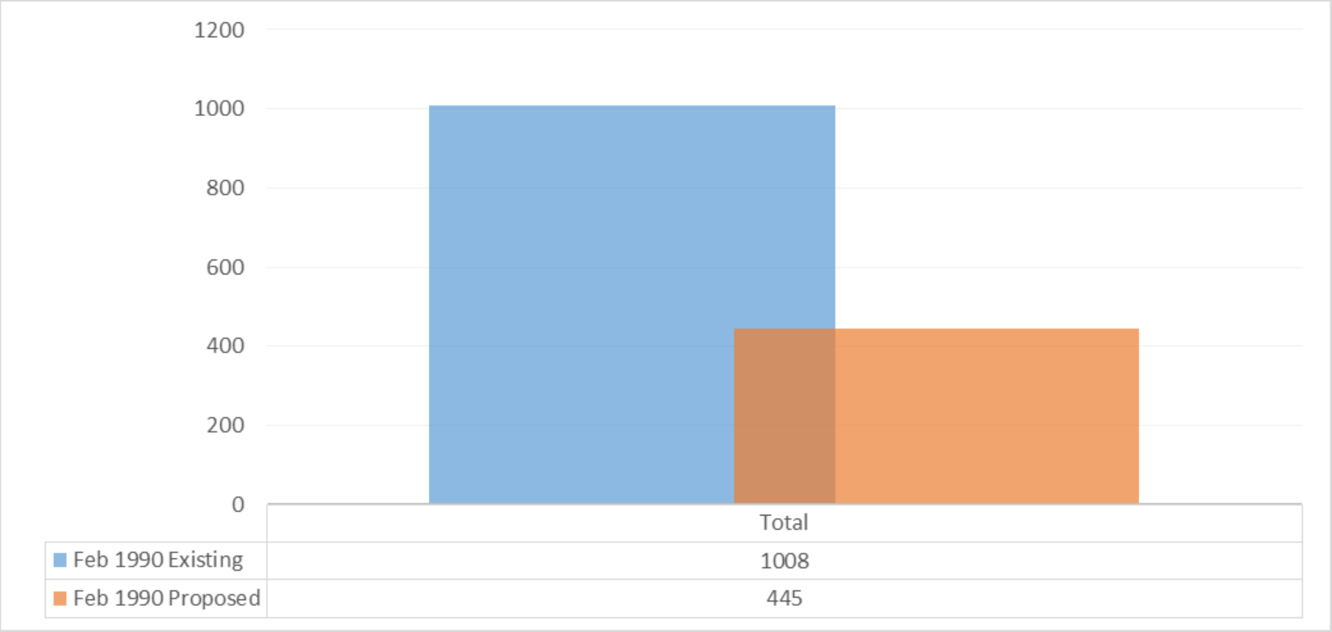


Figure D-29. February 1990 APC Area Impacted Structures (Count)

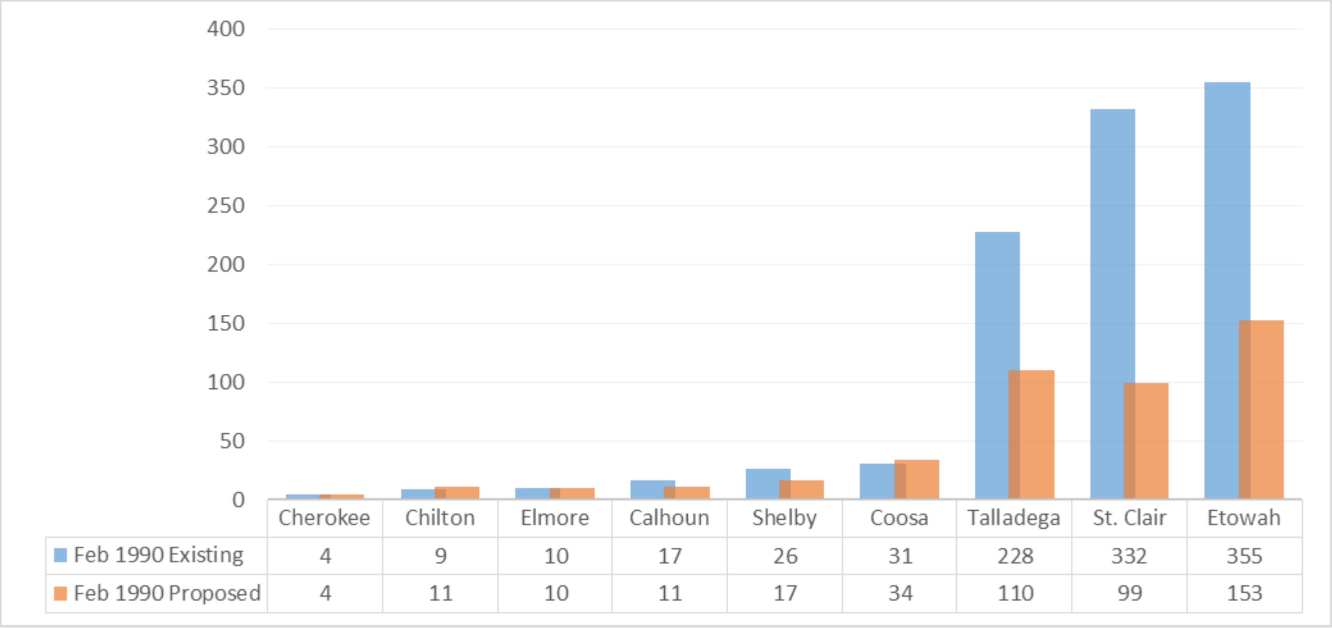


Figure D-30. February 1990 APC Area Total of Downstream Structures Impacted by County (Count)

Figure D-31and Figure D-32 display the amount of flood damages expected at the February 1990 Storm existing and proposed conditions. Overall, damages are reduced under the proposed condition.

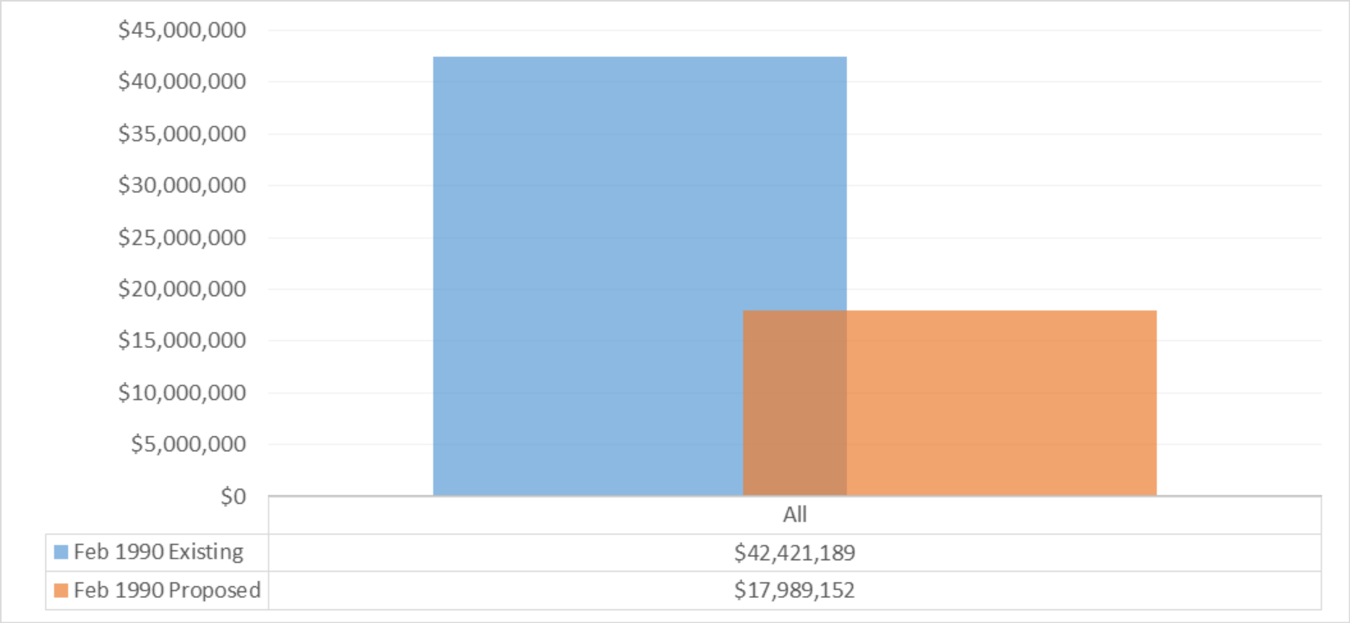
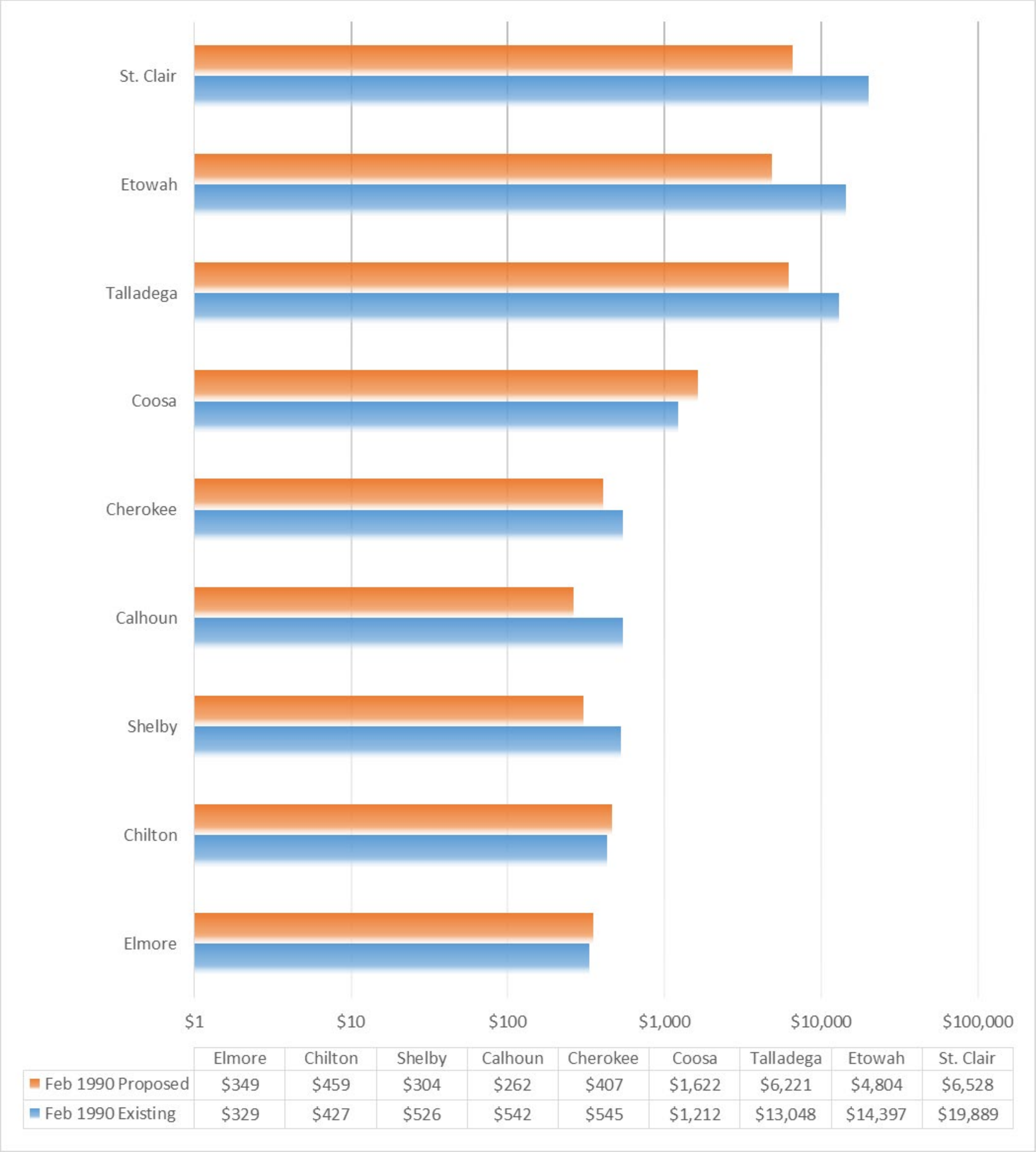


Figure D-31. February 1990 APC Area Total Downstream Flood Damages ($)

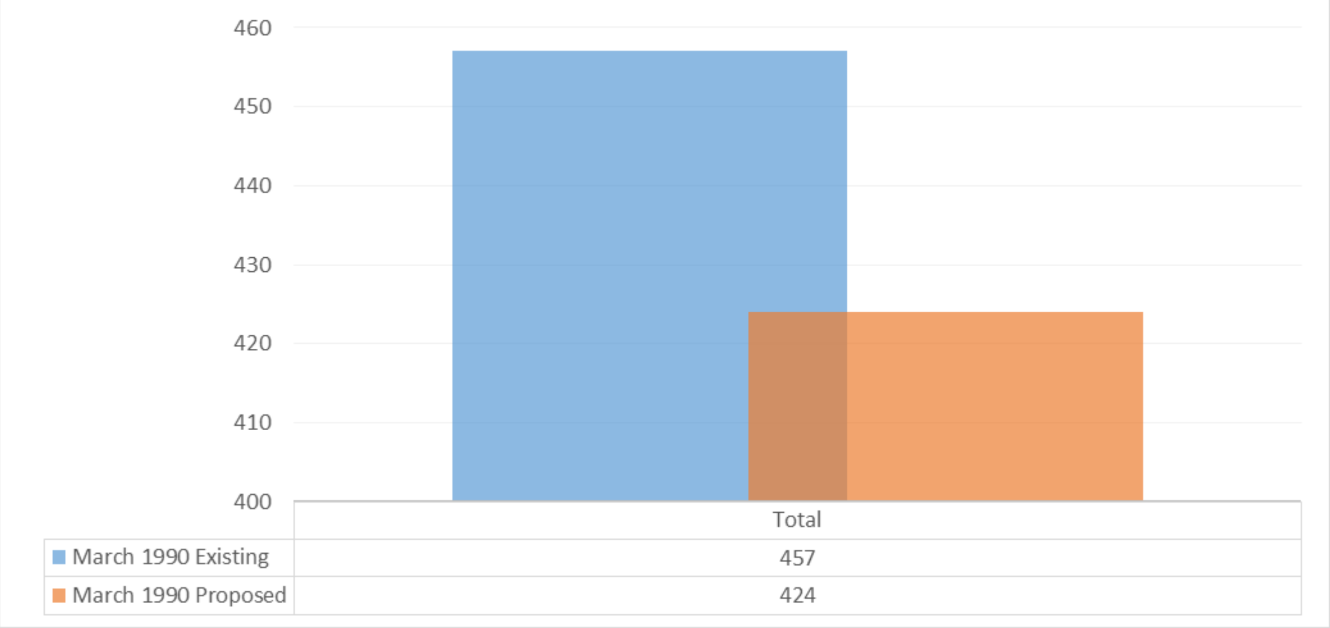


	Elmore	Chilton	Shelby	Calhoun	Cherokee	Coosa	Talladega	Etowah	St. Clair
🟧 Feb 1990 Proposed	$349	$459	$304	$262	$407	$1,622	$6,221	$4,804	$6,528
🟦 Feb 1990 Existing	$329	$427	$526	$542	$545	$1,212	$13,048	$14,397	$19,889

Figure D-32. February 1990 Storm APC Area Total Downstream Flood Damages by County ($1,000)

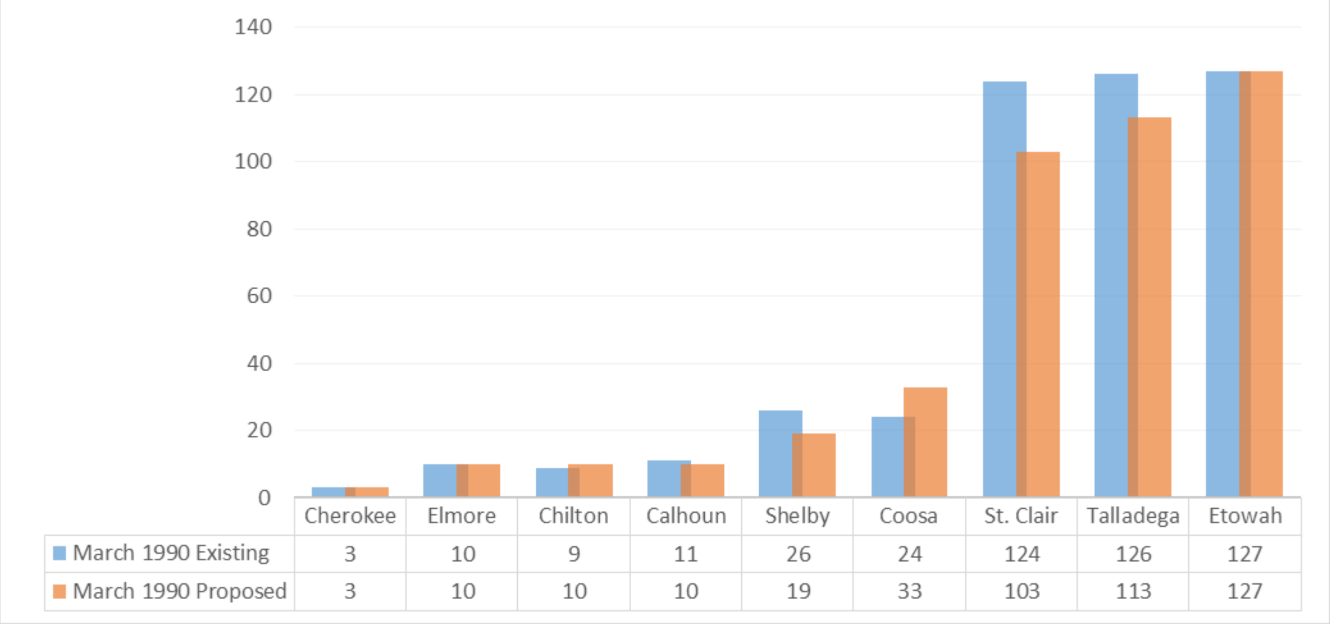
D.8.5.2.1.5 March 1990 Storm

Figure D-33 and Figure D-34 display the number of structures impacted along the Coosa River under the base and proposed conditions for the March 1990 Storm scenario. This storm showed a net reduction of structures impacted under the proposed condition.



	Total
🟦 March 1990 Existing	457
🟧 March 1990 Proposed	424

Figure D-33. March 1990 APC Area Impacted Structures (Count)



	Cherokee	Elmore	Chilton	Calhoun	Shelby	Coosa	St. Clair	Talladega	Etowah
🟦 March 1990 Existing	3	10	9	11	26	24	124	126	127
🟧 March 1990 Proposed	3	10	10	10	19	33	103	113	127

Figure D-34. March 1990 APC Area Total of Downstream Structures Impacted by County (Count)

Figure D-35 and Figure D-36 display the amount of flood damages expected at the March 1990 Storm existing and proposed conditions. Overall, damages are reduced under the proposed condition.

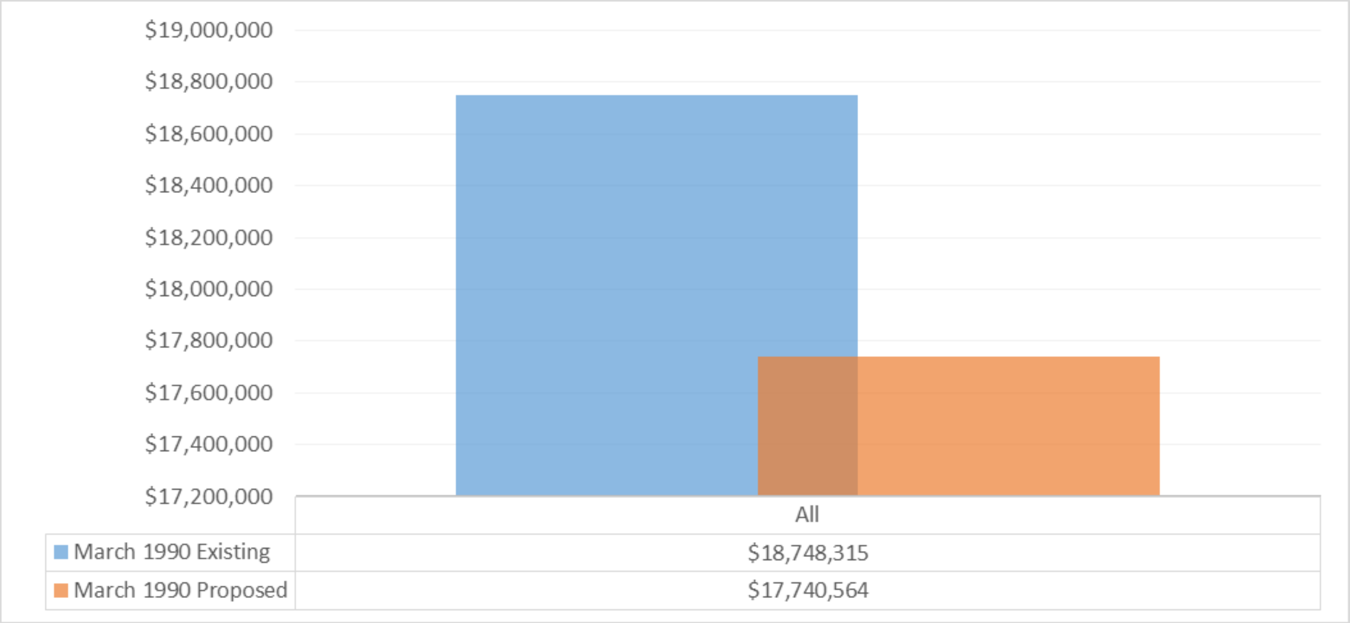
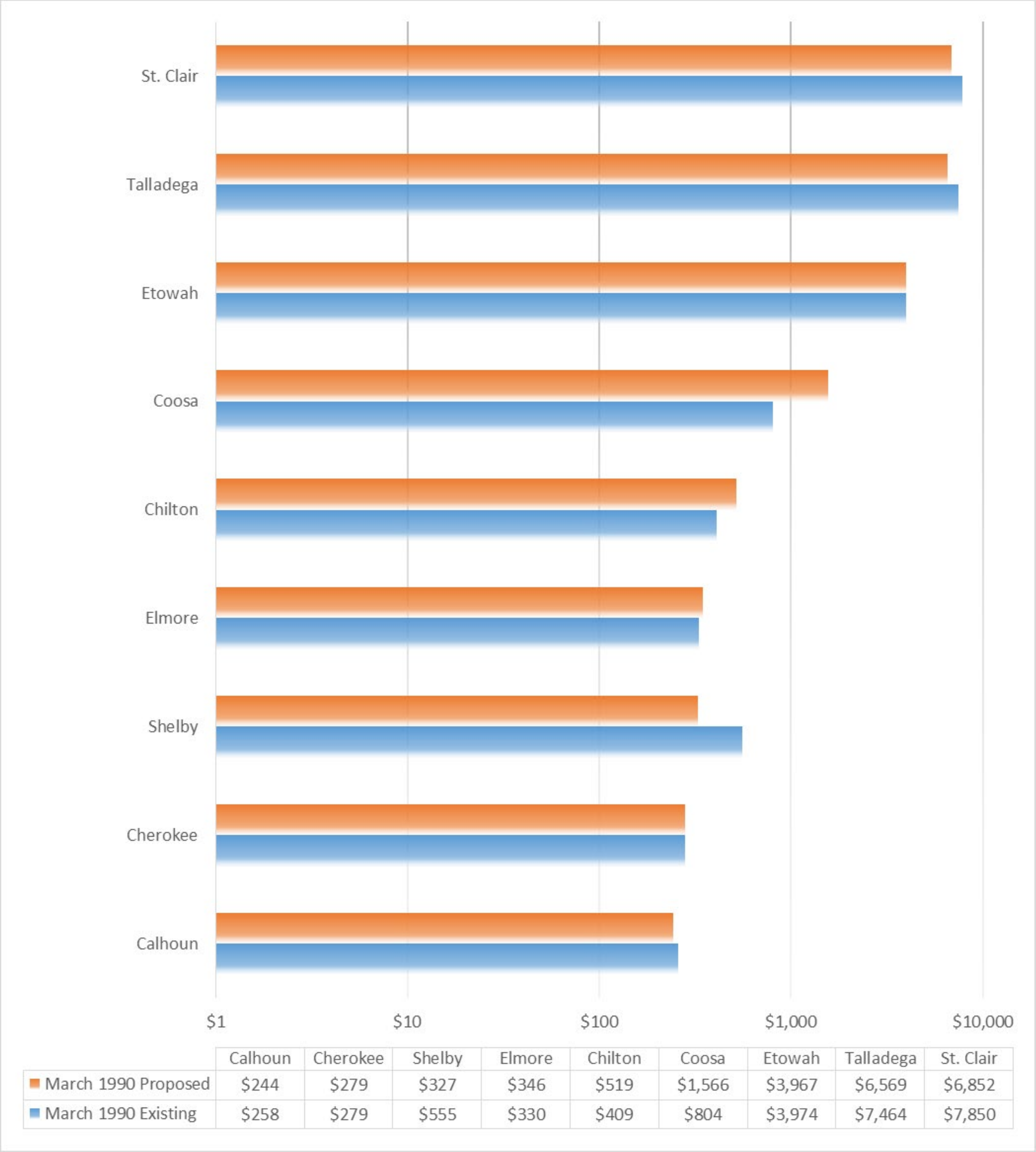


Figure D-35. March 1990 APC Area Total Downstream Flood Damages ($)

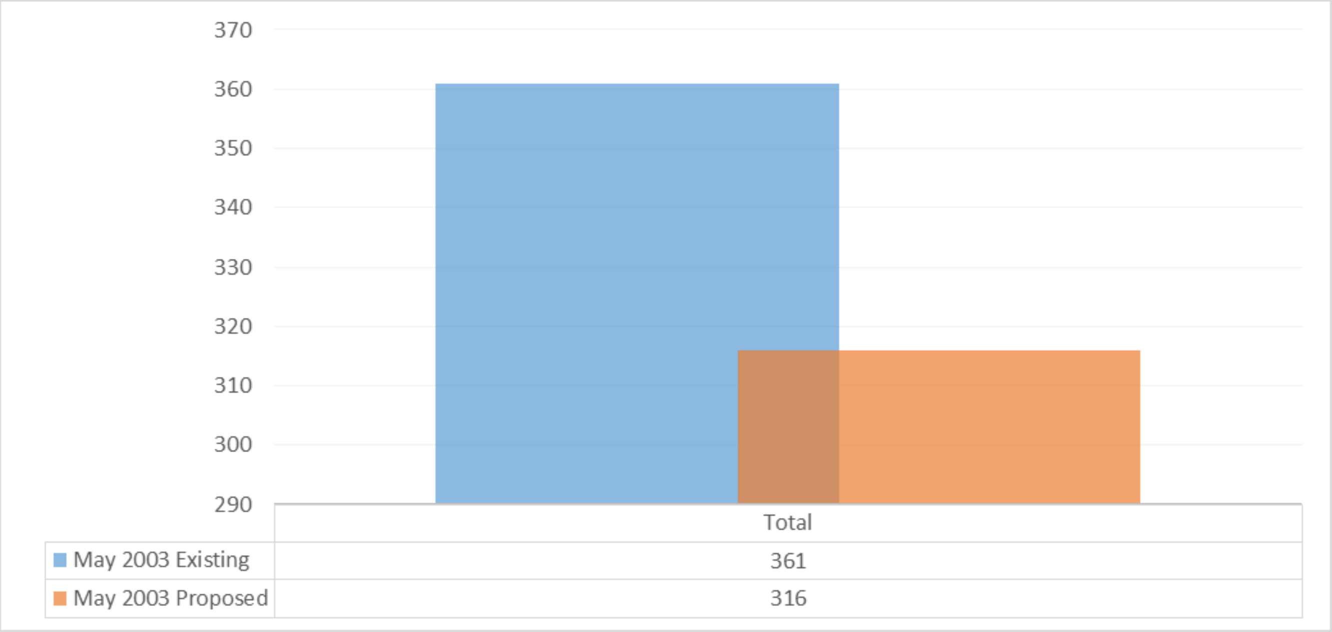


	Calhoun	Cherokee	Shelby	Elmore	Chilton	Coosa	Etowah	Talladega	St. Clair
🟧 March 1990 Proposed	$244	$279	$327	$346	$519	$1,566	$3,967	$6,569	$6,852
🟦 March 1990 Existing	$258	$279	$555	$330	$409	$804	$3,974	$7,464	$7,850

Figure D-36. March 1990 Storm APC Area Total Downstream Flood Damages by County ($1,000)

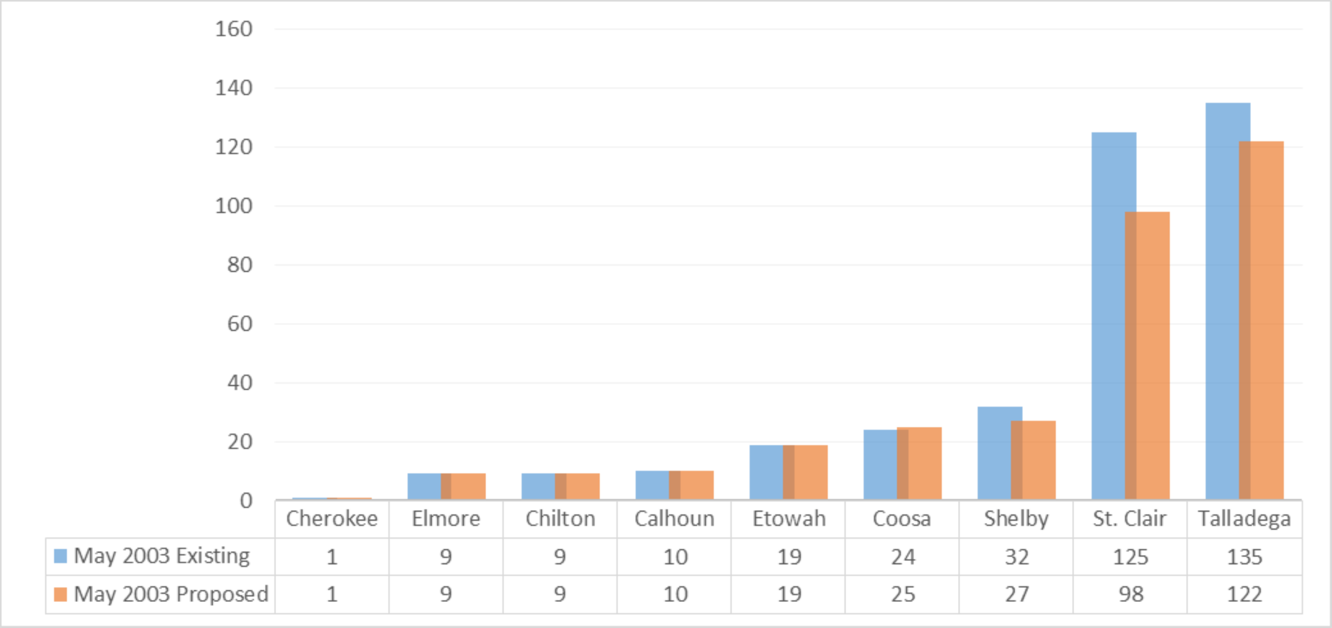
D.8.5.2.1.6 May 2003 Storm

Figure D-37 and Figure D-38 display the number of structures impacted along the Coosa River under the base and proposed conditions for the May 2003 Storm scenario. This storm showed a net reduction of structures impacted under the proposed condition.



	Total
■ May 2003 Existing	361
■ May 2003 Proposed	316

Figure D-37. May 2003 APC Area Impacted Structures (Count)



	Cherokee	Elmore	Chilton	Calhoun	Etowah	Coosa	Shelby	St. Clair	Talladega
■ May 2003 Existing	1	9	9	10	19	24	32	125	135
■ May 2003 Proposed	1	9	9	10	19	25	27	98	122

Figure D-38. May 2003 APC Area Total of Downstream Structures Impacted by County (Count)

Figure D-39 and Figure D-40 display the amount of flood damages expected at the May 2003 Storm existing and proposed conditions. Overall, damages are reduced under the proposed condition.

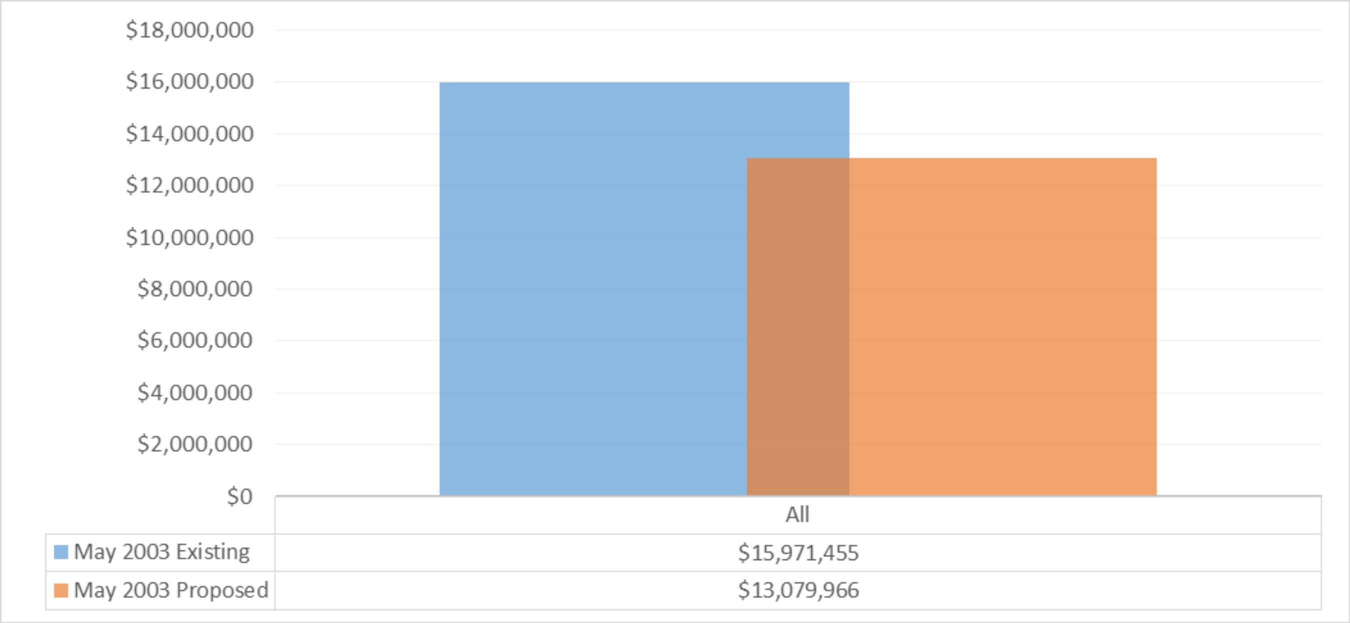
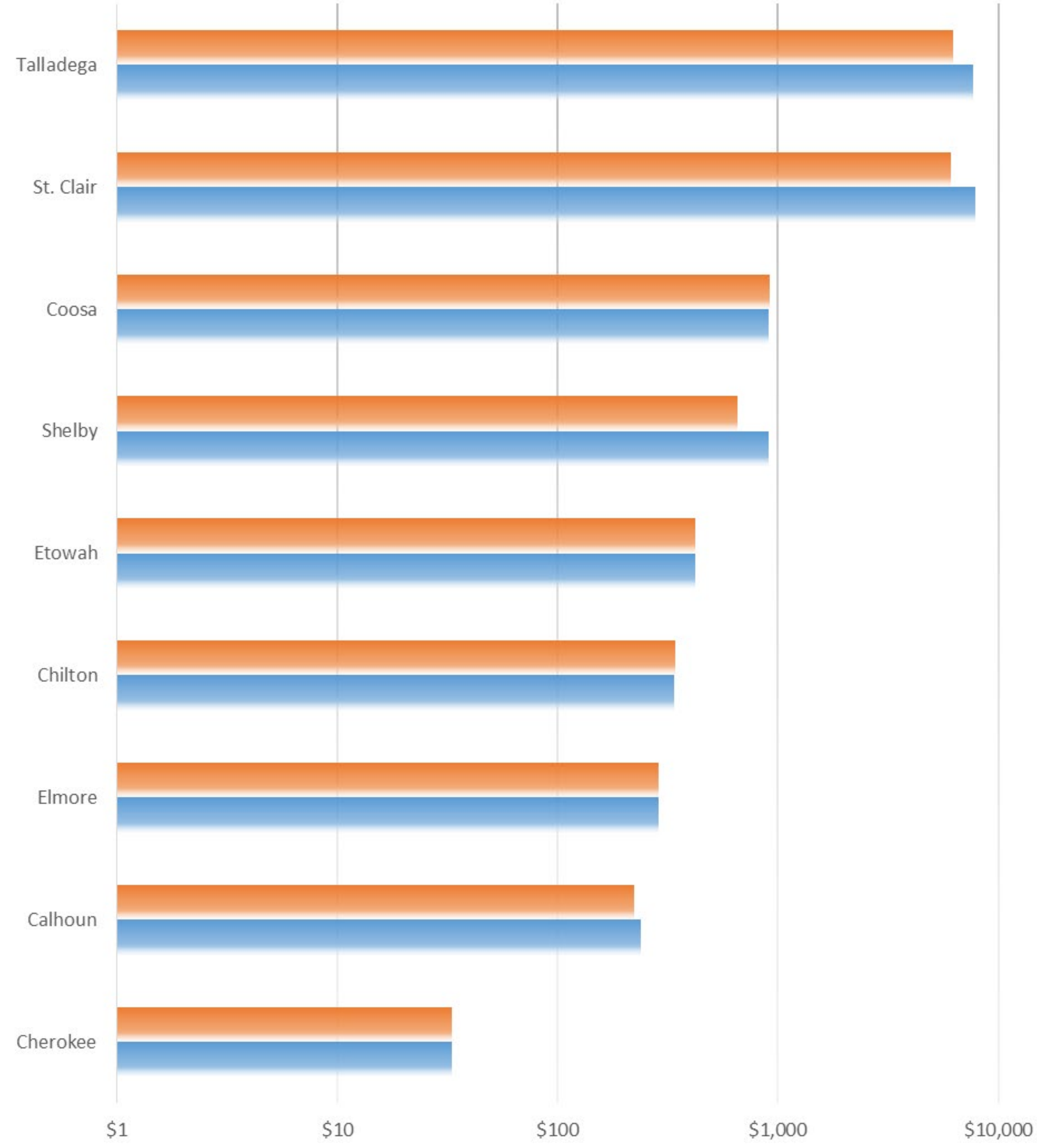


Figure D-39. May 2003 APC Area Total Downstream Flood Damages ($)

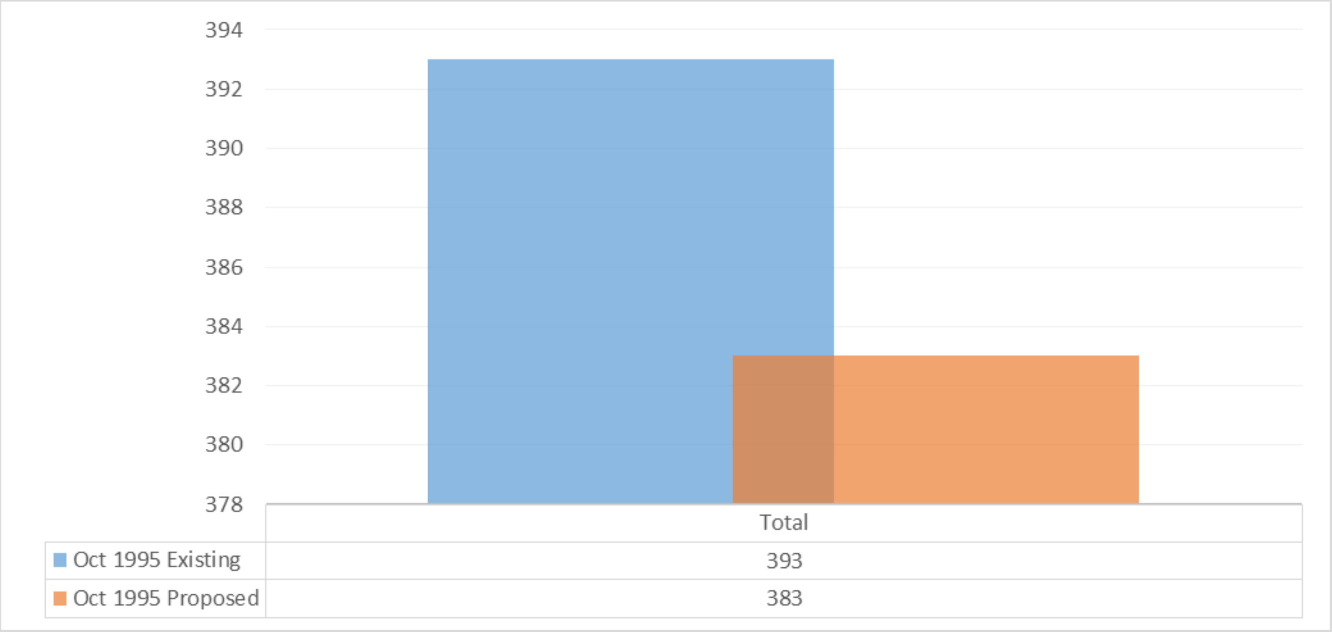


	Cherokee	Calhoun	Elmore	Chilton	Etowah	Shelby	Coosa	St. Clair	Talladega
🟧 May 2003 Proposed	$33	$221	$288	$341	$420	$653	$920	$6,060	$6,244
🟦 May 2003 Existing	$33	$239	$288	$340	$420	$906	$910	$7,871	$7,682

Figure D-40. May 2003 Storm APC Area Total Downstream Flood Damages by County ($1,000)

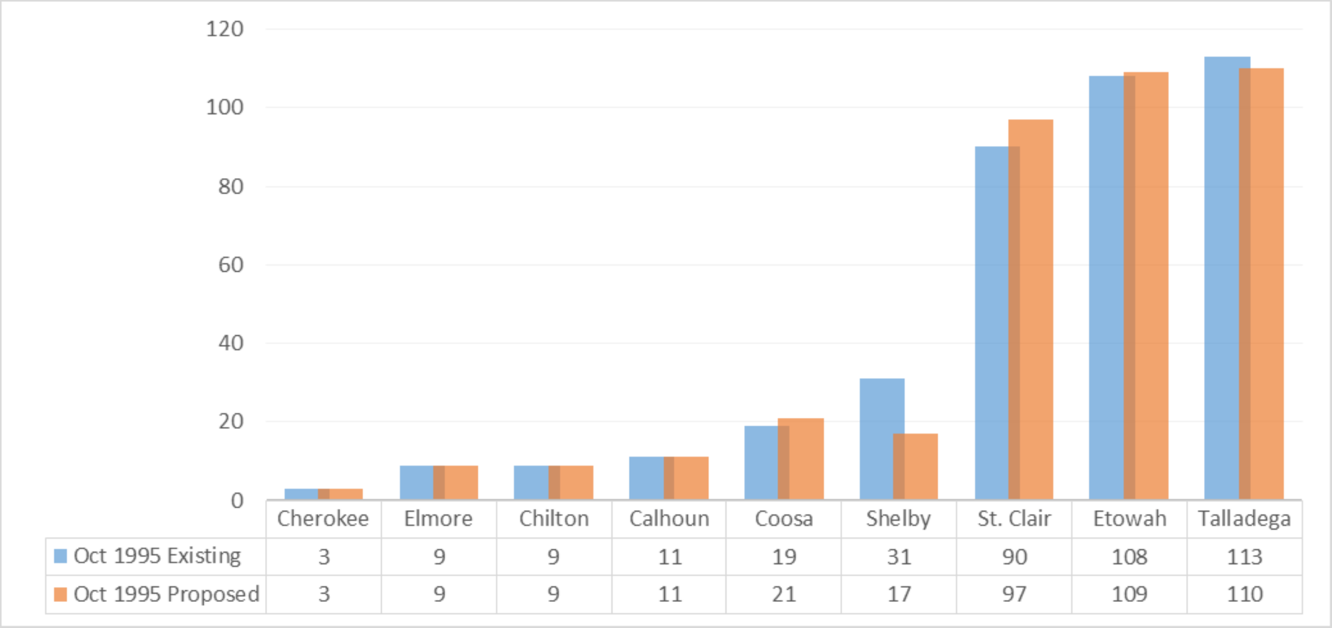
D.8.5.2.1.7 October 1995 Storm

Figure D-41 and Figure D-42 display the number of structures impacted along the Coosa River under the base and proposed conditions for the October 1995 Storm scenario. This storm showed a net reduction of structures impacted under the proposed condition.



	Total
🟦 Oct 1995 Existing	393
🟧 Oct 1995 Proposed	383

Figure D-41. October 1995 APC Area Impacted Structures (Count)



	Cherokee	Elmore	Chilton	Calhoun	Coosa	Shelby	St. Clair	Etowah	Talladega
🟦 Oct 1995 Existing	3	9	9	11	19	31	90	108	113
🟧 Oct 1995 Proposed	3	9	9	11	21	17	97	109	110

Figure D-42. October 1995 APC Area Total of Downstream Structures Impacted by County (Count)

Figure D-43 and Figure D-44 display the amount of flood damages expected at the October 1995 Storm existing and proposed conditions. Overall, damages are increased under the proposed condition.

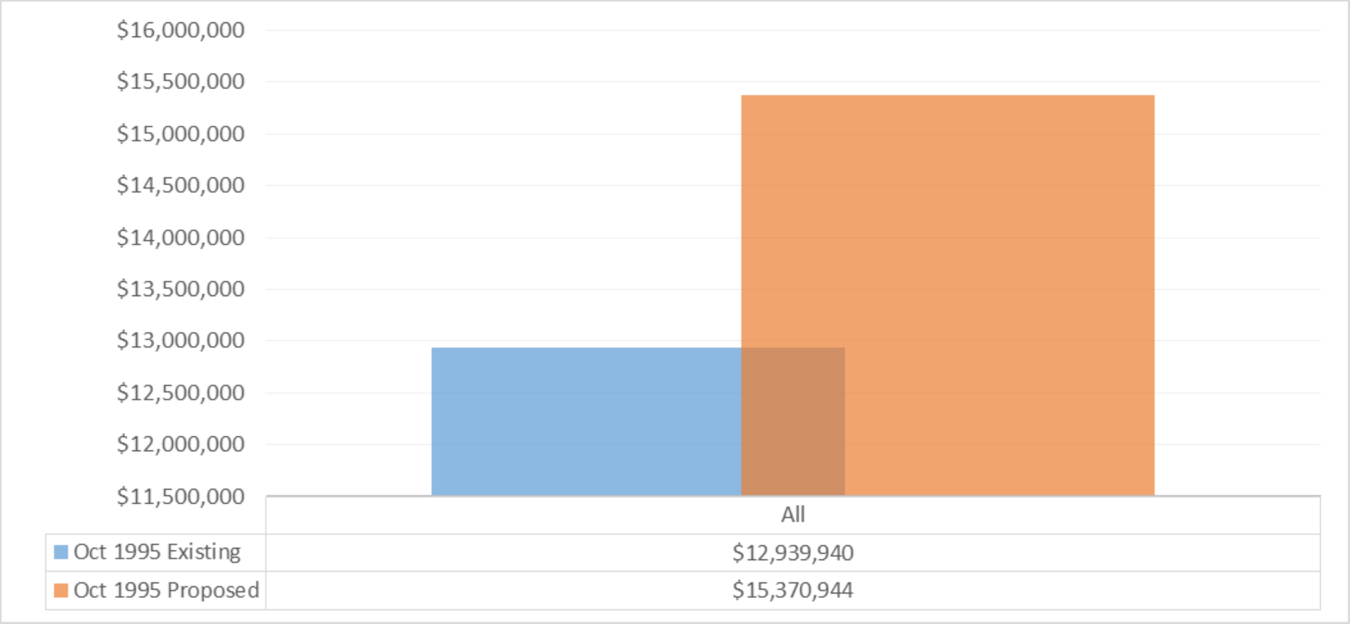
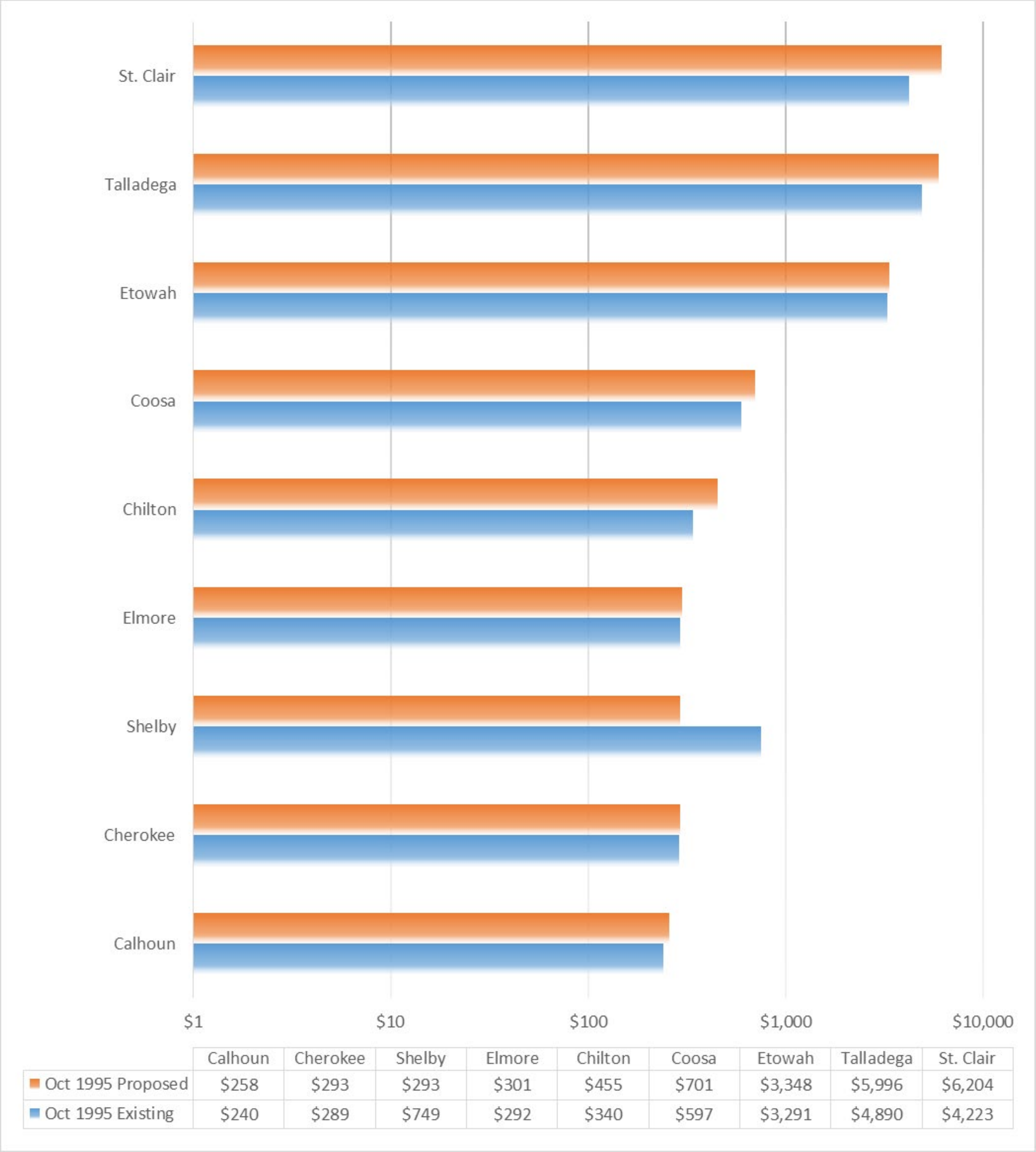


Figure D-43. October 1995 APC Area Total Downstream Flood Damages ($)



	Calhoun	Cherokee	Shelby	Elmore	Chilton	Coosa	Etowah	Talladega	St. Clair
🟧 Oct 1995 Proposed	$258	$293	$293	$301	$455	$701	$3,348	$5,996	$6,204
🟦 Oct 1995 Existing	$240	$289	$749	$292	$340	$597	$3,291	$4,890	$4,223

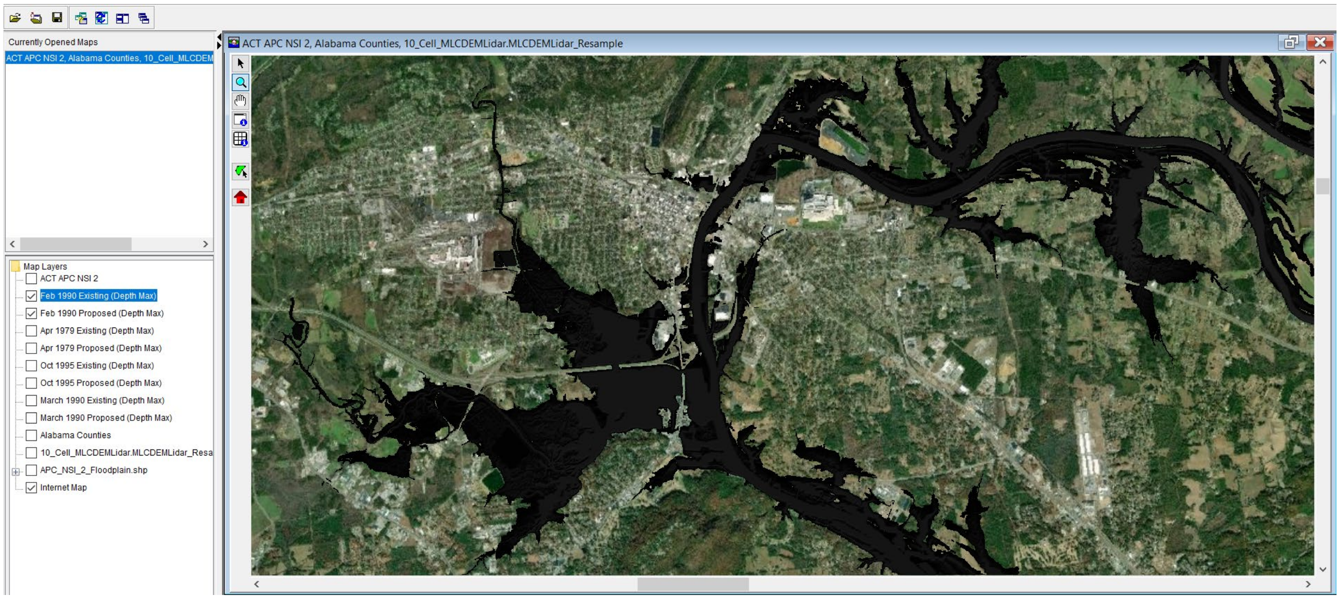
Figure D-44. October 1995 APC Area Total Downstream Flood Damages by County ($1,000)

D.8.5.2.2 Changes to FRM

In all proposed scenarios there was a decrease in the total number of structures impacted, showing no net increase in overall flood risk at the structure level. However, there are increased levels of inundation under the proposed operations.

D.8.5.2.2.1 Changes to FRM at Gadsden and Childersburg, AL

The increased inundation is due to differences in the timed releases of water from the APC Weiss project and would mostly affect crop, pasture and forested land. The extent of flooding for the largest modeled events for the City of Gadsden (below Weiss Lake), and Childersburg (below Lake Logan Martin) are shown in Figure D-45 and Figure D-46 below. Grey and black display the extent of flooding under existing conditions, and blue displays the extent of flooding under the proposed changes. The largest modeled event that impacts Weiss Lake is the Feb 1990 scenario (100-yr event at Weiss Lake). Downstream of Weiss Lake is Gadsden, AL, which benefits from the proposed operations. Figure D-45 shows no visible changes to the extent of flooding between the base and proposed conditions. The largest modeled event that impacts Logan Martin is the Apr 1979 scenario (200-yr storm at Logan Martin). Downstream of Logan Martin is Childersburg, AL, which receives slightly deeper flood waters under the proposed APC operations with cutback operations. When this storm is modeled without the cutback operations, the induced flooding does not occur at Childersburg.

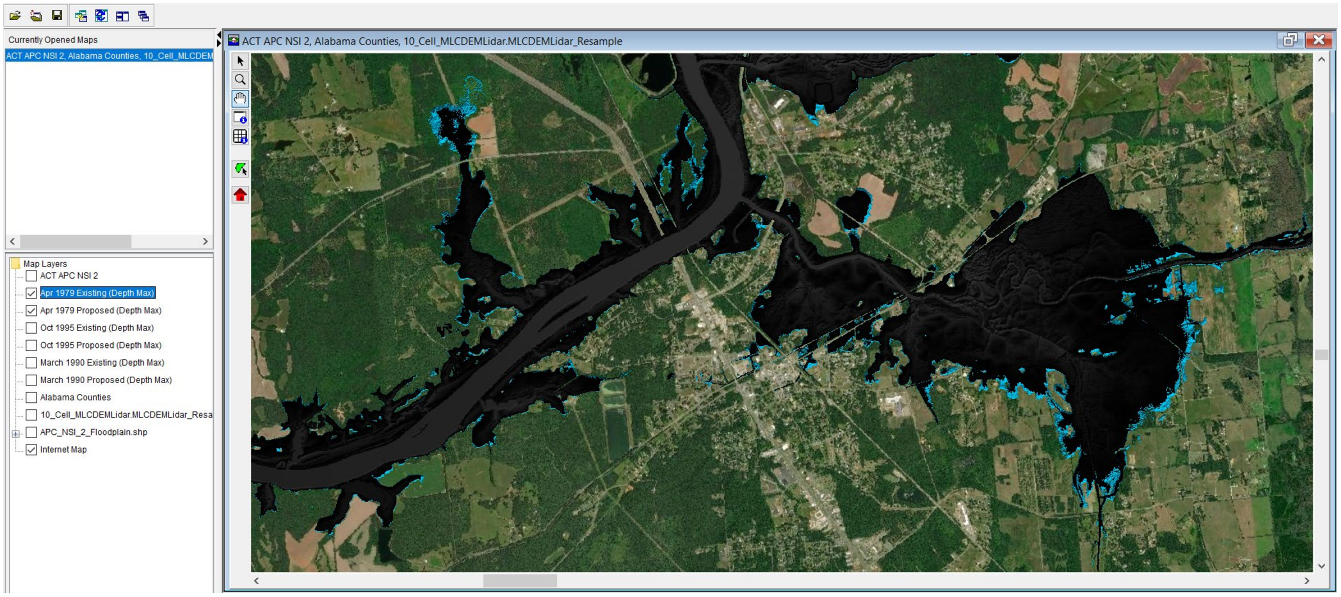

Currently Opened Maps

ACT APC NSI 2, Alabama Counties, 10_Cell_MLCDEM

ACT APC NSI 2, Alabama Counties, 10_Cell_MLCDEMLidar.MLCDEMLidar_Resample

Map Layers
- ☐ ACT APC NSI 2
- ☑ Feb 1990 Existing (Depth Max)
- ☑ Feb 1990 Proposed (Depth Max)
- ☐ Apr 1979 Existing (Depth Max)
- ☐ Apr 1979 Proposed (Depth Max)
- ☐ Oct 1995 Existing (Depth Max)
- ☐ Oct 1995 Proposed (Depth Max)
- ☐ March 1990 Existing (Depth Max)
- ☐ March 1990 Proposed (Depth Max)
- ☐ Alabama Counties
- ☐ 10_Cell_MLCDEMLidar.MLCDEMLidar_Resa
- ☐ APC_NSI_2_Floodplain.shp
- ☑ Internet Map

Figure D-45.Flooding Extents at Gadsden Alabama Weiss Feb 1990 Event (100-yr Storm)



Map Layers
☐ ACT APC NSI 2
☑ Apr 1979 Existing (Depth Max)
☑ Apr 1979 Proposed (Depth Max)
☐ Oct 1995 Existing (Depth Max)
☐ Oct 1995 Proposed (Depth Max)
☐ March 1990 Existing (Depth Max)
☐ March 1990 Proposed (Depth Max)
☐ Alabama Counties
☐ 10_Cell_MLCDEMLidar.MLCDEMLidar_Resa
☐ APC_NSI_2_Floodplain.shp
☑ Internet Map

Figure D-46. Flooding Extents at Childersburg, Alabama Logan Martin Apr 1979 Event (250-yr Storm)

D.8.5.2.2.2 Changes to FRM Overall

The largest changes to FRM occurred during the design storm below Weiss Lake without cutback operations in areas composed mostly of uninhabited crop, pasture and forested land. Overall, populated areas, such as Gadsden and Childersburg, AL were not affected with appropriate cutback/without cutback operations at Weiss Lake and Lake Logan Martin.

Table D-30 below displays which modeled events receive changes to FRM under the respective with or without cutback operation. As seen below, some modeled scenarios undergo changes to FRM under with cutbacks, without cutbacks, or with and without cutback operations.

Table D-30. Changes to FRM by Operation and Location

Location	Modeled Scenario						
	Apr-79	Feb-90	Mar-90	May-03	Oct-95	Back to Back	Design
Below Lay Dam	0	YZ	YZ	YZ	YZ	0	0
Logan Martin to Childersburg	Z	0	0	0	0	0	0
Below Neely-Henry	0	0	0	0	YZ	0	0
Gadsden	0	0	0	0	YZ	0	Y
Weiss-Gadsden	0	0	YZ	0	YZ	0	YZ

Changes to FRM without Cutbacks (Y)
Changes to FRM with Cutbacks (Z)
Changes to FRM with and without Cutbacks (YZ)
No changes (0)

Figure D-47 shows the extent of the existing level of flooding (black), flooding under proposed operations without cutbacks (chartreuse), and extent of flooding under both with and without cutbacks (orange). This area, specifically, was the greatest increase in the extent of flooding under the design storm. The largest increase from existing was under the operations without cutbacks.

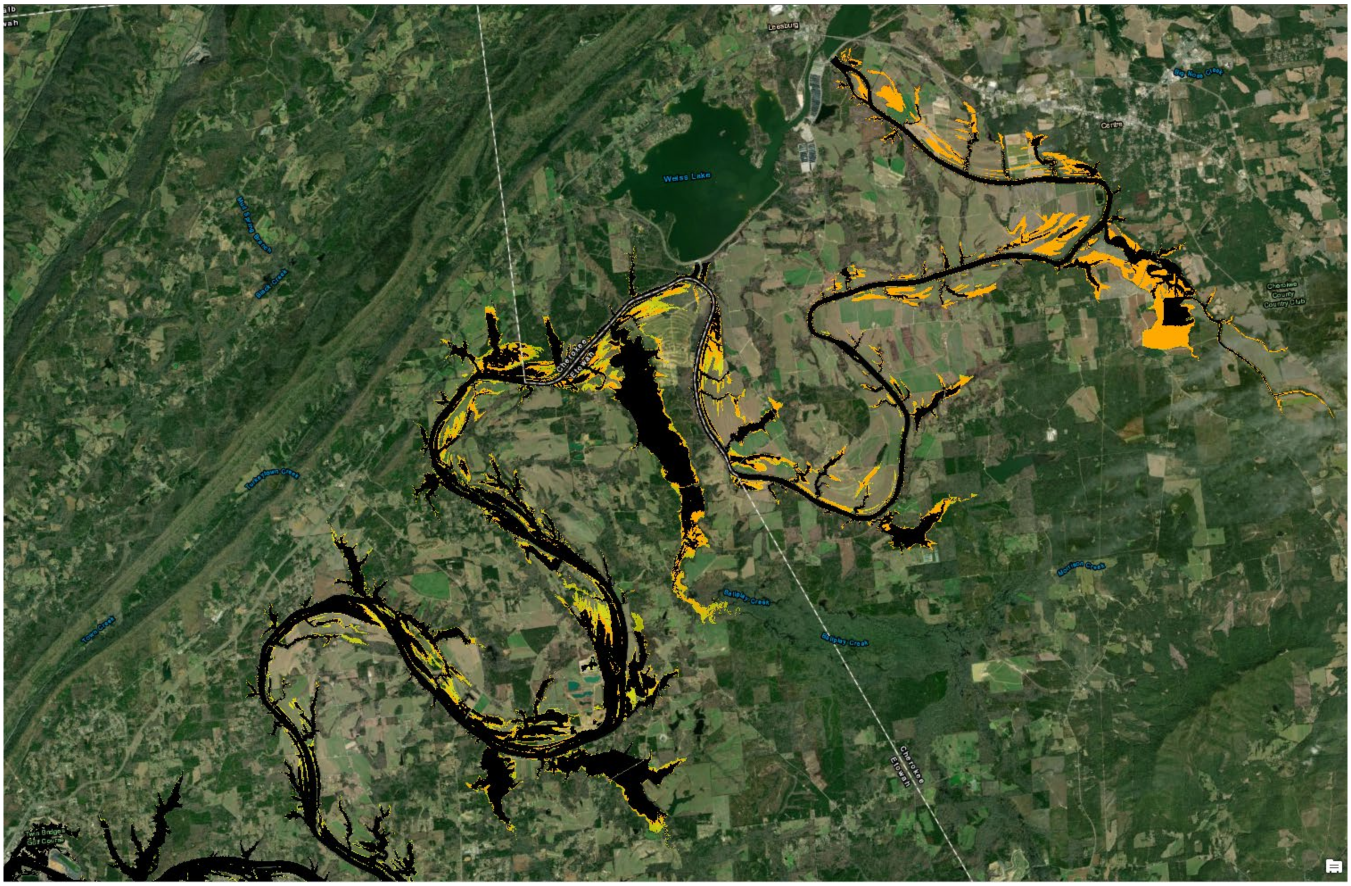


Figure D-47. Flooding Extents below Weiss Lake (Design Storm)

D.9 Additional Impact Analysis

After preliminary reviews and comments, additional analysis of the HEC-FIA model was conducted to highlight the changes occurring in the modeled alternatives. Overall, as stated previously there was a net decrease in impacts to structures. However, within that net decrease, some structures do experience an increase in flooding in the proposed conditions. The scenarios that were evaluated further were the APC Design Storm (100 year storm), and the October 1995 Storm (5 year storm). Results are shown in Table 31.

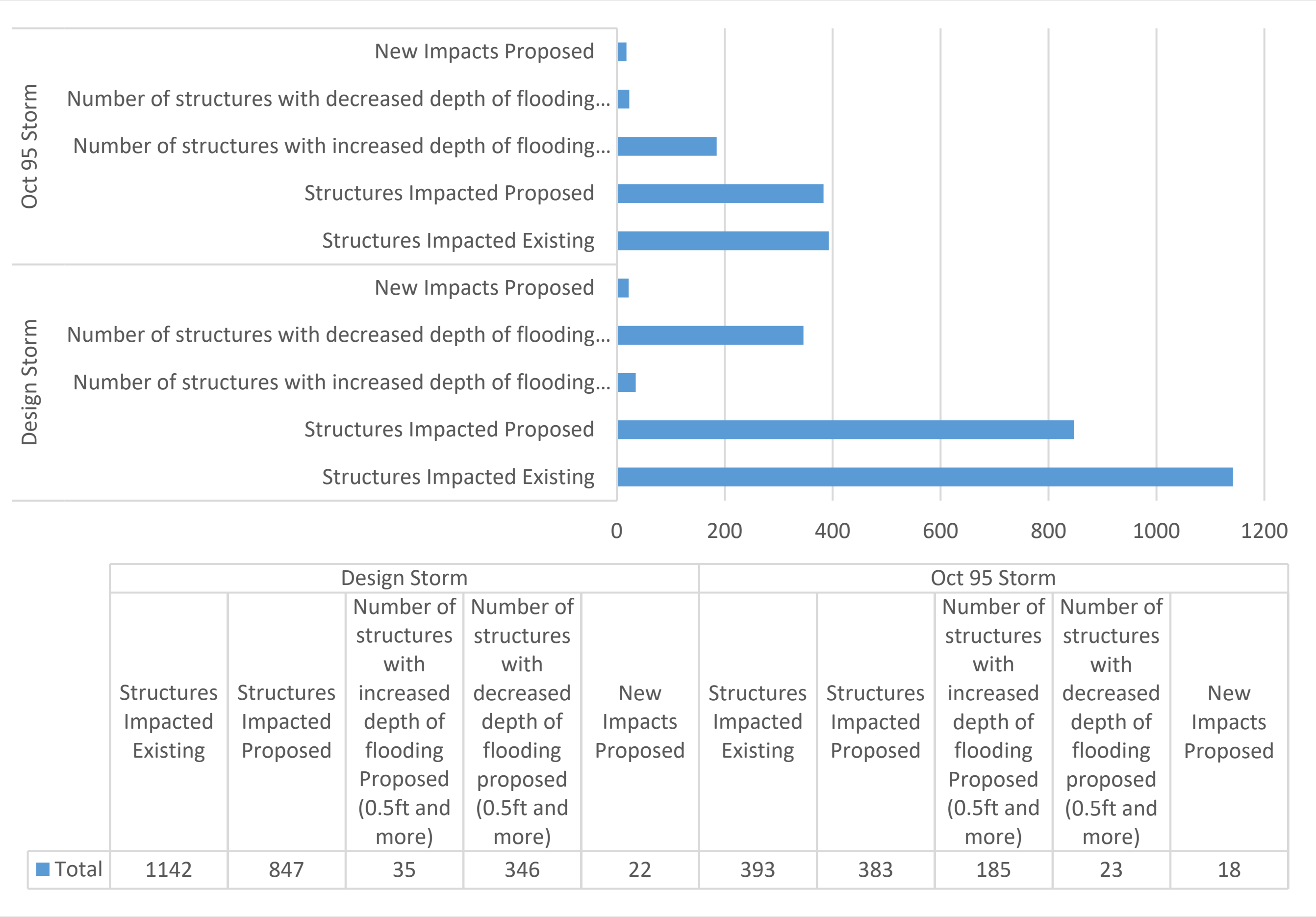
D.9.1 Design Storm

Under the Design Storm modeled scenario there was a net reduction of 295 structures impacted. 346 structures receive a reduction of flooding of less-than or equal-to 0.5ft of flooding. 35 structures receive an increase of 0.5ft or more of flooding, and 22 structures experience flooding due to the proposed operations (new impacts).

D.9.2 October 1995 Storm

Under the October 1995 Storm modeled scenario there was a net reduction of 10 structures impacted. 23 structures receive a reduction of flooding of less-than or equal-to 0.5ft of flooding. 185 structures receive an increase of 0.5ft or more of flooding, and 18 structures experience flooding due to the proposed operations (new impacts).

Table 31: Changes to Structure Inventory Impacts



	Design Storm					Oct 95 Storm				
	Structures Impacted Existing	Structures Impacted Proposed	Number of structures with increased depth of flooding Proposed (0.5ft and more)	Number of structures with decreased depth of flooding proposed (0.5ft and more)	New Impacts Proposed	Structures Impacted Existing	Structures Impacted Proposed	Number of structures with increased depth of flooding Proposed (0.5ft and more)	Number of structures with decreased depth of flooding proposed (0.5ft and more)	New Impacts Proposed
■ Total	1142	847	35	346	22	393	383	185	23	18

D.10 Regional Economic Impacts

Regional economic development benefits (RED) are more localized impacts that benefit the specific region in which they occur, and not the nation as a whole (NED). That is not to say that RED is not a benefits to the region, as it often represents a transfer of economic benefits, such as employment, from outside of the region to within it. However, due to the transfer nature of RED benefits, NED is the type of benefits used to select the TSP.

The U.S Army Corps of Engineers (USACE) Institute for Water Resources, the Louis Berger Group and Michigan State University has developed a regional economic impact modeling tool called RECONS (Regional ECONomic System) to provide estimates of regional and national job creation, and retention and other economic measures such as income, value added, and sales. This modeling tool automates calculations and generates estimates of jobs and other economic measures, such as income and sales associated with USACE's ARRA spending, annual Civil Work program spending and stem-from effects for Ports, Inland Water Way, FUSRAP and Recreation. This is done by extracting multipliers and other economic measures from more than 1,500 regional economic models that were built specifically for USACE's project locations. These multipliers were then imported to a database and the tool matches various spending profiles to the matching industry sectors by location to produce economic impact estimates. The tool will be used as a means to document the performance of direct investment spending of the USACE as directed by the American Recovery and Reinvestment Act (ARRA). The Tool will also allow the USACE to evaluate project and program expenditures associated with the annual expenditure by the USACE.

The following sections report the RECONS model results in FY19 dollars for the Allatoona regional economic impact (REI) area and the Coosa River System regional impact area as well as describing the local purchase coefficient (LPC) at the local state and national levels. The values reported are not reports of changes to operations under the TSP, but the stemming from effects of current expenditures. Operational changes due to the TSP are not expected to alter these results.

D.10.1 Allatoona REI

The following section describes the current FRM, recreation, hydropower, and environmental REI for the Allatoona study area which includes the following counties in Georgia: Barrow, Bartow, Butts, Carroll, Cherokee, Clayton, Cobb, Coweta, Dawson, De Kalb, Douglas, Fayette, Forsyth, Fulton, Gwinnet, Haralson, Heard, Henry, Jasper, Lamar, Meriwether, Newton, Paulding, Pickens, Pike, Rockdale, Spalding, and Walton.

D.10.1.1 Flood Risk Management REI

The following tables describe the current REI for the Allatoona study area with regards to FRM operations.

Table D-32. Allatoona RECONS FRM Input Assumptions ($)

Category	Spending (%)	Spending Amount	Local LPC (%)	State LPC (%)	National LPC (%)
Aggregate Materials	1%	$1,441	55%	81%	97%
Construction of Other New Nonresidential Structures	7%	$8,646	97%	97%	100%
Industrial and Machinery Equipment Rental and Leasing	2%	$3,144	64%	69%	100%
Architectural, Engineering, and Related Services	9%	$11,266	100%	100%	100%

Category	Spending (%)	Spending Amount	Local LPC (%)	State LPC (%)	National LPC (%)
Planning, Environmental, Engineering and Design Studies and Services	3%	$4,323	97%	97%	100%
USACE Overhead	15%	$19,519	100%	100%	100%
Repair and Maintenance Construction Activities	28%	$36,287	100%	100%	100%
USACE Wages and Benefits	30%	$39,824	75%	99%	100%
Private Sector Labor or Staff Augmentation	5%	$6,550	100%	100%	100%
Total	**100%**	**$131,000**	-	-	-

The USACE is planning on expending $131,000 on the project for FRM functions. Of this total project expenditure $118,753 will be captured within the regional impact area. The rest will be leaked out to the state or the nation. The expenditures made by the USACE for various services and products are expected to generate additional economic activity in that can be measured in jobs, income, sales and gross regional product as summarized in the following table and includes impacts to the region, the State impact area, and the Nation. Table D-33 is the overall economic impacts for this analysis.

Table D-33. Allatoona RECONS Summary of FRM Economic Impacts ($)

Impact Areas Impacts		Regional	State	National
Total Spending		$131,000	$131,000	$131,000
Direct Impact				
	Output	$118,753	$129,003	$130,942
	Job	1.15	1.24	1.25
	Labor Income	$76,678	$85,847	$86,718
	Gross Regional Product	$84,005	$94,029	$95,232
Total Impact				
	Output	$242,631	$264,984	$357,588
	Job	2.11	2.30	2.74
	Labor Income	$123,645	$136,578	$161,371
	Gross Regional Product	$163,845	$180,831	$224,552

Table D-34. Allatoona RECONS Recreation Input Assumptions ($)

Category	Spending (%)	Spending Amount	Local LPC (%)	State LPC (%)	National LPC (%)
Construction of Other New Nonresidential Structures	18%	$593,296	97%	97%	100%
USACE Overhead	14%	$465,198	100%	100%	100%
Repair and Maintenance Construction Activities	37%	$1,237,157	100%	100%	100%
USACE Wages and Benefits	28%	$943,880	75%	99%	100%
Private Sector Labor or Staff Augmentation	4%	$131,469	100%	100%	100%
Total	**100%**	**$3,371,000**	**-**	**-**	**-**

The USACE is planning on expending $3,371,000 on the project for recreation functions. Of this total project expenditure $3,112,958 will be captured within the regional impact area. The rest will be leaked out to the state or the nation. The expenditures made by the USACE for various services and products are expected to generate additional economic activity in that can be measured in jobs, income, sales and gross regional product as summarized in the following table and includes impacts to the region, the State impact area, and the Nation. Table D-35 is the overall economic impacts for this analysis.

Table D-35. Allatoona RECONS Summary of Recreation Economic Impacts ($)

Impact Areas Impacts		Regional	State	National
Total Spending		$3,371,000	$3,371,000	$3,371,000
Direct Impact				
	Output	$3,112,958	$3,343,020	$3,370,647
	Job	29.88	31.79	32.02
	Labor Income	$1,835,194	$2,046,946	$2,060,877
	GRP	$2,055,744	$2,285,807	$2,301,830
Total Impact				
	Output	$6,240,942	$6,763,429	$9,267,409
	Job	54.31	58.75	70.78
	Labor Income	$3,027,243	$3,323,107	$3,986,528
	GRP	$4,063,588	$4,452,908	$5,624,671

D.10.1.2 Allatoona Hydropower REI

Table D-36. Allatoona RECONS Hydropower Input Assumptions ($)

Category	Spending (%)	Spending Amount	Local LPC (%)	State LPC (%)	National LPC (%)
Metals and Steel Materials	3%	$77,792	25%	25%	90%
Construction Machinery Manufacturing	3%	$68,640	20%	27%	79%
Turbine Equipment and Parts	1%	$32,032	3%	4%	68%
Switchgear and Switchboard Apparatus Equipment	2%	$45,760	31%	31%	80%
Planning, Environmental, Engineering and Design Studies and Services	2%	$54,912	97%	97%	100%
USACE Overhead	22%	$494,208	100%	100%	100%
Repair and Maintenance Construction Activities	10%	$226,512	100%	100%	100%
Industrial Machinery and Equipment Repair and Maintenance	5%	$112,112	73%	73%	100%
USACE Wages and Benefits	44%	$1,004,432	75%	99%	100%
Private Sector Labor or Staff Augmentation	8%	$171,600	100%	100%	100%
Total	**100%**	**$2,288,000**	-	-	-

The USACE is planning on expending $2,288,000 on the project for hydropower functions. Of this total project expenditure $1,829,199 will be captured within the regional impact area. The rest will be leaked out to the state or the nation. The expenditures made by the USACE for various services and products are expected to generate additional economic activity in that can be measured in jobs, income, sales and gross regional product as summarized in the following table and includes impacts to the region, the State impact area, and the Nation. Table D-37 is the overall economic impacts for this analysis.

Table D-37. Allatoona RECONS Summary of Hydropower Economic Impacts ($)

Impact Areas Impacts		Regional	State	National
Total Spending		$2,288,000	$2,288,000	$2,288,000
Direct Impact				
	Output	$1,829,199	$2,079,082	$2,246,121

Impact Areas Impacts		Regional	State	National
	Job	20.75	22.80	23.50
	Labor Income	$1,405,252	$1,631,212	$1,682,684
	GRP	$1,503,942	$1,749,863	$1,822,656
Total Impact				
	Output	$3,724,627	$4,245,992	$5,957,602
	Job	35.76	40.15	48.65
	Labor Income	$2,109,711	$2,427,137	$2,896,666
	GRP	$2,725,590	$3,136,746	$3,944,577

D.10.1.3 Allatoona Environmental REI

Table D-38. Allatoona RECONS Environmental Input Assumptions ($)

Category	Spending (%)	Spending Amount	Local LPC (%)	State LPC (%)	National LPC (%)
Support Activities for Agriculture and Forestry	6%	$33,245	21%	48%	98%
Construction of Other New Nonresidential Structures	7%	$36,515	97%	97%	100%
Architectural, Engineering, and Related Services	4%	$20,710	100%	100%	100%
Planning, Environmental, Engineering and Design Studies and Services	22%	$117,175	97%	97%	100%
Scientific Research and Development Services	1%	$5,995	32%	32%	99%
USACE Overhead	16%	$89,380	100%	100%	100%
Repair and Maintenance Construction Activities	8%	$44,690	100%	100%	100%
Remediation Services	1%	$5,450	64%	67%	100%
Other Education Services	2%	$9,810	99%	99%	100%
USACE Wages and Benefits	33%	$182,030	75%	99%	100%
Total	**100%**	**$545,000**	**-**	**-**	**-**

The USACE is planning on expending $545,000 on the project for environmental functions. Of this total project expenditure $462,509 will be captured within the regional impact area. The rest will be leaked out to the state or the nation. The expenditures made by the USACE for various services and products are expected to generate additional economic activity in that can be measured in jobs, income, sales and gross regional product as summarized in the following table and includes impacts to the region, the State impact area, and the Nation. Table D-39 is the overall economic impacts for this analysis.

Table D-39. Allatoona RECONS Summary of Environmental Economic Impacts ($)

Impact Areas Impacts		Regional	State	National
Total Spending		$545,000	$545,000	$545,000
Direct Impact				
	Output	$462,509	$515,878	$544,359
	Job	4.58	5.36	6.24
	Labor Income	$325,403	$373,127	$393,250
	GRP	$343,848	$395,003	$415,510
Total Impact				
	Output	$975,513	$1,085,362	$1,491,878
	Job	8.60	9.86	12.63
	Labor Income	$520,269	$586,913	$706,933
	GRP	$676,778	$762,378	$960,307

D.10.2 Coosa River Regional Economic Impacts

The following section describes the current water supply REI for the APC study area on the Coosa River.

Table D-40. APC RECONS Water Supply Input Assumptions ($)

Category	Spending (%)	Spending Amount	Local LPC (%)	State LPC (%)	National LPC (%)
Planning, Environmental, Engineering and Design Studies and Services	5%	$12,750	35%	50%	100%
USACE Overhead	31%	$78,250	77%	89%	100%

Category	Spending (%)	Spending Amount	Local LPC (%)	State LPC (%)	National LPC (%)
USACE Wages and Benefits	64%	$159,000	75%	100%	100%
Total	**100%**	**$250,000**	**-**	**-**	**-**

The USACE is planning on expending $250,000 on the project for all functions. Of this total project expenditure $184,212 will be captured within the regional impact area. The rest will be leaked out to the state or the nation. The expenditures made by the USACE for various services and products are expected to generate additional economic activity in that can be measured in jobs, income, sales and gross regional product as summarized in the following table and includes impacts to the region, the State impact area, and the Nation. Table D-41 is the overall economic impacts for this analysis.

Table D-41. APC RECONS Summary of FRM Economic Impacts ($)

Impact Areas Impacts		Regional	State	National
Total Spending		$250,000	$250,000	$250,000
Direct Impact				
	Output	$184,212	$234,507	$249,974
	Job	2.38	2.94	3.19
	Labor Income	$144,167	$186,876	$197,408
	GRP	$156,390	$202,587	$213,142
Total Impact				
	Output	$338,185	$463,004	$659,274
	Job	3.81	4.89	6.00
	Labor Income	$199,321	$265,925	$332,774
	GRP	$251,926	$344,106	$450,768

D.10.3 ACR Study Area Economic Impacts

For the entire study area including both the Allatoona area and APC/Coosa River areas produces an annual REI of $7,881,727. State impacts are $8,876,969 annually, and National impacts are $11,204,875 annually. Together the entire study area produces $27,963,571 in economic outputs. These economic impacts highlight the benefits to the region, state, and nation, and make the case that continued existence of these projects is a vital asset to the communities that depend on them for economic productivity as well as general FRM, water supply, and hydropower benefits.

Table D-42. ACR RECONS Summary ($)

Impact Areas Impacts		Regional	State	National
Total Spending		$6,585,000	$6,585,000	$6,585,000
Direct Impact				
	Output	$5,707,631	$6,301,490	$6,542,043
	Job	59	64	66
	Labor Income	$3,786,694	$4,324,008	$4,420,937
	GRP	$4,143,929	$4,727,289	$4,848,370
Total Impact				
	Output	$11,521,898	$12,822,771	$17,733,751
	Job	105	116	141
	Labor Income	$5,980,189	$6,739,660	$8,084,272
	GRP	$7,881,727	$8,876,969	$11,204,875

Attachment 1. Recreation Impact Analysis Report—Summary Memorandum

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ALLATOONA LAKE WATER SUPPLY STORAGE REALLOCATION STUDY AND UPDATES TO WEISS AND LOGAN MARTIN RESERVOIRS WATER CONTROL MANUALS

FEASIBILITY REPORT AND INTEGRATED SUPPLEMENTAL ENVIRONMENTAL IMPACT STATEMENT

RECREATION IMPACT ANALYSIS SUMMARY MEMORANDUM

FEBRUARY 2020

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Prepared for

U.S. Army Corps of Engineers
Mobile District

Prepared by

Tetra Tech, Inc.

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EXECUTIVE SUMMARY

This memorandum summarizes the objectives, methods, and results of the recreation analysis performed for the Allatoona Lake Water Supply Storage Reallocation Study and Updates to Weiss And Logan Martin Reservoirs Water Control Manuals Feasibility Report And Integrated Supplemental Environmental Impact Statement (FR/SEIS). The analysis estimates National Economic Development (NED) recreation benefits for the final array of alternatives using the Unit Day Value (UDV) methodology. The purpose of estimating these NED benefits is to facilitate the assessment and comparison of socio-economic and environmental impacts of the tentatively selected plan and other alternatives under consideration. Recreation benefits are not a driver of project selection.

Per the UDV methodology, project visitation was forecasted for each project over the period of analysis, and UDV scores were generated for each project and recreation impact zone. UDV scores were converted to value-per-visit in accordance with the FY20 guidance, and total annual recreation value was estimated by project and alternative.

Scores generated for the UDV analysis were a function of reservoir pool level. For each project, several recreation impact zones (pool level ranges) were defined consistent with existing information about the effects of decreasing pool on recreation. The results from the detailed engineering modeling of the alternatives in the FR/SEIS were queried to tabulate the amount of time during the year the reservoirs would remain within recreation impact zone under each alternative. This allowed estimation of the proportion of annual visitation that would occur within in recreation impact zone and application of the UDV methodology for the FWOP and the alternatives. Based on modeling of reservoir levels documented in the main FR/SEIS, alternatives were categorized into two recreation impact scenarios:

- No Change Scenario – Consisting of the alternatives whose proposed changes would have negligible effects on recreation relative to the Future Without Project (FWOP).
- With Change Scenario – Consisting of the alternatives whose proposed changes would affect recreation at the projects.

As shown in the table below, the With Change Scenario would result in positive net benefits to recreation at all three of the projects, ranging from about 1-3% net gain compared to the FWOP.

Project and Scenario	Annualized Recreation Value ($)	Present Value ($)	Annualized Change vs. Without Project	Percent Change
Allatoona				
No Change Scenario	$75,045,400	$2,026,014,000	$0	0%
With Change Scenario [1]	$75,754,000	$2,045,143,000	$708,600	0.9%
Weiss				
No Change Scenario	$16,152,500	$436,071,000	$0	0%
With Change Scenario [2]	$16,485,700	$445,067,000	$333,200	2.1%
Logan Martin				
No Change Scenario	$16,442,800	$443,910,000	$0	0%
With Change Scenario [2]	$16,950,700	$457,620,000	$507,900	3.1%

[1] Allatoona WCS alternatives: 5, 8, 11, 13

[2] Weiss and Logan Martin WCS alternatives: 9, 10, 11, 12, 13

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Attachment A – UDV Scoring Rubric

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1. INTRODUCTION

1.1. PURPOSE, SCOPE, AND OBJECTIVES

The purpose of this memorandum is to summarize the objectives, methods, and results of the recreation analysis performed for the Allatoona Lake Water Supply Storage Reallocation Study and Updates to Weiss And Logan Martin Reservoirs Water Control Manuals Feasibility Report And Integrated Supplemental Environmental Impact Statement (FR/SEIS). This evaluation is project-wide, inclusive of both federal and non-federal recreation use at the projects.

This analysis estimates National Economic Development (NED) recreation benefits under current water control operations and compares it to the estimated benefits under alternative operational scenarios to allow the calculation of net recreation benefits resulting from proposed operational changes. The purpose of estimating these NED benefits is to facilitate the assessment and comparison of socio-economic and environmental impacts of the tentatively selected plan and other alternatives under consideration. Recreation benefits are not a driver of project selection.

1.2. STUDY AREA

The overall study area is the Alabama-Coosa-Tallapoosa (ACT) River Basin. The ACT River Basin includes the Alabama, Coosa, and Tallapoosa rivers and all areas in the basin boundaries from the headwaters downstream to the mouth of the Alabama River, where it joins the Tombigbee River to form the Mobile River. The ACT River Basin at its confluence with the Tombigbee River has a drainage area of 22,739 square miles and covers portions of the states of Alabama, Georgia, and Tennessee. The ACT River Basin is shown in **Figure 1** (following page).

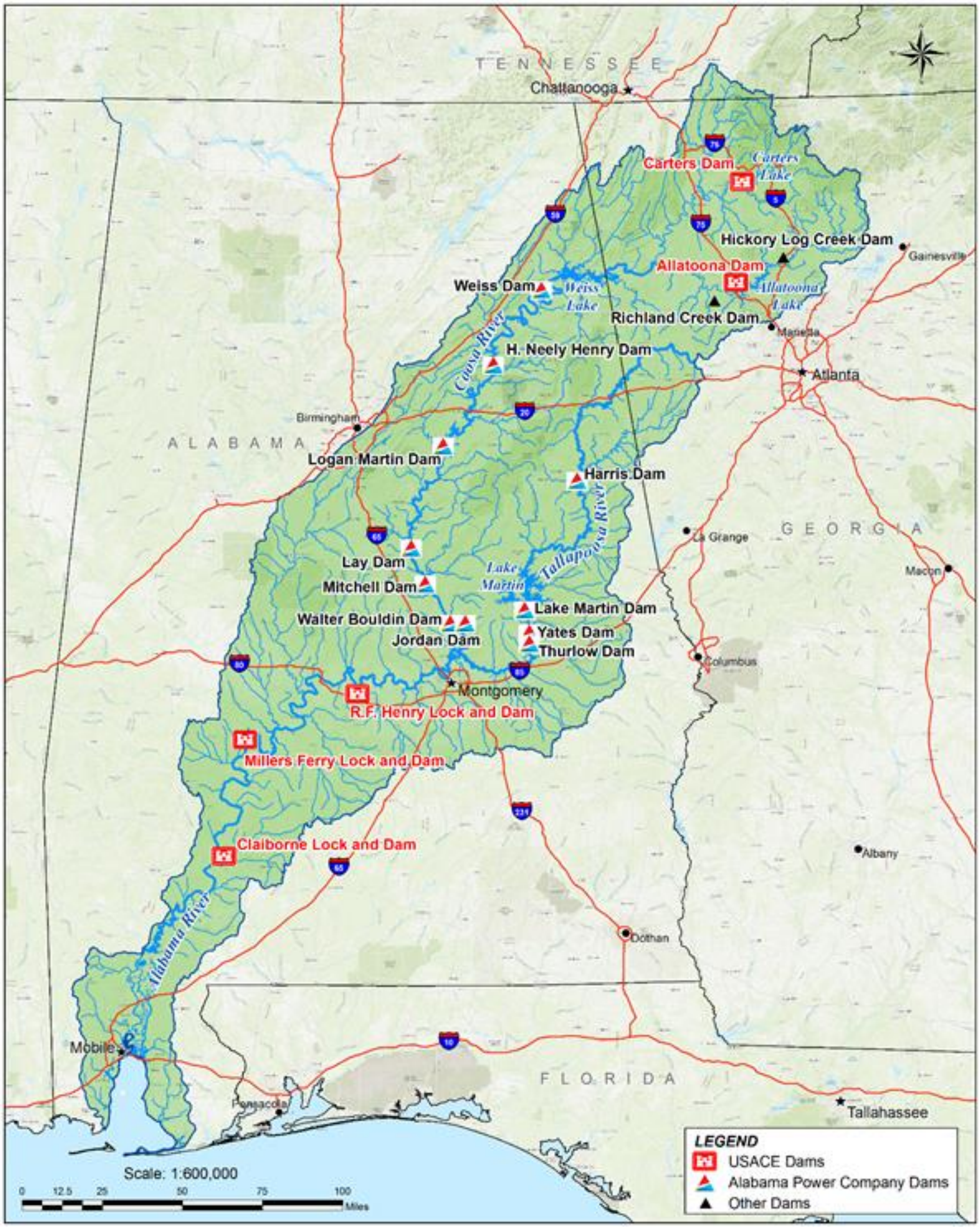
Based on review of engineering modeling results, the proposed operational changes among the alternatives resulted in potential recreational impacts at three projects, including Allatoona Lake (Allatoona), Weiss Lake (Weiss), and Logan Martin Lake (Logan Martin). For this recreation analysis, the study area is limited to these three projects. Allatoona is a USACE project, and Weiss and Logan Martin are both Alabama Power Company (APC) projects.

2. EVALUATION METHODOLOGY

2.1. NED RECREATION ANALYSIS

In this NED recreation analysis, the value of recreation refers to the value provided to recreation visitors and is estimated through approximation of visitors' *willingness to pay* for the recreation opportunity. In the case of a visitor to a Corps project, *willingness to pay* is the total value a visitor would be willing to pay to access the project, which would be the sum of any user fees actually paid, plus the additional amount they would be willing to pay but do not need to pay (referred to as the consumer surplus). The *willingness to pay* approach estimates the total economic value received by visitors to the project. Note that this NED approach to recreation value estimation does not include any payments made for other goods and services in the local economy (e.g. food, lodging, equipment rentals, etc.) associated with each recreation visit (USACE 2000, 1986).

Figure 1 – Study Area



2.2. UNIT DAY VALUE METHOD

The appropriate valuation methodology for estimating visitor *willingness to pay* was selected based on the guidelines in Appendix E, paragraph E-50b(4), in ER 1105-2-100 (USACE 2000). For this study, there is no regional model available for recreation; the project is not creating specialized recreation activities as defined in the ER; and there is no increase in Federal costs for recreation, since the water management alternatives do not include addition of recreation features to the project. As such, the Unit Day Value (UDV) methodology was selected as the appropriate valuation method.

When applying the UDV methodology, two categories of outdoor recreation visits, general and specialized, may be differentiated for evaluation purposes. “General” refers to a recreation visit involving primarily those activities that are attractive to the majority of outdoor users and that generally require the development and maintenance of convenient access and adequate facilities. “Specialized” refers to a recreation visit involving those activities for which opportunities in general are limited, intensity of use is low, and a high degree of skill, knowledge, and appreciation of the activity by the user may often be involved (USACE 2019a). All of the activities for this analysis were determined to fall into the general recreation category. Within the general category, separate values per visit were applied to general fishing & hunting and all other general activities.

The UDV method for estimating recreation benefits approximates the average willingness to pay of users. By applying a unit-day-value per visitor, an approximation of project recreation benefits is obtained. Per the guidance, this analysis does reflect that the proportion of visitation which is for fishing and hunting is assigned a different value per visit than the rest of the visitation.

The UDV process includes scoring of the project site using five guidance-defined criteria to yield a point score for the recreation opportunity at the project. The point score is converted to dollars-per-visit using tables provided in the UDV guidance (updated annually). The final dollars-per-visit value is the UDV. The UDV is then multiplied by the number of annual visitors to generate an estimate of the annual recreation value at the site. This annual value is then projected over the 50-year period of analysis based on visitation projections for the study area.

This method of estimating annual recreation value is completed twice. First, a valuation is completed for the No Action Alternative. Second, a valuation is completed for the “with” project alternatives. The difference between the two estimates is the net recreation value (net benefits) attributable to the alternative being evaluated.

2.3. APPLICATION FOR THIS ANALYSIS

In this analysis, a separate UDV scoring evaluation is presented for each of the three reservoirs (Allatoona, Weiss, and Logan Martin). This approach required site-specific visitation data as well as separate UDV scorings for each of the three reservoirs. The recreation impact analysis was performed on the final array of alternatives (see main FR/SEIS for more detailed descriptions of each alternative). No recreation features are proposed for construction as part of the alternatives. The alternatives affect recreation by altering reservoir pool levels, which in turn affect recreation. The extent to which recreation is affected was accounted for as a function of the amount of time the pool is held at or below several pool levels. For Allatoona, there are four established USACE recreation impact levels which were utilized, as shown in **Table 1**. These specific recreation impact levels were established by USACE to define threshold lake elevations at which impacts to the accessibility and use of recreation facilities (boat ramps, public docks, beaches, etc.) becomes increasingly more severe. The impact levels at

Allatoona Lake range over a 17-foot elevation span between the summer pool level (840 ft) and winter pool level (823 ft).

Table 1. Allatoona Impact Levels

Name	Elevation Zone	Effects on Recreation
Full Pool	840 – 837 feet	No effect
Initial Impact Level	837 – 835 feet	Initial adverse effect
Recreation Impact Level	835 – 828 feet	Major adverse effects
Water Access Limited	Below 828 feet	Activities and access severely restricted

For the two APC projects, Weiss and Logan Martin, coordination with APC confirmed there are no such established impact levels. For the purpose of this analysis, three impact elevation zones were identified (**Table 2**). These zones were based on existing information from APC and public input during the USACE scoping process for this study which indicates that while summer pool levels are the most desirable for recreation, raising winter pool levels at Weiss and Logan Martin by 2-to-3 feet would alleviate the most severe recreation impacts the currently occur during low winter pools, leading to the identification of three impact zones for optimal conditions (summer pool), least-favorable conditions (existing winter pool), and a those elevations in between.

Table 2. Weiss and Logan Martin Impact Levels

Name	Elevation Zone		Effects on Recreation
	Weiss	Logan Martin	
Full Pool	564 – 561 feet	465 – 462 feet	No effect
Reduced Pool	561 – 558 feet	462 – 460 feet	Initial adverse effects
Limited Pool	Below 558 feet	Below 460 feet	Major adverse effects

Pool elevations under each the alternatives were obtained from results of detailed engineering modeling performed for the study (see the main FR/SEIS for more information about the engineering modeling). The engineering modeling considered 11 operational alternatives (see the main FR/SEIS for detailed description of the alternatives).

- #2 - FWOP: Future Without Project Condition
- #3 - WS1: Water Supply 1
- #4 - WS2: Water Supply 2
- #5 - WS3: Water Supply 3
- #8 - WS6: Water Supply 6
- #9 - MFO1: Modified Flood Operations 1
- #10 - WS2 + MFO1: Water Supply 2 + Modified Operations 1
- #11 - WS6 + MFO1: Water Supply 6 + Modified Operations 1
- #12 - WS1 + MFO1: Water Supply 1 + Modified Operations 1
- #13 - WS3 + MFO1: Water Supply 3 + Modified Operations 1

Using the results of the engineering modeling, the amount of time the pool level of each reservoir would remain within each recreation impact zone was extracted (see **Table 4**) and tallied for the entire year.

Next, UDV scores were developed for each reservoir. A UDV score was developed for each pool level at each reservoir (4 scores for Allatoona, and 3 each for Weiss and Logan Martin). In doing so, the effect on recreation for each alternative could be measured as a function of effect on pool level. This approach reflects that pool levels which are less than optimal for recreation would result in reduced value of the recreation opportunity (i.e., visitors have a lower willingness to pay for recreation at these reservoirs as pool levels drop below optimal levels and reduce the quality of the recreation experience).

These scores were converted to a dollar value per recreation visit (see Section 2.7) and then applied to estimates of annual visitation for each project. This step results in an estimate of recreation value at each reservoir for the time spent at each pool level. Adding up the value for each pool level based upon the amount of time at each level resulted in an estimate of recreation value across the 50-year period of analysis. This value was annualized using the Fiscal Year (FY) 2020 Federal discount rate of 2.75% percent to yield an estimate of the average annual recreation value for each alternative. These average annual values can be compared to the without project average annual value to assess the effect of each alternative on recreation value. This method estimates recreation value as a function of change in recreation quality. Based upon the nature of the alternatives, the same future without project visitation levels are applied in the with-project condition as well (see Section 5 for further discussion).

2.4. SUMMARY OF OPERATIONAL CHANGES BY ALTERNATIVE

As noted in the summary, this recreation analysis estimates the recreation impacts associated with each of the alternatives as a function of proposed pool levels throughout the year.

Use of the year-round dataset was determined to be most appropriate based upon the nature of the operational changes proposed in the alternatives and the projects themselves. Changes proposed at Allatoona would affect the pool year-round, requiring a year-long lens to capture all potential effects on recreation. Additionally, the project's proximity to a large urban center, with numerous residential areas immediately adjacent to the lake, results in high potential for recreational use outside the peak season. At Weiss and Logan Martin, proposed changes would have no effect on peak recreation season (Jun – September). However, substantial changes are proposed for the winter pool. Stakeholders at the project have reiterated the importance of winter pool levels on recreation, warranting consideration of year-round effects. The proposed changes would improve lake level conditions over current operations from September through February at Weiss Lake and from October through mid-April at Logan Martin Lake. Substantial recreation use can occur on warm weather days during these periods.

Engineering modeling results were used to estimate the percent of time throughout the year the reservoir would remain within the pool elevations of each impact zone. At the back of this section, **Table 4** summarizes these pool levels for each alternative, and **Figure 2** though **Figure 4** illustrate the values in the tables graphically, showing how long the pool would remain in each zone under each alternative.

As shown in the figure and tables, the alternatives fall into two natural groupings: 1) alternatives exhibiting approximately the same pool level conditions as the FWOP, and 2) alternatives exhibiting increased duration at full pool and decreased duration at the lower pools.

At **Allatoona**:

- Alternatives 3, 4, 9, 10, and 12 exhibit relatively little change from the FWOP, approximately ±1.5% at each impact level.
- Alternatives 5, 8, 11, and 13 all result in an increase in the proportion of time spent at Full Pool, showing ≥4.5% increase over the entire year.

At **Weiss** and **Logan Martin**:

- Alternatives 3, 4, 5, and 8 exhibit negligible changes from the FWOP.
- Alternatives 9, 10, 11, 12, and 13 all show significant increase in the duration of time spent at Full Pool. Review of modeling results show this increase is due to a higher proposed winter pool. At Weiss, these alternatives exhibit a 25% increase in time spent in the Full Pool impact zone. Similarly at Logan Martin, these alternatives exhibit a 33% increase in time spent in the Full Pool impact zone.

2.4.1. TWO RECREATION IMPACT SCENARIOS

Alternatives exhibiting little-to-no change in operations relative to the FWOP would not be expected to significantly affect recreation. Additionally, for alternatives that do include operational changes, those changes were the same across alternatives for a given project. As such, this analysis grouped the alternatives for the purpose of estimating recreation impacts. This grouping supports a simplified discussion of potential impacts, referring either to the group of alternatives under which recreation would be much the same as the FWOP (No Change Scenario), or the group of alternatives under which operational changes would be expected to affect recreation (With Change Scenario). **Table 3** illustrates the grouping of alternatives for the purpose of this analysis. Subsequent sections of the document will refer only to the No Change Scenario (NCS) and the With Change Scenario (WCS). Recreation impacts estimated for the WCS are applicable to all constituent alternatives.

Table 3. Grouping Alternatives for Analysis

Alternative	Allatoona	Weiss	Logan Martin
#2 - FWOP	No Change	No Change	No Change
#3 - WS1	No Change	No Change	No Change
#4 - WS2	No Change	No Change	No Change
#5 - WS3	With Changes	No Change	No Change
#8 - WS6	With Changes	No Change	No Change
#9 - MFO1	No Change	With Changes	With Changes
#10 - WS2 + MFO1	No Change	With Changes	With Changes
#11 - WS6 + MFO1	With Changes	With Changes	With Changes
#12 - WS1 + MFO1	No Change	With Changes	With Changes
#13 - WS3 + MFO1	With Changes	With Changes	With Changes

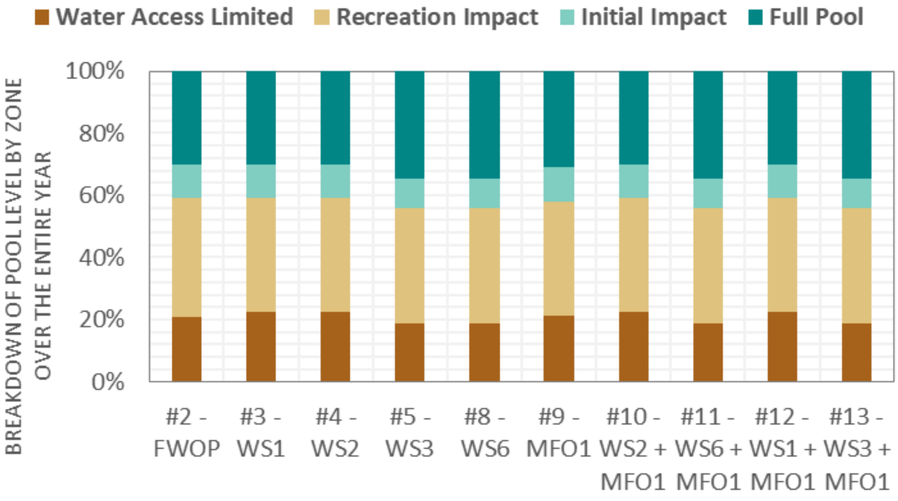


Figure 2 – Allatoona Pool and Recreation Impact Level by Alternative, Entire Year

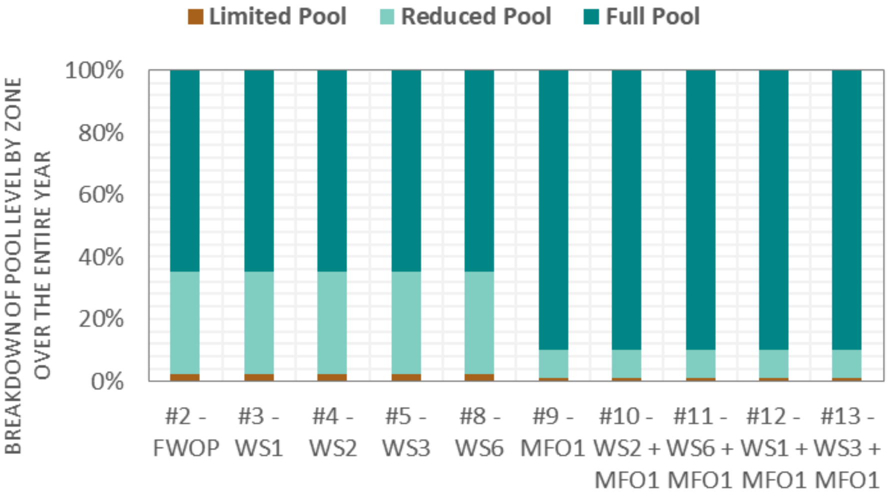


Figure 3 – Weiss Pool and Recreation Impact Level by Alternative, Entire Year

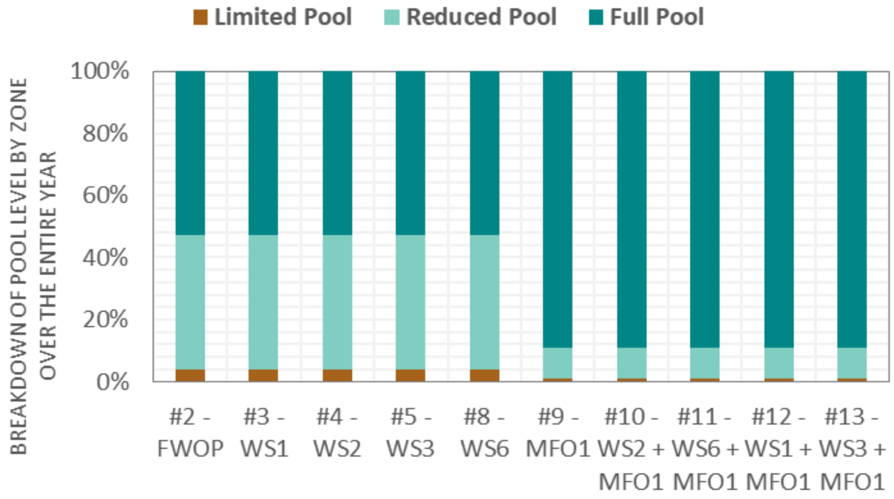


Figure 4 – Logan Martin Pool and Recreation Impact Level by Alternative, Entire Year

Table 4. Alternatives Summary, Pool and Recreation Impact Level by Alternative, Entire Year

Alternative	Allatoona				Weiss			Logan Martin		
	Full Pool	Initial Impact Level	Recreation Impact Level	Water Access Limited	Full Pool	Reduced Pool	Limited Pool	Full Pool	Reduced Pool	Limited Pool
#2 - FWOP	30.2%	10.8%	38.0%	21.0%	64.7%	33.3%	2.0%	53.0%	43.0%	4.0%
#3 - WS1	30.2%	10.8%	36.7%	22.3%	64.7%	33.3%	2.0%	53.0%	43.0%	4.0%
#4 - WS2	30.1%	10.9%	36.7%	22.3%	64.7%	33.3%	2.0%	53.0%	43.0%	4.0%
#5 - WS3	34.7%	9.3%	37.1%	18.9%	64.7%	33.3%	2.0%	53.0%	43.0%	4.0%
#8 - WS6	34.7%	9.3%	37.1%	18.9%	64.7%	33.3%	2.0%	53.0%	43.0%	4.0%
#9 - MFO1	30.8%	11.2%	36.9%	21.1%	90.0%	9.0%	1.0%	89.0%	10.0%	1.0%
#10 - WS2 + MFO1	30.1%	10.9%	36.7%	22.3%	90.0%	9.0%	1.0%	89.0%	10.0%	1.0%
#11 - WS6 + MFO1	34.7%	9.3%	37.1%	18.9%	90.0%	9.0%	1.0%	89.0%	10.0%	1.0%
#12 - WS1 + MFO1	30.2%	10.8%	36.7%	22.3%	90.0%	9.0%	1.0%	89.0%	10.0%	1.0%
#13 - WS3 + MFO1	34.7%	9.3%	37.1%	18.9%	90.0%	9.0%	1.0%	89.0%	10.0%	1.0%

2.5. VISITATION ESTIMATE

Visitation estimates were obtained from available published information. For Allatoona, visitation was obtained from the USACE through its Visitation Estimation and Reporting System (VERS) program (USACE 2019). For Weiss and Logan Martin, best available project-wide visitation was obtained from a recent EA prepared for the Coosa River Hydroelectric Project (FERC 2009). This report included a forecast of visitation by project to 2015 which was used as a baseline for further adjustment and forecast.

To forecast visitation growth during the period of analysis, growth rates applied in *FERC 2009* study were compared to recent regional and statewide general population growth rates available from the U.S. Census Bureau. While Atlanta continues to grow at upwards of 1.5% per year, much of the region surrounding the projects exhibits lower growth rates. For the purpose of conservatively estimating project visitation growth across the projects, a compound annual growth rate of 0.7% was applied to all projects for a period of 10 years. Visitation was held constant for the remainder of the period of analysis in acknowledgment of the uncertainty associated with long-range visitation growth forecasts and carrying capacity of the projects. **Table 5** presents the total visitation estimates for each project.

Table 5. Total Annual Visitation by Project

Year	Allatoona	Weiss	Logan Martin
2020	6,602,900	1,498,800	1,557,000
2030*	7,030,700	1,595,900	1,657,900
Avg. Ann.	**6,987,500**	**1,586,000**	**1,647,700**
** Held at this value for remainder of period of analysis*			

The proportion of visitation for fishing and hunting was also identified. **Table 6** presents these proportions by project. These factors were supported by the visitation source data referenced above and will be used in the analysis to allow application of a separate value per visit for fishing and hunting visits.

Table 6. Proportion of Visitation for Hunting and Fishing

	Allatoona	Weiss	Logan Martin
% Fishing and Hunting	15%	44%	40%

2.6. UDV SCORING / POINT ASSIGNMENT

UDV scoring was developed based upon the expected recreation impact levels described in Section 2.3. For each project, scores were developed for each pool impact level at each reservoir (4 scores at Allatoona, 3 each at Weiss and Logan Martin). In doing so, the recreation value for the NCS and for the WCS could be measured as a function of effect on pool impact level. The five UDV criteria for which points are assigned were:

- Recreation Experience: Score increases in proportion to the number of available activities at the site.

- Availability of Opportunity: Score is based on availability of substitute sites; the fewer the sites in the region that offer comparable recreation experience, the higher the score. In the case of fishing and hunting, reflects effects on likelihood of success.
- Carrying Capacity: Score rates level of facilities at the site to support the activities.
- Accessibility: Score rates ease of access to the site.
- Environmental: Rates the aesthetic/environmental quality of the recreation site/activities.

Scoring was based on the consideration of general recreation activities that would be affected at each project, with the same scores being applied for fishing as all other general recreation activities. **Attachment A** provides a copy of the USACE guidance which contains the scoring rubric. **Table 7** shows the scores developed for each project and pool impact level. In the sections following the table, the rationale is provided for the point assignments according to the five UDV criteria. In Section 2.7, these scores are converted to dollar value equivalents.

Table 7. UDV Score Summary

	Criteria					
	Recreation Experience	**Avail. of Opportunity**	**Carrying Capacity**	**Accessibility**	**Environ-mental**	**Total**
Allatoona						
Full Pool	30	14	14	18	18	**94**
Initial Impact	26	14	14	18	16	**88**
Recreation Impact	26	10	8	14	12	**70**
Water Access Limited	16	6	5	8	10	**45**
Weiss						
Full Pool	27	6	7	13	18	**71**
Reduced Pool	23	6	4	11	14	**58**
Limited Pool	19	6	3	9	10	**47**
Logan Martin						
Full Pool	26	6	7	13	18	**70**
Reduced Pool	22	6	4	11	14	**57**
Limited Pool	18	6	3	9	10	**46**

2.6.1. RECREATION EXPERIENCE

2.6.1.1. ALLATOONA

FULL POOL

This criterion was scored 30 out of 30 points. All high quality and general activities would be available at the lake. Allatoona is one of the nation's most-visited Corps reservoir projects and offers a wide range of activities.

INITIAL IMPACT

This criterion scored 26 out of 30 points. At this level, it would be expected that swim areas would be impacted and there may be some minor navigation hazards, but that most facilities remain available, including boat ramps and docks.

RECREATION IMPACT

This criterion scored 26 out of 30 points, reflecting that even as some effects are increased at swimming areas and beaches, the project would still offer many opportunities for recreation.

WATER ACCESS LIMITED

This criterion scored 16 out of 30 points. At this pool level, land-based activities are still minimally affected but numerous water-based activates are significantly affected. It'd be expected that boating access would be significant hindered, and that navigation hazard would be present in shallower regions of the reservoir, significantly affecting the quality of water-based activities.

2.6.1.2. WEISS

FULL POOL

This criterion was scored 27 out of 30 points. All high quality and general activities would be available at the lake. Weiss is a known high-quality fishing resource and scores highly accordingly.

REDUCED POOL

This criterion was scored 23 out of 30 points. At this level, recreation impact begins to be noticeable, but most activities are still available. Swimming areas become affected usable, and ramps and docks are usable but may need to accommodate the pool level. Some private docks may be unusable. There may be some navigation hazards for boaters.

LIMITED POOL

This criterion was scored 19 out of 30 points. At this impact level significant impacts to recreation are noticeable. Some beaches will become marginally usable, and many public and private boat launches and docks will be unusable. Boaters would need to be on alert for unmarked navigation hazards and may not be able to access all areas of the lake, especially small and shallow coves. Still, land-based activities remain available and most water activities are of reduced quality but still available.

2.6.1.3. LOGAN MARTIN

FULL POOL

This criterion was scored 26 out of 30 points. All high quality and general activities would be available at the lake. Logan Martin is popular regional resource that offers a wide range of activities.

REDUCED POOL

This criterion was scored 22 out of 30 points. At this level, recreation impact begins to be noticeable, but most activities are still available. Swimming areas become affected usable, and ramps and docks are usable but may need to accommodate the pool level. Some private docks may be unusable. There may be some navigation hazards for boaters.

LIMITED POOL

This criterion was scored 18 out of 30 points. At this impact level significant impacts to recreation are noticeable. Some beaches will become marginally usable, and many public and private boat launches and docks will be unusable. Boaters would need to be on alert for unmarked navigation hazards and may not be able to access all areas of the lake, especially small and shallow coves. Still, land-based activities remain available and most water activities are of reduced quality but still available.

2.6.2. AVAILABILITY OF OPPORTUNITY

2.6.2.1. ALLATOONA

FULL POOL

This criterion was scored 14 out of 18 points. This score reflects that other high-quality value activities and general activities are available in the region within a one-hour travel time.

INITIAL IMPACT

This criterion was scored 14 out of 18 points. This impact level would have minimal additional effect on land-based activities and water-based activities may begin to be affected but would largely be available.

RECREATION IMPACT

This criterion was scored 10 out of 18 points as well. At this level of impact, other regional projects might be attractive substitutes, especially for water-based activities. Land based activities would still be minimally affected.

WATER ACCESS LIMITED

This criterion was scored 6 out of 14 points. This additional reduction reflects that, in general, water-based activities would be severely restricted and of reduced quality at this level, likely making additional projects attractive substitutes.

2.6.2.2. WEISS

ALL IMPACT LEVELS

This criterion was scored 6 out of 18 points. This score reflects that there are several locations within one-hour drive time that provide similar recreational opportunities to the public. This score was held constant across all impact levels.

2.6.2.1. LOGAN MARTIN

ALL IMPACT LEVELS

This criterion was scored 6 out of 18 points. This score reflects that there are several locations within one-hour drive time that provide similar recreational opportunities to the public. This score was held constant across all impact levels.

2.6.3. CARRYING CAPACITY

2.6.3.1. ALLATOONA

FULL POOL

This criterion was scored 14 out of 14 points, reflecting that Allatoona is one of the most developed lake recreation projects in the region.

INITIAL IMPACT

This criterion was scored 14 out of 14 points, reflecting that the impacts here would not substantially affect carrying capacity.

RECREATION IMPACT

This criterion was scored 8 out of 14 points. This reduced score reflects that at this pool level, the project may have a reduced functional capacity as beaches, boat ramps, and docks begin to become unusable. Land based facilities would still not be affected significantly.

WATER ACCESS LIMITED

This criterion was scored 5 out of 14 points. Further reduction in the score reflects that the number of accessible boat ramps and other water access points would be further reduced at this pool level.

2.6.3.2. WEISS

FULL POOL

This criterion was scored 7 out of 14 points. The score reflects that the project consists of favorable and commonly requested facilities/amenities that support the most popular activities at the project, and past reports (FERC and USACE 2009) found that there are no major carrying capacity concerns.

REDUCED POOL

This criterion was scored 4 out of 14 points. This score reflects that there would be deterioration of water access conditions would warrant dropping the score by one level.

LIMITED POOL

This criterion was scored 3 out of 14 points. This score reflects that at this lower reservoir level, inaccessibility of boat ramps and docks would affect functional capacity of the project.

2.6.3.1. LOGAN MARTIN

FULL POOL

This criterion was scored 7 out of 14 points. The score reflects that the project consists of favorable and commonly requested facilities/amenities that support the most popular activities at the project, and past reports (FERC and USACE 2009) found that there are no major carrying capacity concerns.

REDUCED POOL

This criterion was scored 4 out of 14 points. This score reflects that there would be deterioration of water access conditions would warrant dropping the score by one level.

LIMITED POOL

This criterion was scored 3 out of 14 points. This score reflects that at this lower reservoir level, inaccessibility of boat ramps and docks would affect functional capacity of the project.

2.6.4. ACCESSIBILITY

2.6.4.1. ALLATOONA

FULL POOL

This criterion was scored 18 out of 18 points, reflecting that Allatoona has very well-developed access to the site and within the site, including access to water-based activities.

INITIAL IMPACT

This criterion was scored 18 out of 18 points, reflecting that the impacts at this level would not substantially alter access via road, boat ramp, and dock.

RECREATION IMPACT

This criterion was scored 14 out of 18 points. This reduced score reflects that at this pool level, access to water-based activities may be affected at some boat ramps and docks, though access to the project and for land-based activities remains good.

WATER ACCESS LIMITED

This criterion was scored 8 out of 18 points. Further reduction in the score reflects that the availability of many boat ramps, docks, and other water access points would be adversely affected at this pool level.

2.6.4.2. WEISS

FULL POOL

This criterion was scored 13 out of 18 points, reflecting that Weiss has good access to and within the site.

REDUCED POOL

This criterion was scored 11 out of 18 points. This score reflects that docks and boat ramps may begin to be affected in this elevation zone which may reduce the quality of access for water-based activities.

LIMITED POOL

This criterion was scored 9 out of 18 points. This score reflects that at this lower reservoir level, inaccessibility of boat ramps and docks would substantially affect access for water-based activities.

2.6.4.1. LOGAN MARTIN

FULL POOL

This criterion was scored 13 out of 18 points, reflecting that Logan Martin has good access to and within the site.

REDUCED POOL

This criterion was scored 11 out of 18 points. This score reflects that docks and boat ramps may begin to be affected in this elevation zone which may reduce the quality of access for water-based activities.

LIMITED POOL

This criterion was scored 9 out of 18 points. This score reflects that at this lower reservoir level, inaccessibility of boat ramps and docks would substantially affect access for water-based activities.

2.6.5. ENVIRONMENTAL

2.6.5.1. ALLATOONA

FULL POOL

This criterion was scored 18 out of 20 points. The score reflects that the project is one of the most popular outdoor recreation areas in the Atlanta region, offering visitors recreation opportunities in a high-quality natural setting while being near a major urban center.

INITIAL IMPACT

This criterion was scored 16 out of 20 points. Factors such as aesthetic quality may be marginally affected by a lowering pool, such as exposure of beaches and shoreline.

RECREATION IMPACT

This criterion was scored 12 out of 20 points. At this pool level, additional bank exposure would be expected that would reduce aesthetic quality.

WATER ACCESS LIMITED

This criterion was scored 10 out of 20 points, reflecting still further reduction of aesthetic quality due to the exposed banks.

2.6.5.2. WEISS

FULL POOL

This criterion was scored 18 out of 20 points. The score reflects that the project offers high quality natural aesthetics that complement popular water-based recreation activities at the project.

REDUCED POOL

This criterion was scored 14 out of 20 points. Factors such as aesthetic quality may be marginally affected by a lowering pool, such as exposure of beaches and shoreline.

LIMITED POOL

This criterion was scored 10 out of 20 points. At this pool level, additional bank exposure would be expected that would reduce aesthetic quality.

2.6.5.1. LOGAN MARTIN

FULL POOL

This criterion was scored 18 out of 20 points. The score reflects that the project offers high quality natural aesthetics that complement popular water-based recreation activities at the project.

REDUCED POOL

This criterion was scored 14 out of 20 points. Factors such as aesthetic quality may be marginally affected by a lowering pool, such as exposure of beaches and shoreline.

LIMITED POOL

This criterion was scored 10 out of 20 points. At this pool level, additional bank exposure would be expected that would reduce aesthetic quality.

2.7. UNIT DAY VALUE CONVERSION

The points described above were converted to a dollar value based on the FY2020 UDV conversion table in EGM 20-03 (USACE 2019a). The scores were interpolated linearly as necessary. **Table 8** shows the point conversion table from the guidance, and **Table 9** summarizes the converted values.

Table 8. FY20 UDV Conversion, Value per Visit

General Recreation		
Point Values	**Fishing & Hunting ($)**	**Other General Activities ($)**
0	$6.06	$4.21
10	$6.85	$5.00
20	$7.37	$5.53
30	$8.16	$6.32
40	$8.95	$7.90
50	$9.74	$8.95
60	$10.80	$9.74
70	$11.32	$10.27
80	$12.11	$11.32
90	$12.38	$12.11
100	$12.64	$12.64

Table 9. Assigned Scores Converted

	Total Points	Value per Visit ($)	
		Hunting & Fishing	All General Activities
Allatoona			
Full Pool	94	$12.48	$12.32
Initial Impact	88	$12.33	$11.95
Recreation Impact	70	$11.32	$10.27
Water Access Limited	45	$9.35	$8.43
Weiss			
Full Pool	71	$11.40	$10.38
Reduced Pool	58	$10.59	$9.58
Limited Pool	47	$9.50	$8.64
Logan Martin			
Full Pool	70	$11.32	$10.27
Reduced Pool	57	$10.48	$9.50
Limited Pool	46	$9.42	$8.53

3. RECREATION VALUE CALCULATIONS

Having completed estimates of visitation for each of the three projects and the UDV scoring, the two are combined to estimate recreation value. Recreation value was estimated for both the NCS and the WCS, and for each of the three projects.

To estimate recreation value, annual visits in each year of the period of analysis were proportionally applied to each pool level/ recreation impact level. Then visits for each pool level are multiplied by the corresponding UDV value in **Table 9** to estimate recreation value by pool level. Adding up these values gives the estimate of total recreation value in that year. The total value for each year is then discounted using the FY 2020 discount rate of 2.75 percent, then summed across each year of the period of analysis, yielding the total present value of recreation for that scenario. This value is amortized to give average annual recreation value over the period of analysis.

This same calculation was completed for the NCS and the WCS at each of the projects. **Table 10** summarizes the results of the recreation valuation calculations.

Table 10. Recreation Value by Project and Scenario

Project and Scenario	Annualized Recreation Value ($)	Present Value ($)	Annualized Change vs. Without Project	Percent Change
Allatoona				
No Change Scenario	$75,045,400	$2,026,014,000	$0	0%
With Change Scenario [1]	$75,754,000	$2,045,143,000	$708,600	0.9%
Weiss				
No Change Scenario	$16,152,500	$436,071,000	$0	0%
With Change Scenario [2]	$16,485,700	$445,067,000	$333,200	2.1%
Logan Martin				
No Change Scenario	$16,442,800	$443,910,000	$0	0%
With Change Scenario [2]	$16,950,700	$457,620,000	$507,900	3.1%

[1] Allatoona WCS alternatives: 5, 8, 11, 13

[2] Weiss and Logan Martin WCS alternatives: 9, 10, 11, 12, 13

4. SUMMARY CONCLUSIONS

As described in Section 2.1, this analysis considers effects on NED recreation value by estimating change in visitor willingness to pay for the recreation opportunity as a function of recreation quality, resulting in an estimate of total economic value received by visitors to the project. It does not estimate any payments made for other goods and services in the local economy (e.g. food, lodging, equipment rentals, etc.) associated with each recreation visit. However, it may be reasonable to expect that higher quality recreation resources would be correlated with higher spending per visit.

As shown in **Table 10**, the With Change Scenario would result in a net increase in total recreation value at the projects. This increase reflects that the alternatives in the With Change Scenario all include operational modifications that would increase the duration of time the reservoirs spend at full pool, which would serve to increase the number of days of optimal recreation conditions with regard to pool elevation. As such, the estimated change in total recreation value is a function of the change in quality of experience for project visitors, not a change in the number of visitors. The analysis estimates that under any of the WPC alternatives, Allatoona would experience an approximate 1% increase in total recreation value, Weiss would experience an approximate 2% increase in recreation value, and Logan Martin would experience an approximate 3% increase in recreation value.

Review of operational changes by alternative in the main FR/SEIS provides an indication of seasonal trends in how these benefits may accrue.

At Allatoona, the WPC alternatives include changes in flood pool and conservation pool which affect reservoir elevation throughout the year, implying that the benefits to recreation estimated in this analysis would accrue to users throughout the year.

In contrast at the APC projects, the WPC alternatives do not substantially affect summer pools. For these alternatives, operational changes focus on the specification of a new winter pool which would raise the reservoir above existing levels during fall and winter seasons. As such, it’s expected that benefits to recreation estimated in this analysis would accrue to visitors during the fall and winter seasons, rather than the spring and summer.

In summary, it is expected that the WPC alternatives would result in net beneficial effects on recreation at each of the projects. Because the WPC alternatives would all have a net reduction in the proportion of time spent below full pool, there appears to be low risk that any of the WPC alternatives would have adverse effects on recreation.

5. UNCERTAINTY CONSIDERATIONS

This analysis applies the UDV methodology to estimate project-scale changes in recreation value based on total annual visitation and aggregate scoring of the projects' recreation opportunities. Key sources of uncertainty in the UDV analysis include the total estimate of visitation and the scores assigned to each project and pool impact zone.

To address uncertainty in visitation, forecasted growth was limited to 10 years and capped. This approach results in visitation over the period of analysis which is likely conservative, minimizing the risk that overestimation of future visitation levels contributes to overestimation of benefits. The extent to which the alternatives would drive changes in visitation level was also considered. Because none of the alternatives include major pool level changes during peak season, when the majority of visits occur, it was judged that the with-project alternatives would not drive significant changes in project-wide annual visitation over the without-project condition. As such, both the No Change Scenario and the With Change Scenario to utilize the same visitation estimates. Any marginal increases in visitation as a result of the proposed operational changes would only serve to further increase the total recreation value.

To address uncertainty associated with the scoring, score reductions associated with adverse pool conditions were moderate. In general, scores in any rubric category did not drop more than two categories between the optimal and worst pool levels. Such an approach was determined to be appropriate given the project-scale lens of the analysis, which estimates average change in value for all users and activities.

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Attachment A – UDV Scoring Rubric

Criteria	Judgment Factors				
Recreation Experience (1) Points Possible: 30	Two general activities (2) 0-4	Several general activities 5-10	Several general activities: one high quality value activity (3) 11-16	Several general activities: more than one high quality value activity 17-23	Numerous high-quality value activities; some general activities 24-30
Availability of Opportunity (4) Points Possible: 18	Several within 1 hr. travel time; a few within 30 min travel time 0-3	Several within 1 hr. travel time; none within 30 min travel time 4-6	One or two within 1 hr. travel time; none within 45 min travel time 7-10	None within 1 hr. travel time 11-14	None within 2 hr. travel time 15-18
Carrying Capacity (5) Points Possible: 14	Minimum facility for development for public health and safety 0-2	Basic facility to conduct activity(ies) 3-5	Adequate facilities to conduct without deterioration of the resource or activity experience 6-8	Optimum facilities to conduct activity at site potential 9-11	Ultimate facilities to achieve intent of selected alternative 12-14
Accessibility Points Possible: 18	Limited access by any means to site or within site 0-3	Fair access, poor quality roads to site; limited access within site 4-6	Fair access, fair road to site; fair access, good roads within site 7-10	Good access, good roads to site; fair access, good roads within site 11-14	Good access, high standard road to site; good access within site 15-18
Environmental Quality Points Possible: 20	Low aesthetic factors (6) that significantly lower quality (7) 0-2	Average aesthetic quality; factors exist that lower quality to a minor degree 3-6	Above average aesthetic quality; any limiting factors can be reasonably rectified 7-10	High aesthetic quality; no factors exist that lower quality 11-15	Outstanding aesthetic quality; no factors exist that lower quality 16-20

Guidance Notes:

(1) Value for water-oriented activities should be adjusted if significant seasonal water level

(2) General activities include those that are common to the region and that are usually of normal quality. This includes picnicking, camping, hiking, riding, cycling, and fishing and hunting of normal quality.

(3) High quality value activities include those that are not common to the region and/or Nation, and that are usually of high quality.

(4) Likelihood of success at fishing and hunting.

(5) Value should be adjusted for overuse.

(6) Major esthetic qualities to be considered include geology and topography, water, and vegetation.

(7) Factors to be considered to lowering quality include air and water pollution, pests, poor climate, and unsightly adjacent areas.

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Attachment 2. Allatoona-Coosa Reallocation Study—Project Impacts to Hydropower Report

US Army Corps
of Engineers
Portland District

Allatoona Dam and Lake

HYDROELECTRIC DESIGN CENTER

PREPARED BY: **Hydropower Analysis Center**

Allatoona Lake

Water Supply Storage Reallocation Study

&

Weiss and Logan Martin Reservoirs

Updates to Project Water Control Manuals

Project Impacts to Hydropower

Prepared By: Hydropower Analysis Center

Hydroelectric Design Center

U.S. Army Corps of Engineers

May 28, 2020

UPDATED October 2020

ABSTRACT

This is an analysis of impacts to hydropower at both Federal and non-Federal plants in the ACT River Basin resulting from allocating additional reservoir storage at Allatoona Lake for increased municipal water supply and simultaneously implementing a modified Flood Risk Management strategy at Weiss and Logan Martin Reservoirs.

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Allatoona-Coosa Reallocation (ACR)

Water Supply Reallocation (WSR)

Hydropower Analysis Draft

1 Introduction:

The U.S. Army Corps of Engineers (USACE), Mobile District is conducting a combined study of Allatoona Lake Water Supply Storage Reallocation and Updates to the Weiss and Logan Martin Reservoirs Project Water Control Manuals. The water supply study will evaluate a March 30, 2018 request by the State of Georgia for a water supply storage reallocation out of Allatoona Lake. The flood storage analysis will evaluate APC's proposal for revised operations at the Weiss and Logan Martin projects for which USACE has navigation and flood risk management oversight.

This report presents an analysis of the effects on hydropower and the monetary value hydropower that are expected to result from proposed changes to system water control operations within the Alabama-Coosa-Tallapoosa (ACT) River Basin. The system hydropower values for energy and capacity were computed for the baseline condition, representing current water control operations, and for alternative flow scenarios associated with these studies.

1.1 Calculation of Hydropower

The calculations of hydropower energy and capacity values are based on seventy-three years of historic hydrology (1939-2011) using the HEC-ResSim model.

To understand how system operations can affect hydropower generation we will first consider the mathematics used to approximate the amount of power produced from a hydropower facility, the power equation (Eq. 1). This equation shows that power is directly proportional to three variables; the efficiency of the plant turbines, the amount of flow going through the turbines, the head, and the height of the water in the reservoir relative to its height after discharge.

$$P = e * g * Q * H$$

Where; P=power (kW),
e=turbine efficiency,
g = gravitational constant (ft/sec^2),
Q-flow (cfs),
H=head (ft).

Reservoir operations can affect all three of these variables. Higher or lower operational reservoir elevations change the head. Maximum or minimum flow requirements used for flood risk management and environmental purpose can affect the flow. Although power is linear in both head and flow, this relationship quickly becomes non-linear with the inclusion of efficiency which is a non-linear function of both head and flow.

1.1 Hydropower Impact Components

In general, the hydropower values resulting from generation can be divided into two components: energy values and capacity values. A change in energy value is the result of a change in the amount of water that is available to pass through the turbines. The value changes both daily and seasonally as a function of the systems electrical load. For example, energy may be more valuable during the height of the summer heat while businesses and residents are attempting to cool their environments as opposed to the fall or winter when air conditioners maybe turned off. The capacity value is a measure of the amount of capacity that the project can reliably contribute towards meeting system peak power demands.

1.1.1 Energy

Energy (generation) summarized and value of energy (generation) calculated in Chapter 3 is based upon the cost of utilizing the most likely alternative source for power. For example, if an operational strategy reduces hydropower storage or flow, the loss in energy value is equivalent to the cost of replacing the lost power with the most likely alternative source of power.

1.1.2 Capacity

There may be a decrease the amount of capacity that the hydropower plant can contribute to the peak system load making it necessary to replace this lost capacity with an alternative source of power made up of a combination of thermal generating plants. Capacity and its value are the subject of Chapter 4.

2 ACT Watershed Bulk Power System Overview

This chapter contains the following: an overview of the power generation system for the ACT River Basin with an emphasis on hydropower, a descriptive analysis of the potential annual and seasonal changes in hydropower production due to water control management decisions, and a description of the process of calculating the changes in the energy and capacity value of the ACT system resulting from the study alternatives.

2.1 Location of ACT River Basin and USACE Projects

The Alabama-Coosa-Tallapoosa (ACT) River Basin watershed lies primarily in the States of Alabama and Georgia.

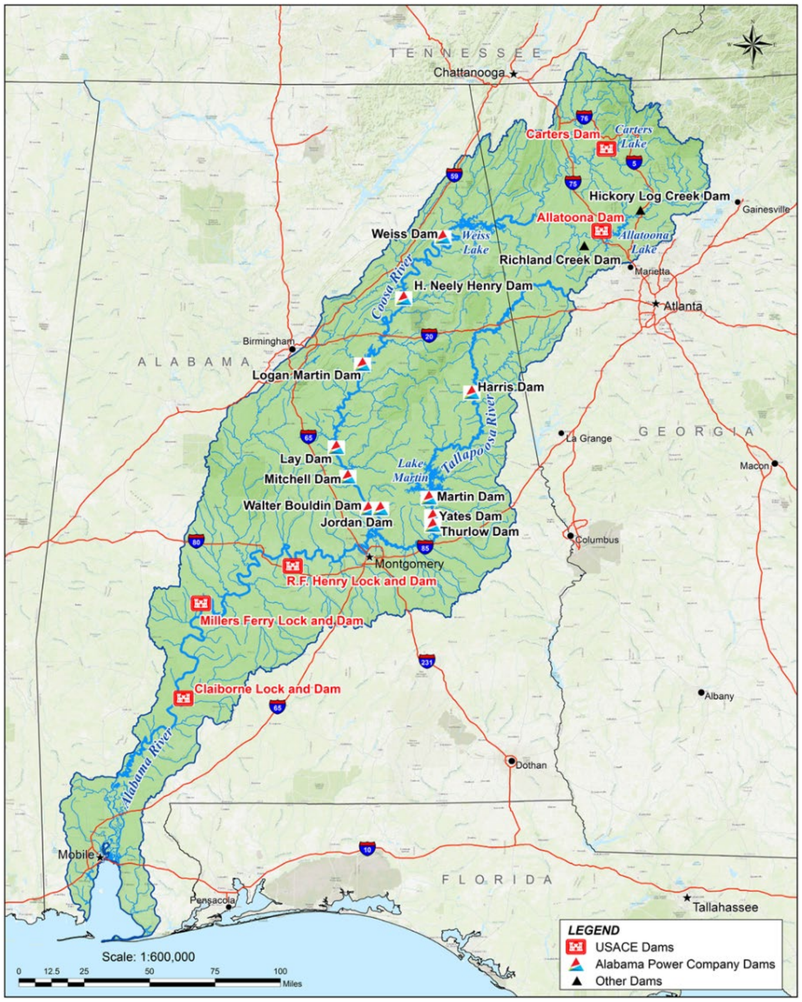


Figure 2-1. ACT watershed hydropower system map

2.2 SERC/Southeastern System Capacity & Power

SERC/Southeastern is responsible for improving the electric power generating system critical infrastructure in the region.

Since 2000, the Southeastern sub-region has undergone a significant increase in natural gas-fired generating plant capacity. Natural gas currently exceeds Coal and Nuclear in percentage of total system capacity at around 38%. Nuclear and Hydroelectric energy make up the remaining generating plant capacity accounting for 30% and 7% of total system capacity respectively (Figure 2-2).

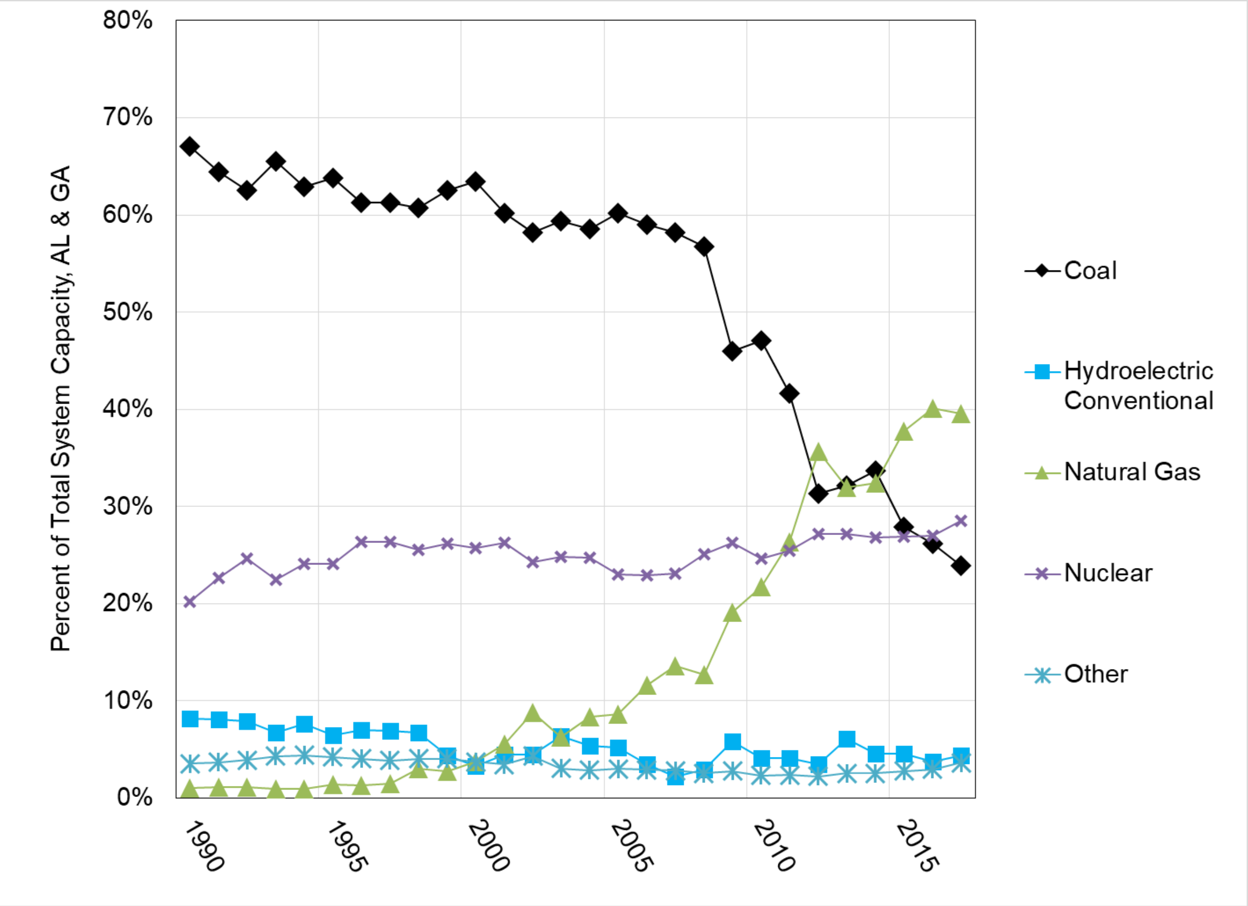


Figure 2-2. Historical trends for the percent of total system capacity for the State of Alabama & Georgia

Coal and nuclear power are predominately run as baseload plants, facilities that produce constant rates of generation to meet the systems continuous regional demands. Natural gas and hydropower plants on the other hand are generally run as peaking plants, meeting the daily and seasonal peak loads throughout the system. This is important, to conceptually which alternative thermal plants might be used to replace hydropower if changes in operations dictated such a need. As an illustrative example consider the 2019 generation pattern reported by the (EIA) for the Southern sub-region (Figure 2-3). Increases (decreases) in percent of total generation for hydropower are matched by decreases (increases) in percent generation for natural gas. The same coupling of energy sources can be seen in the relationship between coal and nuclear power.

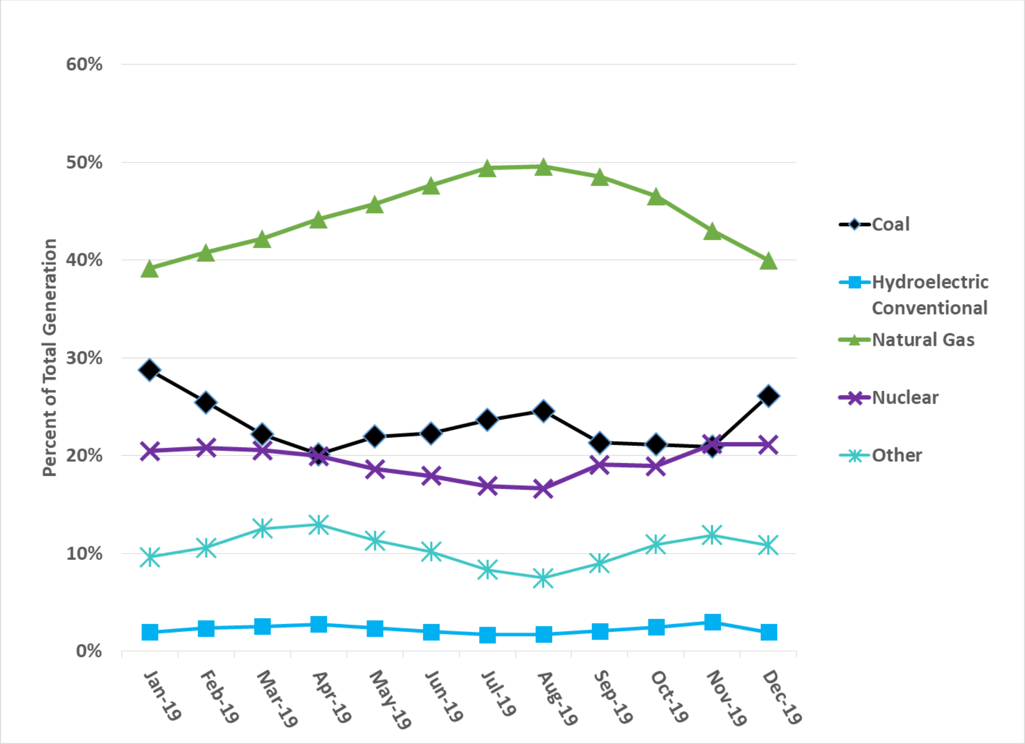


Figure 2-3. Percent of Total Generation by Fuel Type for Southern sub-region

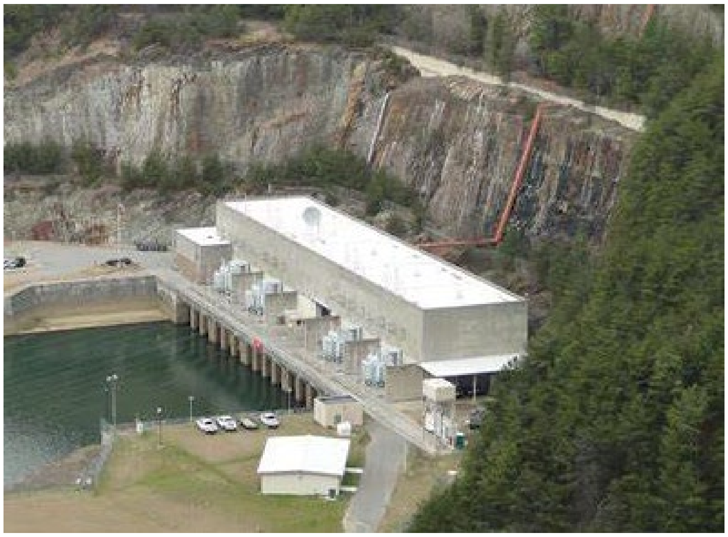
2.3 ACT Hydropower System USACE Hydropower Projects

The Corps of Engineers (Corps) operates four dams with hydropower capabilities in the ACT River Basin. The RF Henry Dam and Millers Ferry Lock and Dam are both located on the Alabama River around 200 miles upstream of Mobile Bay. These two dams work together with a combined generating capacity of 172 MW in supporting multiple purposes other than hydropower including navigation and waste assimilation. Allatoona Dam is located northwest of Atlanta on the Etowah River in Georgia. It is operated as a peaking plant with an installed generating capacity of 72 MW. The final plant, Carters Dam is located on the Coosawattee River in Georgia and is operated as a pump storage plant. This plant consists of two pools, Carters Lake and Carters Reregulation Pool. During peak loading hours, water is released from Carters Lake to the re-regulation pool generating energy. When demand is low, energy is purchased to pump water back into the Carters Lake from the re-regulation pool. This plant has a total generating capacity of 575 MW.

2.3.1.1 Allatoona Dam

Located in Bartow County on the Etowah River near Cartersville, Ga., the Allatoona Dam and Powerhouse is the oldest multipurpose project in the U.S. Army Corps of Engineer's South Atlantic Division. Construction of Allatoona Dam was authorized under the Flood Control Acts of 1941 and 1944 and built to retain the Etowah River, a tributary of the Coosa River. Originally delayed because of World War II, construction of the dam began in 1946 and was completed in late 1949. Allatoona Dam is a concrete gravity dam and was the first of its kind, eventually becoming the model for all future Corps of Engineers-built dams. The filling of the reservoir was completed in May 1950, and the power plant came online the same year. The current plant capacity is 85 MW. Authorized federal purposes for the dam include power, flood control, water supply, and recreation. The current plant capacity is 85 MW and the dam impounds Lake Allatoona, a popular recreation facility that is also managed by the Corps of Engineers.

2.3.1.2 Carters Dam



Carters Dam impounds about 3,200 surface acres of water with more than 60 miles of shoreline. At 445 feet, it is the highest earth-filled dam east of the Mississippi River. Carters Dam is one of the few pump storage facility dams in the nation. Water flows through the turbines to generate power during peak demand periods. During off-peak periods, the units are reversed to pump water back to the upper pool and stored for later use. Located 26.8 miles above the mouth of the Coosawattee River in northwest Georgia, the Carters Dam and Powerhouse were authorized by the Rivers and Harbors Act of 1945. Construction began in 1962 and was completed in 1977. The project came online in 1975. The current plant capacity is 600 MW.

2.3.1.3 Robert F. Henry Lock and Dam

Jones Bluff Reservoir (also known as R. E. "Bob" Woodruff Lake) impounds the Alabama River between Montgomery and Selma in central Alabama. The U. S. Army Corps of Engineers built the Robert F. Henry Lock and Dam to create a 12,510-acre reservoir that provides navigation, hydroelectric power generation, and recreation. Jones Bluff is a riverine impoundment meaning much of the reservoir is confined to the historic river channel. The low retention time and water storage capacity at Jones Bluff often result in frequent winter and spring flooding. Locals still refer to it as the Alabama River; however, numerous creeks have been flooded, providing a wide variety of fishing opportunities. The City of Montgomery is located on Jones Bluff Reservoir. The Jones Bluff Powerhouse at the Robert F. Henry Lock and Dam came online in 1975. The project's current capacity is 82 MW.

2.3.1.4 Millers Ferry Lock and Dam

Millers Ferry Lock and Dam is a lock and hydro-electric dam on the Alabama River, near the community of Millers Ferry, Alabama. It was built by and continues to be operated by the United States Army Corps of Engineers. Construction of the complex began in 1963 and was completed in 1970. The Millers Ferry Powerhouse came online in 1970 and has a generating capacity of 90 megawatts. The dam impounds a 17,200-acre reservoir on the Alabama River, the William (Bill) Dannelly Reservoir is better known locally as “Millers Ferry.” The reservoir covers 27 square miles and has approximately 500 miles of shoreline

2.3.2 Alabama Power Company Hydropower Projects

Eleven non-Corps plants owned by Alabama Power Company are also considered in this analysis. Alabama Power Company owns a total of 14 peaking power plants making up 6% of the company's power generation. The 1,400 MW of installed generating capacity from the 11 plants in this analysis are located on the Tallapoosa and Coosa Rivers.

Table 2-1. Plant characteristics of hydropower projects for ACT Basin

Plant	Owner	Number of Units	Installed Capacity (MW)
Weiss Dam	Alabama Power Company	3	81
H. Neely Henry	Alabama Power Company	3	70
Logan Martin	Alabama Power Company	3	135
Martin	Alabama Power Company	4	186
Lay	Alabama Power Company	6	180
Mitchell	Alabama Power Company	4	166
Jordan	Alabama Power Company	4	100
Walter Bouldin	Alabama Power Company	3	225
Harris	Alabama Power Company	2	132
Yates	Alabama Power Company	2	47
Thurlow	Alabama Power Company	3	78
RF Henry	USACE	4	82
Millers Ferry	USACE	3	90
Allatoona	USACE	3	72
Carters	USACE	4	575
Total		**51**	**2,219**

2.4 Study Alternatives

- **Base2018:** This is the Current Condition (which includes reservoir storage allocations for water supply to 2 entities (CCMWA-12,485 AF and Cartersville-6,054 AF) without capping withdrawals.

- **Base Cap** This is the Current Condition (which includes reservoir storage allocations for water supply to 2 entities (CCMWA-12,485 AF and Cartersville-6,054 AF) with capped withdrawals.

- **FWOP:** Future Without Project (without additional reallocation for (94 MGD or 32,809 AF). This the base case for water supply reallocation alternatives.

- **A03_WS1:** Reallocation of 32,809 AF from Conservation Pool using State of Georgia's water accounting method

- **A04_WS2:** Reallocation of 32,809 AF from Conservation Pool using USACE water accounting method

- **A05_WS3:** Reallocation of 32,809 AF from both Flood Pool and Conservation Pool using State of Georgia's water accounting method

- **A06_WS4:** Reallocation of 32,809 AF from both Flood Pool using USACE water accounting method

- **A08_WS6:** Reallocation of 32,809 AF from both Flood Pool and Conservation Pool using USACE water accounting method

- **A09_FWOPMF**: Modified Flood Operation 1 including Future Without Project (without additional reallocation for (94 MGD or 32,809 AF). This the base case for APC requested modified flood operations with water supply reallocation alternatives.

- **A10_WS2MF:** Modified Flood Operation 1 including (A04_WS2) Reallocation of 32,809 AF from Conservation Pool using USACE water accounting method

- **A11_WS6MF:** Modified Flood Operation 1 including (A08_WS6) Reallocation of 32,809 AF from both Flood Pool and Conservation Pool using USACE water accounting method

- **A12_WS1MF:** Modified Flood Operation 1 including (A03_WS1) Reallocation of 32,809 AF from Conservation Pool using State of Georgia's water accounting method

- **A13_WS3MF:** Modified Flood Operation 1 including (A05_WS3) Reallocation of 32,809 AF from both Flood Pool and Conservation Pool using State of Georgia's water accounting method.

Table 2-2. Characteristics of hydropower projects for ACT Basin

ALTERNATIVE	**Description**	**Attributes**						
		Meets GA 2050 Demands 94MGD	Storage		Reallocation			APC Requested Changes
			USACE	GA	**Inactive Pool**	**Conservation Pool**	**Flood Pool**	
Base2018	No Action		✓					
BaseCap								
FWOP	Future Without Project		✓					
A03_WS1	Water Supply 1	✓		✓		✓		
A04_WS2	Water Supply 2	✓	✓			✓		
A05_WS3	Water Supply 3	✓		✓		✓	✓	
A06_WS4	Water Supply 4	✓	✓				✓	
	Water Supply 5				✓			
A08_WS6	Water Supply 6	✓	✓			✓	✓	
A09_FWOPMF	Modified Flood Operation 1		✓					✓
A10_WS2MF	Water Supply 2 + Modified Flood Operation 1	✓	✓			✓		✓
A11_WS6MF	Water Supply 6 + Modified Flood Operation 1	✓	✓			✓	✓	✓
A12_WS1MF	Water Supply 1 + Modified Flood Operation 1	✓		✓		✓		✓
A13_WS3MF	Water Supply 3 + Modified Flood Operation 1	✓		✓		✓	✓	✓

2.5 Hydropower Generation

To determine the change in energy generation resulting from the Studies' Alternative Plans, an analysis was performed to determine the average annual energy generated in the Base Case, current condition, using the seventy-three-year ResSim Model simulation period. As shown in Figure 2-4 there is a less than a one percent change in average annual energy for each alternative when compared to the baseline condition.

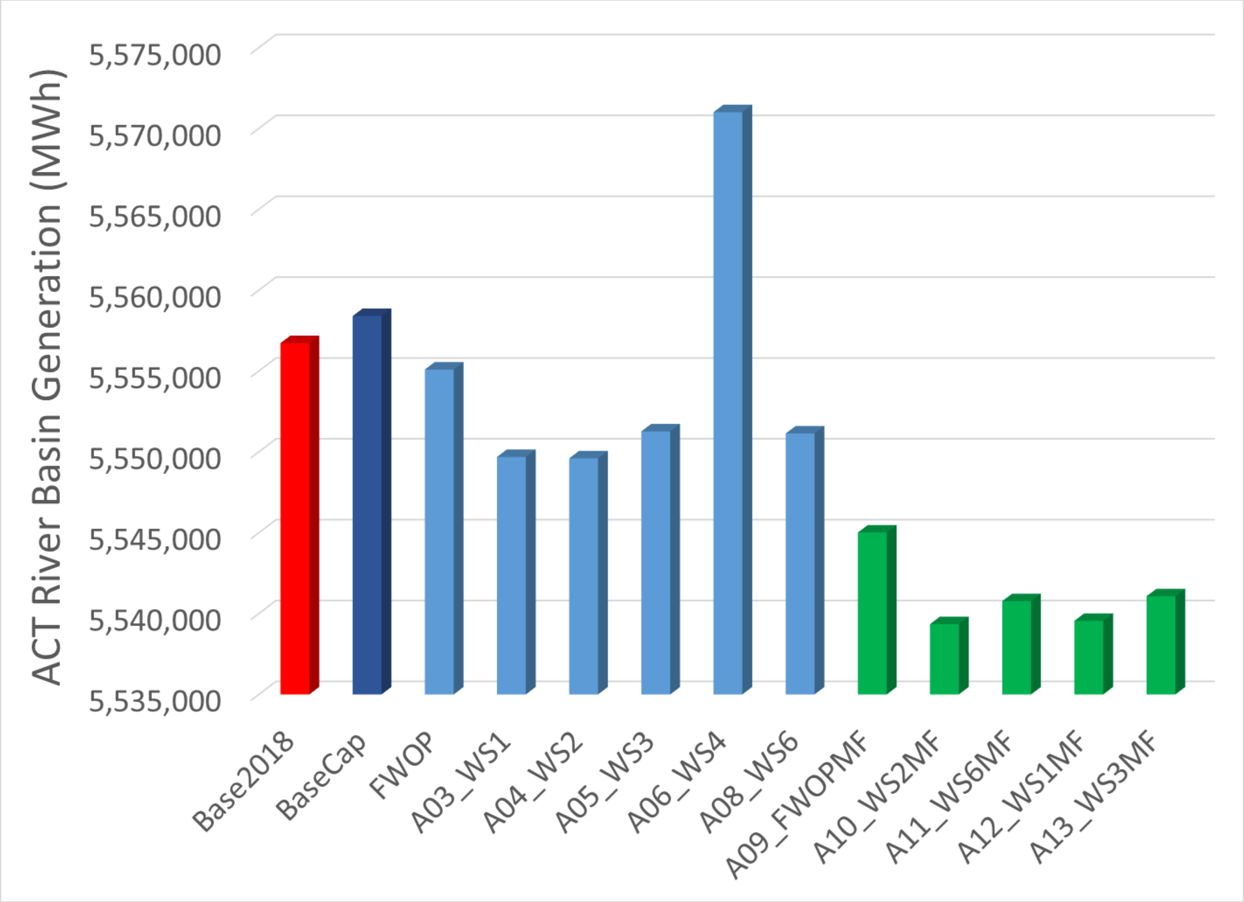


Figure 2-4. Average Annual Hydropower System Generation by Alternatives

The value of the replacement energy has a seasonal trend following the demand and generating resource availability through the year. Therefore, in calculating annual value, it is necessary to look at how the generated energy is distributed on a monthly basis. Figure 2-5 shows both the average monthly energy generated for Base2018 and other alternatives as well. Alternative scenario FWOP shows an increase in power generation from June through November and losses December through May compared to the baseline condition. The other alternative scenarios show similar losses. For alternative scenario A06_WS4 there are power generation losses October through March.

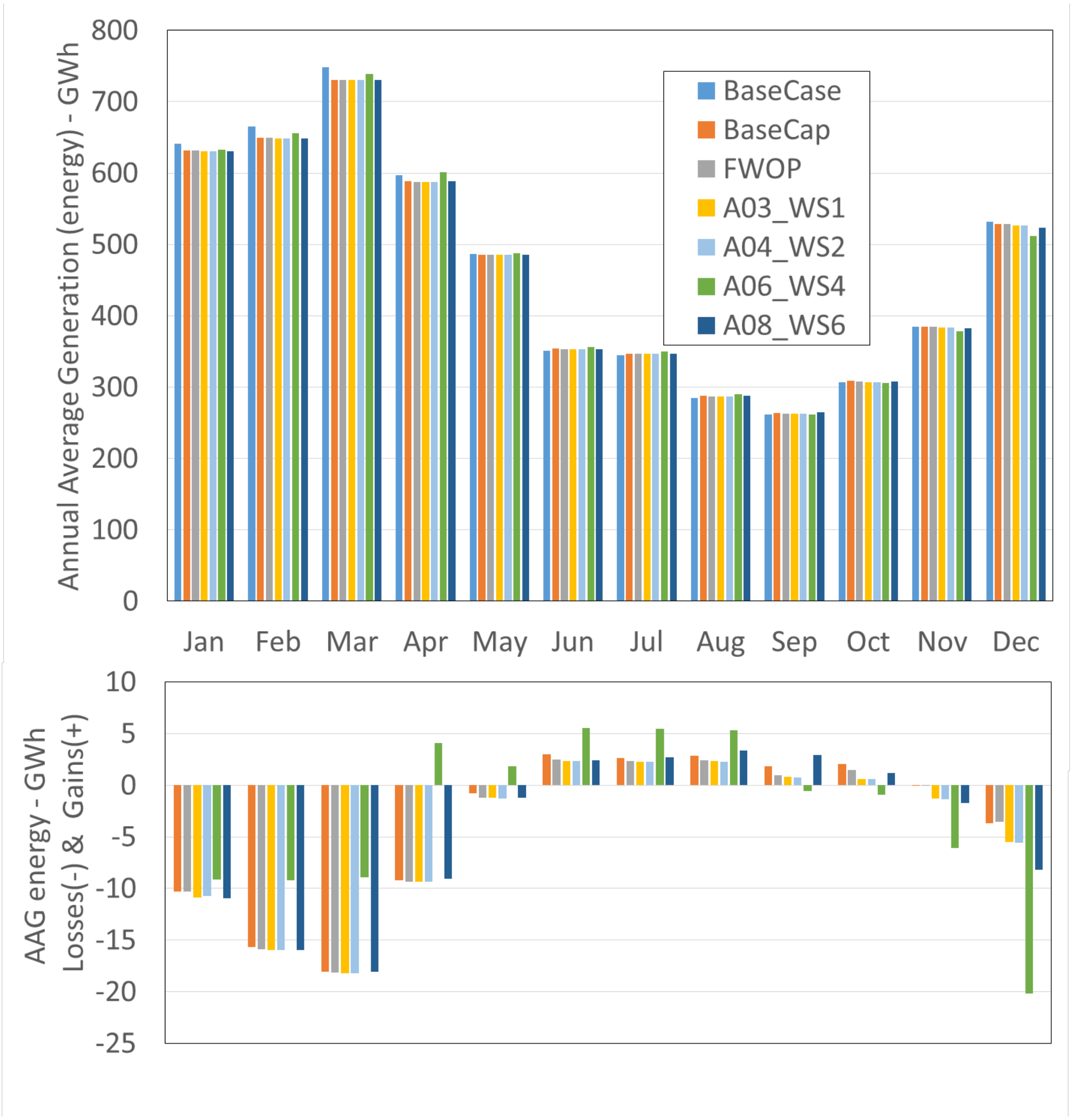


Figure 2-5. Monthly Generation for Alternative Flow Scenarios compared to Base2018

3 Energy & Energy Value

Energy value is computed as the product of the energy loss in megawatt-hours and a block energy price ($/MWh). The block energy price is based on the cost of energy from regional combination of electrical generation plants that would replace the lost energy from the hydropower plant due to operational and/or structural changes.

3.1 Energy Blocks

3.1.1 Energy Blocks Defined

The energy prices used for this analysis reflect the daily differences in peak and off peak operations, the seasonal dynamics related to demand and availability, and the annual forecasted changes due to modifications in capacity and overall demand. The following paragraphs describe the process of obtaining these values.

The regional definition of on-peak hours of generation is 6am to 10pm on weekdays. The off-peak hours of generation are the remaining hours on weekdays and all hours on weekends. However, because generation by USACE hydropower plants in the ACT Basin is concentrated in a subset of the highest-value weekday peak hours to fulfill power contracts, these hours were evaluated separately as contract on-peak hours in order not to understate value. Table 3-1 presents the distribution of hours into generation blocks for contract-peak hours, non-contract peak hours, and off-peak hours for each month of the year, and for weekends. The schedule of generation blocks was provided by the Southeastern Power Administration (SEPA), an agency of the U.S. Department of Energy.

Table 3-1. Generation Block Schedule for SEPA/USACE Hydropower Plants

	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours
Weekdays			
January	11	5	8
February	11	5	8
March	11	5	8
April	6	10	8
May	6	10	8
June	6	10	8
July	6	10	8
August	6	10	8
September	6	10	8
October	11	5	8
November	11	5	8
December	11	5	8
Weekends (All Year)			
All Months	0	0	24

3.1.2 Energy Allocation to Blocks

As an example of how daily energy production is allocated between on-peak and off-peak designations, Table 3-2 below shows the simulated daily energy production for Allatoona Lake for the week of April 1, 1946, under No Action (baseline conditions). The capability varies with the rise and fall of the lake level. The average capability on Tuesday was 93.48 MW and the Generation was 1,758.5 MWh. On-Peak generation for 16 hours could be 1,495.68 MWh, of which 6 hours would be SEPA contract generation (560.9 MWh) and the remaining 10 hours of On-Peak would be non-contract generation (934.8 MWh). Generation in excess of 16 hours on weekdays is off-peak energy (262.8 MWh). All power generated on the weekend is off-peak energy.

Table 3-2. On-Peak & Off-Peak Daily Blocks Energy Allocation for Allatoona Lake – April 1 through 7, 1946

DATE	Day	Capability (MW)	Energy Production (MWh)	Weekday			Weekend
				On-Peak Energy (contract) (MWh)	On-Peak Energy (non-contract) (MWh)	Off-Peak Energy (MWh)	Off-Peak Energy (MWh)
1-Apr-46	Monday	94.29	1,367.9	565.8	802.1	0.0	0.0
2-Apr-46	Tuesday	93.48	1,758.5	560.9	934.8	262.8	0.0
3-Apr-46	Wednesday	91.90	1,789.3	551.4	919.0	318.9	0.0
4-Apr-46	Thursday	90.44	1,773.3	542.6	904.4	326.3	0.0
5-Apr-46	Friday	89.40	1,761.3	536.4	894.0	330.9	0.0
6-Apr-46	Saturday	88.40	1,749.5	0.0	0.0	0.0	1749.5
7-Apr-46	Sunday	91.89	1,231.3	0.0	0.0	0.0	1231.3

This energy block allocation procedure was applied to the RESSIM model output to transform daily energy production into energy blocks. Table 3-3 are the average annual energy blocks for the Base Case.

Table 3-3. Annual Average Monthly Energy Blocks for Allatoona Lake under the Base2018

	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours	Off-Peak Hours
	Weekday	Weekday	Weekday	Weekend
	MWH	MWH	MWH	MWH
Jan	6,814	712	643	2,691
Feb	6,162	640	566	2,513
Mar	7,548	941	806	3,385
Apr	5,631	2,179	830	2,868
May	6,780	1,423	388	2,635
Jun	6,001	322	39	1,051
Jul	6,356	355	84	563
Aug	5,788	165	58	156
Sep	3,658	301	106	665
Oct	3,935	170	195	459
Nov	5,487	221	118	1,297
Dec	9,445	605	444	3,356

3.2 Annual Energy of Alternatives

The Average Annual Energy (hydroelectric generation in MWH) in Table 3-4 and Table 3-5 have been summarized from the river basin operations simulation (model run output files) over the 73-year period of hydrologic record. As shown in the Tables 3-4 below the requested water supply from Lake Allatoona causes small changes in hydropower energy production over the entire basin. As shown in the Tables 3-5 below the result from proposed changes to system water control operations at Weiss and Logan Martin Reservoirs result small changes in hydropower energy production over the entire basin.

Table 3-4. Individual Plant and ACT System Energy – Water Supply Alternatives

Projects V Alternatives >		**Base2018**	**BaseCap**	**FWOP**	**A03_WS1**	**A04_WS2**	**A05_WS3**	**A06_WS4**	**A08_WS6**
ALLATOONA	Federal	107,554	107,910	106,508	104,764	104,756	105,693	112,221	105,686
CARTERS	Federal	659,603	659,601	659,601	659,601	659,601	659,601	659,601	659,601
MILLERS FERRY	Federal	327,871	327,955	327,864	327,771	327,751	327,951	328,723	327,932
RF HENRY	Federal	267,636	267,693	267,580	267,467	267,478	267,526	268,927	267,537
Federal	**subtotal**	**1,362,664**	**1,363,159**	**1,361,553**	**1,359,603**	**1,359,586**	**1,360,771**	**1,369,472**	**1,360,756**
HARRIS	non-Federal	191,251	191,250	191,249	191,252	191,251	191,253	191,253	191,253
HN HENRY	non-Federal	200,935	201,036	200,892	200,607	200,601	200,641	201,952	200,627
JORDAN	non-Federal	277,597	277,621	277,514	277,443	277,448	277,374	276,206	277,384
LAY	non-Federal	650,366	650,615	650,304	649,570	649,555	649,691	652,439	649,666
LOGAN MARTIN	non-Federal	425,101	425,278	424,993	424,444	424,435	424,501	426,116	424,487
MARTIN	non-Federal	417,220	417,217	417,220	417,227	417,225	417,211	417,197	417,212
MITCHELL	non-Federal	550,016	550,193	549,942	549,401	549,393	549,405	550,918	549,403
THURLOW	non-Federal	273,720	273,720	273,720	273,732	273,731	273,716	273,704	273,715
WALTER-BOULDIN	non-Federal	847,320	847,667	847,227	846,259	846,234	846,471	850,548	846,410
WEISS	non-Federal	200,742	200,850	200,681	200,352	200,343	200,441	201,422	200,435
YATES	non-Federal	159,796	159,796	159,794	159,801	159,801	159,791	159,782	159,791
non-Federal	**subtotal**	**4,194,064**	**4,195,243**	**4,193,536**	**4,190,088**	**4,190,017**	**4,190,495**	**4,201,537**	**4,190,383**
System	**TOTAL**	**5,556,728**	**5,558,402**	**5,555,089**	**5,549,691**	**5,549,603**	**5,551,266**	**5,571,009**	**5,551,139**

Table 3-5. Individual Plant and ACT System Energy – Modified Flood Operations Alternatives

Projects V **Alternatives >**		**A09_FWOPMF**	**A10_WS2MF**	**A11_WS6MF**	**A12_WS1MF**	**A13_WS3MF**
ALLATOONA	Federal	106,508	104,756	105,686	104,764	105,693
CARTERS	Federal	659,601	659,601	659,601	659,601	659,601
MILLERS FERRY	Federal	326,674	326,509	326,653	326,617	326,740
RF HENRY	Federal	266,636	266,491	266,576	266,507	266,584
Federal	**subtotal**	**1,359,419**	**1,357,357**	**1,358,516**	**1,357,489**	**1,358,618**
HARRIS	non-Federal	191,254	191,255	191,255	191,254	191,255
HN HENRY	non-Federal	199,980	199,668	199,686	199,673	199,683
JORDAN	non-Federal	275,028	274,938	274,902	274,931	274,928
LAY	non-Federal	647,718	646,975	646,993	646,993	647,042
LOGAN MARTIN	non-Federal	427,838	427,276	427,282	427,282	427,326
MARTIN	non-Federal	417,193	417,191	417,194	417,187	417,211
MITCHELL	non-Federal	547,550	546,998	547,007	547,005	547,014
THURLOW	non-Federal	273,753	273,756	273,748	273,755	273,755
WALTER-BOULDIN	non-Federal	843,352	842,350	842,494	842,392	842,535
WEISS	non-Federal	202,114	201,768	201,878	201,775	201,885
YATES	non-Federal	159,814	159,816	159,812	159,815	159,816
non-Federal	**subtotal**	**4,185,594**	**4,181,991**	**4,182,251**	**4,182,062**	**4,182,450**
System	**TOTAL**	**5,545,013**	**5,539,348**	**5,540,767**	**5,539,551**	**5,541,068**

3.3 Energy Prices

Energy prices can significantly change hourly, daily, and seasonally. Therefore, to estimate lost hydropower energy value, the energy price forecast must consider the monthly, weekly, daily, hourly hydropower energy loss and the variability of the associated energy price.

3.3.1 Locational Marginal Pricing (LMP)

For this study we assume the energy prices for the ACT River Basin are best estimated using hourly Locational Marginal Pricing (LMP) of the Southern Company energy market hub reported in the SERC Southeastern sub-region.

LMP is a computational technique that determines an hourly shadow price for an additional megawatt-hour of demand. The Historical LMP values for the Southern Company hub were downloaded from the Midcontinent Independent System Operator, Inc. (MISO) website.

Hourly LMP only provides historical pricing, so these data were utilized in combination with annual energy price forecast information from the Energy Information Administration (EIA) to develop a forecast for LMP.

3.3.2 Energy Price Forecast

The Energy Information Administration (EIA) publishes an Annual Energy Outlook (AEO) that includes thirty years of forecasted electricity costs for different electric market sub-regions organized by the three cost categories of generation, transmission and distribution. The EIA forecast energy price of 'generation' is the representation of the value of the hydropower produced. The annual EIA 'generation' forecast for the SERC Southeastern sub-region of the electric market module (EMM) was used for the development of the LMP forecast values for this study.

The EIA forecast energy values encompass a wide range of assumptions, including a Reference Case that is used for calculating energy value in this study. The AEO forecast is initiated based on actual electricity prices for that year. Shaping Ratio

The EIA forecast annual energy price is transformed to LMP energy price forecast using a shaping ratio. The shaping ratio is the LMP divided by the annual (historical) EIA 'generation' energy value. The EIA annual forecast value multiplied by the shaping ratio yields the LMP energy price forecast.

The shaping ratios are computed in the following procedure:

$$\frac{LMP_{Future}}{LMP_{Past}} = \frac{EIA\_Generation_{Future}}{EIA\_Generation_{Past}}$$

This can be rewritten as:

$$LMP_{Future} = EIA\_Generation_{Future} * \frac{LMP_{Past}}{EIA\_Generation_{Past}}$$

Future LMP values can then be computed by the product of the EIA generation forecast and a shaping ratio defined as:

$$ShapingRatio = \frac{LMP_{Past}}{EIA\_Generation_{Past}}$$

These shaping ratios are defined to reflect the daily and seasonal variability of the daily generation blocks in Table 3-1. To replicate this schedule, daily historical LMP values are sorted from high to low and divided into three blocks, with the highest LMP values associated with the on-peak weekday hours, and the lowest LMP values associated with the weekend off-peak hours. Seasonal by computing shaping ratios for each month. These shaping ratios are computed as averages among days with like generation block (weekday/weekend) and months:

$$ShapingRatio(month, generation\_block) = Average\left(\frac{LMP_{Past}(month, generation\_block, year)}{EIA\_Generation_{Past}(year)}\right)$$

This produces the following equation to estimate LMP forecasts for the daily energy blocks described in Table 3-6 for each month.

$$LMP_{Future}(generation\_block, month) = EIA\_Generation_{Future} * ShapingRatio(generation\_block, month)$$

Hourly shaping ratios for each day are ranked and assigned to each block (formation of blocks described in Paragraph 3.1 above) where the highest values are assigned to On-Peak Hours (contract). Values assigned to each block are then averaged.

Table 3-6. Shaping Factors

	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours	
	Weekdays			Weekends
January	0.485054	0.376382	0.326469	0.354919
February	0.383435	0.314129	0.261670	0.309643
March	0.397256	0.322919	0.253950	0.310099
April	0.512373	0.399539	0.276843	0.331983
May	0.519168	0.381093	0.247215	0.326035
June	0.582671	0.405047	0.259241	0.371095
July	0.627908	0.424394	0.281826	0.383134
August	0.530104	0.372813	0.263075	0.340036
September	0.566264	0.377356	0.255276	0.339360
October	0.534241	0.393816	0.282966	0.371733
November	0.537600	0.409543	0.334303	0.381755
December	0.461476	0.374494	0.313106	0.377930

3.3.3 EIA Long Term Forecast

Figure 3-1 depicts the 2020 EIA reference case generation cost forecast for the SERC Southeast sub-region. The average annual energy value based upon the EIA 30-year price forecast is amortized to a single number using the current federal discount rate of 2.75%.

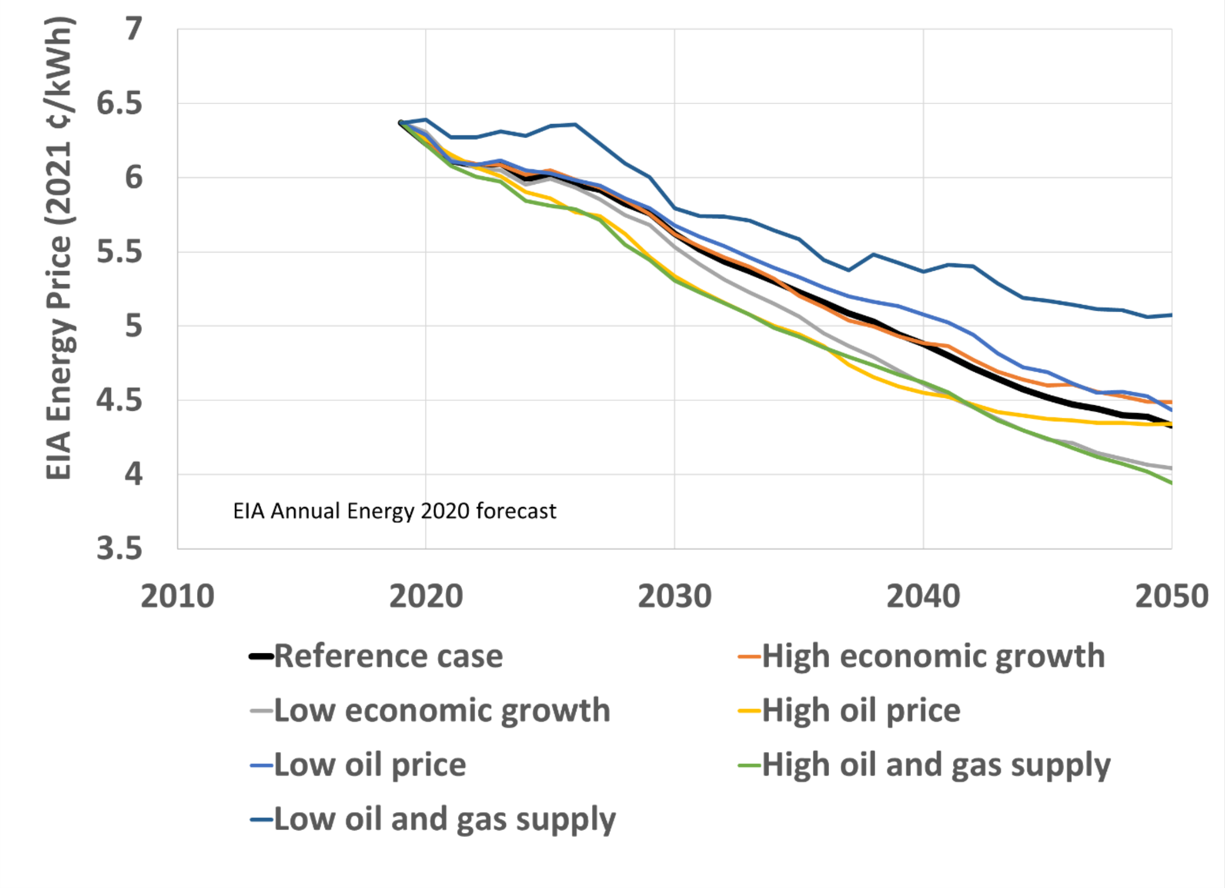


Figure 3-1. EIA Generation Cost forecast for SERC Southeast Sub-region

3.3.4 Energy Price Sensitivity

The 2020 EIA Energy Price Forecast included scenarios that influence the Energy Price Forecast. These 2020 scenarios were amortized to show the possible range or variability due factors that influence 2020 EIA Energy Price forecast. Table 3-7 shows the possible magnitude of variability, or sensitivity in energy forecast values. The Reference Case is used for this study.

Table 3-7. Energy Price Sensitivity to 2020 Forecast Scenarios

EIA Price Forecast Scenarios	Annual Energy Price (¢/kWh)	Reference Case Deviation
Low oil and gas resource and technology	6.01	8.60%
High oil price	5.64	1.92%
Low economic growth	5.60	1.18%
High economic growth	5.54	0.02%
Reference case	5.54	---
Low oil price	5.40	-2.54%
High oil and gas resource and technology	5.24	-5.30%

Federal Interest Rate	2.75%
Period of Years	50

[EIA Annual Energy OUTLOOK 2020]

3.3.5 Energy Prices - Reference Case

The amortized value (long-term) for the current 2020 EIA Reference Case of $55.39/MWh (2021$) is then multiplied by the daily shaping factors for each generation block (weekday/weekend) for the daily energy prices (LMP) for each month.

Table 3-8. Block Energy Prices ($2021/MWh)

Month	Southern Co Energy Prices (2021$/MWh)			
	On-Peak Hours (contract)	On-Peak Hours (non-contract)	Off-Peak Hours	
	Weekday			Weekend
January	$26.86	$20.85	$18.08	$19.66
February	$21.24	$17.40	$14.49	$17.15
March	$22.00	$17.88	$14.07	$17.17
April	$28.38	$22.13	$15.33	$18.39
May	$28.75	$21.11	$13.69	$18.06
June	$32.27	$22.43	$14.36	$20.55
July	$34.78	$23.51	$15.61	$21.22
August	$29.36	$20.65	$14.57	$18.83
September	$31.36	$20.90	$14.14	$18.80
October	$29.59	$21.81	$15.67	$20.59
November	$29.78	$22.68	$18.52	$21.14
December	$25.56	$20.74	$17.34	$20.93

3.4 Energy Value

Although all plants in this system are defined as peaking plants the actual hydropower operations of the individual power plants can vary significantly. For example, some plants may turn completely off and then back on again during peak demand periods, while others may have a minimum flow requirement that constantly generates a small amount of electricity with a maximum generation occurring during peak demand periods. Unfortunately, the detailed hourly generation information required from each plant to determine the daily on-peak and off-peak percentage of total generation is not available. To calculate the energy value, the method assumes that plants will operate to maximize energy; that is, to generate the maximum amount of energy during periods of peak demand.

Table 3-9. Individual Plant and ACT System Energy Value – Water Supply Alternatives

Projects V Alternatives >		**Base2018**	**BaseCap**	**FWOP**	**A03_WS1**	**A04_WS2**	**A05_WS3**	**A06_WS4**	**A08_WS6**
ALLATOONA	Federal	$2,699,829	$2,709,558	$2,676,237	$2,630,384	$2,629,652	$2,658,159	$2,854,898	$2,657,454
CARTERS	Federal	$18,218,896	$18,218,829	$18,218,829	$18,218,829	$18,218,829	$18,218,829	$18,218,829	$18,218,829
MILLERS FERRY	Federal	$7,699,163	$7,701,220	$7,699,270	$7,696,831	$7,696,362	$7,701,158	$7,717,960	$7,700,894
RF HENRY	Federal	$6,362,043	$6,363,766	$6,361,240	$6,358,281	$6,358,594	$6,360,167	$6,390,233	$6,360,494
Federal	**subtotal**	**$34,979,931**	**$34,993,372**	**$34,955,577**	**$34,904,325**	**$34,903,437**	**$34,938,313**	**$35,181,920**	**$34,937,671**
HARRIS	non-Federal	$4,695,548	$4,695,526	$4,695,317	$4,695,310	$4,695,154	$4,695,638	$4,697,346	$4,695,690
HN HENRY	non-Federal	$4,648,894	$4,651,305	$4,648,250	$4,641,367	$4,641,235	$4,642,595	$4,668,918	$4,642,367
JORDAN	non-Federal	$6,496,887	$6,497,446	$6,495,310	$6,493,759	$6,493,866	$6,492,090	$6,467,618	$6,492,392
LAY	non-Federal	$14,813,636	$14,819,894	$14,813,398	$14,796,578	$14,795,912	$14,800,454	$14,850,318	$14,799,581
LOGAN MARTIN	non-Federal	$9,790,080	$9,794,573	$9,788,410	$9,775,545	$9,775,100	$9,777,902	$9,810,591	$9,777,349
MARTIN	non-Federal	$10,031,863	$10,032,885	$10,031,863	$10,032,257	$10,032,128	$10,032,646	$10,038,331	$10,032,813
MITCHELL	non-Federal	$12,600,602	$12,605,068	$12,599,559	$12,586,982	$12,586,594	$12,587,995	$12,616,133	$12,587,673
THURLOW	non-Federal	$6,429,159	$6,429,238	$6,428,526	$6,428,981	$6,358,594	$6,429,123	$6,431,964	$6,429,109
WALTER-BOULDIN	non-Federal	$18,961,115	$18,969,892	$18,960,229	$18,937,801	$18,936,794	$18,944,290	$19,025,480	$18,942,495
WEISS	non-Federal	$4,781,207	$4,783,958	$4,780,247	$4,771,987	$4,771,857	$4,774,404	$4,797,547	$4,774,417
YATES	non-Federal	$3,751,837	$3,751,890	$2,676,237	$3,751,696	$3,751,646	$3,751,790	$3,753,506	$3,751,787
non-Federal	**subtotal**	**$97,000,828**	**$97,031,674**	**$95,917,346**	**$96,912,264**	**$96,838,877**	**$96,928,927**	**$97,157,752**	**$96,925,673**
System	**TOTAL**	**$131,980,759**	**$132,025,046**	**$130,872,923**	**$131,816,589**	**$131,742,314**	**$131,867,239**	**$132,339,673**	**$131,863,344**

NEXT PAGE - Individual Plant and ACT System Energy Value – APC Modified Flood Management Plan

Table 3-10. Individual Plant and ACT System Energy Value – APC Modified Flood Management Alternatives

Projects V Alternatives >		A09_FWOPMF	A10_WS2MF	A11_WS6MF	A12_WS1MF	A13_WS3MF
ALLATOONA	Federal	$2,676,237	$2,629,652	$2,657,454	$2,630,384	$2,658,159
CARTERS	Federal	$18,218,829	$18,218,829	$18,218,829	$18,218,829	$18,218,829
MILLERS FERRY	Federal	$7,669,412	$7,665,630	$7,669,042	$7,668,193	$7,671,118
RF HENRY	Federal	$6,335,652	$6,332,112	$6,334,444	$6,332,671	$6,334,953
Federal	**subtotal**	**$34,900,130**	**$35,154,825**	**$33,795,496**	**$34,850,077**	**$34,883,059**
HARRIS	non- Federal	$4,692,897	$4,693,027	$4,693,312	$4,692,993	$4,693,264
HN HENRY	non- Federal	$4,622,920	$4,615,556	$4,616,168	$4,615,693	$4,616,303
JORDAN	non- Federal	$6,447,975	$6,445,968	$6,445,268	$6,445,825	$6,445,727
LAY	non- Federal	$14,738,096	$14,720,483	$14,721,250	$14,721,250	$14,723,865
LOGAN MARTIN	non- Federal	$9,829,360	$9,815,830	$9,816,157	$9,816,157	$9,818,317
MARTIN	non- Federal	$10,021,980	$10,021,764	$10,022,815	$10,022,046	$10,022,840
MITCHELL	non- Federal	$12,536,493	$12,523,382	$12,524,688	$12,523,775	$12,525,003
THURLOW	non- Federal	$6,423,502	$6,423,716	$6,424,032	$6,423,948	$6,424,172
WALTER-BOULDIN	non- Federal	$18,849,909	$18,825,824	$18,831,639	$18,827,158	$18,832,606
WEISS	non- Federal	$4,813,317	$4,804,834	$4,807,717	$4,805,081	$4,807,991
YATES	non- Federal	$3,748,463	$3,748,583	$3,748,800	$3,748,682	$3,748,846
non-Federal	**subtotal**	**$96,724,914**	**$96,638,968**	**$96,651,844**	**$96,642,607**	**$96,658,933**
System	**TOTAL**	**$131,625,043**	**$131,793,793**	**$130,447,340**	**$131,492,685**	**$131,541,991**

4 Capacity & Capacity Value

Capacity value is defined as the product of the change in dependable capacity and a capacity unit value, representing the capital cost of constructing replacement thermal generating plant capacity for the lost hydropower.

4.1 Dependable Capacity

The dependable capacity of a hydropower project is a measure of the amount of capacity that the project can reliably contribute towards meeting system peak power demands. If a hydropower project always maintains approximately the same head, and there is always an adequate supply of stream flow so that there is enough generation for the full capacity to be usable in the system load, the full installed generator capacity can be considered dependable. In some cases, even the overload capacity is dependable.

At storage projects, normal reservoir drawdown can result in a reduction of capacity due to a loss in head. At other times, diminished stream flows during low flow periods may result in insufficient generation to support the available capacity in the load. Dependable capacity accounts for these factors by giving a measure of the amount of capacity that can be provided with some degree of reliability during peak demand periods.

4.1.1 Basis for Dependable Capacity Calculation Method

Dependable capacity can be computed in several ways. The method that is most appropriate for evaluating the dependable capacity of a hydropower plant in a predominantly thermal generating plant-based power system, like the ACT River Basin, has been found to be the Average Availability Method.

This method is described in Section 6-7g of EM 1110-2-1701, Hydropower, dated 31 December 1985. Studies have shown that this method gives similar results to the more rigorous LOLP (Loss of Load Probability) studies.

The occasional unavailability of a portion of a hydropower project's generating capacity due to hydrologic variations are treated in the same manner as the occasional unavailability of all or part of a thermal generating plant's generating capacity due to forced outages.

In order to evaluate the average dependable capacity for a project, a long-term record of project operation must be used. Actual project operating records would be most desirable; however, certain factors may preclude the use of these records. The period of operation may not be long enough to give a statistically reliable value. Furthermore, operating changes may have occurred over the life of the project, which would make actual data somewhat inconsistent. In order to assure the greatest possible consistency in this calculation, the seventy three-year RESSIM model simulation for the ACT River Basin (1939-2011) was used.

4.1.2 Dependable Capacity Calculation Procedure

The dependable capacity calculation procedure for the ACT River Basin projects begins with approximating each project's contribution in meeting the system capacity requirements demand for the regional critical year. Average weekly energy is used in this study because of characteristic hourly-daily-weekly cyclical peak energy demand during the annual low water (hydropower)/high energy demand 4-month period. Southeastern Power Administration determined marketable capacity based on the regional drought in 1981.

- Each project's contribution of power is determined by first calculating each project's weekly average (generation) energy produced (MWh) for the peak demand months of mid-May through mid-September of 1981 (SEPA determined critical year) from the RESSIM model baseline run. Average weekly energy is characteristic the hourly-daily-weekly cyclical peak energy demand during the annual low water (hydropower)/high energy demand 4-month period.

- This number is then divided by SEPA's defined marketable capacity[1] (MW). This gives an estimate of the required/expected weekly hours (H) of generation in the peak demand period for each project (Table2-4).

- Next, each project's weekly average energy produced (MWh) during the peak demand months was calculated for each simulated year.

- Dividing these values by each project's required/expected weekly average hours (H) on peak determined in the previous step, yields an array of yearly supportable capacity values.

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[1] Coordination with SEPA confirmed marketable capacity values for the Corps hydropower plants and the critical water year of 1981. Installed capacity was assumed for all non-Corps plants

- The average across the array is each project's supportable capacity is the dependable capacity. (illustrated in Table 4-1)

Table 4-1. Dependable Capacity by the Average Availability Method (Base2018)

Year	Annual Critical Period			
	Average Weekly Energy (MWh)	Potential Supportable Capacity (MW)	Machine Capability (MW)	Actual Supportable Capacity (MW)
1939	1501.15	108.78	81.689	81.689
1940	1398.89	101.37	82.133	82.133
1941	1180.87	85.57	81.171	81.171
1942	1344.17	97.40	81.864	81.864
1943	1725.72	125.05	82.069	82.069
1944	1693.29	122.70	81.772	81.772
1945	1410.03	102.18	81.754	81.754
1946	2570.70	186.28	81.279	81.279
1947	1240.05	89.86	81.540	81.540
1948	2177.03	157.76	82.245	82.245
1949	2870.93	208.04	82.019	82.019
1950	1626.02	117.83	81.956	81.956
1951	1225.11	88.78	81.237	81.237
1952	1450.72	105.12	81.609	81.609
1953	1227.99	88.98	81.015	81.015
1954	990.86	71.80	80.804	71.801
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2001	1723.68	124.90	81.653	81.653
2002	687.21	49.80	79.612	49.798
2003	3627.60	262.87	81.475	81.475
2004	1316.63	95.41	81.741	81.741
2005	2947.44	213.58	82.009	82.009
2006	647.39	46.91	80.154	46.912
2007	343.71	24.91	77.739	24.907
2008	478.24	34.65	79.808	34.655
2009	958.25	69.44	80.853	69.439
2010	1384.01	100.29	81.366	81.366
2011	720.32	52.20	80.189	52.197
			Dependable Capacity	75.618

4.1.3 Alternative's Dependable Capacity

This process is repeated for Base2018 and alternative water control operations using the RESSIM model runs. The average dependable capacity difference between the flow scenarios and Base2018 is the gain or loss in dependable capacity caused by changes in water control operations. Results are shown in Table 4-2.

Table 4-2. Individual Plant Dependable Capacity – Water Supply Alternatives

Projects V Alternatives >		**Base2018**	**BaseCap**	**FWOP**	**A03_WS1**	**A04_WS2**	**A05_WS3**	**A06_WS4**	**A08_WS6**
ALLATOONA	Federal	75.618	75.817	75.685	74.809	74.722	76.086	77.773	76.021
CARTERS	Federal	586.965	586.964	586.964	586.964	586.964	586.964	586.964	586.964
MILLERS FERRY	Federal	87.129	87.138	87.129	88.713	87.139	88.733	87.260	88.734
RF HENRY	Federal	75.915	75.924	75.910	79.340	75.918	79.341	76.070	79.341
Federal	**subtotal**	**825.627**	**825.843**	**825.687**	**829.826**	**824.743**	**831.124**	**828.067**	**831.059**
HARRIS	non-Federal	125.030	125.028	125.043	131.768	125.078	131.783	124.944	131.785
HN HENRY	non-Federal	56.793	56.814	56.805	56.773	56.765	56.834	56.997	56.829
JORDAN	non-Federal	104.824	104.825	104.822	104.811	104.810	104.841	104.813	104.845
LAY	non-Federal	159.361	159.409	159.380	159.325	159.306	159.481	159.803	159.470
LOGAN MARTIN	non-Federal	127.342	127.383	127.337	127.296	127.272	127.465	127.964	127.458
MARTIN	non-Federal	180.698	180.614	180.698	180.733	180.746	180.798	180.559	180.795
MITCHELL	non-Federal	159.372	159.413	159.374	159.327	159.308	159.494	159.957	159.484
THURLOW	non-Federal	76.808	76.792	76.811	76.849	76.860	76.847	76.723	76.851
WALTER-BOULDIN	non-Federal	209.849	209.959	209.849	209.727	209.675	210.158	211.384	210.130
WEISS	non-Federal	71.266	71.291	71.253	71.219	71.209	71.355	71.826	71.346
YATES	non-Federal	45.800	44.904	44.912	44.931	44.938	44.944	44.881	44.944
non-Federal	**subtotal**	**1317.142**	**1316.432**	**1316.284**	**1322.758**	**1315.967**	**1323.999**	**1319.852**	**1323.939**
System	**TOTAL**	**2142.770**	**2142.275**	**2141.971**	**2152.584**	**2140.710**	**2155.124**	**2147.919**	**2154.998**

Table 4-3. Individual Plant Dependable Capacity – Modified Flood Operations Alternatives

Projects V Alternatives >		**A09_FWOPMF**	**A10_WS2MF**	**A11_WS6MF**	**A12_WS1MF**	**A13_WS3MF**
ALLATOONA	Federal	75.685	74.722	76.021	74.809	76.086
CARTERS	Federal	586.964	586.964	586.964	586.964	586.964
MILLERS FERRY	Federal	88.718	88.702	88.726	88.706	88.723
RF HENRY	Federal	79.354	79.355	79.355	79.355	79.355
Federal	**subtotal**	**830.721**	**829.743**	**831.066**	**829.833**	**831.128**
HARRIS	non-Federal	131.761	131.754	131.773	131.753	131.759
HN HENRY	non-Federal	56.764	56.716	56.780	56.720	56.789
JORDAN	non-Federal	104.845	104.832	104.865	104.829	104.866
LAY	non-Federal	159.314	159.212	159.224	159.224	159.366
LOGAN MARTIN	non-Federal	127.257	127.161	127.181	127.181	127.340
MARTIN	non-Federal	180.679	180.670	180.769	180.670	180.742
MITCHELL	non-Federal	159.288	159.194	159.359	159.208	159.366
THURLOW	non-Federal	76.897	76.847	76.862	76.846	76.846
WALTER-BOULDIN	non-Federal	209.554	209.311	209.738	209.348	209.756
WEISS	non-Federal	71.127	71.073	71.220	71.082	71.232
YATES	non-Federal	44.955	44.925	44.940	44.924	44.933
non-Federal	**subtotal**	**1322.440**	**1321.694**	**1322.711**	**1321.786**	**1322.996**
System	**TOTAL**	**2153.161**	**2151.437**	**2153.777**	**2151.619**	**2154.125**

4.2 Capacity Unit Value Calculation

Capacity unit values represent the capital cost and the fixed O&M cost of the most likely thermal generation alternative that would carry the same increment of load as the proposed hydropower project or modification. As discussed below in the screening curve analysis description, the cost effectiveness of the different thermal resources depends on how and when the resource is used. For example, coal fired plants may be used to replace a base loading hydropower plant while a gas fired turbine plant may be used to replace a peaking hydropower operation. A gas fired combined cycle plant would be used in an intermediate mode of load-following. In this section the process of determining the least costly, most likely combination of thermal generating resources, which would replace lost hydropower, is described. Also, the method calculating the capacity unit value is presented.

4.2.1 Typical Hourly System Generation

To establish the most likely thermal generation alternative, an analysis of how hydropower is currently dispatched/operated in the regional power system. The goal of this analysis is to show how much capacity can be defined as base load, how much can be defined as intermediate load, and how much can be defined as peaking. Typically, the process of computing a capacity value is done on a plant by plant basis, however the necessary data, hourly generation for a typical year was only available for the four USACE plants. In this regard, a total system typical hourly generation exceedance curve is developed.

Production of the total system exceedance chart is based on two assumptions;

- The non-USACE plants acted similar in operation to the four USACE plants.

  This assumption is reasonable since the non-Corps plants are similarly defined as peaking plants like the USACE facilities.

- The USACE hydropower plants' typical year occurred concurrently.

With these assumptions the typical hourly generations for the USACE plants were combined and then divided by nameplate capacity of all four USACE plants. This allows for an exceedance curve for percent of nameplate capacity. (Figure 4-1). This can then be made to represent the entire system by simply multiplying the y-axis in Figure 4-1 by the total system capacity of ACT system (Table 2-4).

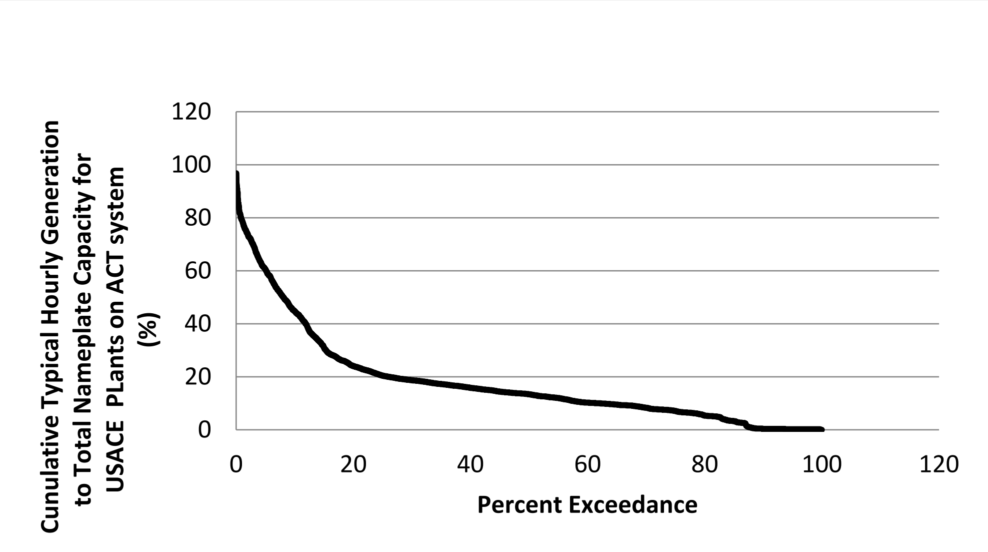

Figure 4-1. Percent of Nameplate capacity exceedance chart for USACE plants

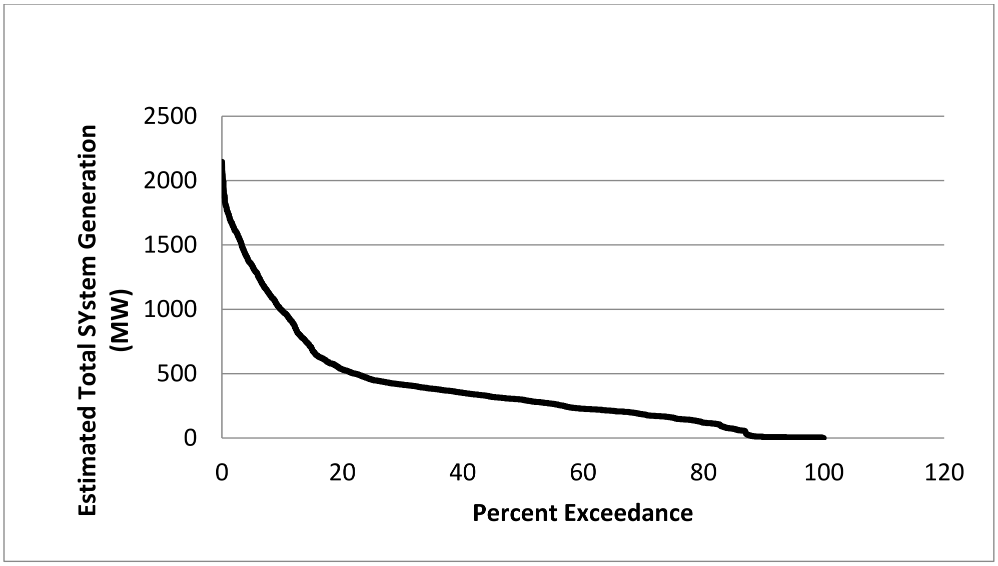

Figure 4-2. Load duration curve for ACT watershed hydropower system

4.2.2 Screening Curve Analysis

A screening curve is a plot of annual total plant costs for a thermal generating plant [fixed (capacity) cost plus variable (operating) cost] versus annual plant factor (PF). When this is applied to multiple types of thermal generation resources, the screening curve provides an algebraic way to show which type of thermal generation is the least cost alternative for each plant factor range.

The screening curve assumes a linear function defined by the following equation:

$$AC = CV + (EV * 0.0876 * PF)$$

where: AC = annual thermal generating plant total cost (\$/kW-year)
CV = thermal generating plant capacity cost (\$/KkW-year)
EV = thermal generating plant operating cost (\$/MWh)

4.2.2.1 Plant Capacity Cost

Plant capacity cost for coal-fired steam, gas-fired combined cycle and gas-fired combustion turbine plants were computed using procedures developed by the Federal Energy Regulatory Commission (FERC). Capacity values were computed for the states in the SEPA region (AL, GA, MS, FL) based on a 2-3/4 percent interest rate and 2021 price levels. Adjusted capacity values are shown in Table 4-5. The adjusted capacity values incorporate adjustments to account for differences in reliability and operating flexibility between hydropower and thermal generating power plants. See EM 1110-2-1701, Hydropower, Section 9-5c for further discussion of the capacity value FERC adjustments.

4.2.2.2 Plant Operating Costs

Operating costs for coal-fired steam, gas-fired combined cycle and gas-fired combustion turbine plants were developed using information obtained from the publication EIA Electric Power Monthly (DOE/EIA-0226) and other sources. The information obtained included fuel costs, heat rates and variable O&M costs. The resulting values, based on 2021 price levels, are shown in Table 4-4. Since current Corps of Engineers policy does not allow the use of real fuel cost escalation, these values were assumed to apply over the entire period of analysis.

Table 4-4. Adjusted Capacity and Operating Costs for SEPA Region

State	CO		CC		CT	
	Capacity $/KW-yr	Energy $/MWh	Capacity $/KW-yr	Energy $/MWh	Capacity $/KW-yr	Energy $/MWh
Alabama	$312.33	$22.74	$145.74	$22.31	$124.15	$32.60
Georgia	$312.45	$26.50	$145.74	$20.66	$124.15	$30.07
Mississippi	$311.59	$27.09	$145.55	$21.64	$124.15	$30.92
Florida	$312.49	$27.80	$145.74	$23.87	$124.15	$34.98
Average	**$312.22**	**$26.03**	**$145.69**	**$22.12**	**$124.15**	**$32.14**

4.2.2.3 Screening Curve

The plot for each thermal generation type was developed by computing the annual plant cost for various plant factors ranging from zero to 100 percent. The plots are shown in the lower portion of Figure 4-3.

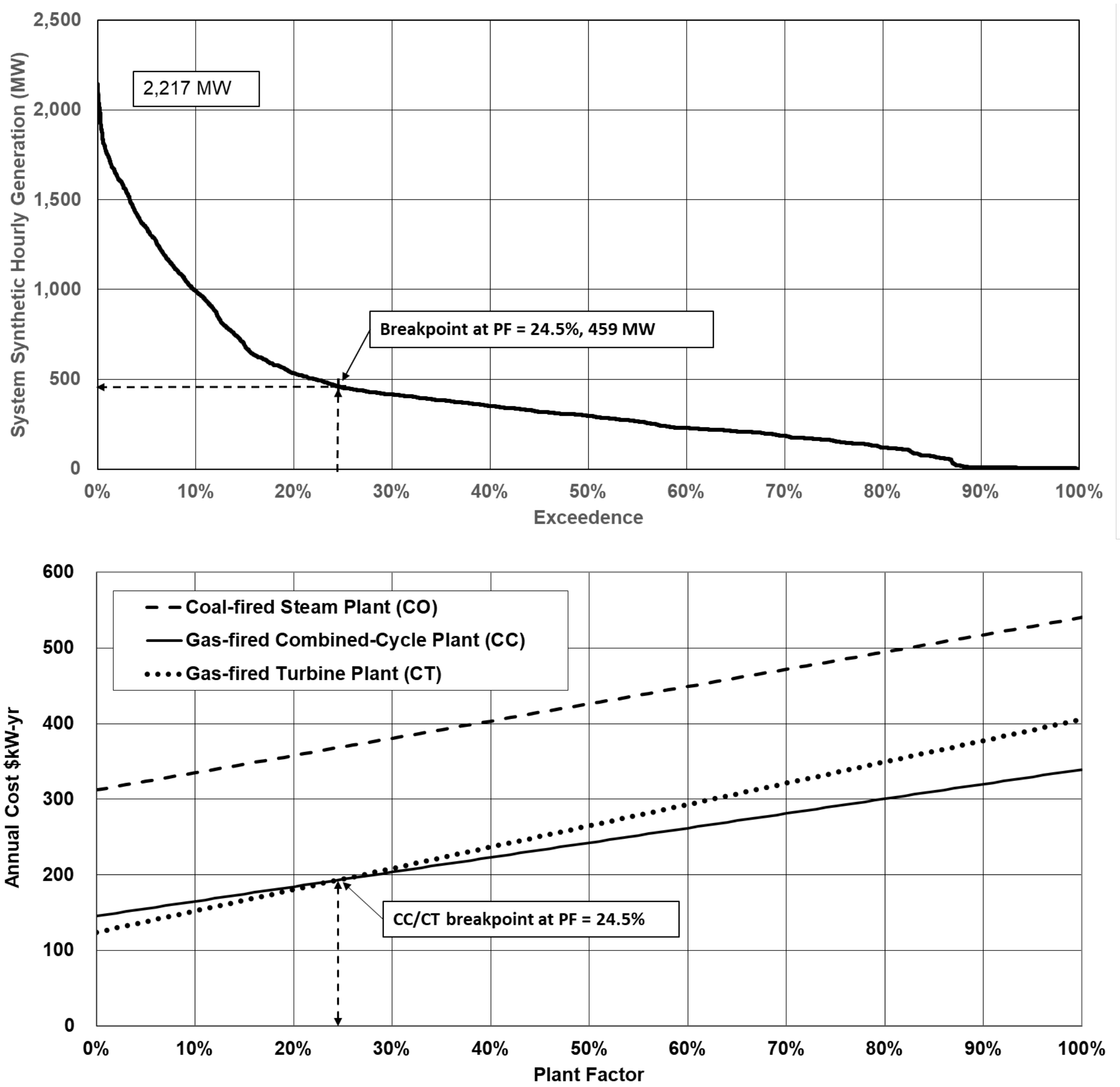

Figure 4-3. Screening Curve for Thermal Generating Plant Types in the SEPA Region

4.2.2.4 Interpretation

The Screening Curve shows that the gas-fired combustion turbine plant type is the least expensive for plants operating less than 24.5% of the time, while plant operating more of the time the gas-fire combined cycle plant is the least expensive. The maximum system operating capacity is shown as 2,217 MW, of that total system capacity up to 459 MW would operate more than 24.5% of time and the least cost operation plant type would be gas-fired combined cycle plant type. The remaining system capacity of 1,758 MW runs less than 24.5% of time and the least cost thermal generating plant type would be the gas-fired combustion plant type.

The most likely least cost combination of thermal generating plant types that could be used to replace the system hydropower would be 1,667 MW of gas-fired combustion turbine plant type and 550 MW of gas-fired combined cycle plant type.

4.2.3 Composite Capacity Unit Value

The process for calculating the composite unit capacity value for the ACT River Basin system is described by the following algorithm;

- From the screening curve, determine the "breakpoints" (the plant factors at which the least cost plant type changes).

- Find the points on the generation-duration curve where the percent of time generation is numerically identical to the plant factor breakpoints defined in the preceding step; these intersection points define the portion of the generation that would be carried by each thermal generation plant type.

- Calculate percent of total generating capacity for each thermal alternative using the portions defined in the prior step above.

- Calculate the composite unit capacity of the system as an average of each the thermal alternative's capacity cost weighted by their percent of total generating capacity defined in the prior step.

The composite unit capacity values are computed for ACT river basin system is calculated in Table 4-9.

Table 4-5. Composite Unit Capacity Value for ACT system

Thermal Generating Plant Type	**Capacity MW**	**Proportion %**	Plant Type **Cost $/kW-yr**	Proportion of **Cost $/kW-yr**
Combustion Turbine	1,758	79.30%	$124.15	$32.14
Combined Cycle	459	20.70%	$145.69	$22.12
System Total	2,217	100.00%		$128.61

Estimated Replacement Dependable Capacity Value is **$128.61**/kW-yr.

The value of capacity for each alternative is determined by multiplying the dependable capacity for each alternative in Tables 4-2 and 4-3 by the composite unit capacity value in Table 4-9. The value of capacity under each alternative is listed in Tables 4-10 and 4-11 below.

Table 4-6. Value of Individual Plant Dependable Capacity – Water Supply Alternatives

Alternatives > Projects V		**Base2018**	**BaseCap**	**FWOP**	**A03_WS1**	**A04_WS2**	**A05_WS3**	**A06_WS4**	**A08_WS6**
ALLATOONA	Federal	$9,725,232	$9,750,813	$9,733,881	$9,621,229	$9,609,987	$9,785,481	$10,002,355	$9,777,113
CARTERS	Federal	$75,489,581	$75,489,396	$75,489,396	$75,489,396	$75,489,396	$75,489,396	$75,489,396	$75,489,396
MILLERS FERRY	Federal	$11,205,660	$11,206,806	$11,205,615	$11,409,319	$11,206,965	$11,412,005	$11,222,559	$11,412,024
RF HENRY	Federal	$9,763,461	$9,764,596	$9,762,725	$10,203,925	$9,763,825	$10,203,984	$9,783,323	$10,203,984
Federal	**subtotal**	$106,183,933	$106,211,611	$106,191,617	$106,723,868	$106,070,173	$106,890,866	$106,497,633	$106,882,517
HARRIS	non-Federal	$16,080,059	$16,079,814	$16,081,757	$16,946,663	$16,086,307	$16,948,631	$16,069,046	$16,948,897
HN HENRY	non-Federal	$7,304,157	$7,306,859	$7,305,711	$7,301,512	$7,300,602	$7,309,369	$7,330,374	$7,308,743
JORDAN	non-Federal	$13,481,412	$13,481,587	$13,481,187	$13,479,699	$13,479,677	$13,483,649	$13,479,996	$13,484,178
LAY	non-Federal	$20,495,364	$20,501,629	$20,497,842	$20,490,832	$20,488,332	$20,510,876	$20,552,264	$20,509,446
LOGAN MARTIN	non-Federal	$16,377,419	$16,382,708	$16,376,792	$16,371,576	$16,368,396	$16,393,319	$16,457,463	$16,392,400
MARTIN	non-Federal	$23,239,618	$23,228,766	$23,239,618	$23,244,096	$23,245,711	$23,252,374	$23,221,667	$23,252,068
MITCHELL	non-Federal	$20,496,844	$20,502,136	$20,497,100	$20,491,009	$20,488,606	$20,512,492	$20,572,127	$20,511,280
THURLOW	non-Federal	$9,878,252	$9,876,189	$9,878,696	$9,883,591	$9,884,950	$9,883,235	$9,867,405	$9,883,842
WALTER-BOULDIN	non-Federal	$26,988,635	$27,002,847	$26,988,669	$26,972,926	$26,966,317	$27,028,399	$27,186,145	$27,024,870
WEISS	non-Federal	$9,165,574	$9,168,753	$9,163,821	$9,159,464	$9,158,136	$9,177,001	$9,237,515	$9,175,829
YATES	non-Federal	$5,890,338	$5,775,052	$5,776,102	$5,778,594	$5,779,478	$5,780,229	$5,772,178	$5,780,280
non-Federal	**subtotal**	$169,397,672	$169,306,340	$169,287,294	$170,119,963	$169,246,512	$170,279,573	$169,746,180	$170,271,833
System	**TOTAL**	$275,581,606	$275,517,951	$275,478,911	$276,843,831	$275,316,685	$277,170,438	$276,243,812	$277,154,349

Table 4-7. Value of Individual Plant Dependable Capacity – Modified Flood Operations Alternatives

Alternatives > Projects V		**A09_FWOPMF**	**A10_WS2MF**	**A11_WS6MF**	**A12_WS1MF**	**A13_WS3MF**
ALLATOONA	Federal	$9,733,848	$9,609,996	$9,777,061	$9,621,185	$9,785,420
CARTERS	Federal	$75,489,440	$75,489,440	$75,489,440	$75,489,440	$75,489,440
MILLERS FERRY	Federal	$11,410,022	$11,407,964	$11,411,051	$11,408,479	$11,410,665
RF HENRY	Federal	$10,205,718	$10,205,847	$10,205,847	$10,205,847	$10,205,847
Federal	**subtotal**	$106,839,028	$106,713,247	$106,883,398	$106,724,951	$106,891,372
HARRIS	non-Federal	$16,945,782	$16,944,882	$16,947,326	$16,944,753	$16,945,525
HN HENRY	non-Federal	$7,300,418	$7,294,245	$7,302,476	$7,294,759	$7,303,633
JORDAN	non-Federal	$13,484,115	$13,482,444	$13,486,688	$13,482,058	$13,486,816
LAY	non-Federal	$20,489,374	$20,476,255	$20,477,799	$20,477,799	$20,496,061
LOGAN MARTIN	non-Federal	$16,366,523	$16,354,176	$16,356,748	$16,356,748	$16,377,197
MARTIN	non-Federal	$23,237,126	$23,235,969	$23,248,701	$23,235,969	$23,245,229
MITCHELL	non-Federal	$20,486,030	$20,473,940	$20,495,161	$20,475,741	$20,496,061
THURLOW	non-Federal	$9,889,723	$9,883,293	$9,885,222	$9,883,164	$9,883,164
WALTER-BOULDIN	non-Federal	$26,950,740	$26,919,488	$26,974,404	$26,924,246	$26,976,719
WEISS	non-Federal	$9,147,643	$9,140,699	$9,159,604	$9,141,856	$9,161,148
YATES	non-Federal	$5,781,663	$5,777,804	$5,779,733	$5,777,676	$5,778,833
non-Federal	**subtotal**	$170,079,137	$169,983,194	$170,113,862	$169,994,769	$170,150,387
System	**TOTAL**	$276,918,165	$276,696,441	$276,997,260	$276,719,720	$277,041,759

5 Value of Hydropower - Summary

The following tables present a summary of the total hydropower value for the alternatives of this Allatoona-Coosa Reallocation (ACR) Study. Hydropower Value is the sum of energy value and capacity value.

Table 5-1. Value of Individual Plant Hydropower (energy+capacity) – Water Supply Alternatives

Alternatives > Projects V		Base2018	BaseCap	FWOP	A03_WS1	A04_WS2	A05_WS3	A06_WS4	A08_WS6
ALLATOONA	Federal	$12,425,061	$12,460,371	$12,410,118	$12,251,613	$12,239,639	$12,443,640	$12,857,253	$12,434,567
CARTERS	Federal	$93,708,477	$93,708,225	$93,708,225	$93,708,225	$93,708,225	$93,708,225	$93,708,225	$93,708,225
MILLERS FERRY	Federal	$18,904,823	$18,908,026	$18,904,885	$19,106,150	$18,903,327	$19,113,163	$18,940,519	$19,112,918
RF HENRY	Federal	$16,125,504	$16,128,362	$16,123,965	$16,562,206	$16,122,419	$16,564,151	$16,173,556	$16,564,478
Federal	**subtotal**	**$141,163,864**	**$141,204,983**	**$141,147,194**	**$141,628,193**	**$140,973,610**	**$141,829,179**	**$141,679,553**	**$141,820,188**
HARRIS	non-Federal	$20,775,607	$20,775,340	$20,777,074	$21,641,973	$20,781,461	$21,644,269	$20,766,392	$21,644,587
HN HENRY	non-Federal	$11,953,051	$11,958,164	$11,953,961	$11,942,879	$11,941,837	$11,951,964	$11,999,292	$11,951,110
JORDAN	non-Federal	$19,978,299	$19,979,033	$19,976,497	$19,973,458	$19,973,543	$19,975,739	$19,947,614	$19,976,570
LAY	non-Federal	$35,309,000	$35,321,523	$35,311,240	$35,287,410	$35,284,244	$35,311,330	$35,402,582	$35,309,027
LOGAN MARTIN	non-Federal	$26,167,499	$26,177,281	$26,165,202	$26,147,121	$26,143,496	$26,171,221	$26,268,054	$26,169,749
MARTIN	non-Federal	$33,271,481	$33,261,651	$33,271,481	$33,276,353	$33,277,839	$33,285,020	$33,259,998	$33,284,881
MITCHELL	non-Federal	$33,097,446	$33,107,204	$33,096,659	$33,077,991	$33,075,200	$33,100,487	$33,188,260	$33,098,953
THURLOW	non-Federal	$16,307,411	$16,305,427	$16,307,222	$16,312,572	$16,243,544	$16,312,358	$16,299,369	$16,312,951
WALTER-BOULDIN	non-Federal	$45,949,750	$45,972,739	$45,948,898	$45,910,727	$45,903,111	$45,972,689	$46,211,625	$45,967,365
WEISS	non-Federal	$13,946,781	$13,952,711	$13,944,068	$13,931,451	$13,929,993	$13,951,405	$14,035,062	$13,950,246
YATES	non-Federal	$9,642,175	$9,526,942	$8,452,339	$9,530,290	$9,531,124	$9,532,019	$9,525,684	$9,532,067
non-Federal	**subtotal**	**$266,398,500**	**$266,338,014**	**$265,204,640**	**$267,032,227**	**$266,085,389**	**$267,208,500**	**$266,903,932**	**$267,197,506**
System	**TOTAL**	**$407,562,365**	**$407,542,997**	**$406,351,834**	**$408,660,420**	**$407,058,999**	**$409,037,677**	**$408,583,485**	**$409,017,693**

Table 5-2. Value of Individual Plant Hydropower (energy+capacity) – Modified Flood Operations Alternatives

Alternatives > Projects V		**A09_FWOPMF**	**A10_WS2MF**	**A11_WS6MF**	**A12_WS1MF**	**A13_WS3MF**
ALLATOONA	Federal	$12,410,118	$12,239,639	$12,434,567	$12,251,613	$12,443,640
CARTERS	Federal	$93,708,225	$93,708,225	$93,708,225	$93,708,225	$93,708,225
MILLERS FERRY	Federal	$19,079,389	$19,382,242	$17,745,544	$19,076,627	$19,081,829
RF HENRY	Federal	$16,541,393	$16,537,919	$16,790,612	$16,538,469	$16,540,791
Federal	**subtotal**	**$141,739,125**	**$141,868,025**	**$140,678,947**	**$141,574,934**	**$141,774,485**
HARRIS	non-Federal	$21,024,219	$21,023,456	$21,026,053	$21,023,321	$21,024,372
HN HENRY	non-Federal	$11,923,276	$11,909,830	$11,918,621	$11,910,420	$11,919,919
JORDAN	non-Federal	$19,932,131	$19,928,362	$19,931,991	$19,927,922	$19,932,552
LAY	non-Federal	$35,227,409	$35,196,751	$35,199,043	$35,199,043	$35,219,988
LOGAN MARTIN	non-Federal	$26,195,895	$26,169,999	$26,172,913	$26,172,913	$26,195,550
MARTIN	non-Federal	$33,259,080	$33,257,686	$33,271,504	$33,258,036	$33,268,097
MITCHELL	non-Federal	$33,022,555	$32,997,346	$33,019,809	$32,999,522	$33,021,045
THURLOW	non-Federal	$16,313,203	$16,306,970	$16,309,301	$16,307,071	$16,307,360
WALTER-BOULDIN	non-Federal	$45,800,620	$45,745,289	$45,806,089	$45,751,436	$45,809,383
WEISS	non-Federal	$13,960,937	$13,945,530	$13,967,314	$13,946,988	$13,969,117
YATES	non-Federal	$9,530,181	$9,526,360	$9,528,499	$9,526,380	$9,527,618
non-Federal	**subtotal**	**$266,189,506**	**$266,007,579**	**$266,151,137**	**$266,023,052**	**$266,195,001**
System	**TOTAL**	**$407,928,631**	**$407,875,604**	**$406,830,084**	**$407,597,986**	**$407,969,486**

6 PMA REVENUE

“Revenues foregone to hydropower are the reduction in revenues accruing to the U.S. Treasury as a result of the reduction in hydropower outputs based on the existing rates charged by the power marketing agency.”[2]

“The Corps does not market the power it produces; marketing is done by the Federal power marketing agencies (Southeastern Power Administration, Southwestern Power Administration, Western Area Power Administration, Bonneville Power Administration, Alaska Power Administration) through the Secretary of Energy. The rates are set by the marketing agency to: (a) recover costs (producing and transmitting) over a reasonable period of years (50 years usually); and (b) encourage widespread use at the lowest possible rates to consumers, consistent with sound business principles. …”[3]

6.1 Composite Revenue Rate

Revenue foregone is to be based on the current SEPA contract rates applicable to power generation by the 3 upper Savannah River hydropower plants. A composite rate was developed by SEPA[4,5], using a procedure in Figure 6-1 which combines the Georgia-Alabama-South Carolina (GA-AL-SC) system energy and capacity, and power sales contract rates which recover costs of producing and transmitting hydroelectric power Composite Revenue Rate.

SEPA calculation procedure for developing the Composite Revenue Rate is in Figure 6-1.

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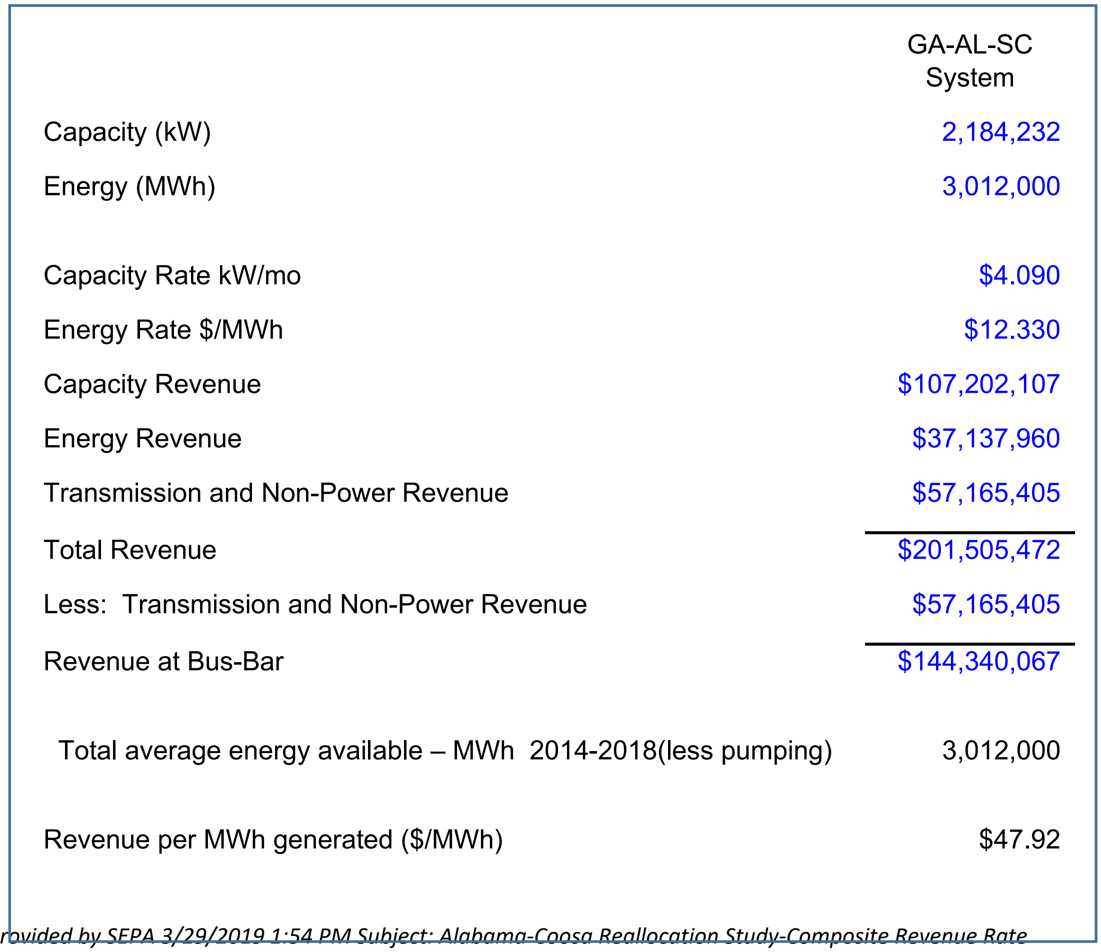
[2] Engineer Manual ER 1105-2-100, 22 April 2000, “Planning Guidance Notebook”, Appendix E – Civil Works, Section VIII – Water Supply, E-57 Other Authorities, (d) Reallocation of Storage, (2) Cost of Storage, (b) Revenue Foregone, page E-217.

[3] Engineer Manual ER 1105-2-100, 22 April 2000, “Planning Guidance Notebook”, Appendix E – Civil Works, Section VI – Hydroelectric Power, e-46 Special Considerations, b. Coordination Initiatives, (2) Marketing Agencies, page E-175.

[4] Transmitted in an email, SUBJECT: RE: Alabama-Coosa Reallocation Study-Composite Revenue Rate, To: Russ Davidson, From: Cathy Stillson, SEPA, Cc: Douglas Spencer, SEPA, Sent: Friday, March 29, 2019 1:54 PM.

[5] Confirmation email for application to Hartwell Water Supply Study. From: Cathy Stillson, SEPA, Sent: Tuesday, April 07, 2020 6:14 AM, To: Davidson, Russell L CIV (USA), Douglas Spencer, SEPA, Cc: Morris, Jeffrey SAS, Subject: SUBJECT: RE: USACE Savannah River Projects



	GA-AL-SC System
Capacity (kW)	2,184,232
Energy (MWh)	3,012,000
Capacity Rate kW/mo	$4.090
Energy Rate $/MWh	$12.330
Capacity Revenue	$107,202,107
Energy Revenue	$37,137,960
Transmission and Non-Power Revenue	$57,165,405
Total Revenue	$201,505,472
Less: Transmission and Non-Power Revenue	$57,165,405
Revenue at Bus-Bar	$144,340,067
Total average energy available – MWh 2014-2018(less pumping)	3,012,000
Revenue per MWh generated ($/MWh)	$47.92

Note: Provided by SEPA 3/29/2019 1:54 PM Subject: Alabama-Coosa Reallocation Study-Composite Revenue Rate

Figure 6-1. SEPA Composite Revenue Rate

SEPA Composite Revenue Rate; $47.92 per kWh

6.2 Hydropower Revenue Foregone Computed

Hydropower losses due to the anticipated Water Supply withdrawals will reduce revenue to SEPA. Revenue loss due to in energy and capacity losses of alternative storage reallocation A08_WS6 is computed in Figure 6-2 following the method in Figure 6-1.

		A08_WS6	
SEPA	**GA-AL-SC System**	**-Loss/ +Gains from FWOP**	**GA-AL-SC System (modified)**
Capacity (kW)	2,184,232	5,372	2,189,604
Energy (MWh)	3,012,000	-797	3,011,203
Capacity Rate $/MW-mo (mils/kW-mo)	$4.09		$4.09
Energy Rate $/MWh	$12.33		$12.33
Capacity Revenue	$107,202,107		$107,465,764
Energy Revenue	$37,137,960		$37,128,133
Transmission and Non-Power Revenue	$57,165,405		$57,165,405
Total Revenue	$201,505,472		$201,759,302
Less: Transmission and Non-Power Revenue	$57,165,405		$57,165,405
Revenue at Bus-Bar	$144,340,067		$144,593,897
Revenue Foregone at Bus-Bar			**$253,831**
Average Energy Available (MWh) 2014-2018 (less pumping)	3,012,000		
Composite Revenue Rate ($/MWh)	**$47.92**		

Figure 6-2. Revenue Foregone is computed following SEPA method in Figure 6-1.

There are capacity gains because there is a seasonal shift in downstream water availability due to upstream seasonal water supply withdrawals and related return flows. Water Supply contracts require increased withdrawals in the annual critical period when hydropower capacity is determined. Water Supply users' increased water withdrawals increase return flow to downstream powerplants increasing capacity. Capacity gains are described in Chapter 4, Table 4-3. Capacity changes are combined with the GA-AL-SC System capacity (Marketable Capacity).

There is a net loss of annual energy (generation) due these Water Supply withdrawals described in Chapter 3, Table 3-4. These energy changes are combined with the GA-AL-SC System annual average (2014-2018) energy.

The Power Contract rates are applied to the changed capacity and energy, which reflect alternative conditions, then summed to yield the equivalent GA-AL-SC system Revenue at Bus-Bar. Revenue foregone is the difference between Current Revenue at Bus-Bar for the GA-AL-SC System and Revenue at Bus-Bar for the GA-AL-SC System (modified) for each of the Alternative Reallocations from Allatoona Lake storage.

6.1 Revenue Foregone Summarized

Table 6-1. Revenue Foregone following SEPA

Allatoona Water Supply Reallocation Alternative	**SEPA Power Sales Contract**	**Capacity Rate** $/kW-mo	**Energy Rate** $/MWh	**SEPA Revenue Foregone**
	GA-AL-SC System	4.09	12.33	
		Annual Capacity (kW)	**Annual Energy** (MWh)	
		2,184,232	3,012,000	
A03_WS1	-Loss/+Gains from **FWOP**	4,138	-1,950	**$179,050**
	GA-AL-SC System (modified kW or MWh)	2,188,370	3,010,050	
A04_WS2	-Loss/+Gains from **FWOP**	-945	-1,967	**-$70,634**
	GA-AL-SC System (modified kW or MWh)	2,183,287	3,010,033	
A05_WS3	-Loss/+Gains from **FWOP**	5,436	-782	**$257,157**
	GA-AL-SC System (modified kW or MWh)	2,189,668	3,011,218	
A06_WS4	-Loss/+Gains from **FWOP**	2,379	7,919	**$214,403**
	GA-AL-SC System (modified kW or MWh)	2,186,611	3,019,919	
A08_WS6	-Loss/+Gains from **FWOP**	5,372	-797	**$253,831**
	GA-AL-SC System (modified kW or MWh)	2,189,604	3,011,203	

6.1 Alternative Computation for Revenue Foregone - Summarized

Alternatively, SEPA Power Sales Contract Rates are applied directly to capacity and energy for each of the alternatives to compute expected PMA revenue following guidance in Footnote 2.

Table 6-2. Expected PMA Revenue

Reallocation Alternatives	**ALLATOONA**		**CARTERS**		**MILLERS FERRY**		**RF HENRY**		**TOTAL**	
	Capacity (MW)	**Energy (MWh)**	**Capacity (MW)**	**Energy (MWh)**	**Capacity (MW)**	**Energy (MWh)**	**Capacity (MW)**	**Energy (MWh)**	**Capacity (MW)**	**Energy (MWh)**
FWOP	75.685	106,508	586.964	659,601	87.129	327,864	75.910	267,580	825.688	1,361,553
A03_WS1	74.809	104,764	586.964	659,601	88.713	327,771	79.340	267,467	829.826	1,359,603
A04_WS2	74.722	104,756	586.964	659,601	87.139	327,751	75.918	267,478	824.743	1,359,586
A05_WS3	76.086	105,693	586.964	659,601	88.733	327,951	79.341	267,526	831.124	1,360,771
A06_WS4	77.773	112,221	586.964	659,601	87.260	328,723	76.070	268,927	828.067	1,369,472
A08_WS6	76.021	105,686	586.964	659,601	88.734	327,932	79.341	267,537	831.060	1,360,756

SEPA Power Sales Contract Rates		
Capacity	$4.09	$/kW-mo.
Energy	$12.33	/MWh

Reallocation Alternatives	**ALLATOONA**		**CARTERS**		**MILLERS FERRY**		**RF HENRY**		**TOTAL Federal Revenue**			
	Capacity Revenue ($)	**Energy Revenue ($)**	**Capacity Revenue ($)**	**Energy Revenue ($)**	**Capacity Revenue ($)**	**Energy Revenue ($)**	**Capacity Revenue ($)**	**Energy Revenue ($)**	**Capacity Revenue ($)**	**Energy Revenue ($)**	**TOTAL Revenue ($)**	**TOTAL Revenue Foregone ($)**
FWOP	$3,714,620	$1,313,244	$28,808,193	$8,132,880	$4,276,291	$4,042,563	$3,725,663	$3,299,261	$40,524,767	$16,787,948	$57,312,716	---
A03_WS1	$3,671,626	$1,291,740	$28,808,193	$8,132,880	$4,354,034	$4,041,416	$3,894,007	$3,297,868	$40,727,860	$16,763,905	$57,491,765	**$179,050**
A04_WS2	$3,667,356	$1,291,641	$28,808,193	$8,132,880	$4,276,782	$4,041,170	$3,726,055	$3,298,004	$40,478,386	$16,763,695	$57,242,082	**-$70,634**
A05_WS3	$3,734,301	$1,303,195	$28,808,193	$8,132,880	$4,355,016	$4,043,636	$3,894,056	$3,298,596	$40,791,566	$16,778,306	$57,569,872	**$257,157**
A06_WS4	$3,817,099	$1,383,685	$28,808,193	$8,132,880	$4,282,721	$4,053,155	$3,733,516	$3,315,870	$40,641,528	$16,885,590	$57,527,118	**$214,403**
A08_WS6	$3,731,111	$1,303,108	$28,808,193	$8,132,880	$4,355,065	$4,043,402	$3,894,056	$3,298,731	$40,788,425	$16,778,121	$57,566,546	**$253,831**

7 PMA CREDITS

7.1 Guidance

Project costs originally allocated to hydropower are being repaid through power revenues which are based on rates designed by the Federal power marketing agency (PMA) to recover allocated costs plus interest within 50 years of the date of commercial power operation. If a portion of the storage is reallocated from hydropower to water supply, the PMA's repayment obligation must be reduced in proportion to the lost energy and marketable capacity.

Planning Guidance Notebook, Appendix E-57d(3) of ER 1105-2-100 (22 April 2002) states that;

"If hydropower revenues are being reduced as a result of the reallocation, the power marketing agency will be credited for the amount of revenues to the Treasury foregone as a result of the reallocation assuming uniform annual repayment."

Paragraph d(2)(b) states that;

"Revenues foregone to hydropower are the reduction in revenues accruing to the Treasury as a result of the reduction in hydropower outputs based on the Baseline rates charged by the power marketing agency. Revenues foregone from other project purposes are the reduction in revenues accruing to the Treasury based on any Baseline repayment agreements."

ER 1105-2-100 also allows the marketing agency credit for any additional costs above the lost revenue to recover costs of purchased power to meet the obligations of the current power sales contract(s) relating to the marketing of power from the hydro project(s) where storage is being reallocated. The continuation of Appendix E-57d(3), provides the following guidance:

"In instances where Baseline contracts between the power marketing agency and their customer would result in a cost to the Federal Government to acquire replacement power to fulfill the obligations of contracts, an additional credit to the power marketing agency can be made for such costs incurred during the remaining period of the contracts."

In both cases the credit in each year will be based on the revenue lost or the replacement costs actually incurred (and documented) by the power marketing agency.

7.2 Estimate of Credits

Estimate of credit to the PMA will be the same as revenue foregone which is based on the change energy between an Alternative and a Base Case multiplied by the SEPA Composite Revenue Rate.

Additional credit will be based on revenue lost or replacement costs actually incurred.

7.3 Remaining Period of Contract

SEPA contracts for the sale of power to the Georgia-Alabama-South Carolina system customers include an evergreen provision, which means they remain in effect until cancelled. As such, the contracts should be considered in effect in perpetuity.

8 GREENHOUSE GAS EMISSIONS

An environmental value associated with hydropower generation is avoided emissions. Emissions would be avoided by generating electricity from hydropower as opposed to generating electricity from a thermal, fossil fuel source. Quantifying these avoided emissions depends on the generating resource mix of the power that is displaced by the hydropower project. Although monetizing the value of these increased emissions is wrought with uncertainty, it does provide a way to compare consequence of lost hydropower in the region and to compare the addition of both financial and environmental consequences.

8.1 Emission Change due to Lost Hydropower

Lost hydropower may change emissions in two ways.

- First, a hydropower lost may cause a shift in the fuel generation mix, when capacity constraints cause the hydropower plant to shift from peaking to off-peak generation.
- Secondly, more thermal generation may be required when the capacity constraint causes losses in gross hydropower generation.

Calculating changes in emissions for the first case would require a detailed description of hourly regional generation mixes and some assumptions on how these would change given more demand. It is deemed beyond this study to look to qualify these changes in emissions; however, for the second case regional emission factors supplied the Environmental Protection Agency's (EPA) Emissions & Generation Resource Integrated Database (eGRID) are suitable. Only the second case is considered in this study.

8.2 Emissions & Generation Resource Integrated Database (eGRID)

A brief description of the eGrid database used to quantify emissions, a brief description of the Social Cost of Carbon used to monetize the increase in emissions, and the results and methodology used to estimate consequences of lost hydropower.

8.2.1 Generating Resource Mix

Since different regions have different generating resource mixes, this factor is regionally dependent. This factor may also be seasonally or even hourly dependent as different mixes of generating resources are required to meet demand.

The Environmental Protection Agency's eGrid (http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html) is a comprehensive database of environmental attributes of electric power systems, incorporating data from several federal agencies. One field of data stored in the eGrid database is emission rates for 26 eGrid sub-regions. These regions are constrained within a single North American Electric Reliability Corporation (NERC) region with similar emissions and generating resource mixes.

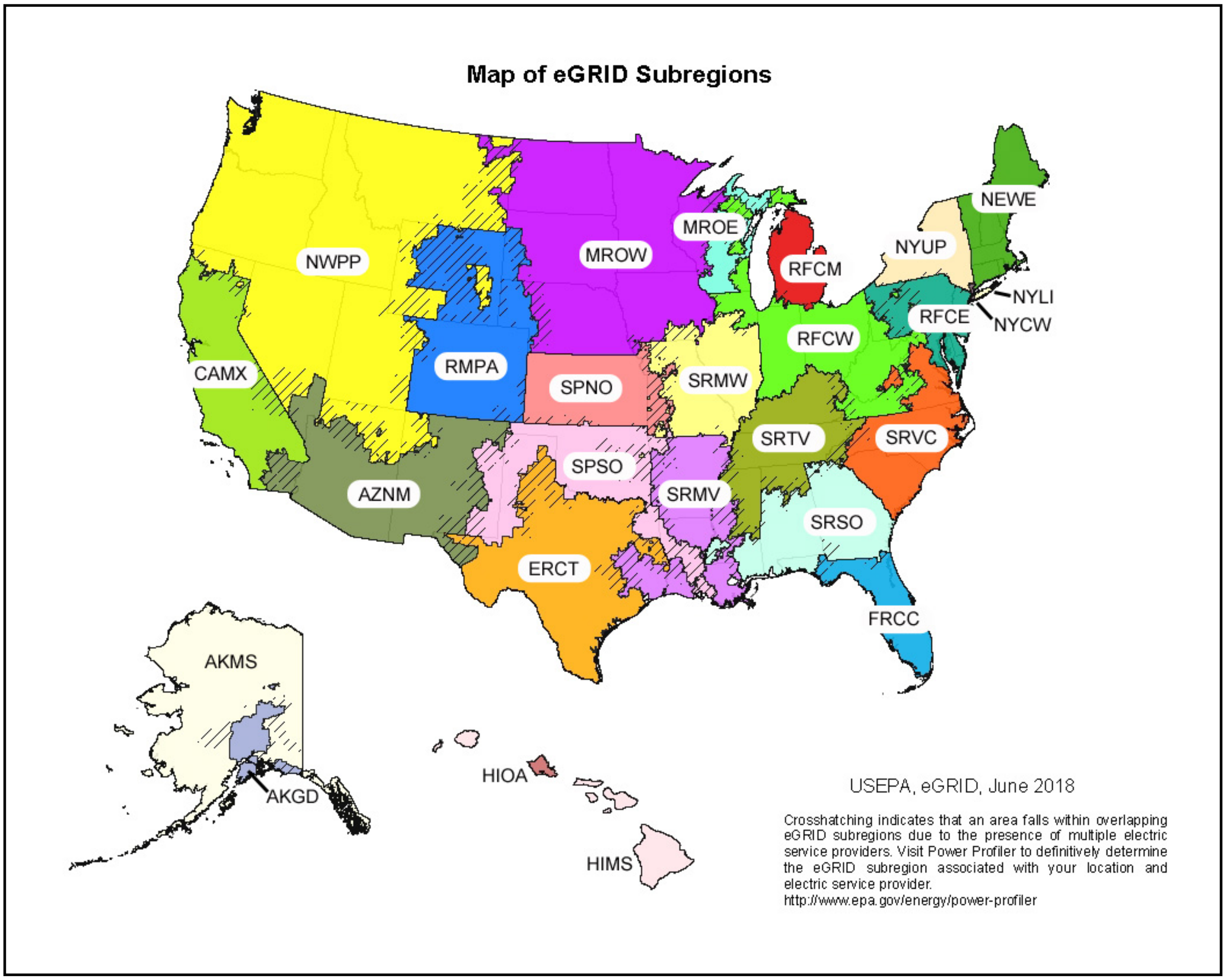


Figure 8-1 eGRID Sub-regions Map

Net generation for this sub-region SERC-Southeast (SRSO) is 264,562,049 MWh while the hydropower portion of the sub-regional hydropower is about 1.95% (~5,169,028 MWh) the average annual generation for Base2018 in this study, is 5,556,728 MWh or about 2.1% of the regional generating resources. If all hydropower were to be excluded from the sub-regional generation resources the emission rate may increase by about 2%. This study will result in very small incremental changes (<0.05%) in hydropower so no adjustment was made to emission rate.

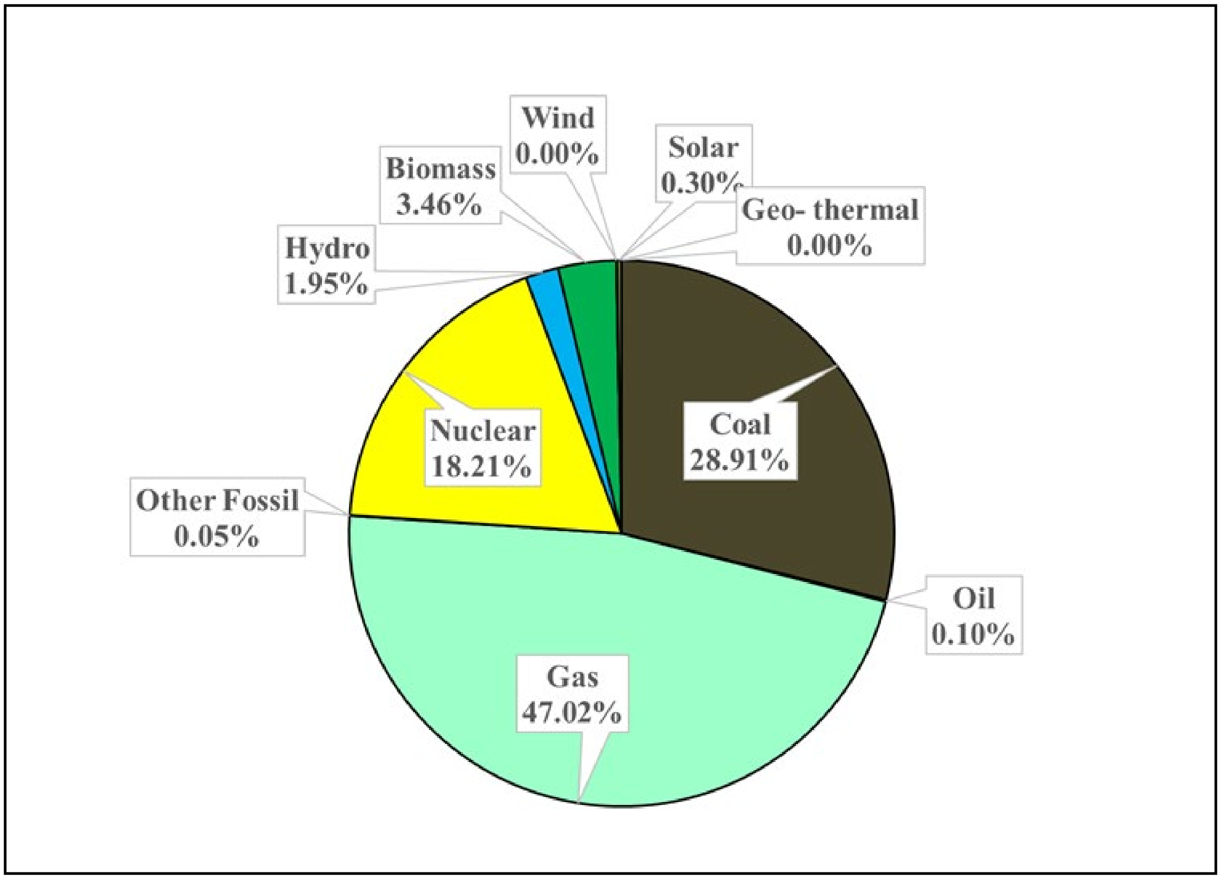


Figure 8-2. Generating Resource Mix for sub-region SERC Southeast (SRSO)

8.2.2 Emission Rates

Emission rates from the eGrid database are defined as pounds per MWh for three greenhouse gases (GHG): carbon dioxide, methane, and nitrous oxide. These are further divided into baseload and non-baseload generating resources. Since Alabama-Coosa-Tallapoosa Basin projects' hydropower is often used to replace the generating resources on the margin this study uses the non-baseload emission rates for SRSO (SERC Southeast) sub-region.

Table 1-1 lists the emission rates used in this study for the GHG calculated in the eGrid database for the SRSO (SERC South) sub-region. Also included in this table is the emission rate for equivalent carbon dioxide (CDE) for the generating resource mix. This metric is used to define the total global warming potential (GWG) from the mix of the greenhouse gases defined by the eGrid database using the equivalent concentration of carbon dioxide as a reference.

Table 8-1. Emission Rates

Sub-region Output Emission Rates (eGRID2016)									
eGRID sub-region acronym	**eGRID sub-region name**	**Non-baseload output emission rates**							**Grid Gross Loss (%)**
		lb/MWh							
		CO_2	**CH_4**	**N_2O**	**CO_2e**	**Annual NO_x**	**Ozone Season NO_x**	**SO_2**	
SRSO	SERC South	1,453.5	0.115	0.017	1,461.1	0.8	0.7	0.6	4.49%

The SERC South sub-regional emissions rate for GHG is the carbon dioxide equivalent (CO_2e) rate of 1,461.1 lb/MWh. This equivalent rate sums the GHG effect of the listed emissions.

8.3 GHG Emissions due to Loss of Hydropower Plant

This CO_2e (GHG) emissions rate is multiplied by the hydropower generation to quantify the emissions that would likely occur should hydropower plant become unavailable and be replaced by other electrical power generating resources within the sub-region to serve the demand for electrical power. CO_2e (GHG) emission quantities are expressed in thousands of metric tons (kt).

Table 8-2. GHG Emissions of Individual Plant – Water Supply Alternatives

Alternatives > **Projects V**		**Base2018**	**BaseCap**	**FWOP**	**A03_WS1**	**A04_WS2**	**A05_WS3**	**A06_WS4**	**A08_WS6**
ALLATOONA	Federal	71.281	71.517	70.588	69.432	69.427	70.048	74.374	70.043
CARTERS	Federal	437.148	437.146	437.146	437.146	437.146	437.146	437.146	437.146
MILLERS FERRY	Federal	217.294	217.350	217.290	217.228	217.215	217.347	217.859	217.335
RF HENRY	Federal	177.374	177.412	177.337	177.262	177.269	177.301	178.229	177.308
Federal	**subtotal**	**903.097**	**903.426**	**902.361**	**901.069**	**901.057**	**901.843**	**907.608**	**901.832**
HARRIS	non-Federal	126.750	126.749	126.749	126.751	126.750	126.751	126.752	126.751
HN HENRY	non-Federal	133.169	133.235	133.140	132.951	132.947	132.973	133.843	132.964
JORDAN	non-Federal	183.975	183.992	183.921	183.874	183.877	183.828	183.054	183.835
LAY	non-Federal	431.026	431.191	430.985	430.498	430.489	430.579	432.400	430.562
LOGAN MARTIN	non-Federal	281.733	281.850	281.662	281.298	281.292	281.335	282.406	281.326
MARTIN	non-Federal	276.510	276.508	276.510	276.514	276.513	276.504	276.494	276.505
MITCHELL	non-Federal	364.520	364.637	364.471	364.112	364.107	364.115	365.117	364.113
THURLOW	non-Federal	181.406	181.406	181.406	181.414	181.414	181.403	181.395	181.403
WALTER-BOULDIN	non-Federal	561.556	561.786	561.495	560.853	560.836	560.993	563.695	560.953
WEISS	non-Federal	133.041	133.112	133.000	132.782	132.776	132.841	133.491	132.837
YATES	non-Federal	105.903	105.904	105.903	105.907	105.907	105.901	105.894	105.900
non-Federal	**subtotal**	**2,779.590**	**2,780.371**	**2,779.241**	**2,776.954**	**2,776.907**	**2,777.224**	**2,784.542**	**2,777.149**
System	**TOTAL**	**3,682.687**	**3,683.797**	**3,681.602**	**3,678.023**	**3,677.964**	**3,679.067**	**3,692.150**	**3,678.982**

Table 8-3. GHG Emissions of Individual Plant – Modified Flood Operations Alternatives

Alternatives > Projects V		A09_FWOPMF	A10_WS2MF	A11_WS6MF	A12_WS1MF	A13_WS3MF
ALLATOONA	Federal	70.588	69.427	70.043	69.432	70.048
CARTERS	Federal	437.146	437.146	437.146	437.146	437.146
MILLERS FERRY	Federal	216.501	216.392	216.487	216.463	216.545
RF HENRY	Federal	176.711	176.615	176.671	176.626	176.677
Federal	**subtotal**	**900.947**	**899.580**	**905.866**	**899.668**	**900.416**
HARRIS	non-Federal	126.752	126.753	126.753	126.752	126.753
HN HENRY	non-Federal	132.535	132.329	132.341	132.332	132.339
JORDAN	non-Federal	182.273	182.213	182.189	182.209	182.207
LAY	non-Federal	429.271	428.779	428.791	428.791	428.823
LOGAN MARTIN	non-Federal	283.547	283.175	283.179	283.179	283.208
MARTIN	non-Federal	276.492	276.491	276.493	276.488	276.504
MITCHELL	non-Federal	362.886	362.519	362.526	362.524	362.530
THURLOW	non-Federal	181.428	181.430	181.425	181.430	181.429
WALTER-BOULDIN	non-Federal	558.926	558.262	558.358	558.290	558.385
WEISS	non-Federal	133.950	133.720	133.793	133.725	133.798
YATES	non-Federal	105.916	105.917	105.914	105.917	105.917
non-Federal	**subtotal**	**2,773.976**	**2,771.589**	**2,771.761**	**2,771.637**	**2,771.893**
System	**TOTAL**	**3,674.923**	**3,671.168**	**3,672.108**	**3,671.304**	**3,672.309**

8.4 Equivalent Passenger Vehicle GHG Emissions

- Extract from EPA “Energy and the Environment”- Greenhouse Gases Equivalencies Calculator - Calculations and References. Link to this information;

  https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references

8.4.1 Passenger vehicles per year[6]

Passenger vehicles are defined as 2-axle 4-tire vehicles, including passenger cars, vans, pickup trucks, and sport/utility vehicles.

In 2016, the weighted average combined fuel economy of cars and light trucks was 22.0 miles per gallon (FHWA 2018). The average vehicle miles traveled (VMT) in 2016 was 11,507 miles per year (FHWA 2018).

In 2016, the ratio of carbon dioxide emissions to total greenhouse gas emissions (including carbon dioxide, methane, and nitrous oxide, all expressed as carbon dioxide equivalents) for passenger vehicles was 0.988 (EPA 2018).

The amount of carbon dioxide emitted per gallon of motor gasoline burned is 8.89×10^{-3} metric tons, as calculated in the “Gallons of gasoline consumed” section above.

To determine annual greenhouse gas emissions per passenger vehicle, the following methodology was used: VMT was divided by average gas mileage to determine gallons of gasoline consumed per vehicle per year. Gallons of gasoline consumed was multiplied by carbon dioxide per gallon of gasoline to determine carbon dioxide emitted per vehicle per year. Carbon dioxide emissions were then divided by the ratio of carbon dioxide emissions to total vehicle greenhouse gas emissions to account for vehicle methane and nitrous oxide emissions.

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[6] **Sources:**

- EPA (2018). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2016. Chapter 3 (Energy), Tables 3-12, 3-13, and 3-14. Environmental Protection Agency, Washington, D.C. EPA #430-R-18-003 (PDF) (109 pp, 3 MB About PDF)
- FHWA (2018). Highway Statistics 2016. Office of Highway Policy Information, Federal Highway Administration. Table VM-1. (1 pp, 11 KB About PDF)

8.4.2 Calculation

Note: Due to rounding, performing the calculations given in the equations below may not return the exact results shown.

8.89×10^{-3} *metric tons* CO_2*/gallon gasoline* ×

11,507 VMT *(car/truck average)* ×

1/22.0 miles per gallon *(car/truck)* ×

1 CO_2*,* CH_4*, and* N_2O */ 0.988* CO_2

= 4.71 metric tons CO_2e ***/ vehicle / year***

8.4.3 Passenger Vehicle Equivalent Emissions

Table 8-4. Passenger Vehicle Equivalent Emissions for Individual Plant Loss – Water Supply Alternatives

Alternatives > **Projects V**		**Base2018**	**BaseCap**	**FWOP**	**A03_WS1**	**A04_WS2**	**A05_WS3**	**A06_WS4**	**A08_WS6**
ALLATOONA	Federal	15,134	15,184	14,987	14,741	14,740	14,872	15,791	14,871
CARTERS	Federal	92,813	92,812	92,812	92,812	92,812	92,812	92,812	92,812
MILLERS FERRY	Federal	46,135	46,147	46,134	46,121	46,118	46,146	46,255	46,143
RF HENRY	Federal	37,659	37,667	37,651	37,635	37,637	37,644	37,841	37,645
Federal	**subtotal**	**191,740**	**191,810**	**191,584**	**191,310**	**191,307**	**191,474**	**192,698**	**191,472**
HARRIS	non-Federal	26,911	26,911	26,911	26,911	26,911	26,911	26,911	26,911
HN HENRY	non-Federal	28,274	28,288	28,267	28,227	28,226	28,232	28,417	28,230
JORDAN	non-Federal	39,061	39,064	39,049	39,039	39,040	39,029	38,865	39,031
LAY	non-Federal	91,513	91,548	91,504	91,401	91,399	91,418	91,805	91,415
LOGAN MARTIN	non-Federal	59,816	59,841	59,801	59,724	59,722	59,732	59,959	59,730
MARTIN	non-Federal	58,707	58,707	58,707	58,708	58,708	58,706	58,704	58,706
MITCHELL	non-Federal	77,393	77,418	77,382	77,306	77,305	77,307	77,520	77,306
THURLOW	non-Federal	38,515	38,515	38,515	38,517	38,517	38,514	38,513	38,514
WALTER-BOULDIN	non-Federal	119,226	119,275	119,213	119,077	119,074	119,107	119,681	119,098
WEISS	non-Federal	28,246	28,262	28,238	28,191	28,190	28,204	28,342	28,203
YATES	non-Federal	22,485	22,485	22,485	22,486	22,486	22,484	22,483	22,484
non-Federal	**subtotal**	**590,146**	**590,312**	**590,072**	**589,587**	**589,577**	**589,644**	**591,198**	**589,628**
System	**TOTAL**	**781,887**	**782,122**	**781,656**	**780,897**	**780,884**	**781,118**	**783,896**	**781,100**

Table 8-5. Passenger Vehicle Equivalent Emissions for Individual Plant Loss – Modified Flood Operations Alternatives

Alternatives > Projects V		**A09_FWOPMF**	**A10_WS2MF**	**A11_WS6MF**	**A12_WS1MF**	**A13_WS3MF**
ALLATOONA	Federal	14,987	14,740	14,871	14,741	14,872
CARTERS	Federal	92,812	92,812	92,812	92,812	92,812
MILLERS FERRY	Federal	45,966	45,943	45,963	45,958	45,976
RF HENRY	Federal	37,518	37,498	37,510	37,500	37,511
Federal	**subtotal**	**191,284**	**190,994**	**192,328**	**191,012**	**191,171**
HARRIS	non-Federal	26,911	26,911	26,911	26,911	26,911
HN HENRY	non-Federal	28,139	28,095	28,098	28,096	28,097
JORDAN	non-Federal	38,699	38,686	38,681	38,685	38,685
LAY	non-Federal	91,140	91,036	91,038	91,038	91,045
LOGAN MARTIN	non-Federal	60,201	60,122	60,123	60,123	60,129
MARTIN	non-Federal	58,703	58,703	58,703	58,702	58,706
MITCHELL	non-Federal	77,046	76,968	76,969	76,969	76,970
THURLOW	non-Federal	38,520	38,520	38,519	38,520	38,520
WALTER-BOULDIN	non-Federal	118,668	118,527	118,547	118,533	118,553
WEISS	non-Federal	28,439	28,391	28,406	28,392	28,407
YATES	non-Federal	22,487	22,488	22,487	22,488	22,488
non-Federal	**subtotal**	**588,955**	**588,448**	**588,484**	**588,458**	**588,512**
System	**TOTAL**	**780,238**	**779,441**	**779,641**	**779,470**	**779,683**

8.5 Social Cost of Carbon (SCC)

Social Cost of Carbon is an attempt to monetize the consequences of an incremental increase in carbon emissions for a given year. This estimate was developed by the Interagency Working Group on Social Cost of Carbon for the U.S government with the intent to include this cost into cost-benefit analysis. Consequences included in this valuation include net agricultural productivity, human health, property damages from increased flood risk, and the value of ecosystem services due to climate change.

The reference used to calculate the social cost of carbon has been officially withdrawn but is listed here as basis for computing SCC;

Technical Support Document:
Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis
Under Executive Order 12866 *(withdrawn[7])*
Interagency Working Group on Social Cost of Greenhouse Gases, United States Government
August 2016
(https://19january2017snapshot.epa.gov/sites/production/files/2016-12/documents/sc_co2_tsd_august_2016.pdf).

Table 8-6. Social Cost of CO_2, 2010 – 2050 (in 2007 dollars per metric ton of CO_2). [Ref. Table 2]

Year	**5% Average**	**3% Average**	**2.5% Average**	**High Impact (95th Percentile - Discount Rate 3%)**
2010	10	**31**	50	86
2015	11	**36**	56	105
2020	12	**42**	62	123
2025	14	**46**	68	138
2030	16	**50**	73	152
2035	18	**55**	78	168
2040	21	**60**	84	183
2045	23	**64**	89	197
2050	26	**69**	95	212

For purposes of this analysis the 3% Discount Rate for Average Conditions is used and the interpolated value in Table 8-4 for the year 2021 was updated from 2007 dollars to 2021 dollars using the gross domestic product (Chained) Price Index.

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1 **Presidential Executive Order on Promoting Energy Independence and Economic Growth** Issued on: March 28, 2017 - … the following documents issued by the IWG shall be withdrawn as no longer representative of governmental policy: … (vi) Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis (August 2016).

8.5.1 Social Cost of Carbon Rate

The Social Cost of Carbon used in this analysis is $48 per metric ton (t) of CO_2.

Table 8-7. Social Cost of Carbon SCC [(CO_2) $/t]

	Year	**Interpolated (2007 $)**	**updated to (2021$)**
Discount Rate 3% Average Conditions	2021	$43	$54

The Social Cost of Carbon used in this analysis is $54 per metric ton (t) of CO_2.

The emission rate for CO_2 is 1,453.50 lb/MWh in Table 8-1, which different than CO_2e (GHG) emission rate.

8.6 Value of Social Cost of Carbon of Alternatives

These CO_2 emissions would likely occur should hydropower become unavailable and be replaced by other electrical power generating resources within the sub-region to serve the demand for electrical power. The region would experience increased emissions and their concomitant social impacts.

The quantity of CO_2 emissions is then multiplied by the SCC rate of $54/t to obtain the Social Cost of Carbon.

The Social Cost of Carbon (SCC) are expressed in millions of dollars.

Table 8-8. Value of Social Cost of Carbon of Individual Plants (x $millions)– Water Supply Alternatives

Alternatives > Projects V		Base2018	BaseCap	FWOP	A03_WS1	A04_WS2	A05_WS3	A06_WS4	A08_WS6
ALLATOONA	Federal	$3.8	$3.8	$3.8	$3.7	$3.7	$3.8	$4.0	$3.8
CARTERS	Federal	$23.5	$23.5	$23.5	$23.5	$23.5	$23.5	$23.5	$23.5
MILLERS FERRY	Federal	$11.7	$11.7	$11.7	$11.7	$11.7	$11.7	$11.7	$11.7
RF HENRY	Federal	$9.5	$9.5	$9.5	$9.5	$9.5	$9.5	$9.6	$9.5
Federal	**subtotal**	**$48.5**	**$48.5**	**$48.5**	**$48.4**	**$48.4**	**$48.4**	**$48.8**	**$48.4**
HARRIS	non-Federal	$6.8	$6.8	$6.8	$6.8	$6.8	$6.8	$6.8	$6.8
HN HENRY	non-Federal	$7.2	$7.2	$7.2	$7.1	$7.1	$7.1	$7.2	$7.1
MITCHELL	non-Federal	$19.6	$19.6	$19.6	$19.6	$19.6	$19.6	$19.6	$19.6
THURLOW	non-Federal	$9.7	$9.7	$9.7	$9.7	$9.7	$9.7	$9.7	$9.7
WALTER-BOULDIN	non-Federal	$30.2	$30.2	$30.2	$30.1	$30.1	$30.1	$30.3	$30.1
JORDAN	non-Federal	$9.9	$9.9	$9.9	$9.9	$9.9	$9.9	$9.8	$9.9
LAY	non-Federal	$23.2	$23.2	$23.2	$23.1	$23.1	$23.1	$23.2	$23.1
LOGAN MARTIN	non-Federal	$15.1	$15.1	$15.1	$15.1	$15.1	$15.1	$15.2	$15.1
MARTIN	non-Federal	$14.9	$14.9	$14.9	$14.9	$14.9	$14.9	$14.9	$14.9
WEISS	non-Federal	$7.1	$7.2	$7.1	$7.1	$7.1	$7.1	$7.2	$7.1
YATES	non-Federal	$5.7	$5.7	$5.7	$5.7	$5.7	$5.7	$5.7	$5.7
non-Federal	**subtotal**	**$149.3**	**$149.4**	**$149.3**	**$149.2**	**$149.2**	**$149.2**	**$149.6**	**$149.2**
System	**TOTAL**	**$197.8**	**$197.9**	**$197.8**	**$197.6**	**$197.6**	**$197.6**	**$198.3**	**$197.6**

Table 8-9. Value of Social Cost of Carbon of Individual Plants (x $millions)– Modified Flood Operations Alternatives

Alternatives > **Projects V**		**A09_FWOPMF**	**A10_WS2MF**	**A11_WS6MF**	**A12_WS1MF**	**A13_WS3MF**
ALLATOONA	Federal	$3.79	$3.73	$3.76	$3.73	$3.76
CARTERS	Federal	$23.48	$23.48	$23.48	$23.48	$23.48
MILLERS FERRY	Federal	$11.63	$11.62	$11.63	$11.63	$11.63
RF HENRY	Federal	$9.49	$9.49	$9.49	$9.49	$9.49
Federal	**subtotal**	**$48.40**	**$48.32**	**$48.37**	**$48.33**	**$48.37**
HARRIS	non-Federal	$6.81	$6.81	$6.81	$6.81	$6.81
HN HENRY	non-Federal	$7.12	$7.11	$7.11	$7.11	$7.11
MITCHELL	non-Federal	$19.49	$19.47	$19.47	$19.47	$19.47
THURLOW	non-Federal	$9.75	$9.75	$9.75	$9.75	$9.75
WALTER-BOULDIN	non-Federal	$30.03	$29.99	$29.99	$29.99	$30.00
JORDAN	non-Federal	$9.79	$9.79	$9.79	$9.79	$9.79
LAY	non-Federal	$23.06	$23.03	$23.03	$23.03	$23.04
LOGAN	non-Federal	$15.23	$15.21	$15.21	$15.21	$15.21
LOGAN MARTIN	non-Federal	$14.85	$14.85	$14.85	$14.85	$14.85
WEISS	non-Federal	$7.20	$7.18	$7.19	$7.18	$7.19
YATES	non-Federal	$5.69	$5.69	$5.69	$5.69	$5.69
non-Federal	**subtotal**	**$149.02**	**$148.89**	**$148.90**	**$148.89**	**$148.90**
System	**TOTAL**	**$197.42**	**$197.21**	**$197.26**	**$197.22**	**$197.27**

Attachment 3. 2017 Allatoona Master Plan Update -Allatoona Carrying Capacity Study

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Allatoona Recreation Carrying Capacity Study

Completed by USACE
February 2017

Contents

1 Purpose

The Allatoona Recreation Carrying Capacity Study evaluates the ability of the Allatoona Lake Project to accommodate existing and future recreation uses, and it assesses whether these uses are suitable, given the potential effects on recreational, environmental, and social resources. Carrying capacity is defined as the amount and type of use that an area can sustain over a given period of time. Carrying capacities can protect users' experiences by preventing overcrowding, which causes deterioration of the natural attributes and impedes each user's ability to move freely and to fully enjoy the natural setting without undue stress and distraction.

2 Regional Recreation Resources

2.1 Area Recreation

There are two other lakes in the Allatoona Lake area: Lake Lanier to the northeast on the Chattahoochee River and Carter's Lake to the north on the Coosawattee River. There are also numerous parks and other outdoor opportunities.

2.2 Other USACE Projects in the Area

Both Lake Lanier and Carter's Lake are multipurpose reservoirs operated by the U.S. Army Corps of Engineers. For this study, populations were used from the 50-mile region of influence.

2.3 Project Description

Operated by the U.S. Army Corps of Engineers (USACE), Allatoona Lake ("Allatoona" or "project") is located on the Etowah River in Bartow County, GA, approximately 48 miles upstream from Rome, 4 miles east of Cartersville, and 30 miles northwest of Atlanta. The left abutment is built into the north slope of Vineyard Mountain, and the right abutment extends into the south slope of Pine Mountain. The main lake at summer pool (elevation 840 MSL) includes a water surface area of 11,800 acres and an additional 24,944 acres of surrounding fee land

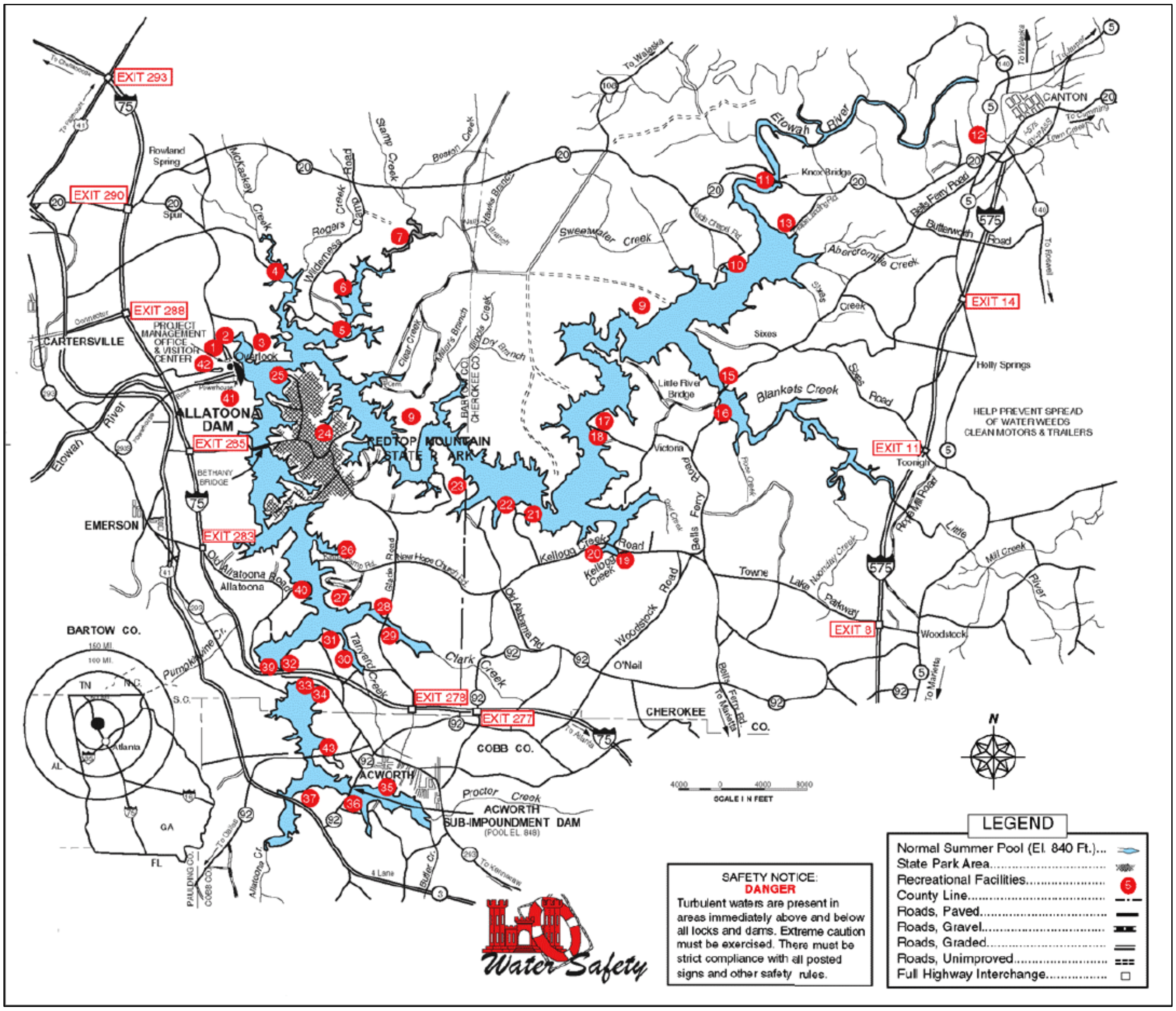
2.3.1 Recreation Areas

Within the Allatoona Lake Project boundary, there are 60 management areas, ranging from fully developed campgrounds to access points. Thirty-one of these areas are currently managed by USACE, 21 are currently managed by public agencies, and 8 marinas are managed by concessionaire lease. USACE receives support from the Georgia Department of Natural Resources (GDNR) in managing all of its wildlife management areas.

Allatoona Lake has 8 currently functioning campgrounds (with a total 580 campsites), 16 day-use areas, 8 public marinas, 37 swimming areas, 45 playgrounds, 4 fishing docks, and 35 trails (82 trail miles). The project experiences a large number of different recreation activities. Some of the more popular activities include developed camping, boating, hiking, sightseeing, swimming, picnicking, hunting, fishing, and observing wildlife.

A map of the project's recreation areas is provided in Figure 1.

Figure 1. Allatoona Lake Project Recreation Areas



SAFETY NOTICE:
DANGER
Turbulent waters are present in areas immediately above and below all locks and dams. Extreme caution must be exercised. There must be strict compliance with all posted signs and other safety rules.

2.4 Influence of Other Recreational Projects

The influence of competing projects and per capita visitation assumptions were carefully considered in developing the future visitation estimates for Allatoona Lake.

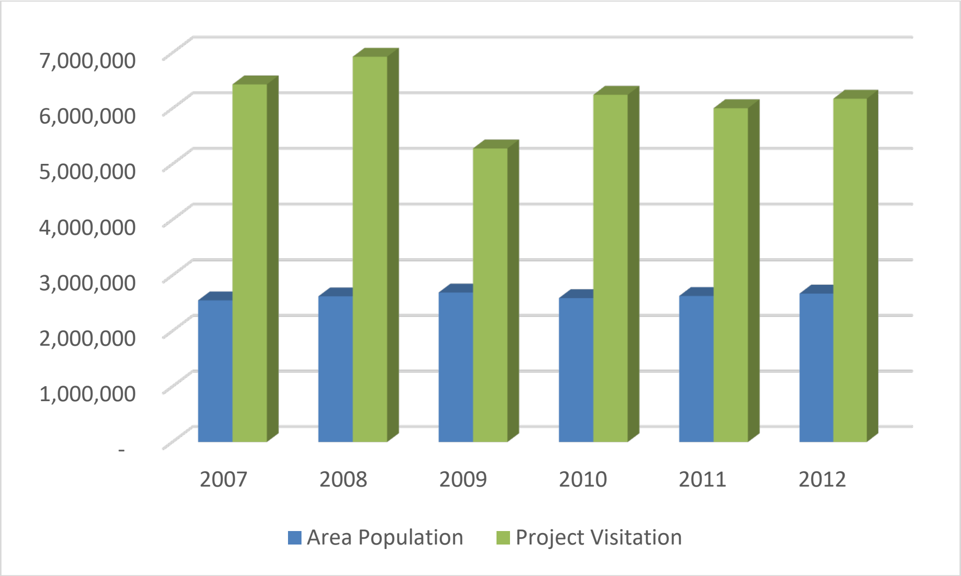
3 Visitation Profile

In general, Allatoona Lake is visited predominately by local residents during peak recreation season from June to August. Visitation at all USACE sites is generally concentrated during the weekends in both peak and non-peak seasons. The Carrying Capacity Study discusses the Allatoona Lake visitation patterns in detail. Overall project visitation was examined from 2002 through 2012.

3.1 Project Visitation

Project visitation and area population for 2002 through 2012 are displayed in Figure 2. Population includes 12 counties in Georgia—Bartow, Cherokee, Cobb, Dawson, Douglas, Floyd, Forsyth, Fulton, Gordon, Paulding, Pickens, and Polk. 2010 census data states that the total population for these counties is 2,590,340.

Figure 2. Project Visitation and Area Population



Source: USACE, 2016 and U.S. Census Bureau, 2016

3.2 Per Capita Use Rate

Visitation and population data for the area for 2007 through 2012 were used to determine the current per capita visitation rate for the 50-mile region of influence. The average per capita use rate for this area is 2.355; however, using the average use rate to project future demand is not the ideal method for Allatoona Lake. Table 1 shows the changes in per capita use rate over the 2007-2012 time period. There is not a strongly correlated relationship between population and project visits; therefore, using a per capita use rate of 1.96 provides a more conservative estimate.

Table 1: 2007–2030 Per Capita Use Rate

Year	Area Population* (50-mile radius)	Visitation**	Per Capita Use Rate***
2007	2,550,196	6,431,973	2.52
2008	2,622,835	6,929,550	2.64
2009	2,691,020	5,281,347	1.96
2010	2,590,340	6,245,913	2.41
2011	2,629,400	6,004,769	2.28
2012	2,672,106	6,175,062	2.31
2020	3,435,814	6,743,066	1.96
2025	3,806,703	7,470,966	1.96
2030	4,191,686	8,226,527	1.96

**Area population numbers for the years after 2012 are projections from the Georgia State Water Plan.*
***Visitation numbers for the years after 2012 are projections based on the lowest per capita use rate for the previous 6 years (2007-2012).*
****The per capita use rate for the years after 2012 is the average per capita use rate based on the previous 3 years (2010-2012).*

3.3 Project Site Area Visitation

Historic visitation records from 2002 through 2012 for each recreation area for which data is available are provided below (Figures 3-76). Some sites show no data for certain years or months due to closures. In addition, detailed Year 2002 data is not available for all areas; for those areas, the year total is used and is not broken down to all months.

The following PSA's were not included in the Design Load and Parking Demand analysis due to data anomalies or missing data: Aqua Sports, Atlanta Boat Club, City of Atlanta Recreation Area, City of Emerson - Luke's Site, Coosa Steel Corporation Recreation Area, Devereux Foundation, First Baptist Church of Marietta - Chapel Knoll, First United Methodist Church of Decatur - Camp 175,Hillhouse Lodge, Holly Springs Recreation Association, Kellogg Creek Day Use, Lake Forrest Country Club, Lutherwood, Metro Atlanta Recovery Residences, Northwest Georgia Girl Scout Council, Old Hwy 41 #2 Day Use and WTSD & Associates, LLC.

Note that there is a steep drop in the rate of visitation in 2009. This sudden drop of visitation across the entire project could possibly be explained by the administration of a visitor survey; however, for the purposes of this study, the drop in visitation is assumed to be due to drought and the general economic downturn of 2009.

Figure 3: Acworth Lake Visitation 2002-2012

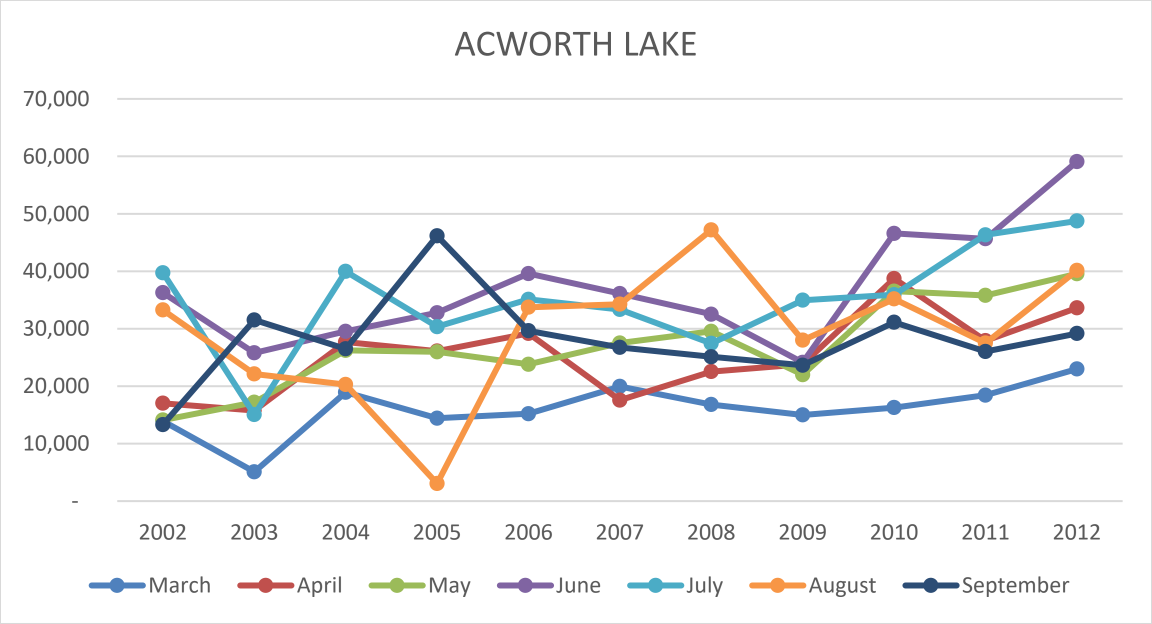


Figure 4: Allatoona Boat and Ski Visitation 2002-2012

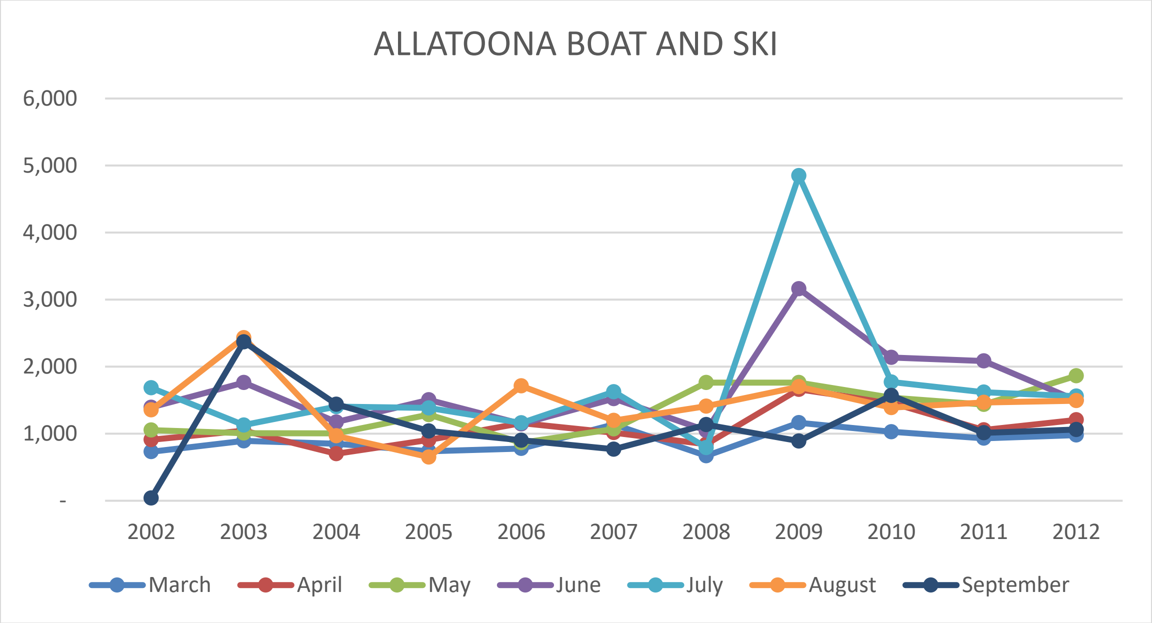


Figure 5: Allatoona Canoe and Sail Visitation 2002-2012

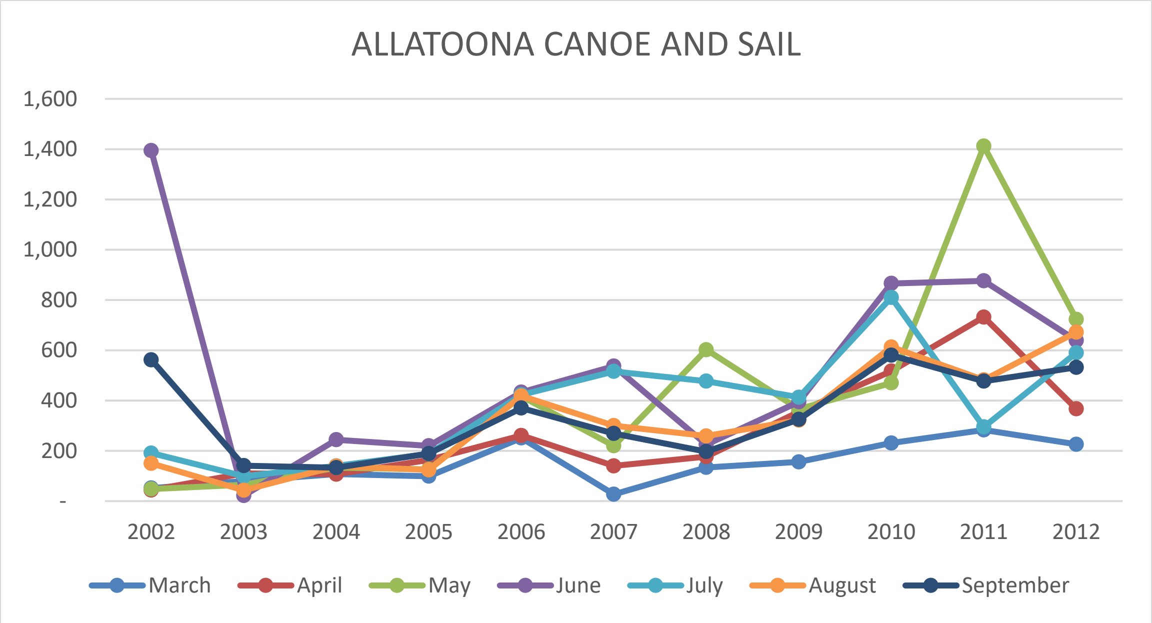


Figure 6: Allatoona Yacht Club Visitation 2002-2012

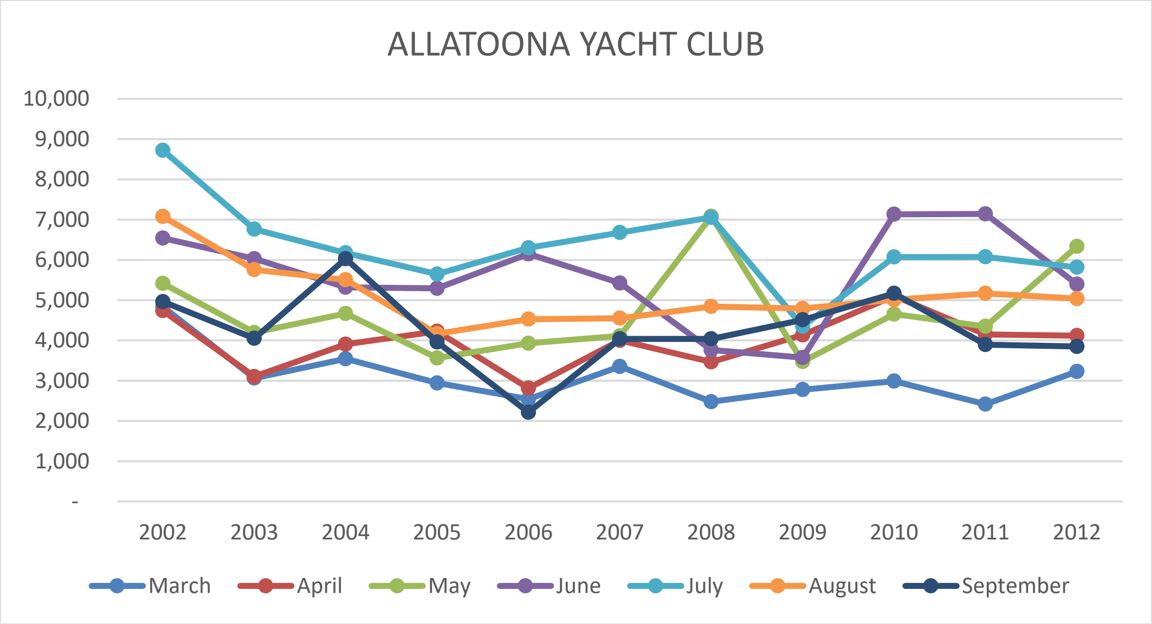


Figure 7: Aqua Sports Visitation 2002-2012

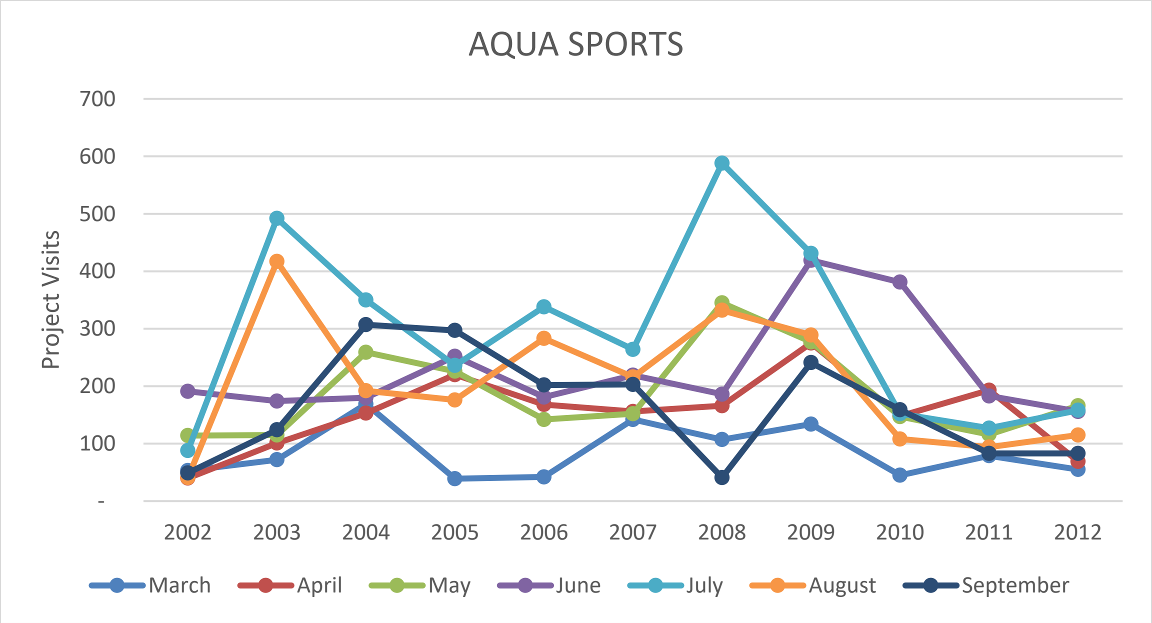


Figure 8: Atlanta Boat Club Visitation 2002-2012

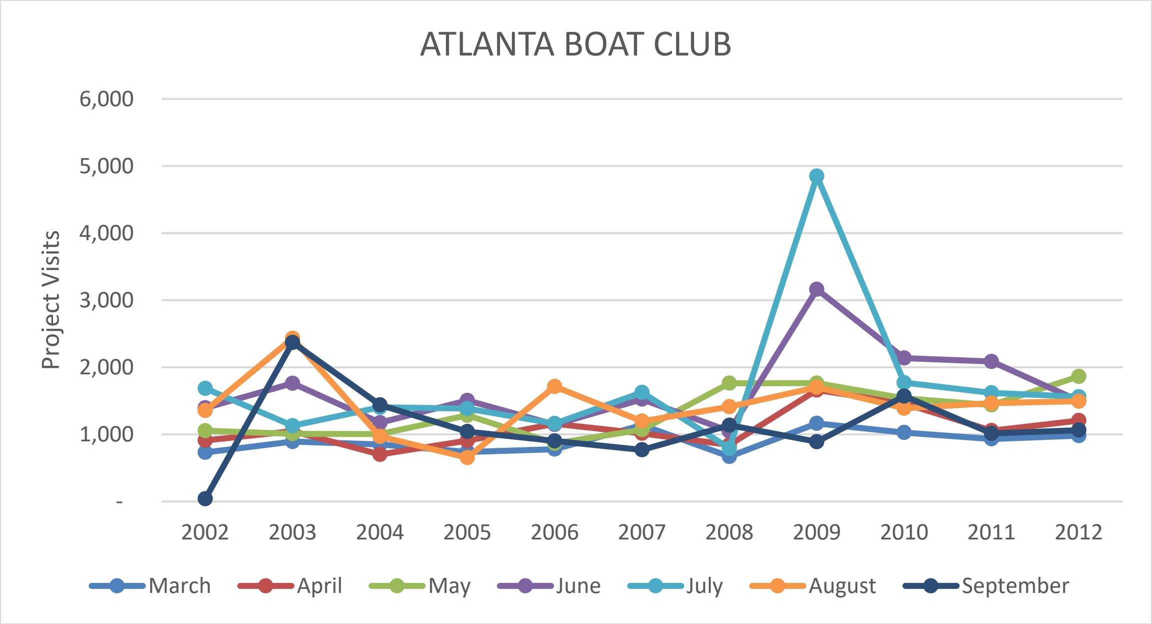


Figure 9: Atlanta Yacht Club Visitation 2002-2012

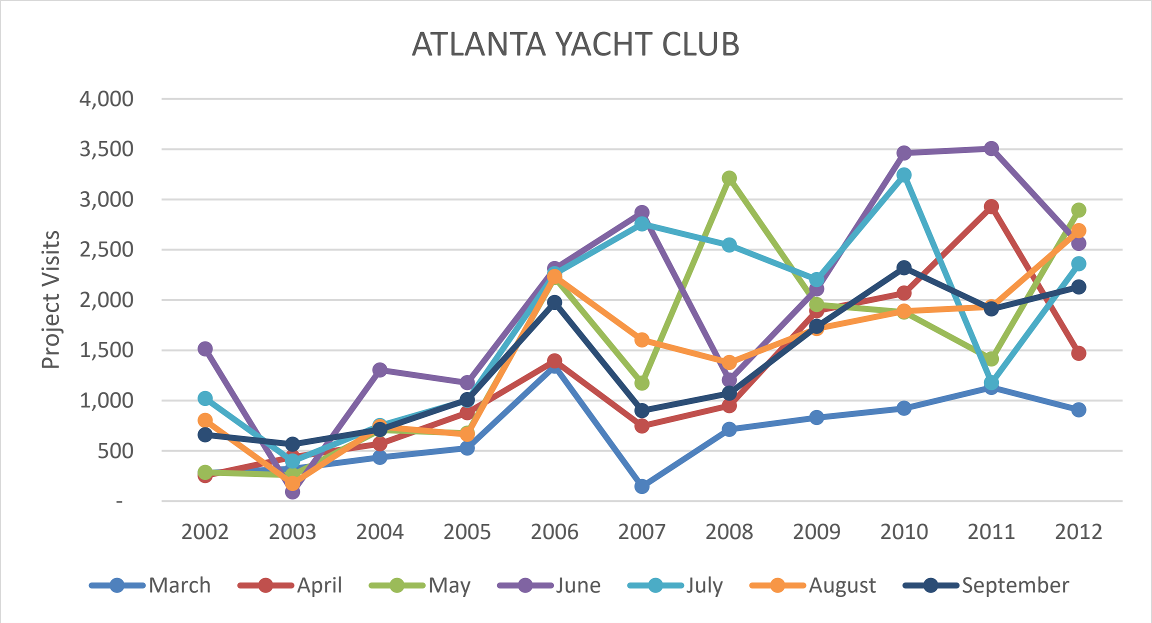


Figure 10: Bartow Carver Visitation 2002-2012

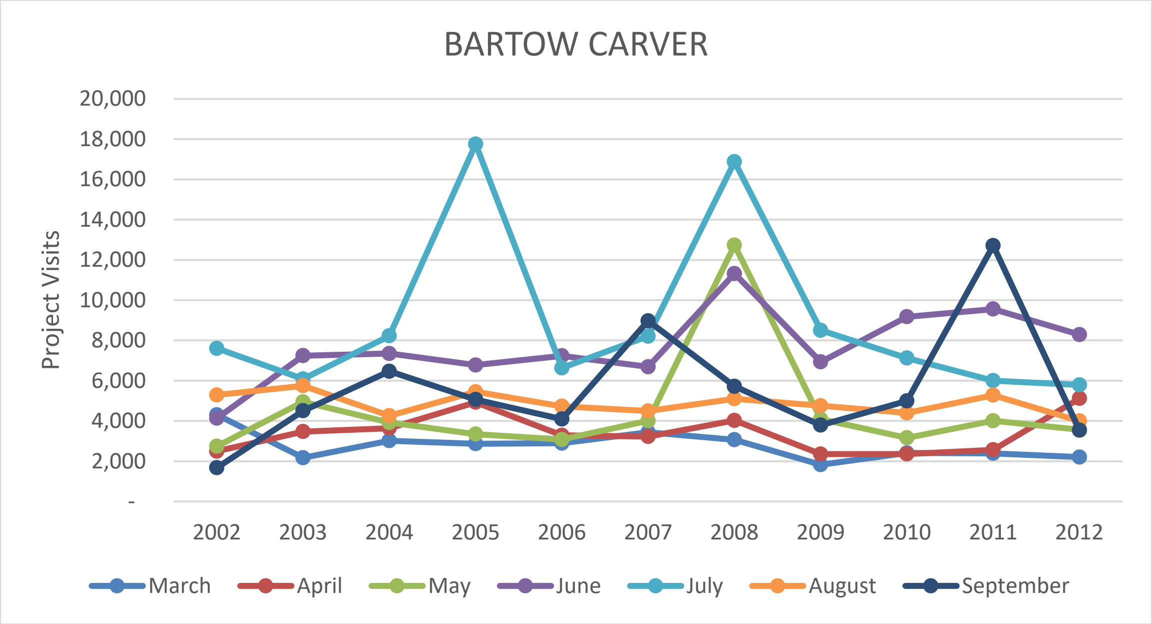


Figure 11: Bartow County - Gatewood Park Visitation 2002-2012

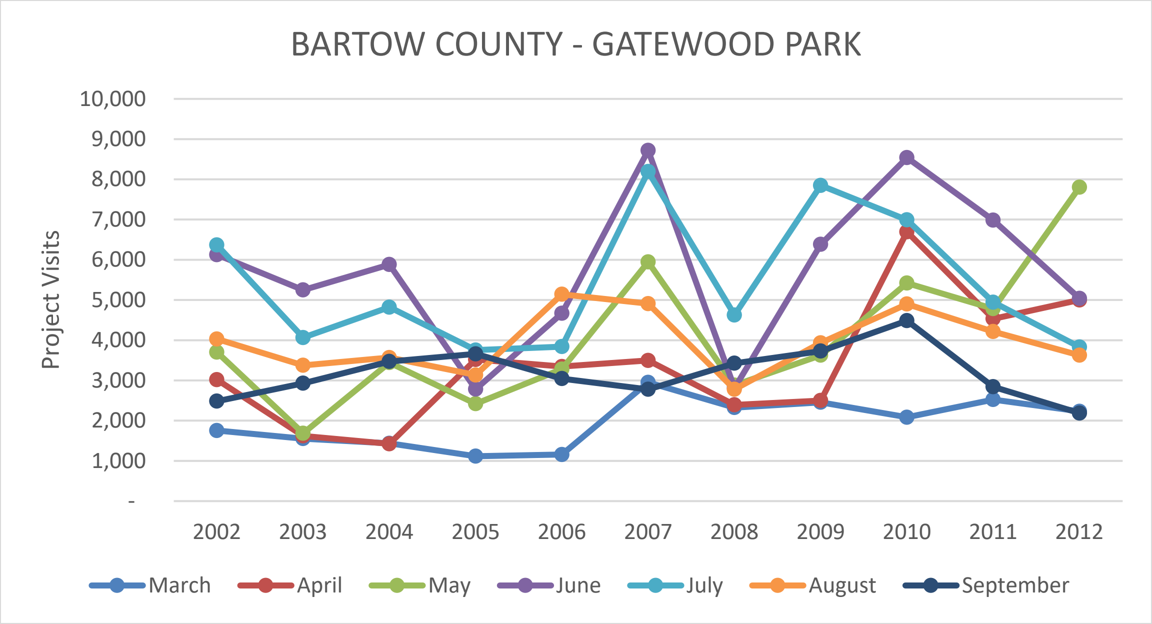


Figure 12: Big K Club Visitation 2002-2012

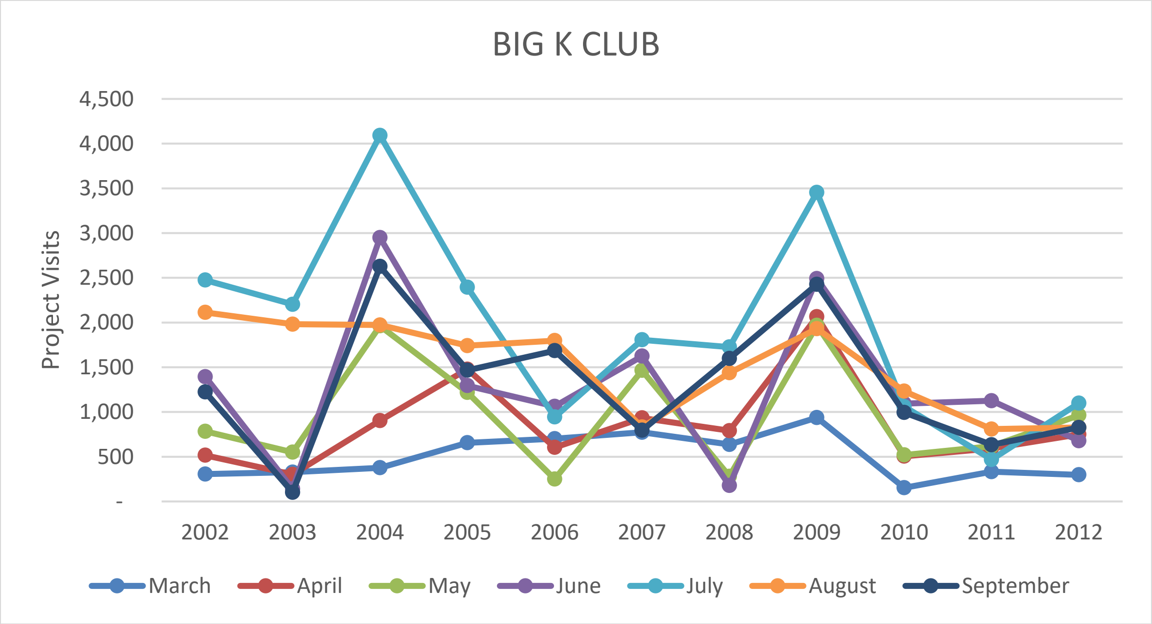


Figure 13: Blockhouse #2 Ramp Visitation 2002-2012

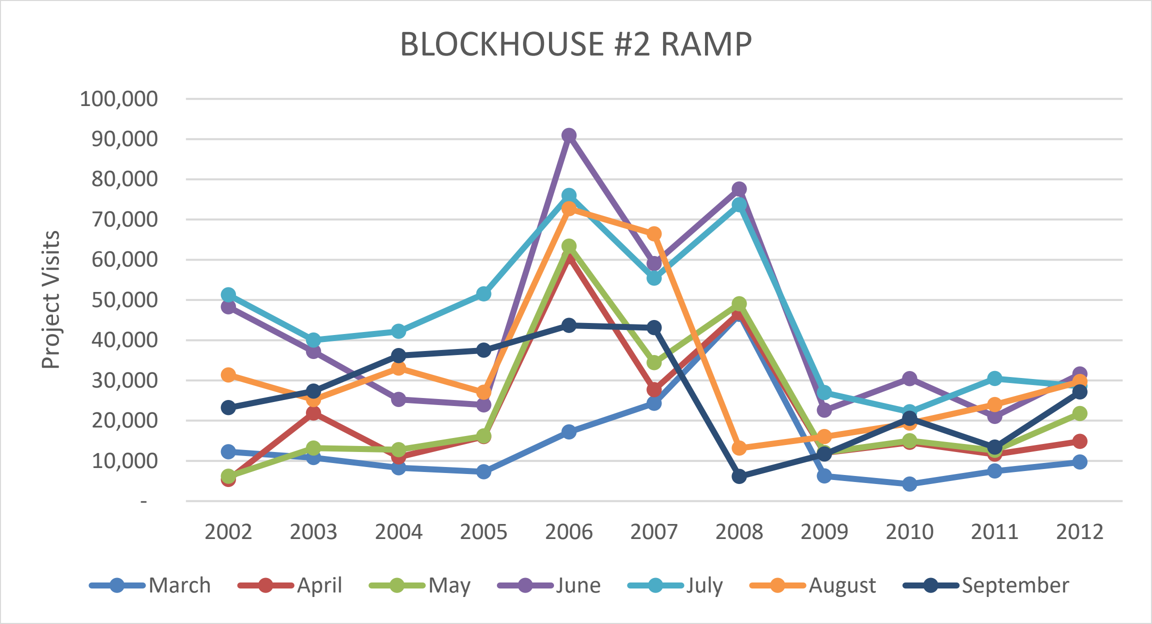


Figure 14: Boy Scouts of America - Explorer Scout Camp - Camp Allatoona Visitation 2002-2012

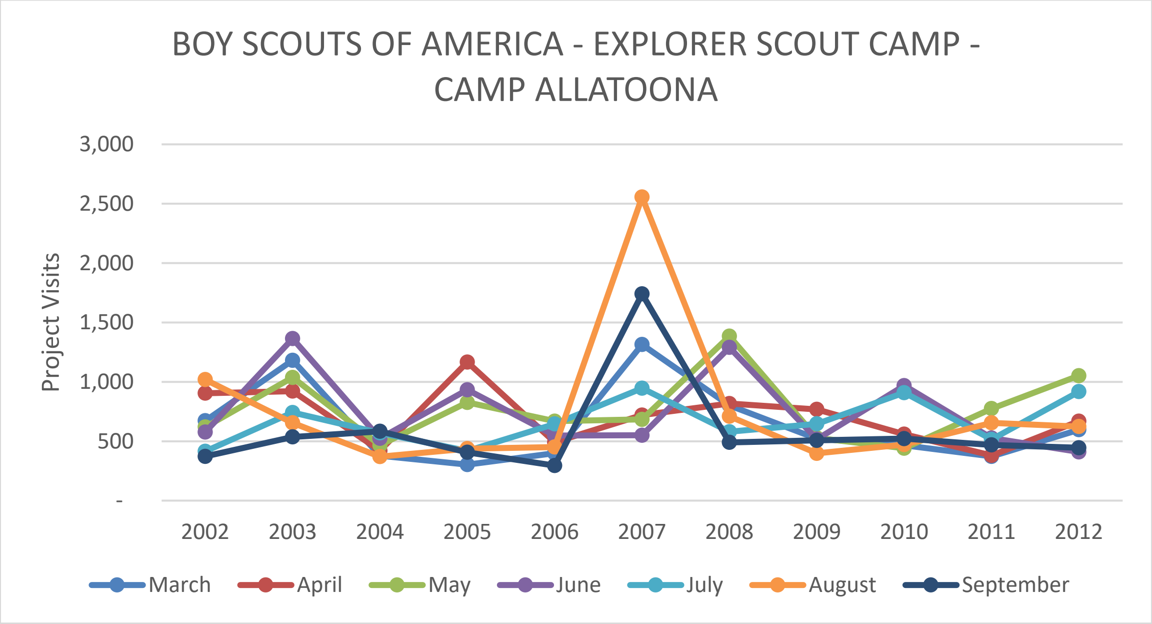


Figure 15: Cherokee County - Blankets Creek Visitation 2002-2012

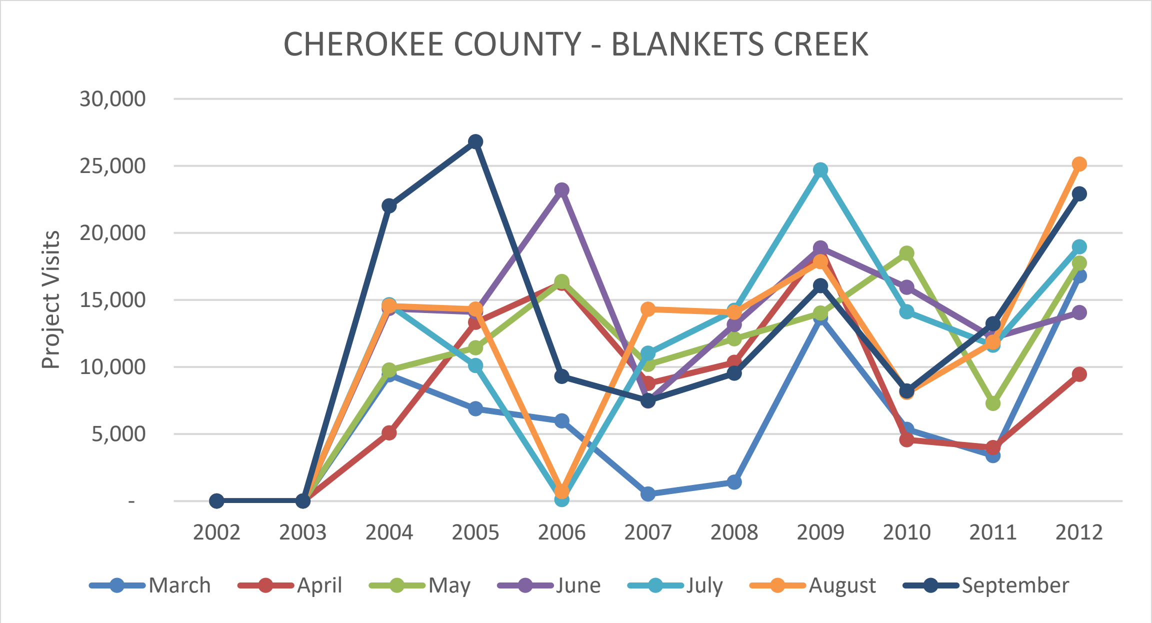


Figure 16: Cherokee County - Cherokee Mills Day Use Visitation 2002-2012

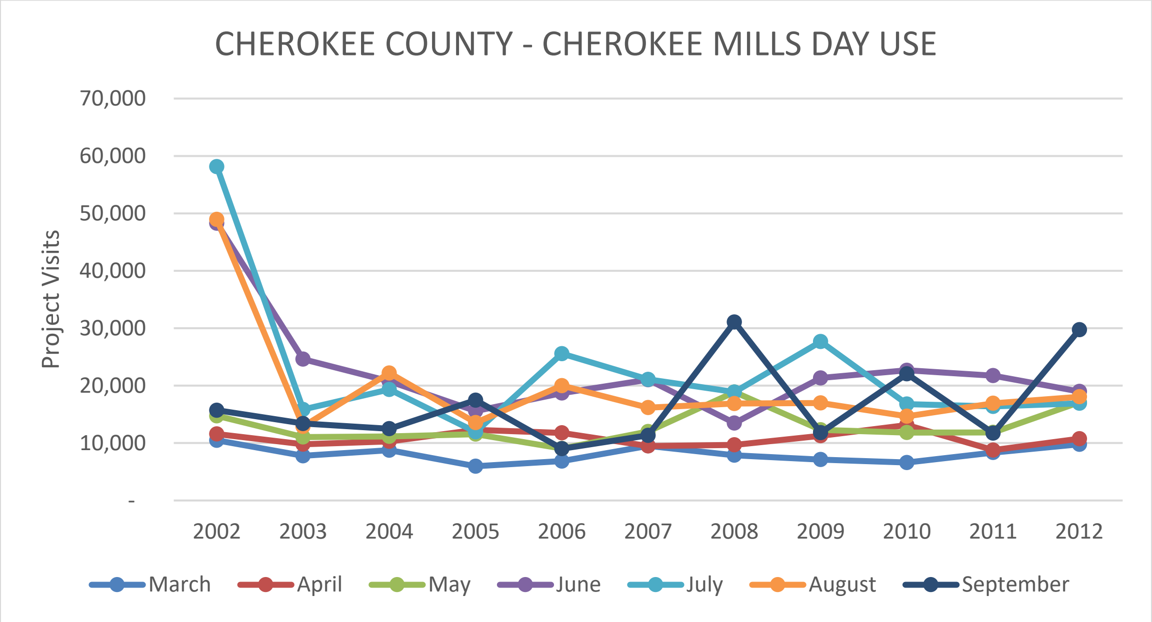


Figure 17: Cherokee County – Field's Landing Visitation 2002-2012

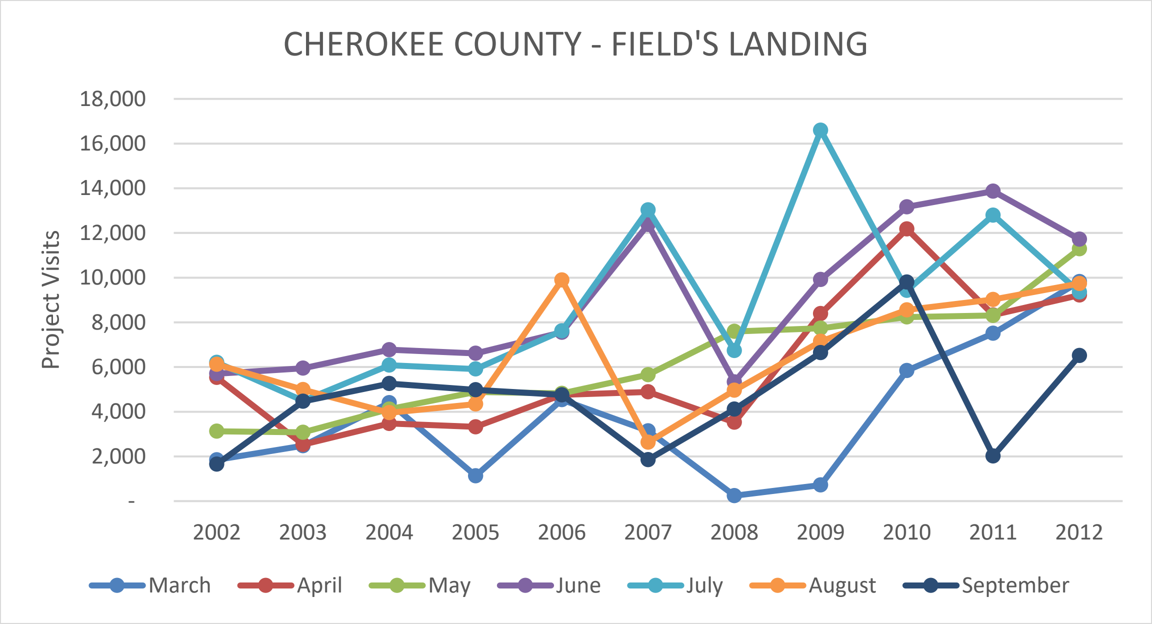


Figure 18: Cherokee County - J.J. Biello Park Visitation 2002-2012

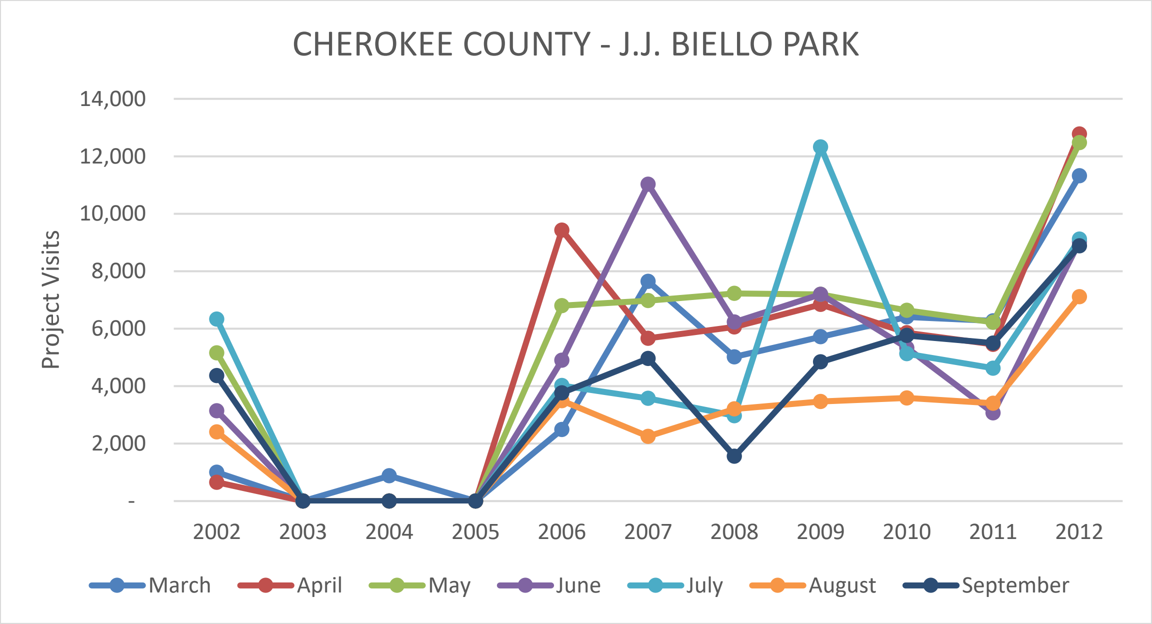


Figure 19: Cherokee Presbytery - Camp Cherokee Visitation 2002-2012

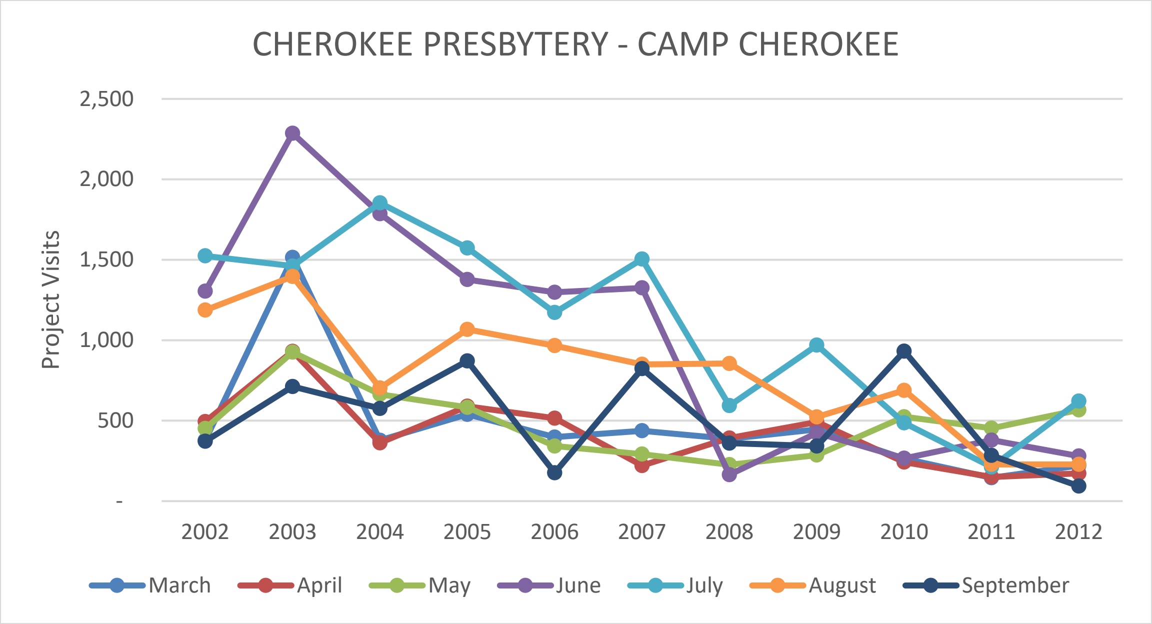


Figure 20: City of Atlanta Recreation Area Visitation 2002-2012

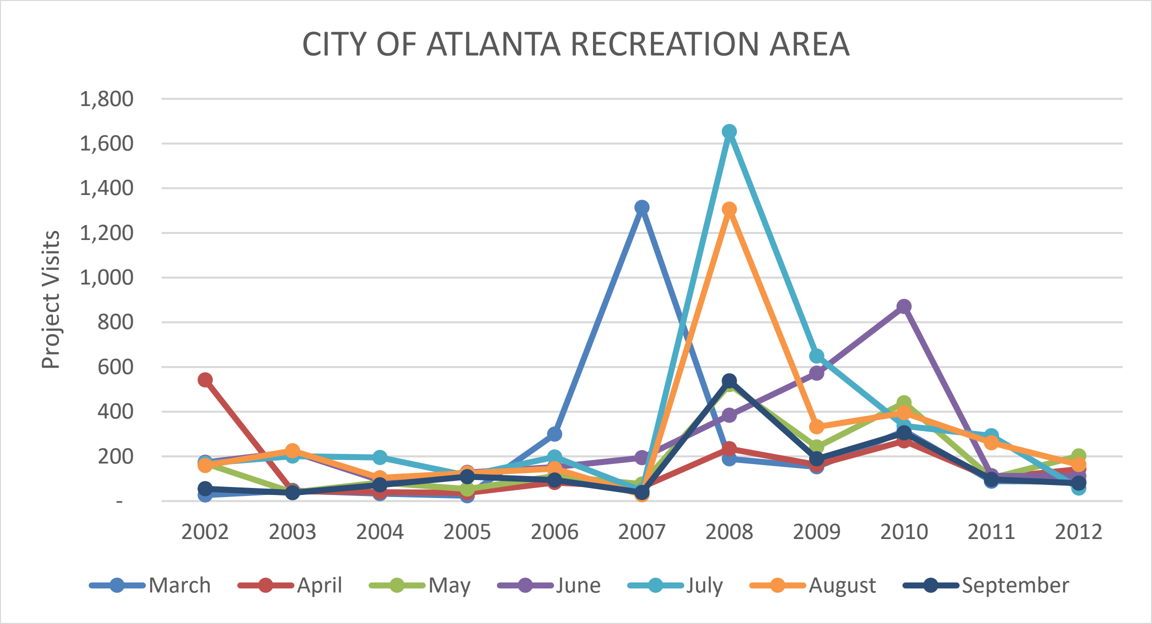


Figure 21: City of Canton - Boling Park Visitation 2002-2012

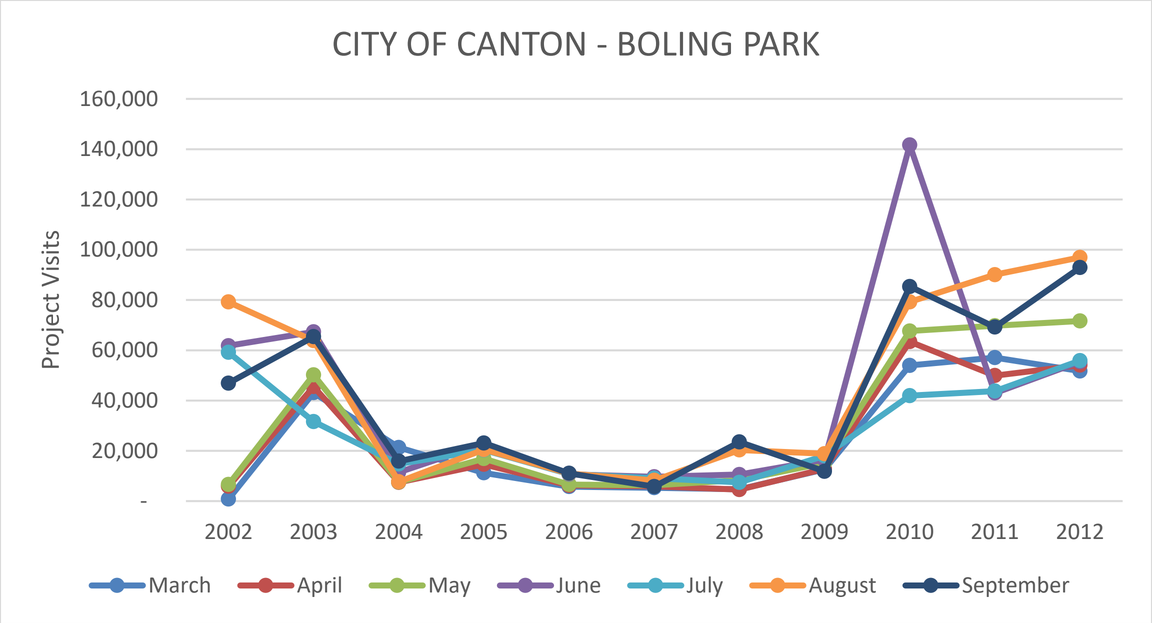


Figure 22: City of Emerson - Luke's Site Visitation 2002-2012

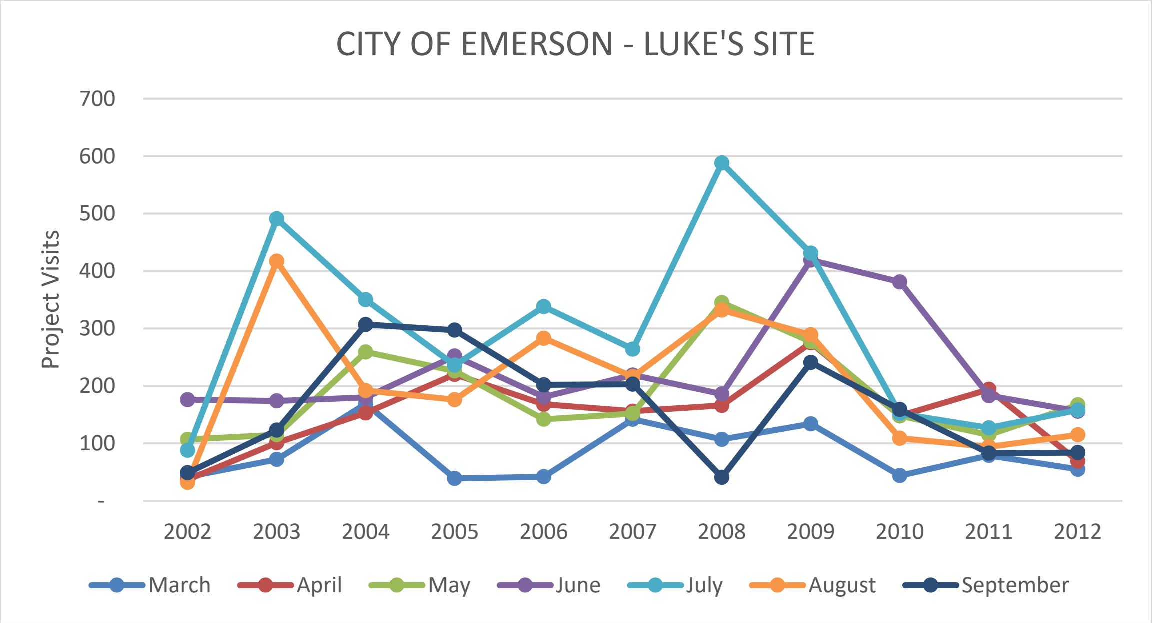


Figure 23: Clark Creek North Campground Visitation 2002-2012

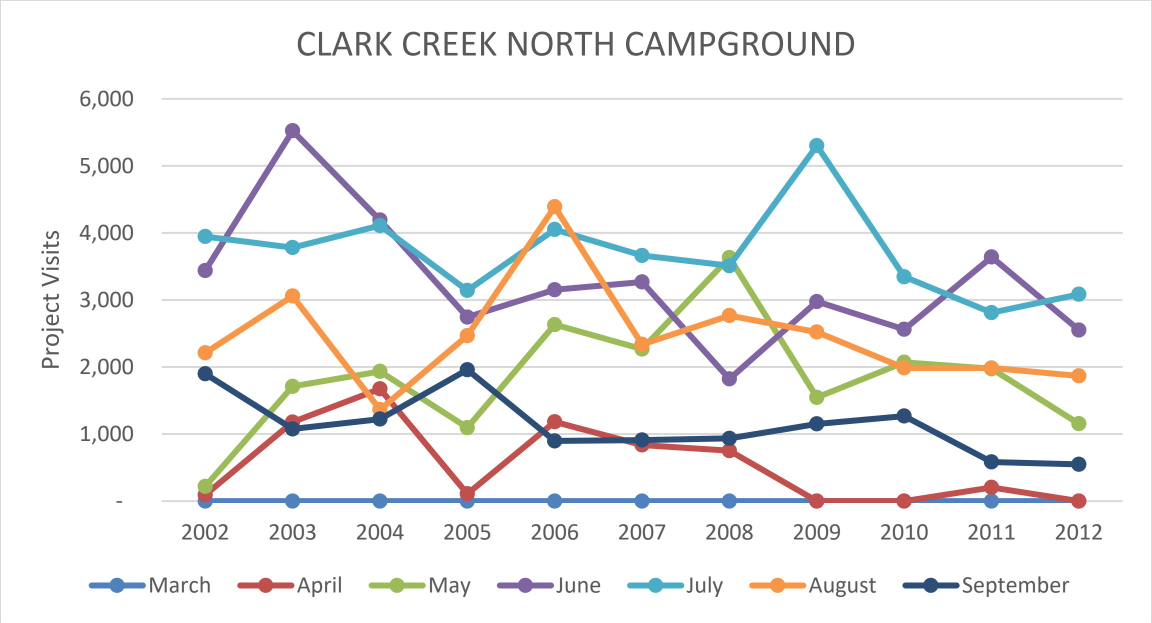


Figure 24: Clark Creek South Ramp Visitation 2002-2012

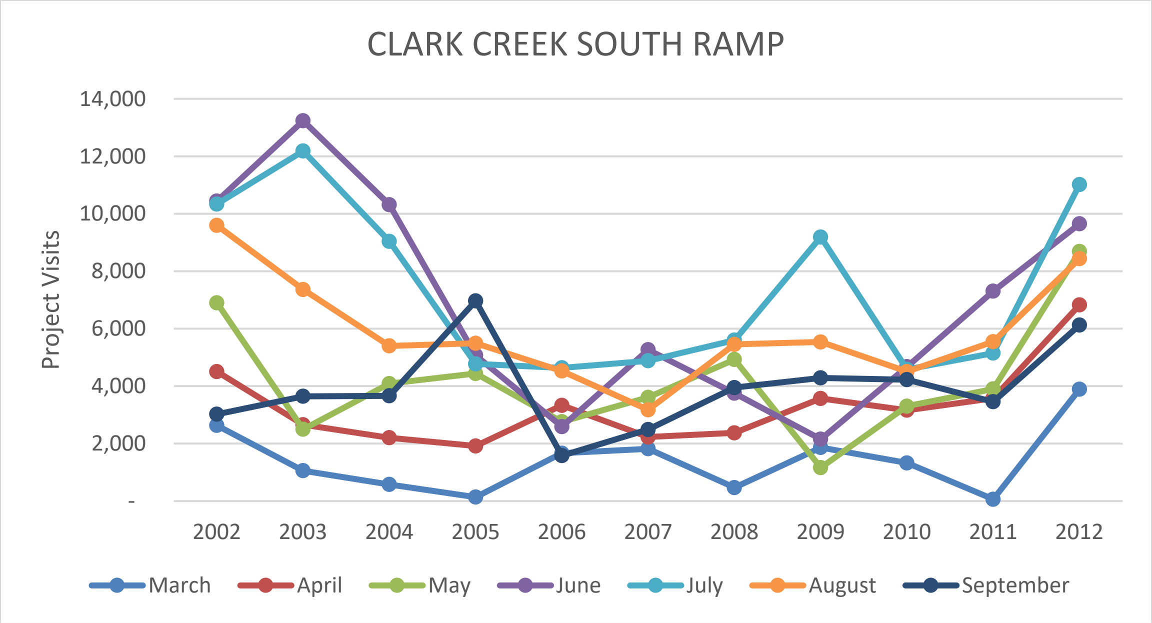


Figure 25: Cobb County - Acworth Regional Park Visitation 2002-2012

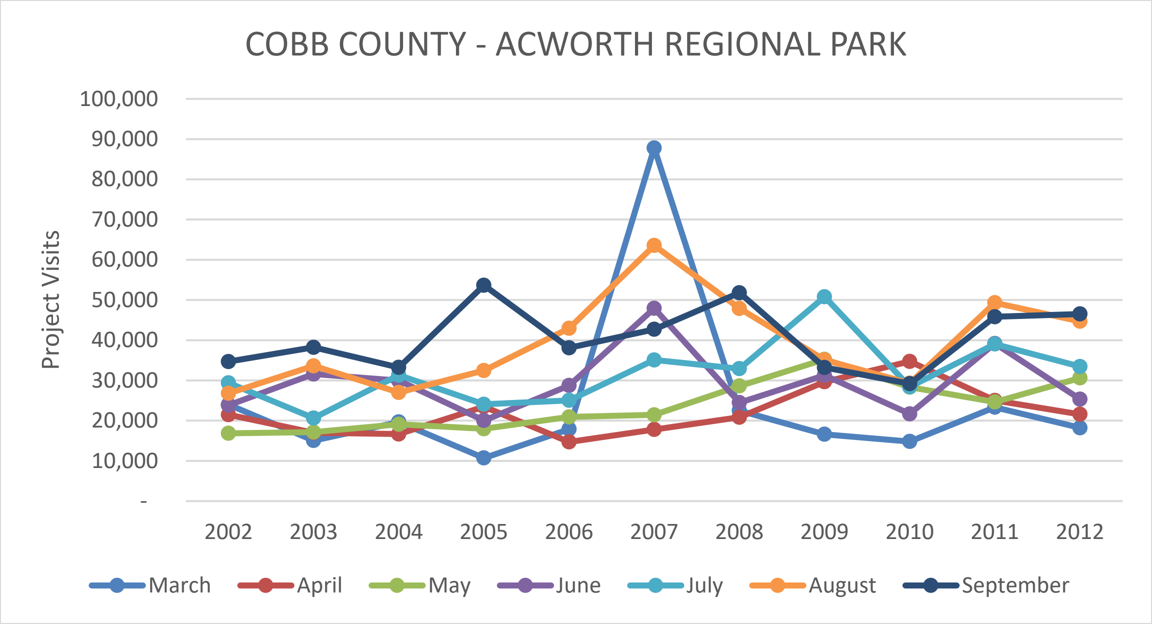


Figure 26: Cooper Branch Day Use Area #1 Visitation 2002-2012

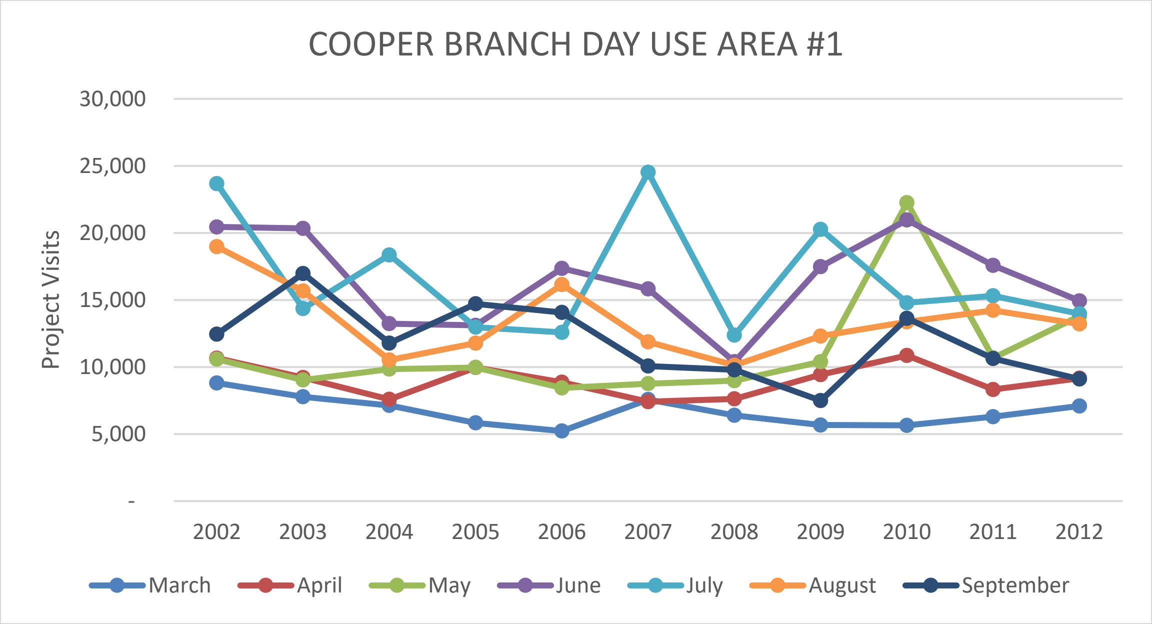


Figure 27: Cooper's Furnace Day Use Area Visitation 2002-2012

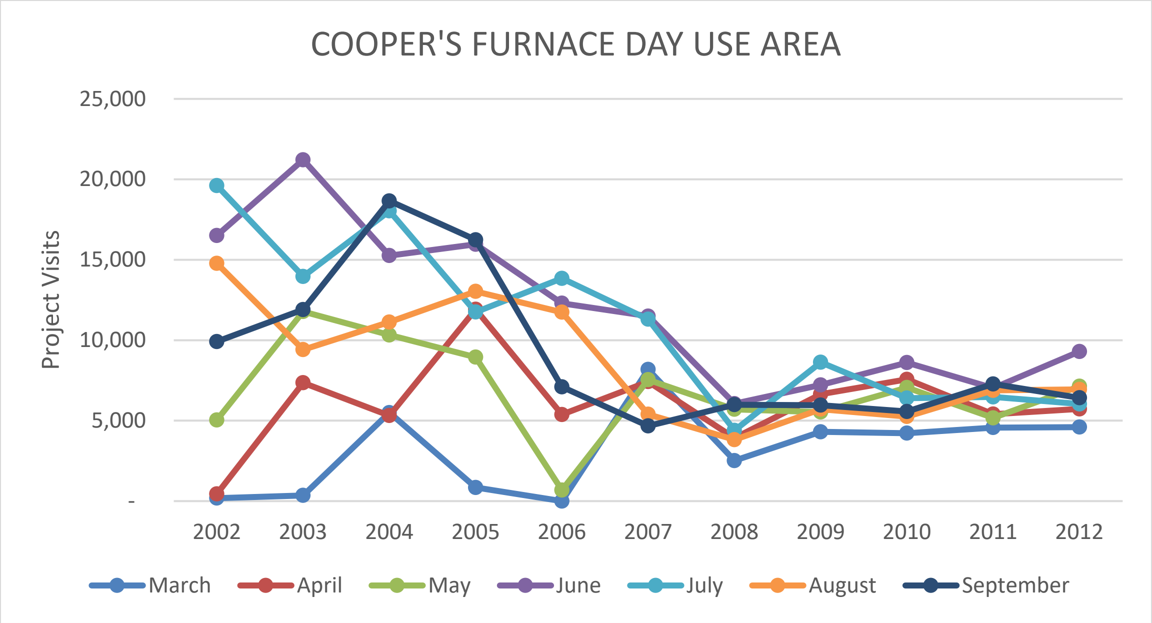


Figure 28: Coosa Steel Corporation Recreation Area Visitation 2002-2012

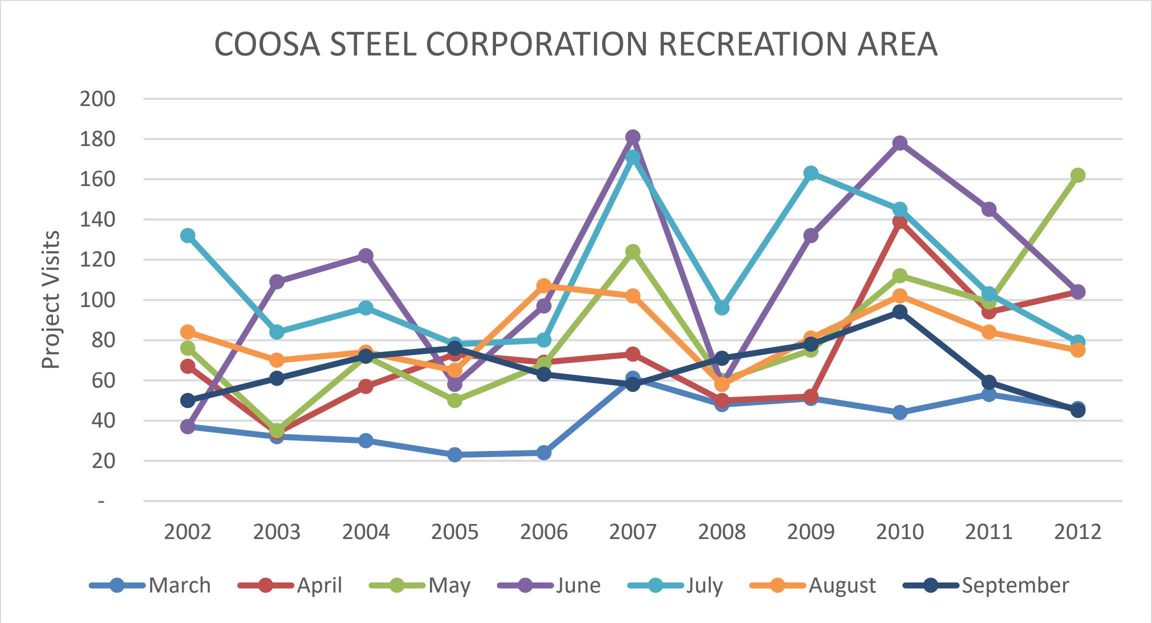


Figure 29: Cushing Memorial Park Visitation 2002-2012

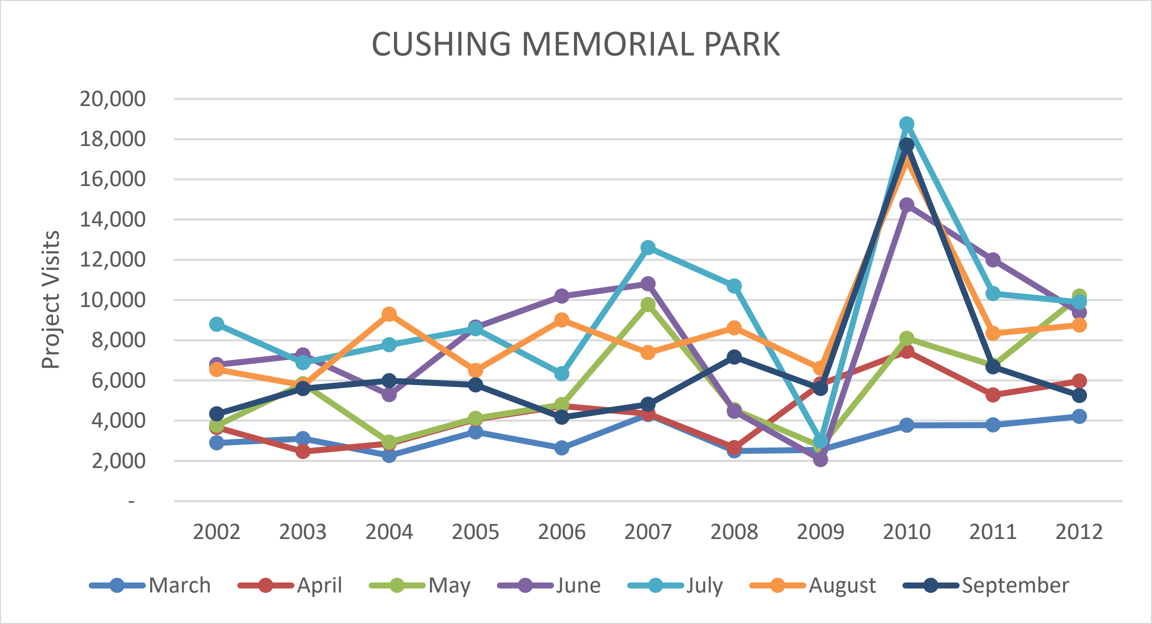


Figure 30: Dallas Landing Visitation 2002-2012

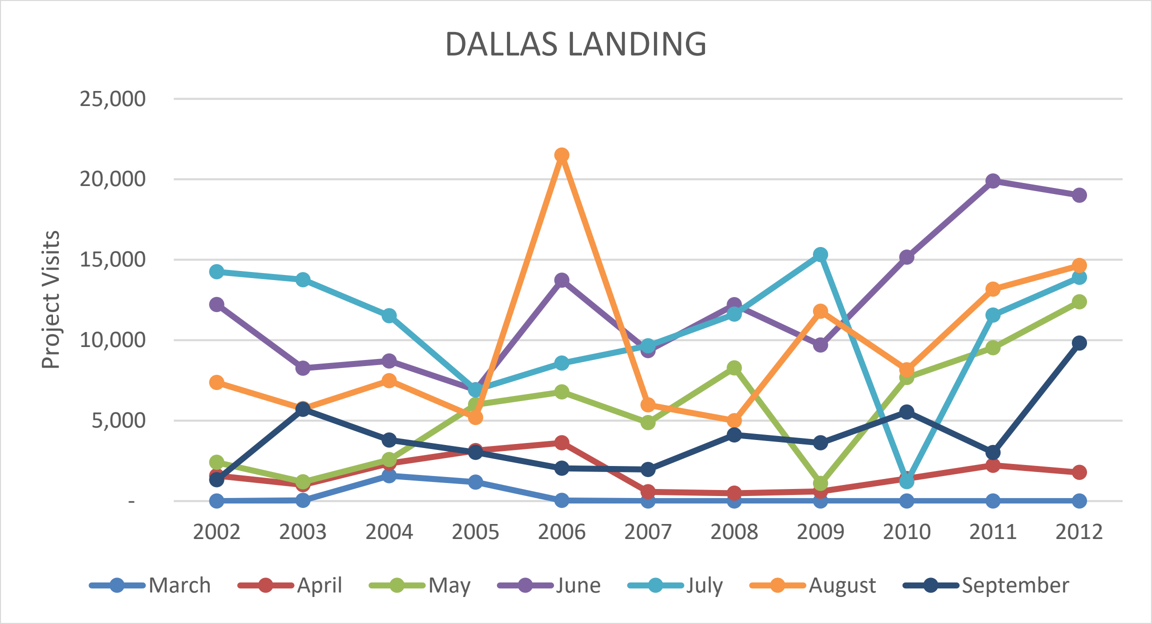


Figure 31: Devereux Foundation Visitation 2002-2012

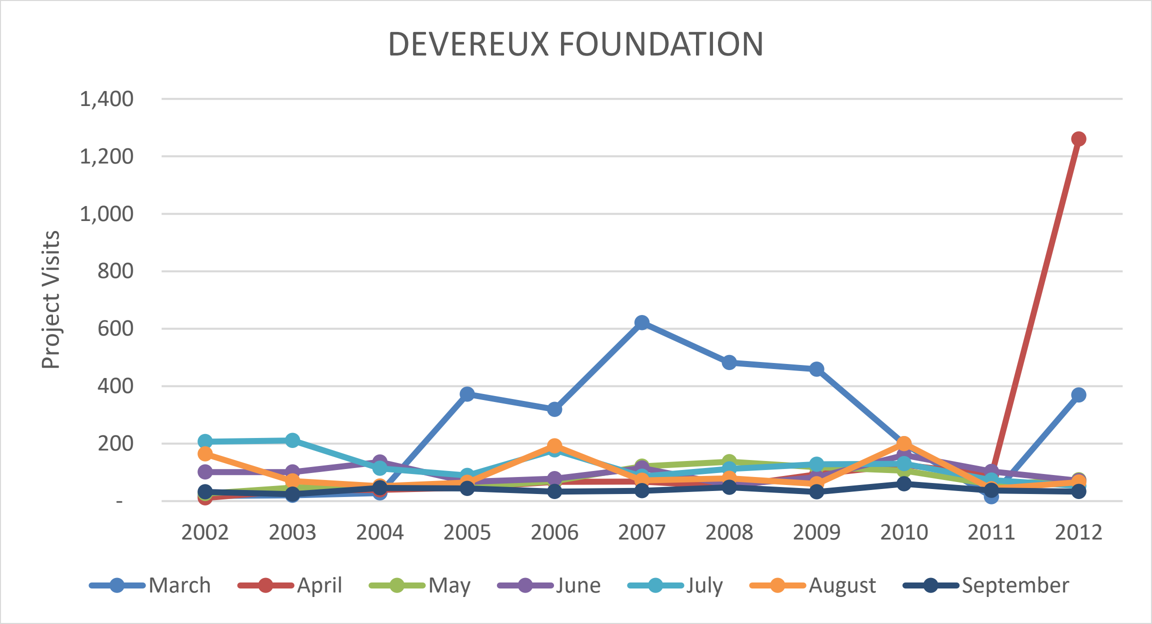


Figure 32: Etowah Yacht Club Visitation 2002-2012

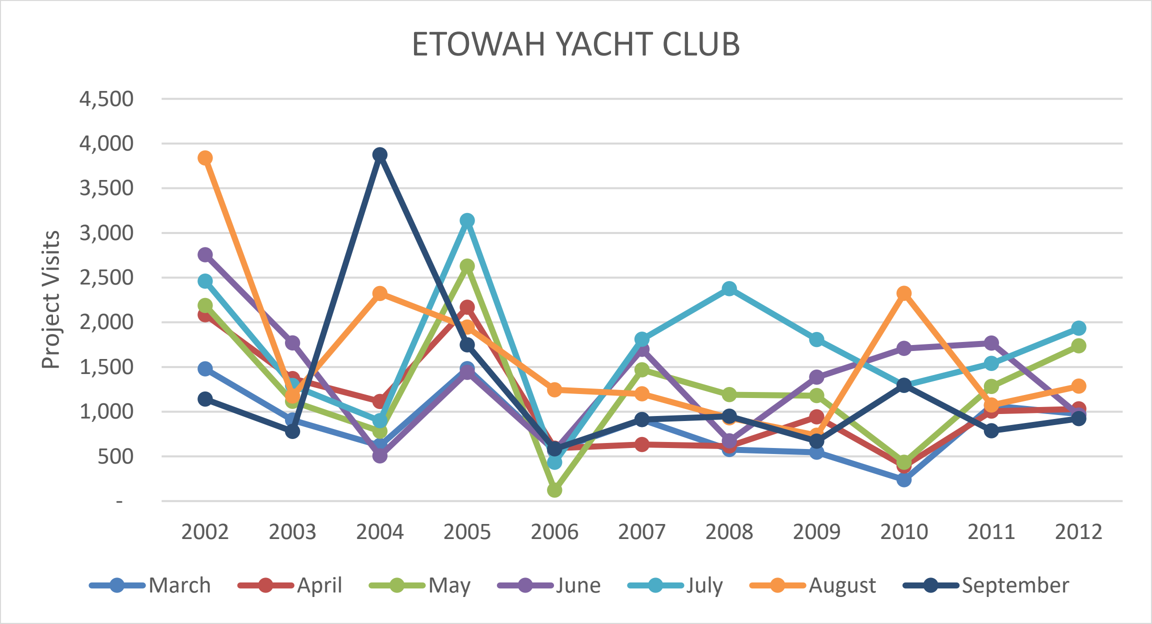


Figure 33: First Baptist Church of Marietta - Chapel Knoll Visitation 2002-2012

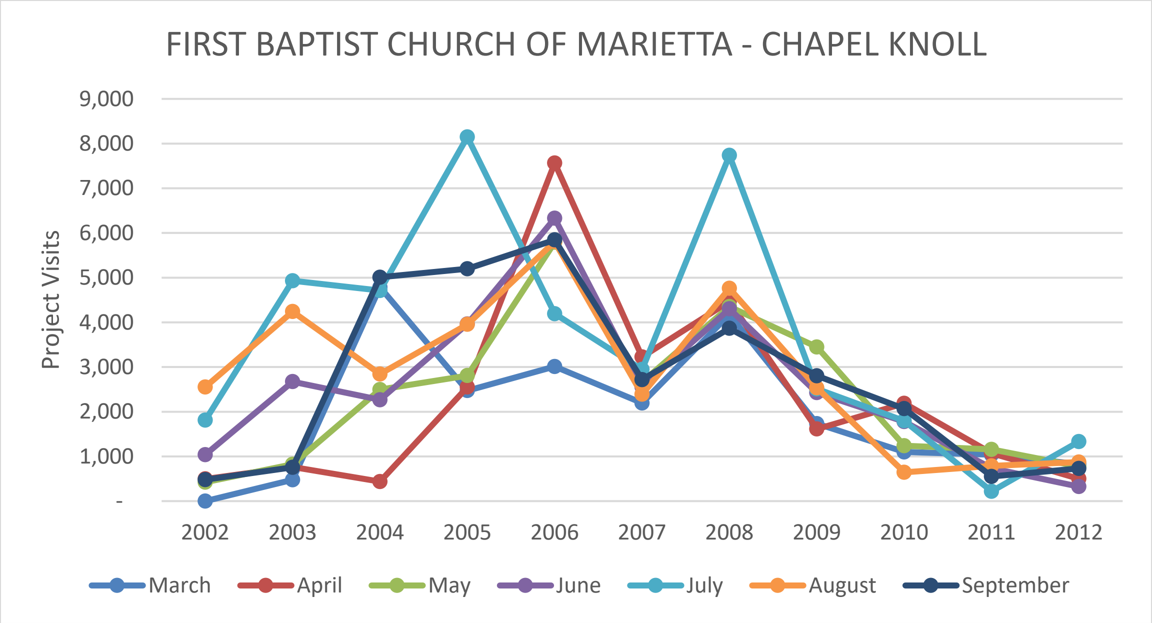


Figure 34: First United Methodist Church of Decatur - Camp 175 Visitation 2002-2012

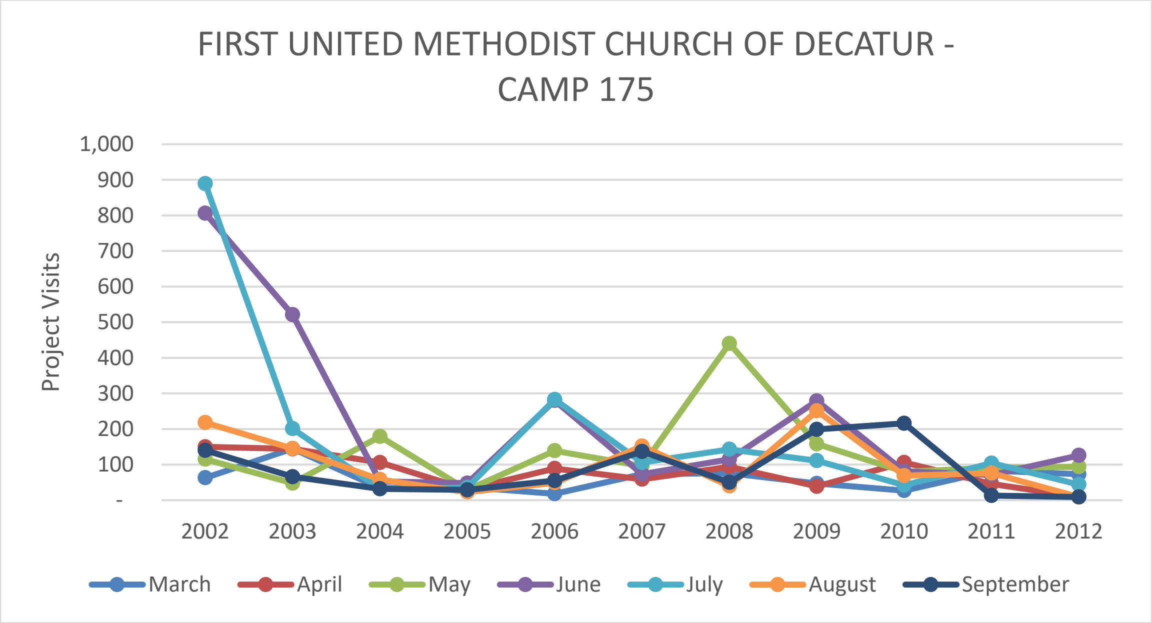


Figure 35: Galts Ferry Day Use Visitation 2002-2012

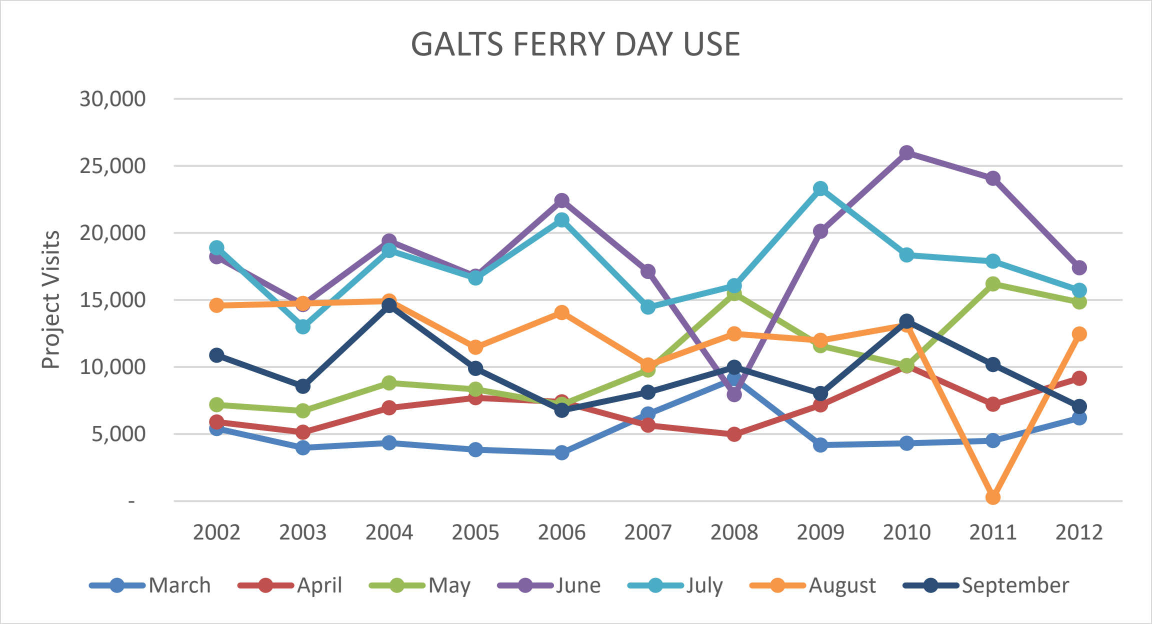


Figure 36: Georgia Department of Natural Resources - Red Top Mountain Visitation 2002-2012

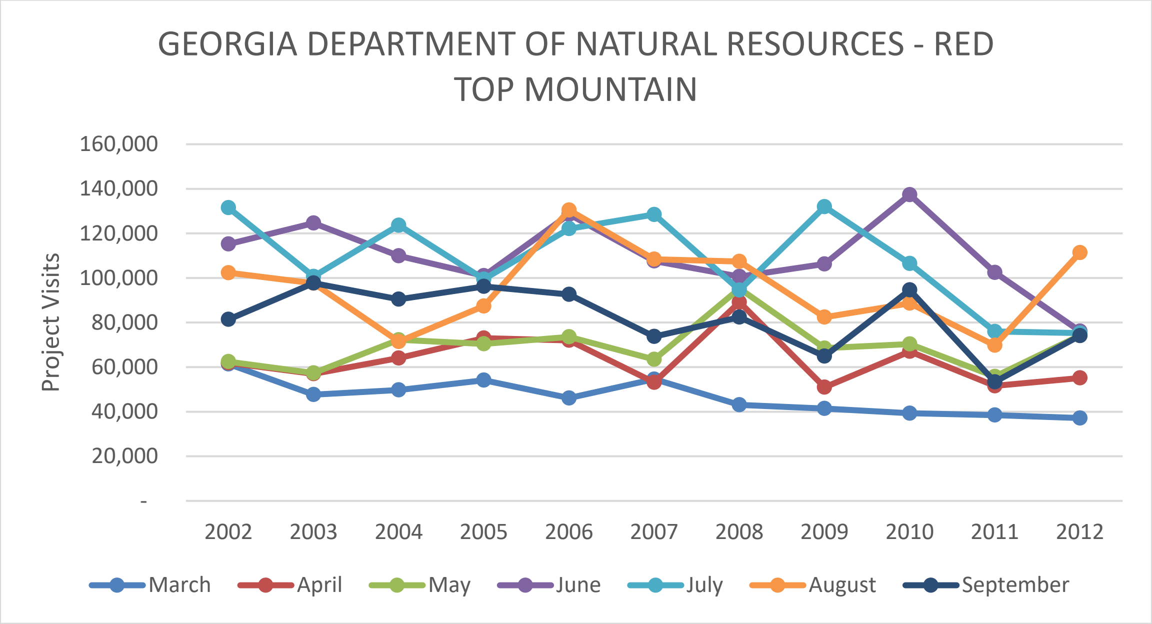


Figure 37: Glade Marina Visitation 2002-2012

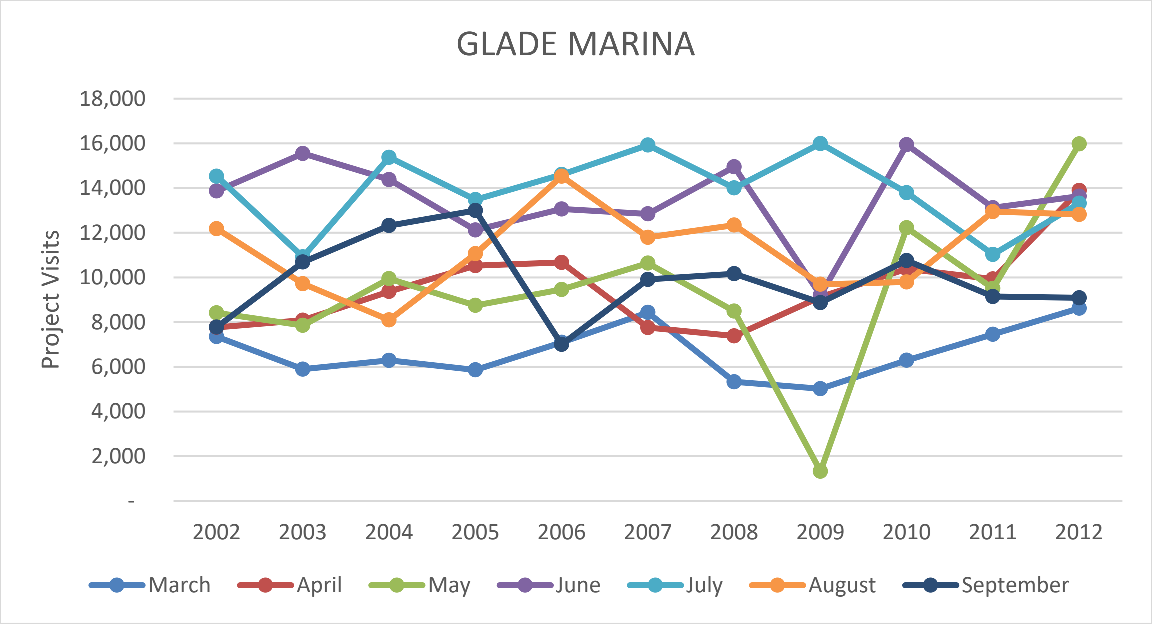


Figure 38: Harbour Town Marina Visitation 2002-2012

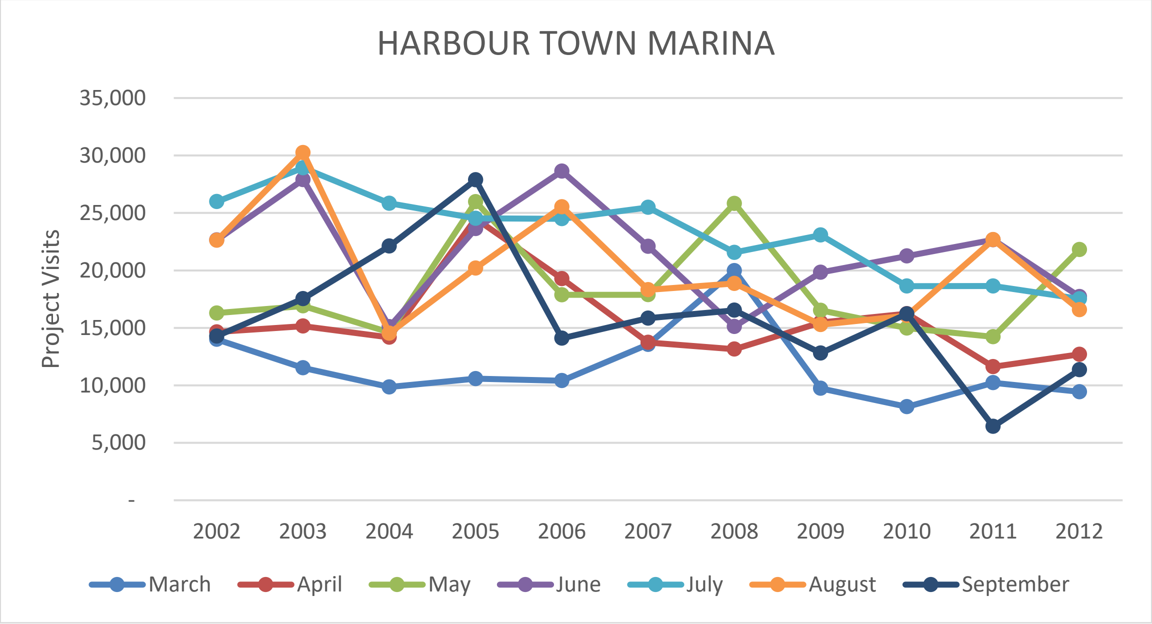


Figure 39: Hillhouse Lodge Visitation 2002-2012

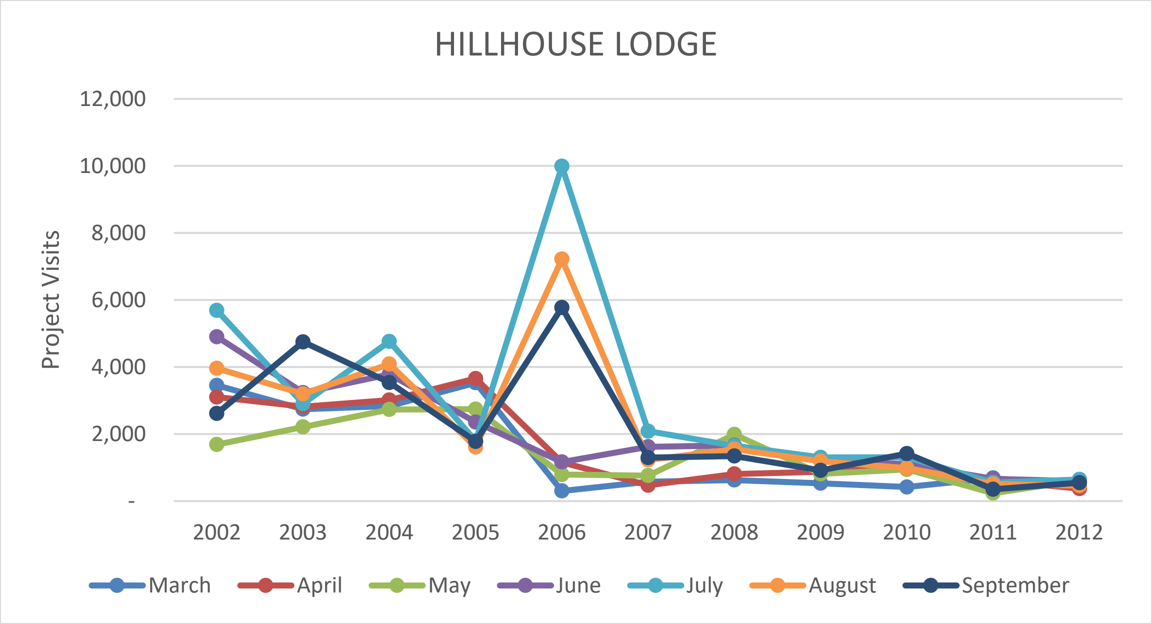


Figure 40: His Camp - Camp Gideon Visitation 2002-2012

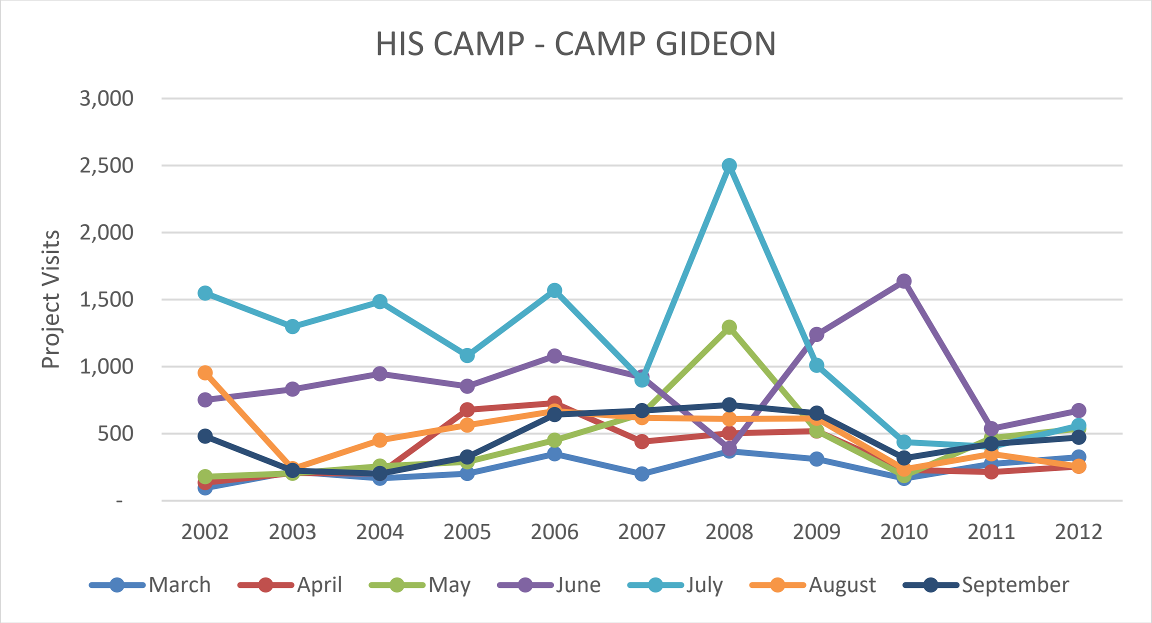


Figure 41: Holly Springs Recreation Association Visitation 2002-2012

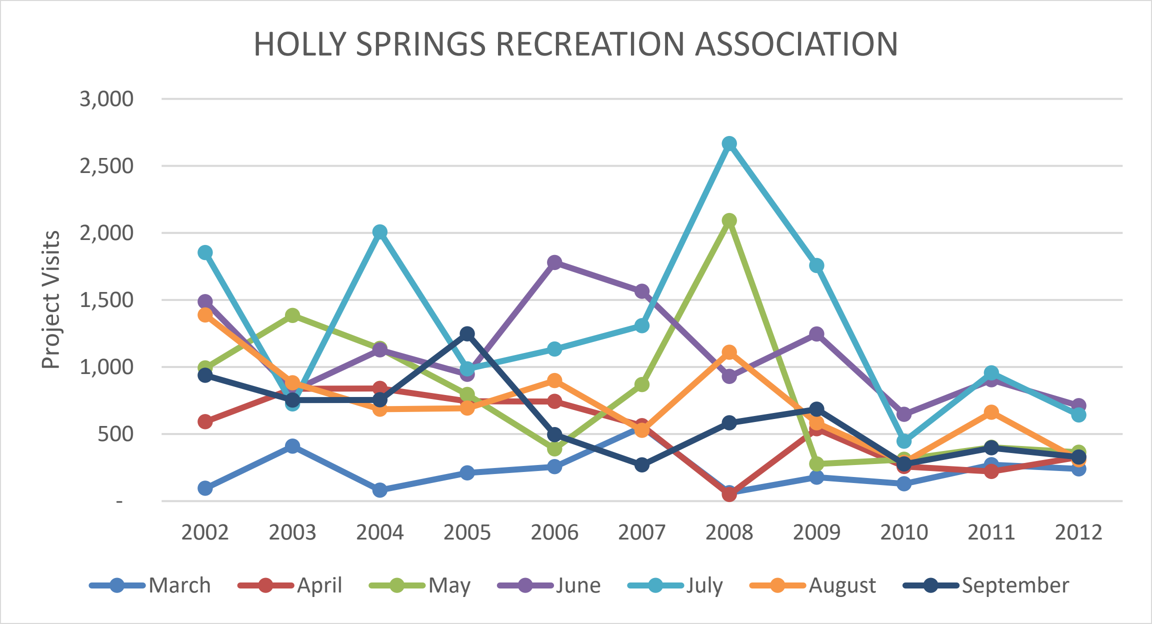


Figure 42: Kellogg Creek Day Use Visitation 2002-2012

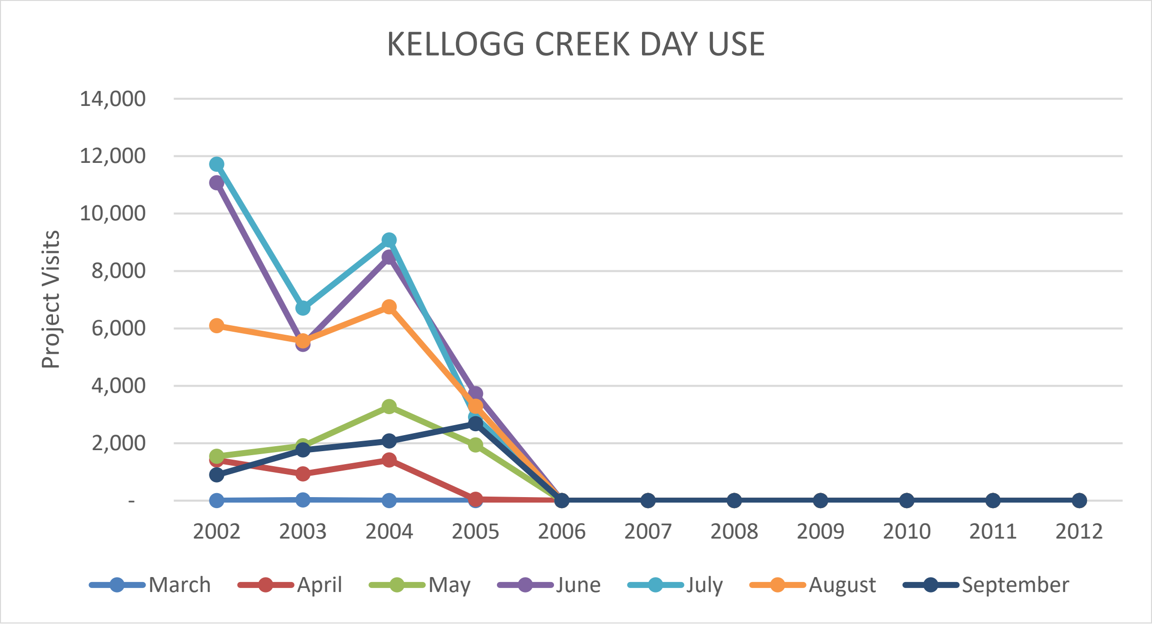


Figure 43: Knox Bridge Day Use Visitation 2002-2012

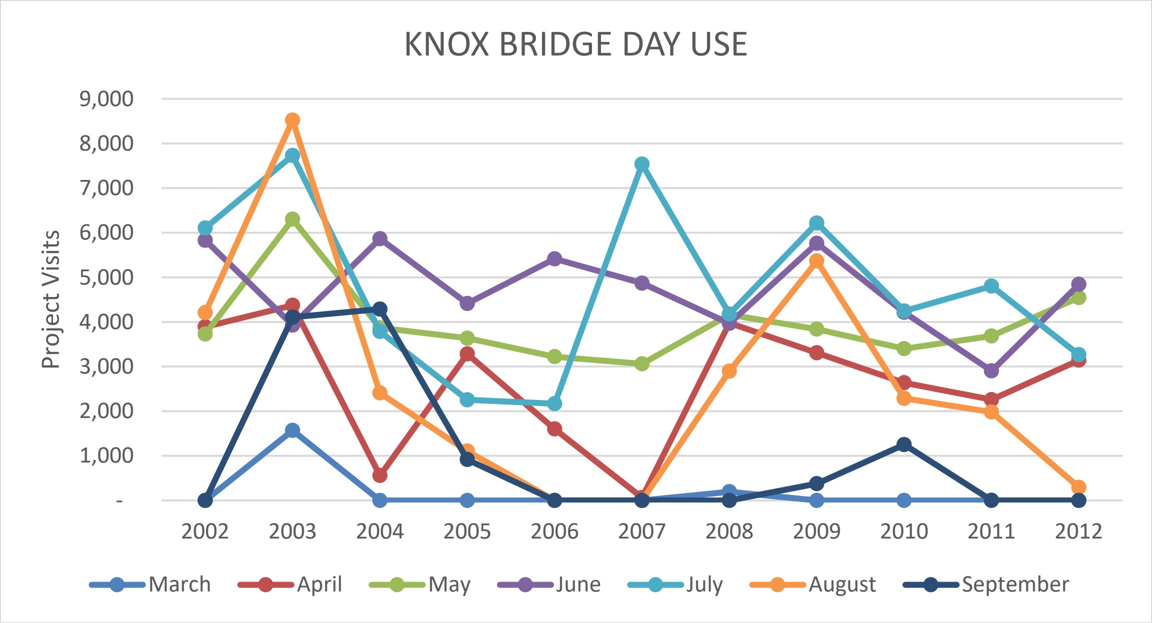


Figure 44: Lake Forrest Country Club Visitation 2002-2012

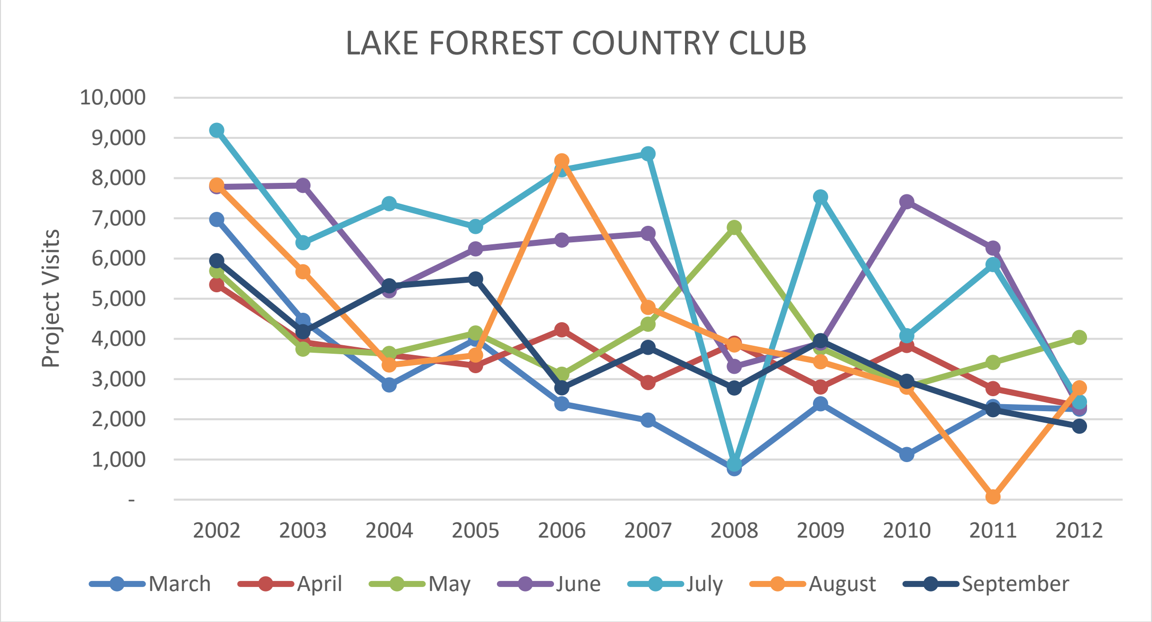


Figure 45: Leon E. Williams – Holiday Marina Visitation 2002-2012

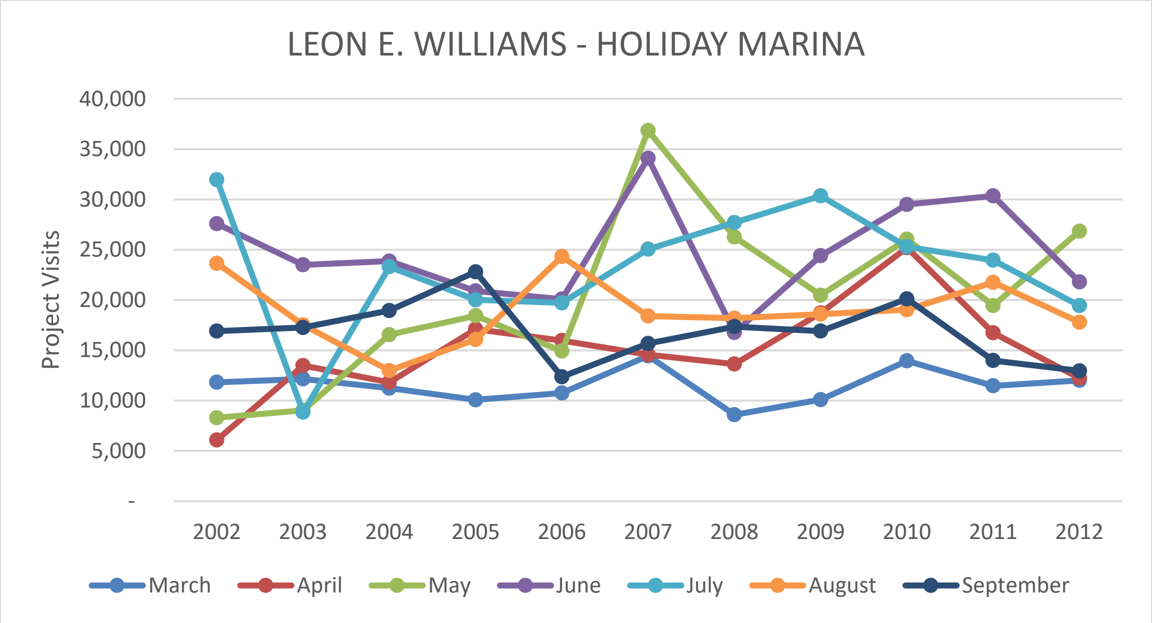


Figure 46: Little River Landing Marina Visitation 2002-2012

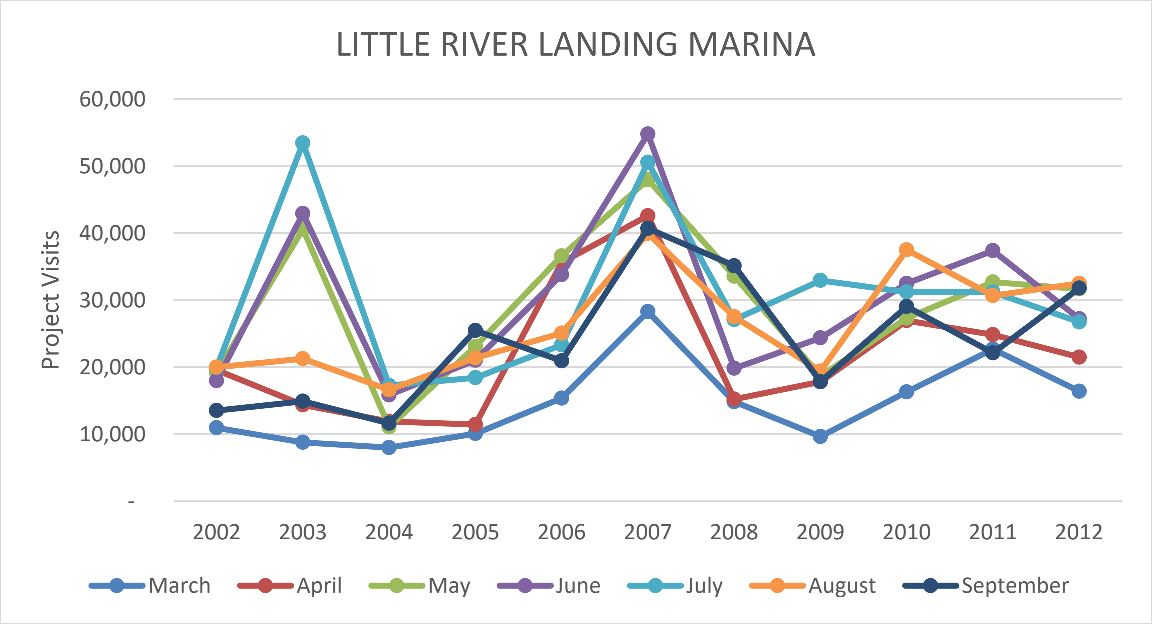


Figure 47: Lutherwood Visitation 2002-2012

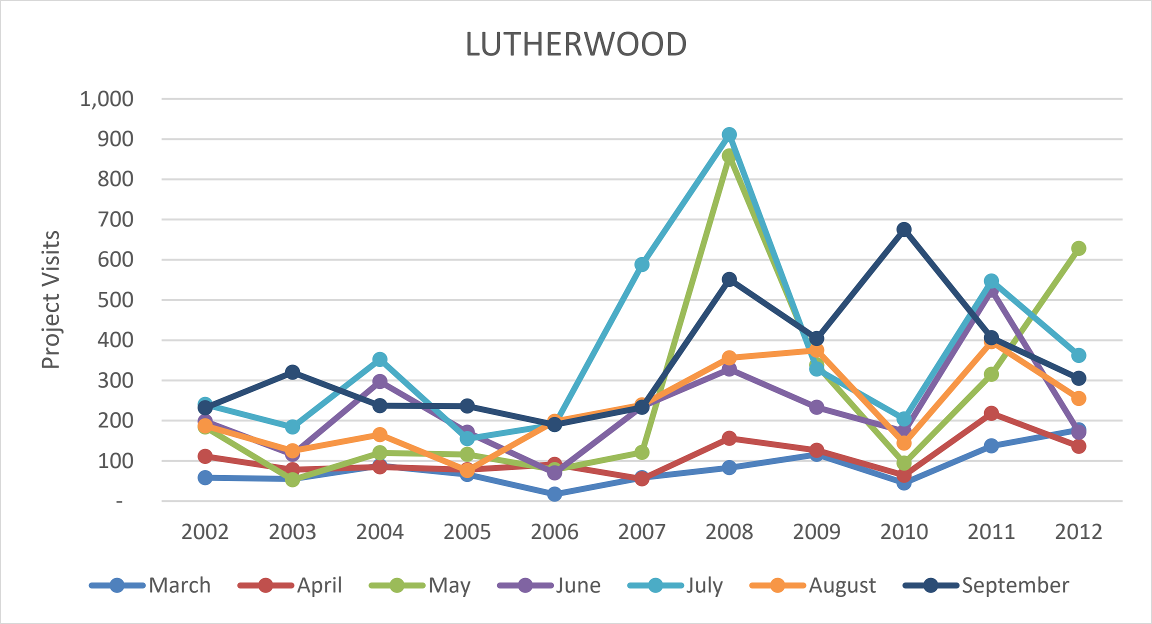


Figure 48: McKaskey Creek Campground Visitation 2002-2012

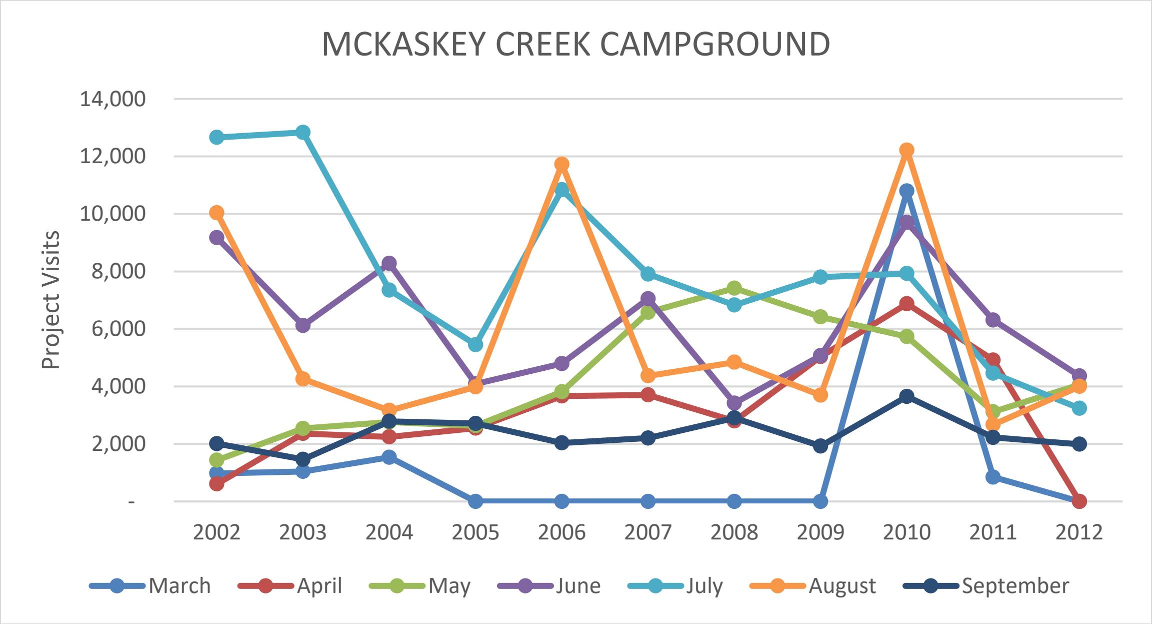


Figure 49: McKinney Campground Visitation 2002-2012

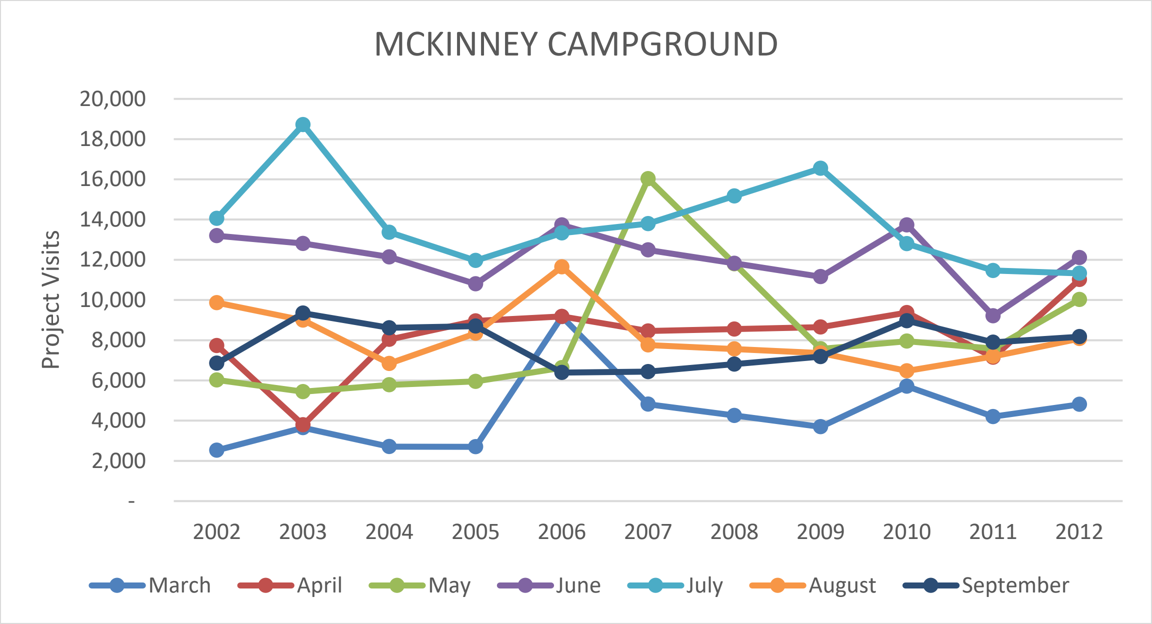


Figure 50: Metro Atlanta Recovery Residences Visitation 2002-2012

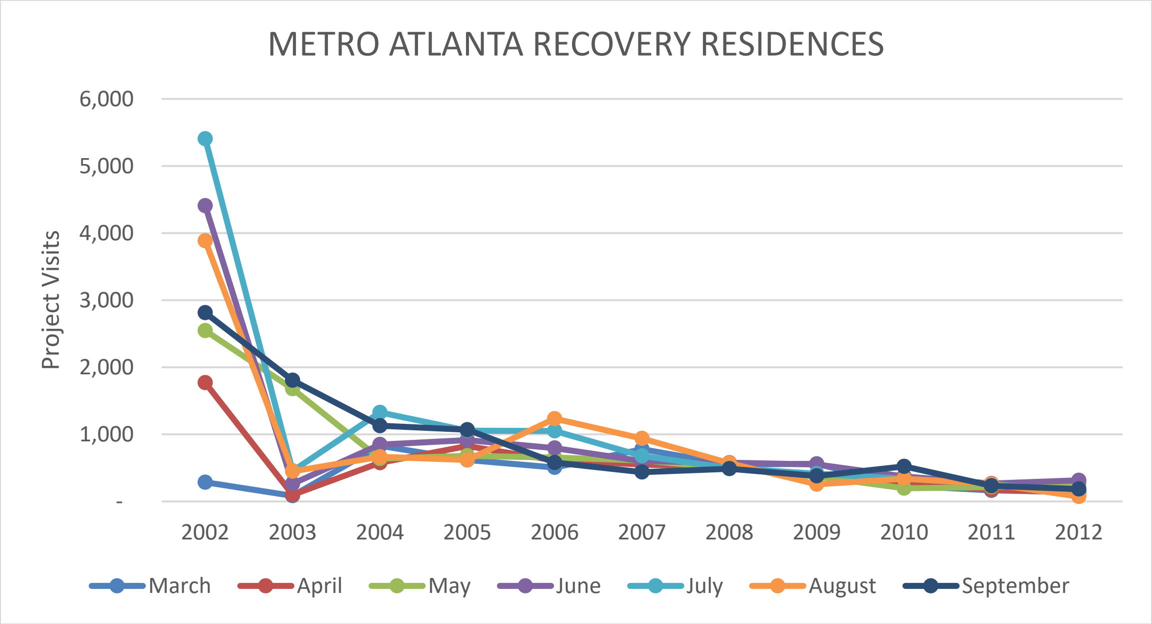


Figure 51: Minuteman Recreation Association Visitation 2002-2012

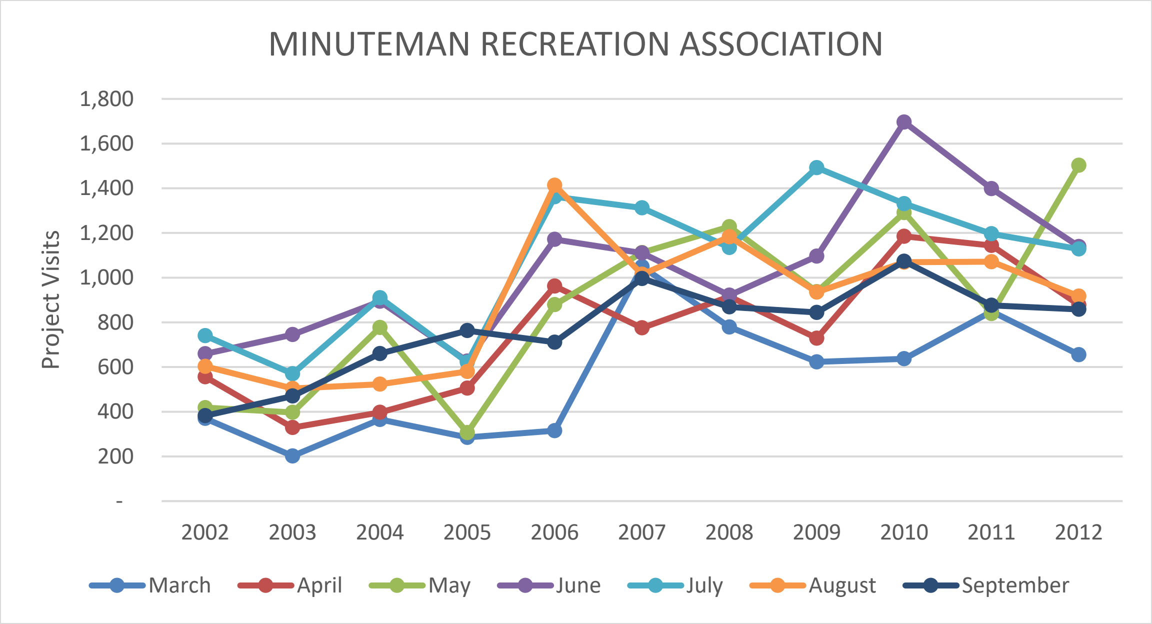


Figure 52: Northwest Georgia Girl Scout Council Visitation 2002-2012

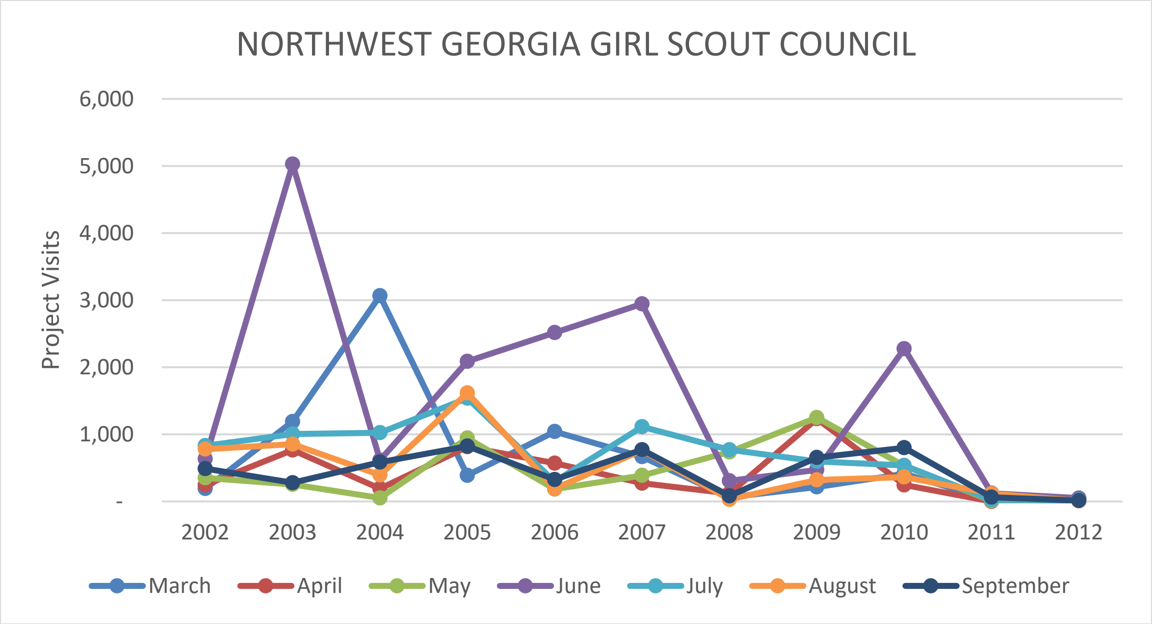


Figure 53: Northwest Georgia Girl Scout Council - Camp Pine Acres Visitation 2002-2012

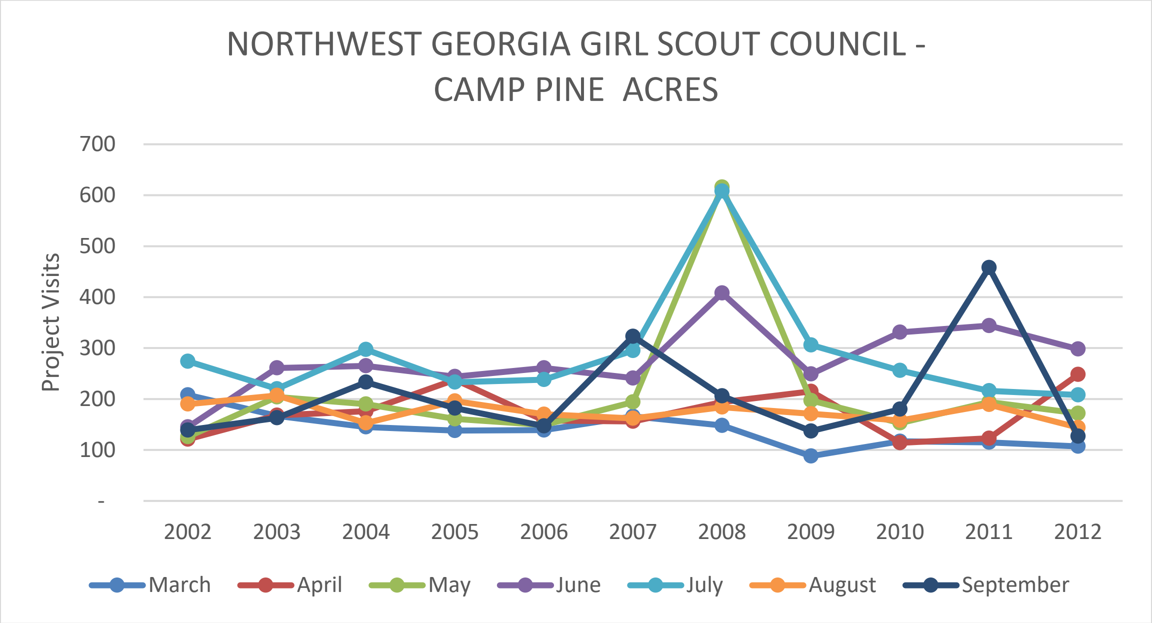


Figure 54: Northwest Georgia Council, Boy Scouts of America - Camp Westin Visitation 2002-2012

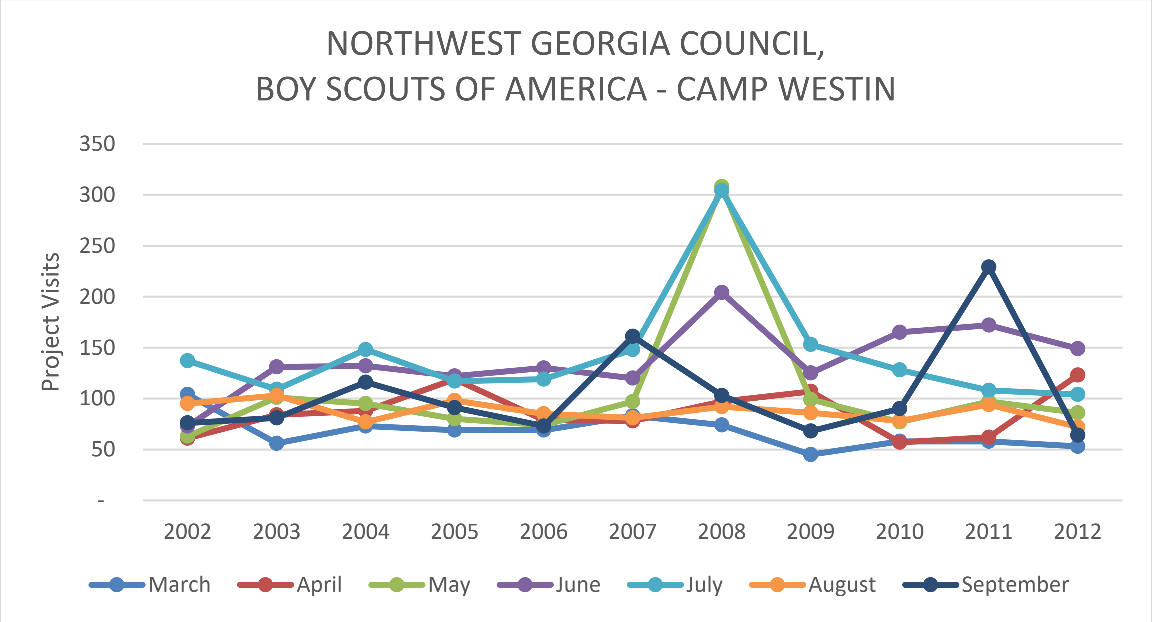


Figure 55: Old Hwy 41 #1 Day Use Visitation 2002-2012

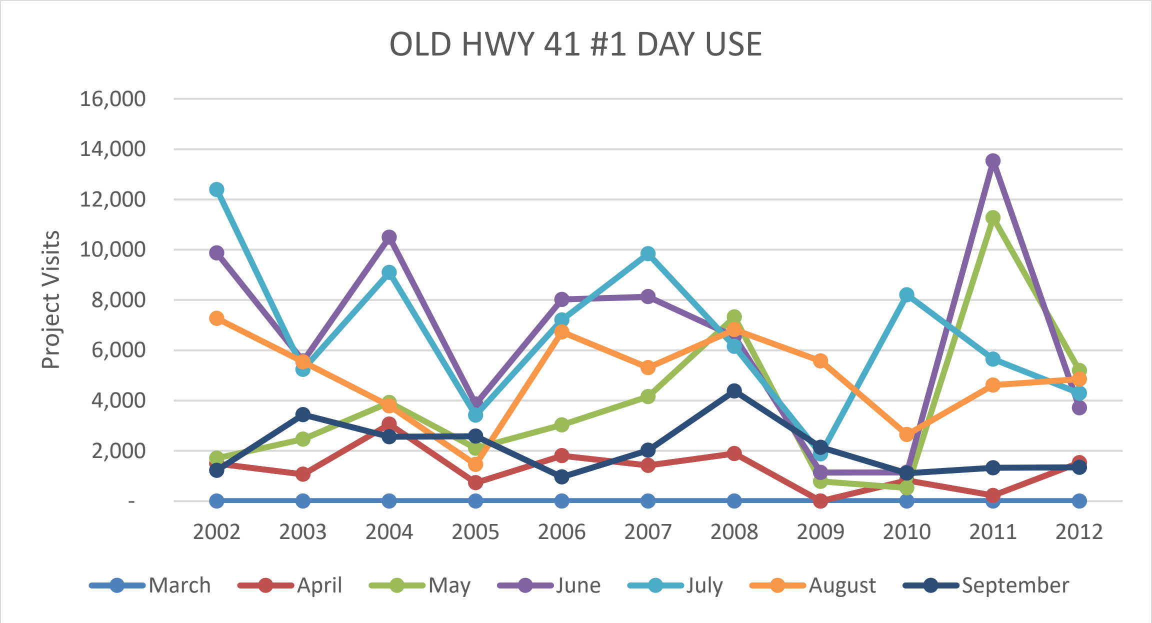


Figure 56: Old Hwy 41 #2 Day Use Visitation 2002-2012

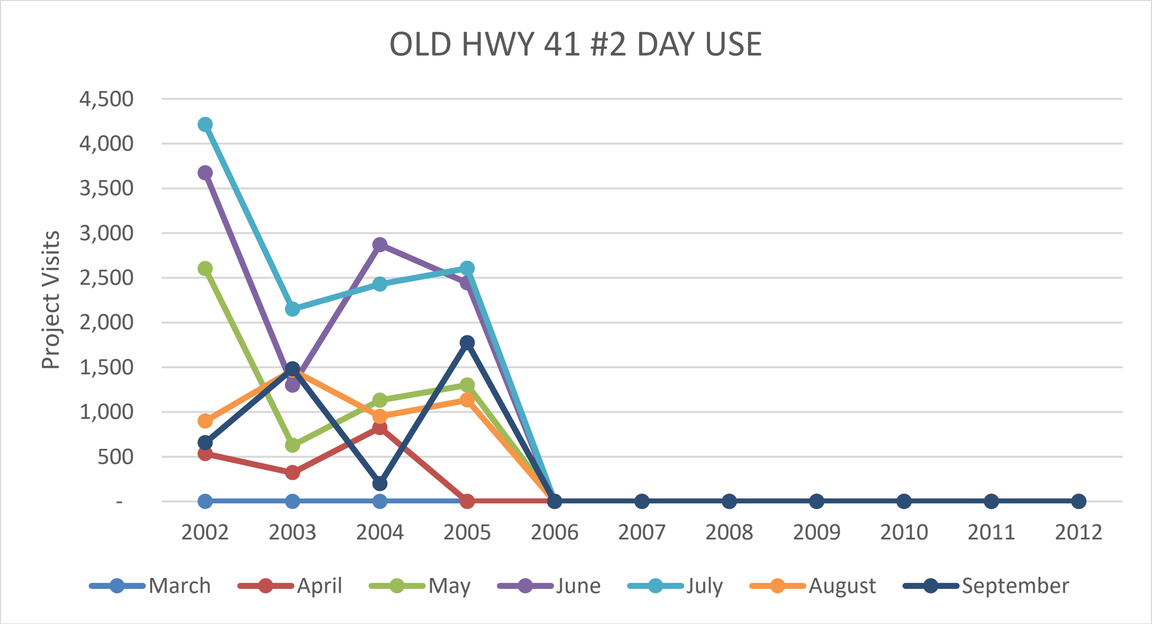


Figure 57: Old Hwy 41 #3 Campground Visitation 2002-2012

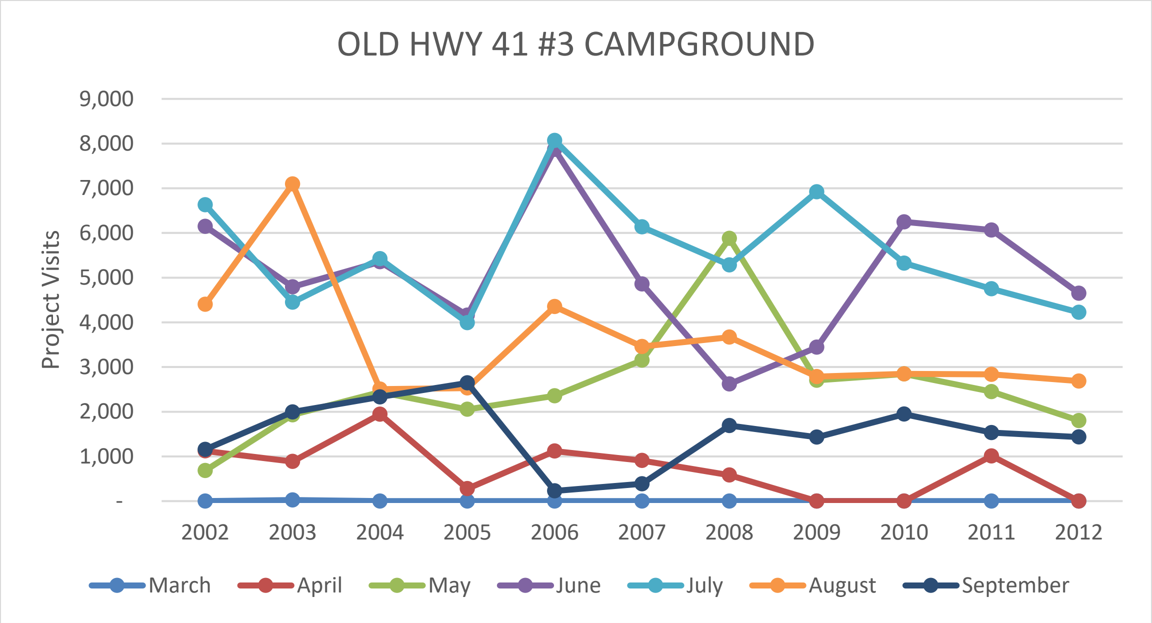


Figure 58: Payne Campground Visitation 2002-2012

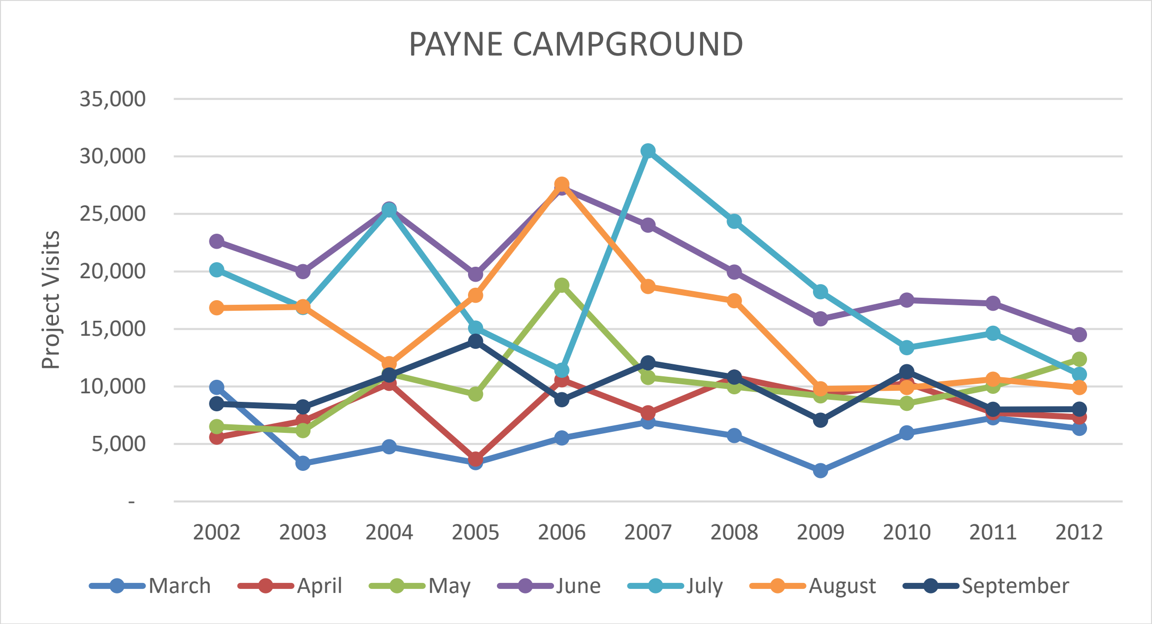


Figure 59: Proctor Landing Visitation 2002-2012

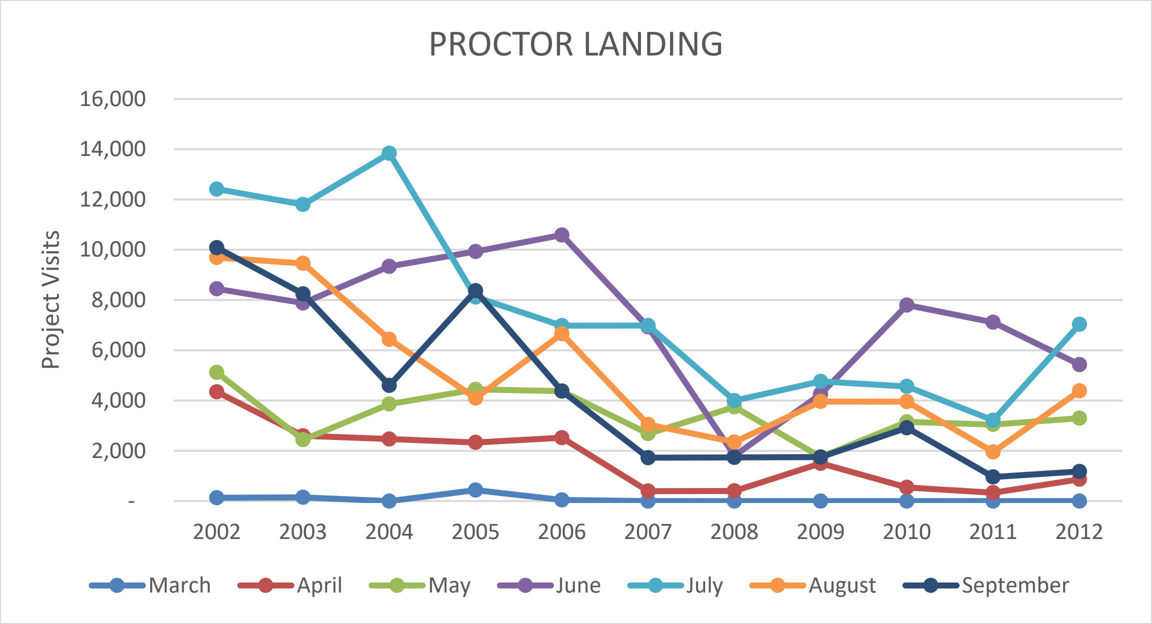


Figure 60: PS Marina 3 - Allatoona Landing Visitation 2002-2012

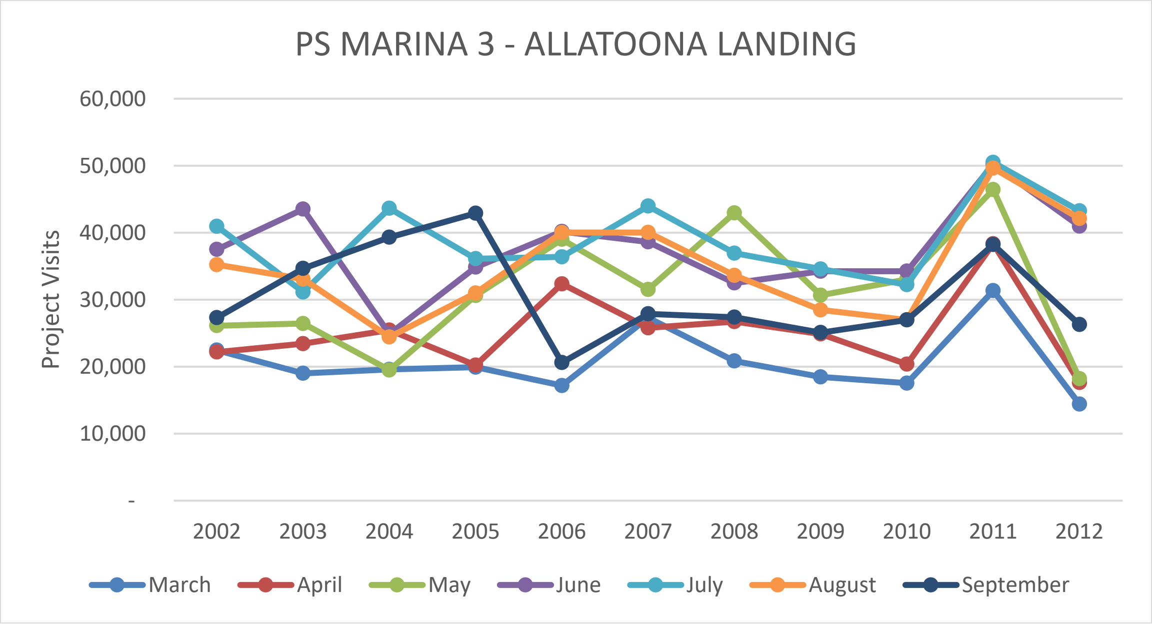


Figure 61: Riverside Day Use Visitation 2002-2012

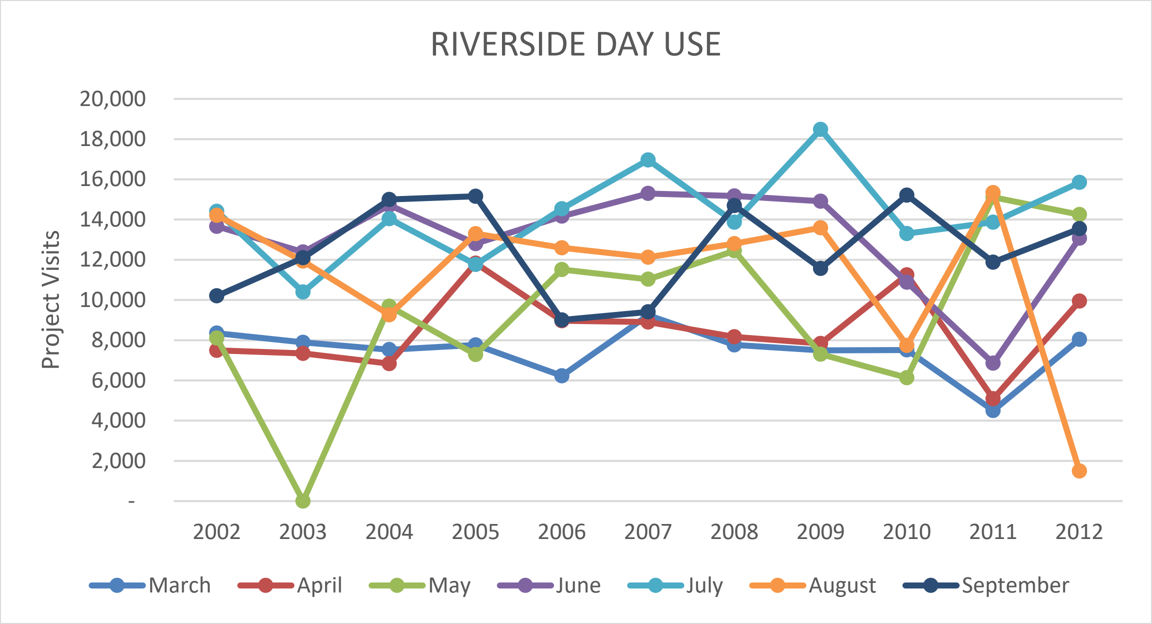


Figure 62: South Cherokee Recreation Association Visitation 2002-2012

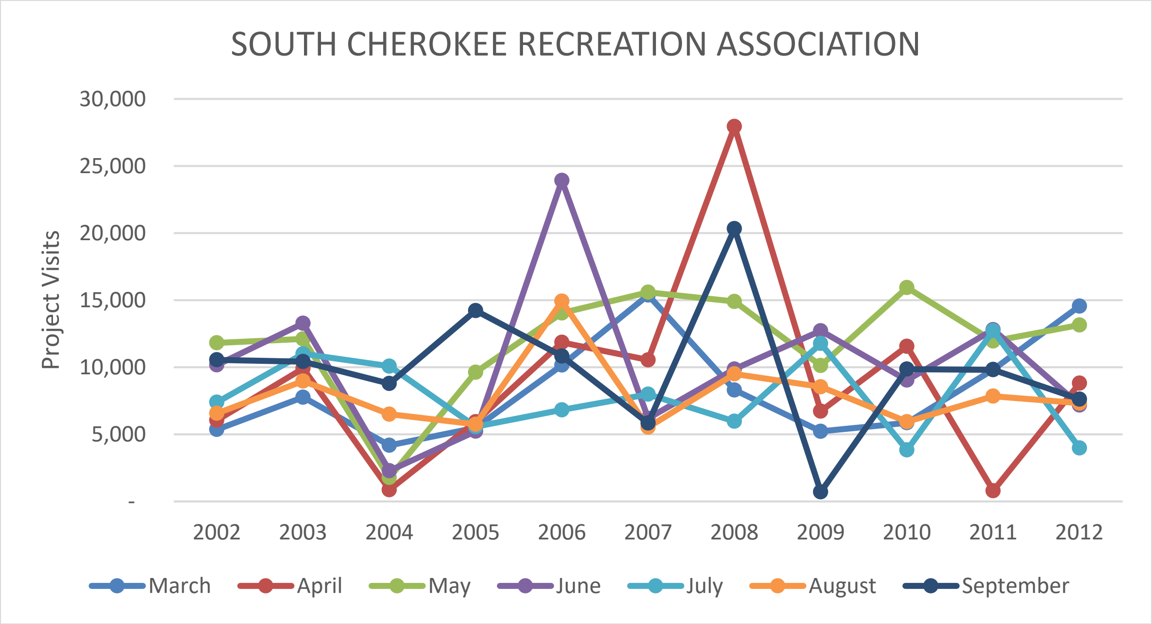


Figure 63: Stamp Creek Day Use Visitation 2002-2012

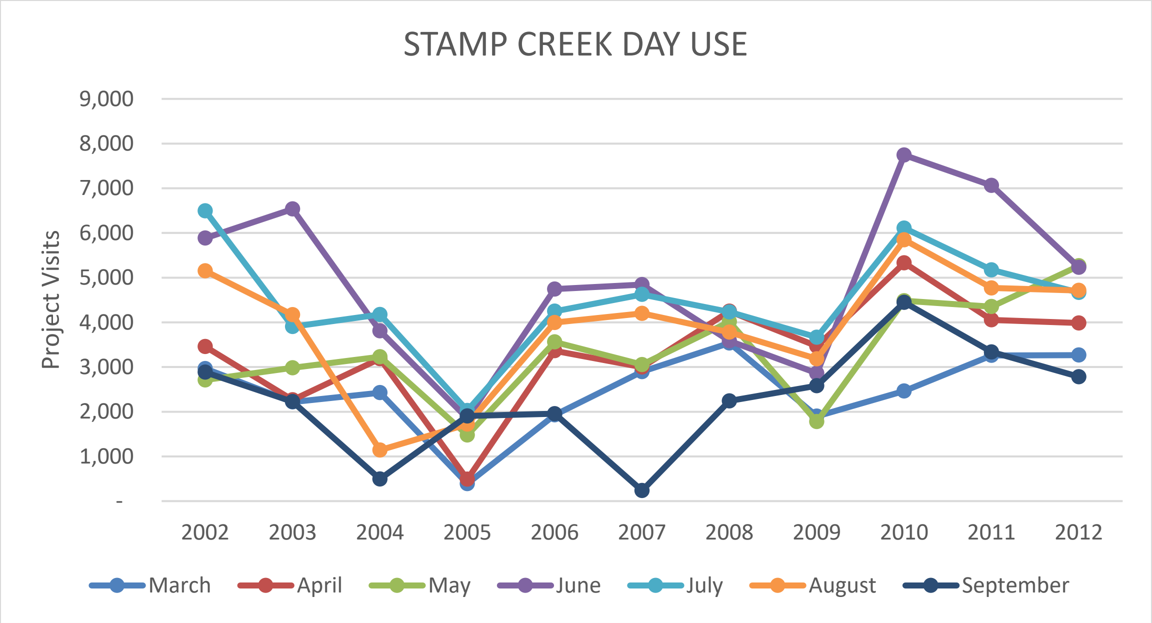


Figure 64: Sweetwater Campground Visitation 2002-2012

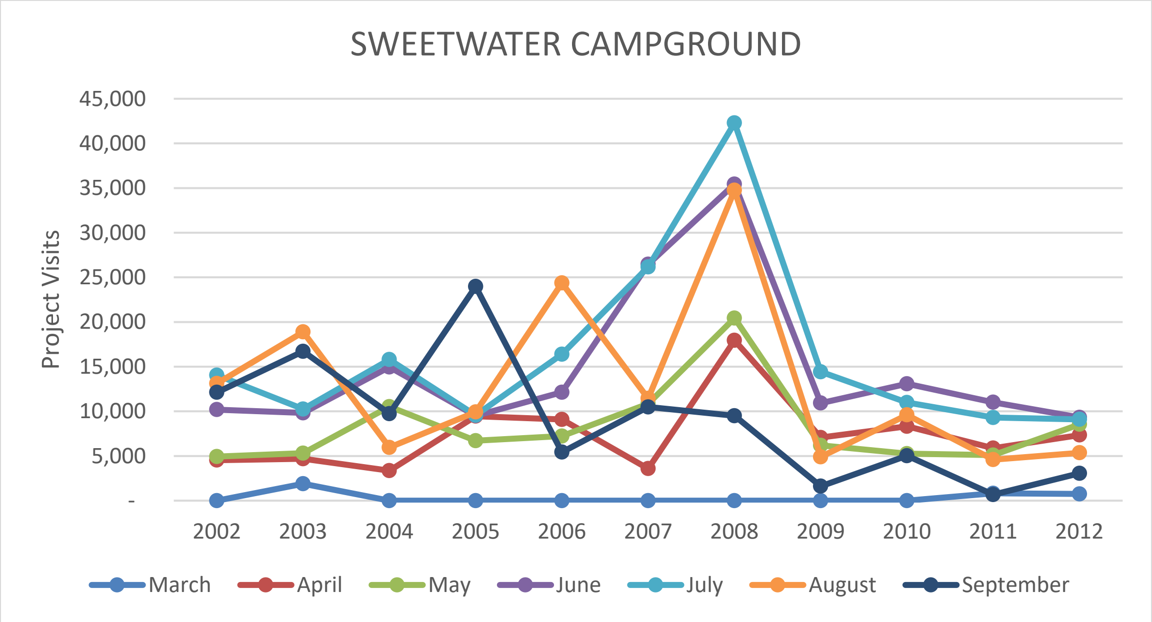


Figure 65: Sweetwater Day Use Visitation 2002-2012

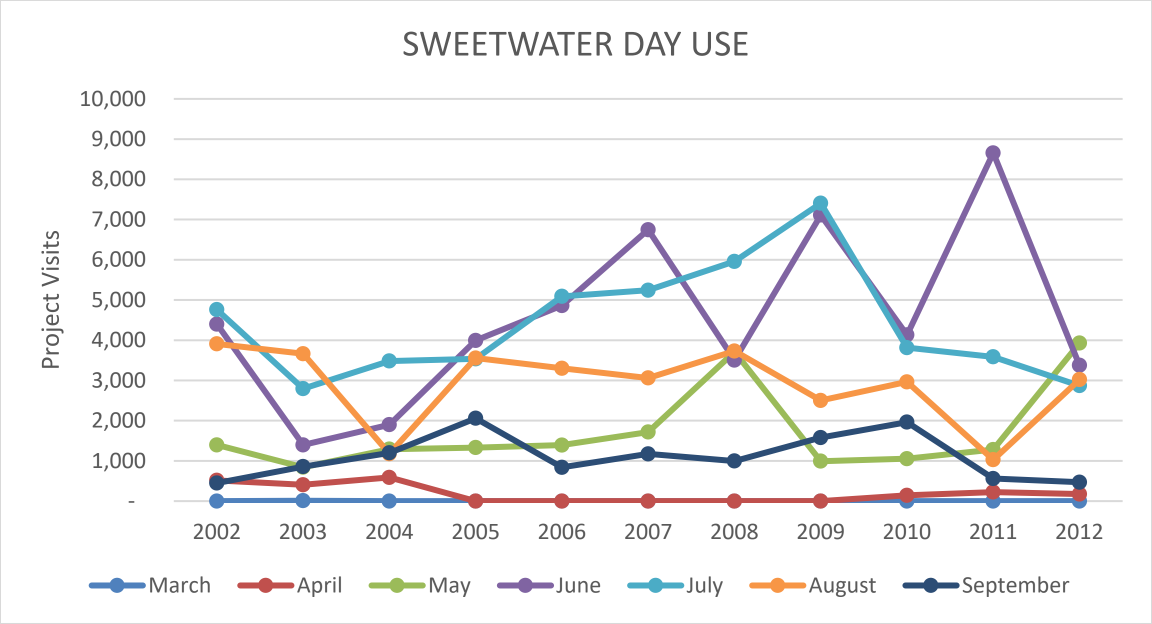


Figure 66: Traina Enterprises - Wilderness Camp Marina Visitation 2002-2012

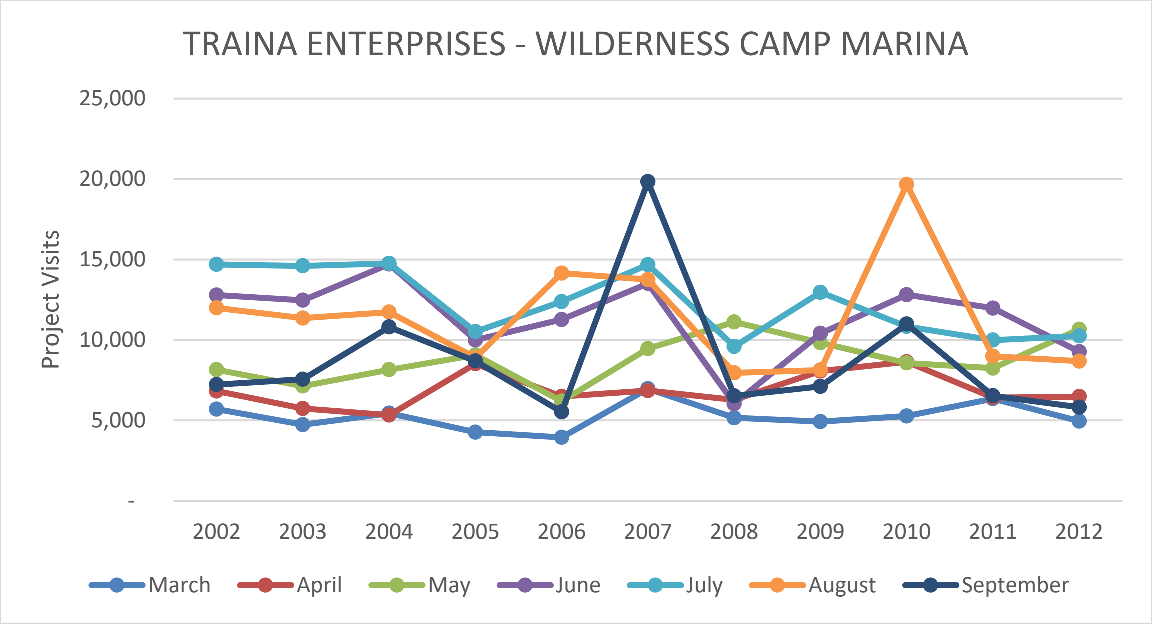


Figure 67: Upper Stamp Creek Campground Visitation 2002-2012

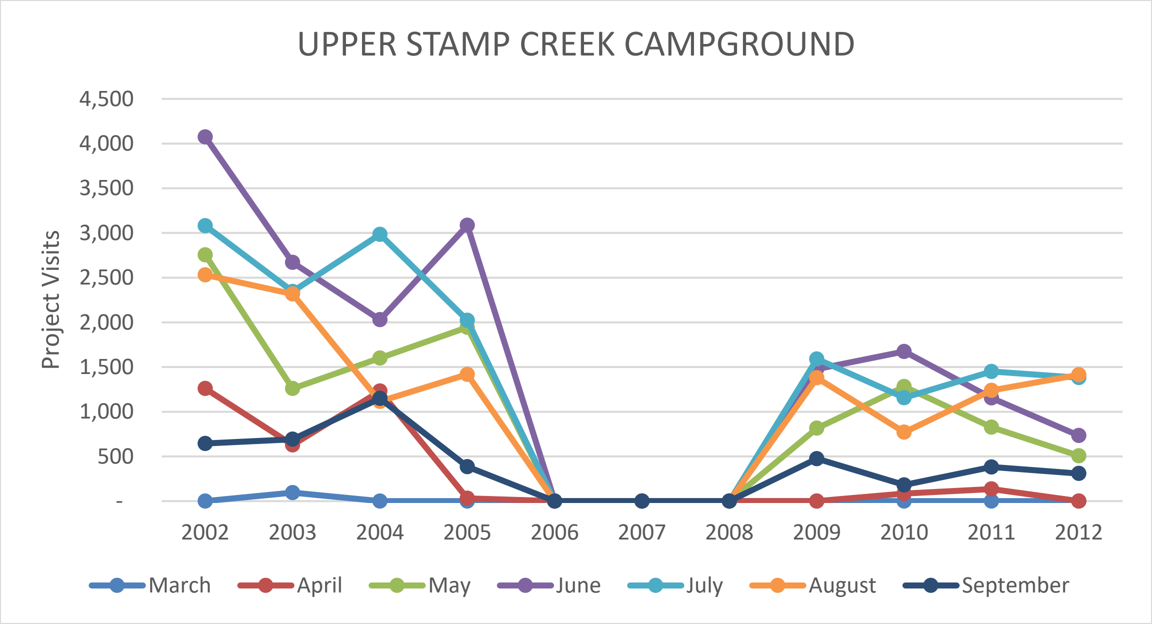


Figure 68: Upper Tanyard Day Use Visitation 2002-2012

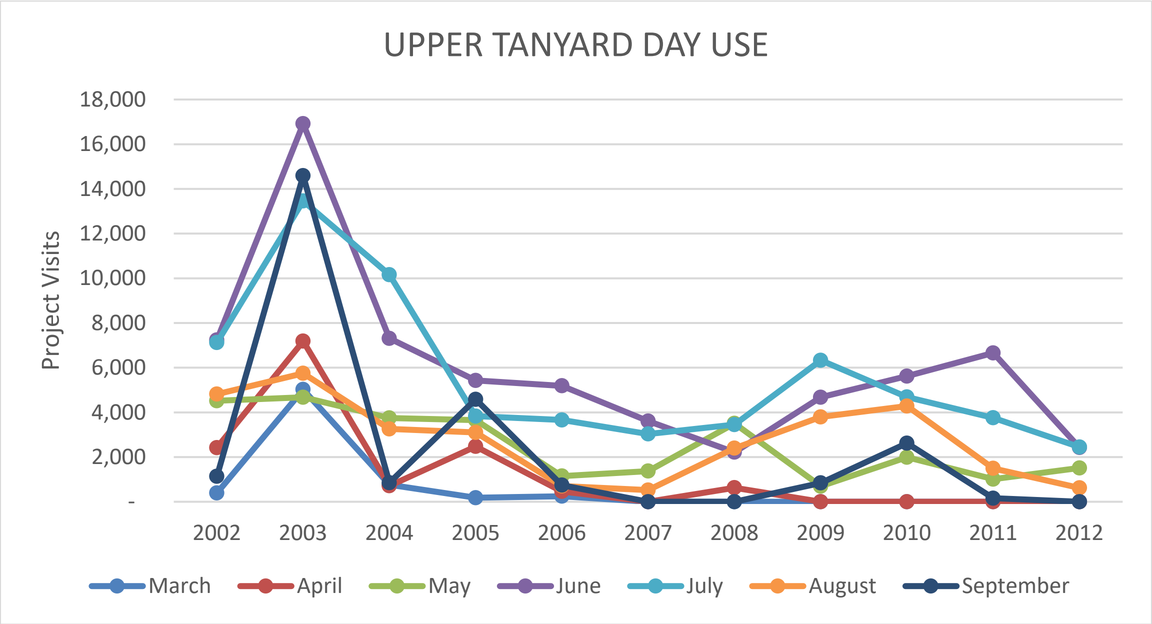


Figure 69: US Naval Air Station Visitation 2002-2012

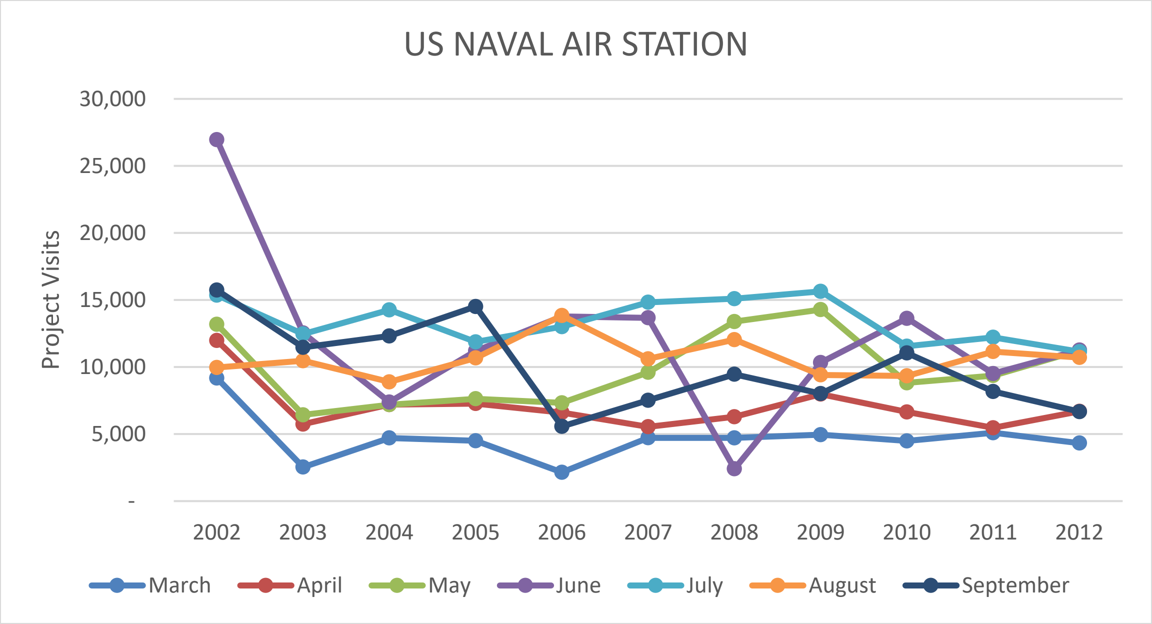


Figure 70: Victoria Campground Visitation 2002-2012

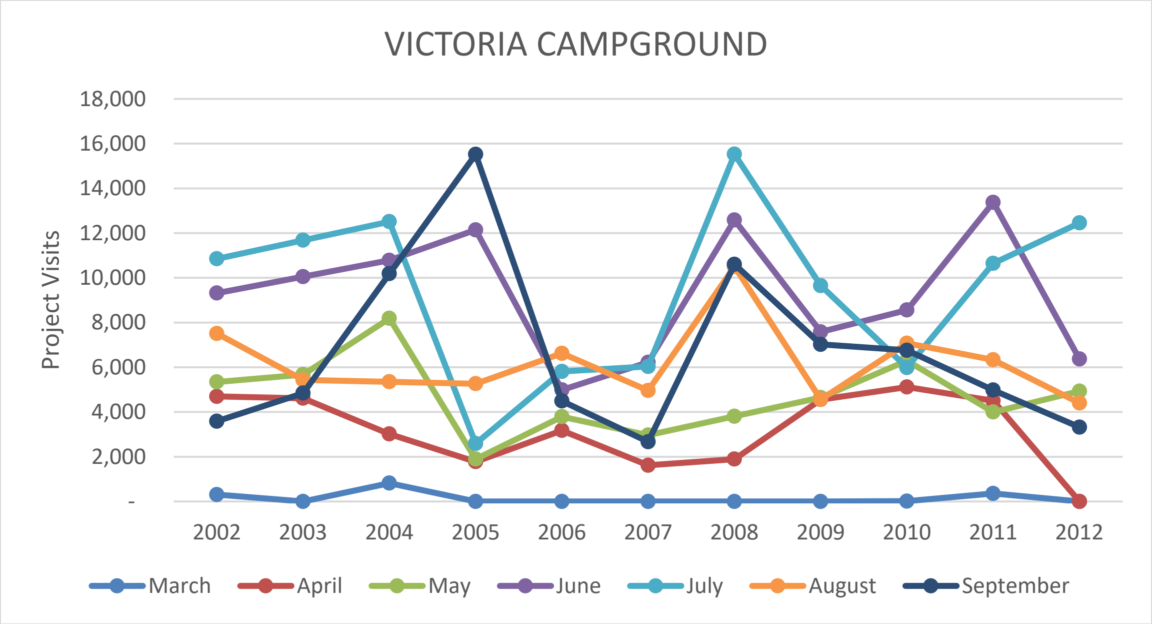


Figure 71: Victoria Day Use Visitation 2002-2012

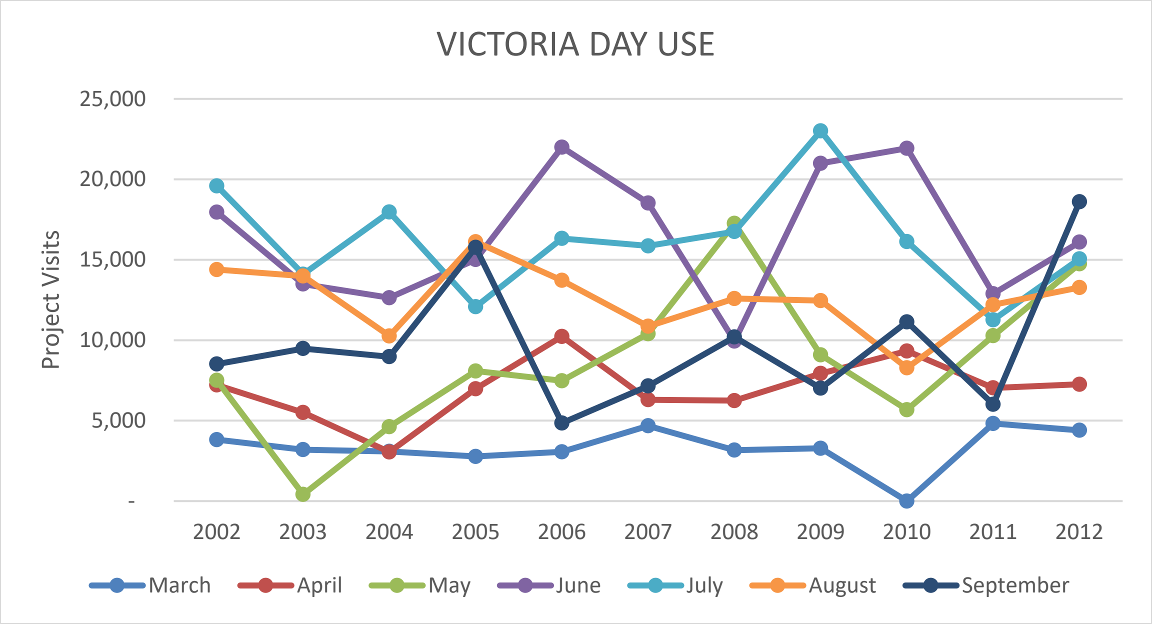


Figure 72: Victoria Harbour Marina Visitation 2002-2012

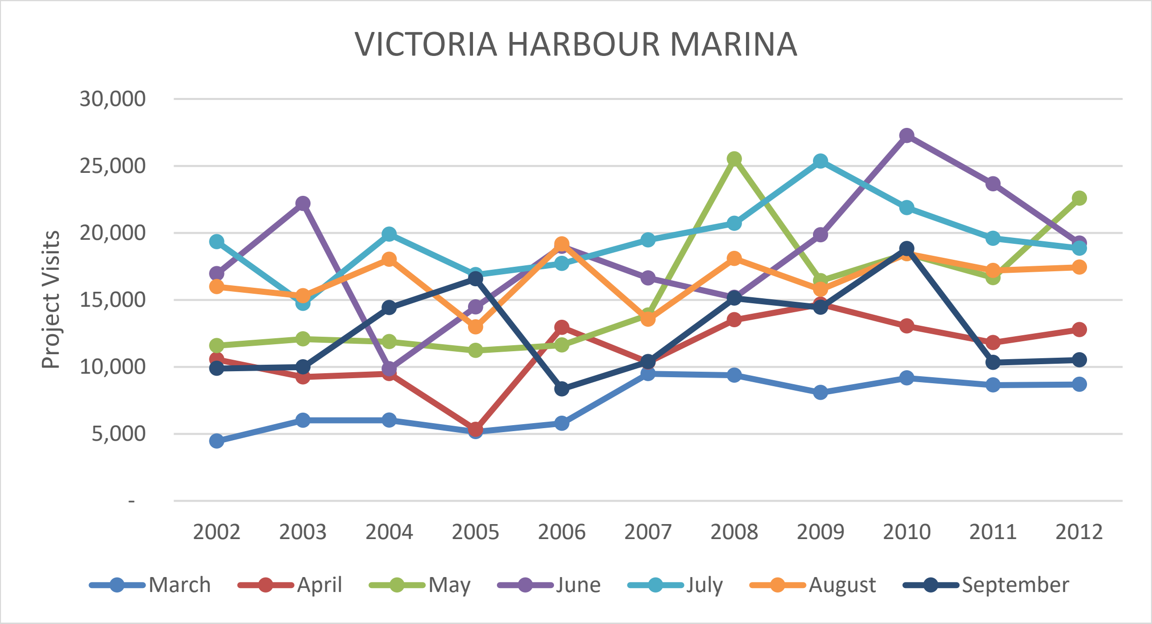


Figure 73: Wildlife Action Visitation 2002-2012

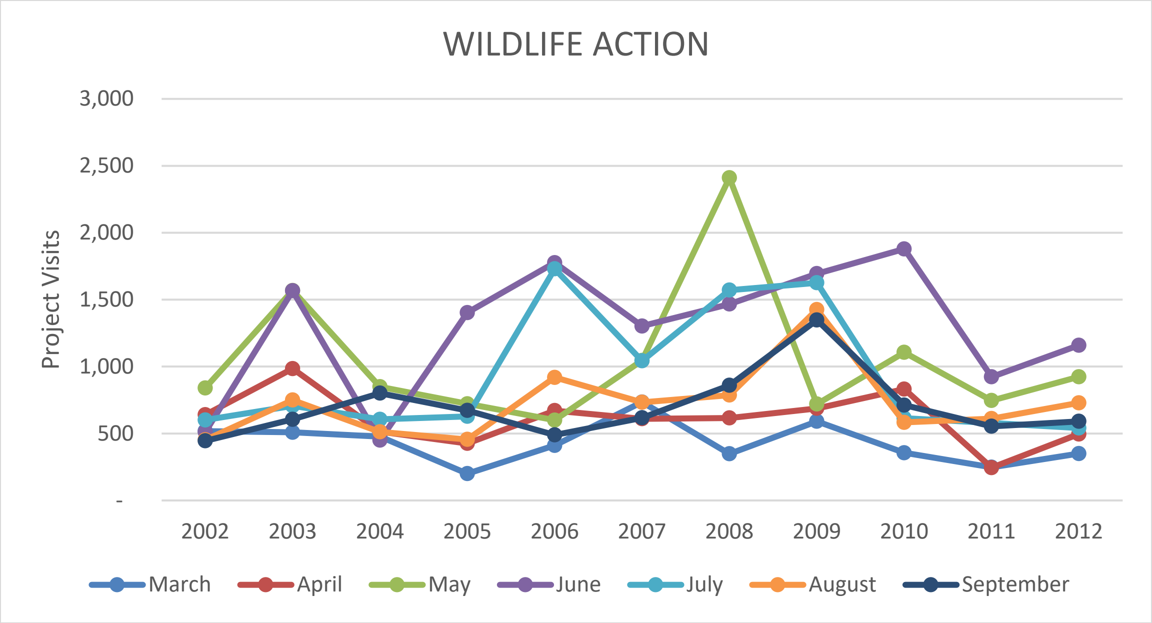


Figure 74: WTSD & Associates, LLC Visitation 2002-2012

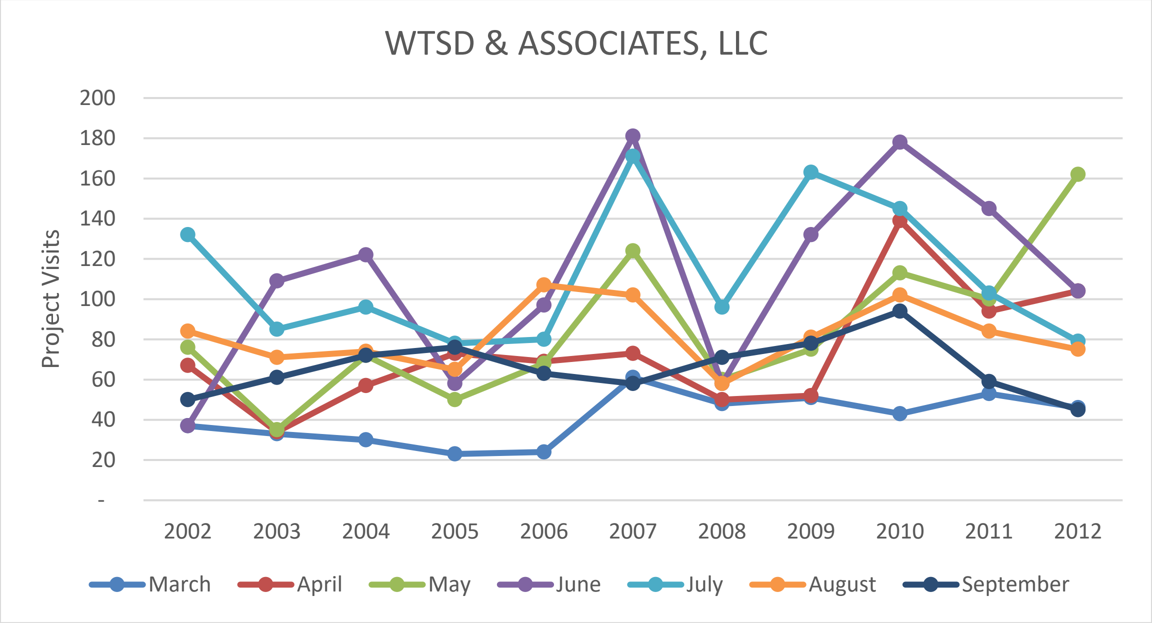


Figure 75: YMCA of Metro Atlanta - Cherokee YMCA Visitation 2002-2012

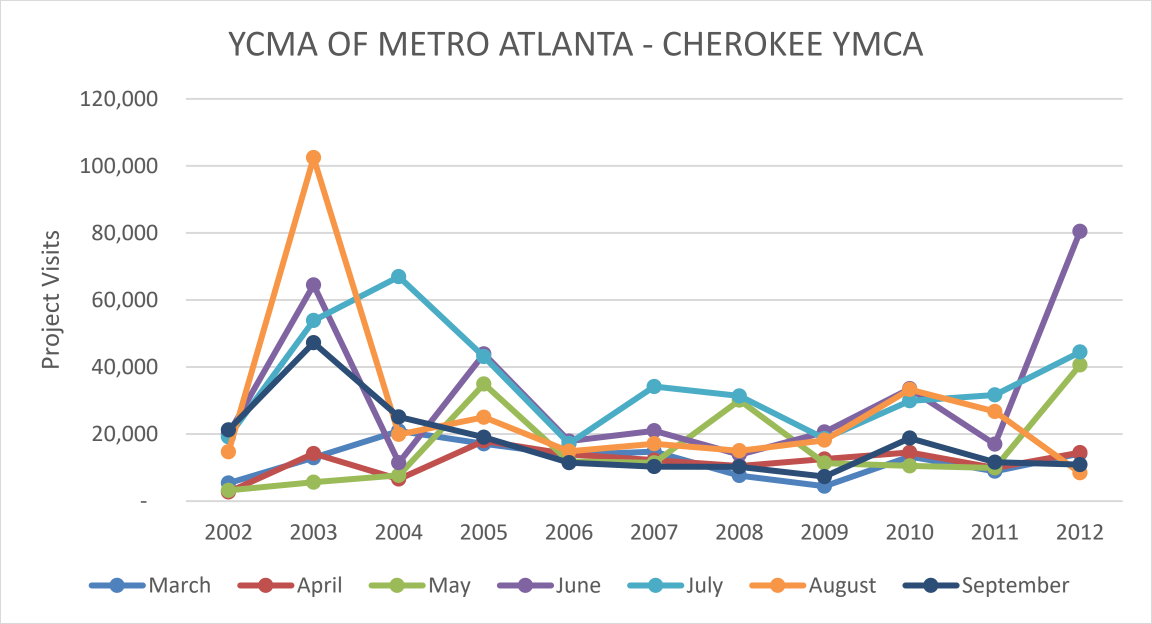
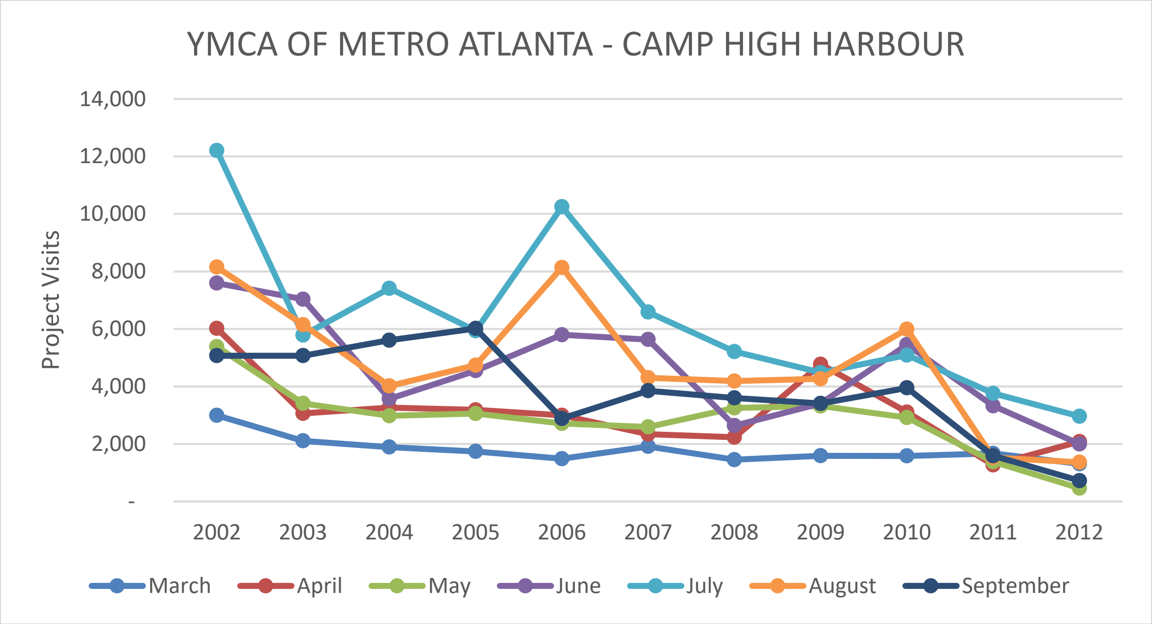


Figure 76: YMCA of Metro Atlanta - Camp High Harbour Visitation 2002-2012



Source: USACE 2016.

4 Recreation Carrying Capacity

It is important to establish the carrying capacity of a project so that there are appropriate parking and facilities, and the quality of the recreation experience is maintained. Recreation carrying capacity can be analyzed in several ways. For this analysis, the parking spaces and general visitation data were used to establish general recreation carrying capacity. In order to determine peak season weekend day visitation, the visitation for June, July, and August is summed. Years 2010 and 2012 are used to determine the average base values. Design load is calculated as the number of peak season visits multiplied by the percent of visitation occurring on weekends divided by the number of peak season weekend days. In order to determine the parking demand at the project, the design load is used with assumptions for turnover rate (calculated as hours the project is open divided by the average day use hours per person), persons per vehicle, and existing parking. The values for Day Use hours and Visitors per Vehicle were taken from existing data sources including VERS and local Allatoona Lake records. For more informed calculations, a survey would need to be conducted at the project.

Design load and parking demand were calculated for individual recreation areas to help aid in planning. To calculate design load, annual visits for the individual recreation area were needed. This number was calculated by representing the recreation area as a percentage of overall project visitation based on the average recreation area visitation for the years 2010 and 2012. The average percentage was multiplied by the projected project visitation values(displayed in column four of each table below) , and annual visits were multiplied by the percentage of visitation occurring during the peak season to calculate peak season visitation.

Parking demand for each individual recreation area was calculated and is displayed below (Tables 2-113). Based on the analysis, there are areas where demand exceeds existing parking supply. Other areas have enough supply that it will not be exceeded by future demand. There is some uncertainty in the analysis related to multiple factors including population projections, individual PSA turnover rates and variance in per capita use rate from year to year. The net difference in parking capacity therefore can vary from what is displayed below.

Table 2: Acworth Lake Authority Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	117,683	301,422	6,245,913	4.83%	39.04%	14	75%	28	3,152
2012	147,981	305,380	6,175,062	4.95%	48.46%	14	75%	28	3,964
2020	144,132	329,442	6,743,066	4.89%	43.75%	14	75%	28	3,861
2030	159,691	365,005	7,470,966	4.89%	43.75%	14	75%	28	4,277

Table 3: Acworth Lake Authority Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	3,152	3.66	3.28	3.11	309	333	24
2012	3,964	3.66	3.28	3.11	389	333	-56
2020	3,861	3.66	3.28	3.11	379	333	-46
2030	4,277	3.66	3.28	3.11	419	333	-86

Table 4: Allatoona Boat and Ski Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	5,297	18,618	6,245,913	0.30%	28.45%	14	75%	28	142
2012	4,551	17,333	6,175,062	0.28%	26.26%	14	75%	28	122
2020	5,338	19,514	6,743,066	0.29%	27.35%	14	75%	28	143
2030	5,914	21,620	7,470,966	0.29%	27.35%	14	75%	28	158

Table 5: Allatoona Boat and Ski Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	142	4.35	2.76	1.91	27	6	-21
2012	122	4.35	2.76	1.91	23	6	-17
2020	143	4.35	2.76	1.91	27	6	-21
2030	158	4.35	2.76	1.91	30	6	-24

Table 6: Allatoona Yacht Club Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	18,216	54,688	6,245,913	0.88%	33.31%	14	75%	28	488
2012	16,251	48,227	6,175,062	0.78%	33.70%	14	75%	28	435
2020	18,712	55,852	6,743,066	0.83%	33.50%	14	75%	28	501
2030	20,732	61,881	7,470,966	0.83%	33.50%	14	75%	28	555

Table 7: Allatoona Yacht Club Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	488	4.35	2.76	1.91	93	139	46
2012	435	4.35	2.76	1.91	83	139	56
2020	501	4.35	2.76	1.91	95	139	44
2030	555	4.35	2.76	1.91	105	139	34

Table 8: Atlanta Yacht Club Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	8,592	21,766	6,245,913	0.35%	39.47%	14	75%	28	230
2012	7,608	18,889	6,175,062	0.31%	40.28%	14	75%	28	204
2020	8,798	22,062	6,743,066	0.33%	39.88%	14	75%	28	236
2030	9,747	24,444	7,470,966	0.33%	39.88%	14	75%	28	261

Table 9: Atlanta Yacht Club Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	230	4.35	2.76	1.91	44	46	2
2012	204	4.35	2.76	1.91	39	46	7
2020	236	4.35	2.76	1.91	45	46	1
2030	261	4.35	2.76	1.91	50	46	-4

Table 10: Bartow Carver Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	20,697	42,842	6,245,913	0.69%	48.31%	14	75%	28	554
2012	18,075	37,170	6,175,062	0.60%	48.63%	14	75%	28	484
2020	21,046	43,421	6,743,066	0.64%	48.47%	14	75%	28	564
2030	23,317	48,108	7,470,966	0.64%	48.47%	14	75%	28	625

Table 11: Bartow Carver Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	554	3.66	3.28	3.11	54	96	42
2012	484	3.66	3.28	3.11	47	96	49
2020	564	3.66	3.28	3.11	55	96	41
2030	625	3.66	3.28	3.11	61	96	35

Table 12: Bartow County - Gatewood Park Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	20,430	47,751	6,245,913	0.76%	42.78%	14	75%	28	547
2012	12,496	35,824	6,175,062	0.58%	34.88%	14	75%	28	335
2020	17,605	45,336	6,743,066	0.67%	38.83%	14	75%	28	472
2030	19,506	50,229	7,470,966	0.67%	38.83%	14	75%	28	522

Table 13: Bartow County - Gatewood Park Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	547	4.35	2.76	1.91	104	252	148
2012	335	4.35	2.76	1.91	64	252	188
2020	472	4.35	2.76	1.91	89	252	163
2030	522	4.35	2.76	1.91	99	252	153

Table 14: Big K Club Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	3,384	10,766	6,245,913	0.17%	31.43%	14	75%	28	91
2012	2,604	6,107	6,175,062	0.10%	42.64%	14	75%	28	70
2020	3,387	9,146	6,743,066	0.14%	37.04%	14	75%	28	91
2030	3,753	10,133	7,470,966	0.14%	37.04%	14	75%	28	101

Table 15: Big K Club Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	91	4.07	2.95	2.71	11	15	4
2012	70	4.07	2.95	2.71	9	15	6
2020	91	4.07	2.95	2.71	11	15	4
2030	101	4.07	2.95	2.71	13	15	2

Table 16: Blockhouse #2 – Ramp Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	71,979	161,112	6,245,913	2.58%	44.68%	14	75%	28	1,928
2012	89,867	175,678	6,175,062	2.84%	51.15%	14	75%	28	2,407
2020	87,631	182,887	6,743,066	2.71%	47.92%	14	75%	28	2,347
2030	97,090	202,629	7,470,966	2.71%	47.92%	14	75%	28	2,601

Table 17: Blockhouse #2 – Ramp Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,928	4.07	2.95	2.71	241	128	-113
2012	2,407	4.07	2.95	2.71	301	128	-173
2020	2,347	4.07	2.95	2.71	294	128	-166
2030	2,601	4.07	2.95	2.71	325	128	-197

Table 18: Boy Scouts of America – Explorer Scout Camp - Camp Allatoona Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	2,349	7,516	6,245,913	0.12%	31.25%	14	75%	28	63
2012	1,952	7,041	6,175,062	0.11%	27.72%	14	75%	28	52
2020	2,330	7,901	6,743,066	0.12%	29.49%	14	75%	28	62
2030	2,582	8,754	7,470,966	0.12%	29.49%	14	75%	28	69

Table 19: Boy Scouts of America – Explorer Scout Camp - Camp Allatoona Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	63	4.35	2.76	1.91	12	58	46
2012	52	4.35	2.76	1.91	10	58	48
2020	62	4.35	2.76	1.91	12	58	46
2030	69	4.35	2.76	1.91	13	58	45

Table 20: Cherokee County - Blanket's Creek Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	38,149	87,440	6,245,913	1.40%	43.63%	14	75%	28	1,022
2012	58,140	185,150	6,175,062	3.00%	31.40%	14	75%	28	1,557
2020	55,631	148,290	6,743,066	2.20%	37.52%	14	75%	28	1,490
2030	61,636	164,298	7,470,966	2.20%	37.52%	14	75%	28	1,651

Table 21: Cherokee County - Blanket's Creek Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,022	3.66	3.28	3.11	100	137	37
2012	1,557	3.66	3.28	3.11	153	137	-16
2020	1,490	3.66	3.28	3.11	146	137	-9
2030	1,651	3.66	3.28	3.11	162	137	-25

Table 22: Cherokee County - Cherokee Mills Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	54,122	128,407	6,245,913	2.06%	42.15%	14	75%	28	1,450
2012	53,990	129,052	6,175,062	2.09%	41.84%	14	75%	28	1,446
2020	58,695	139,775	6,743,066	2.07%	41.99%	14	75%	28	1,572
2030	65,031	154,864	7,470,966	2.07%	41.99%	14	75%	28	1,742

Table 23: Cherokee County - Cherokee Mills Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,450	3.66	3.28	3.11	142	140	-2
2012	1,446	3.66	3.28	3.11	150	140	-10
2020	1,572	3.66	3.28	3.11	163	140	-23
2030	1,742	3.66	3.28	3.11	180	140	-40

Table 24: Cherokee County - Field's Landing Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	31,155	86,480	6,245,913	1.38%	36.03%	14	75%	28	835
2012	30,807	75,444	6,175,062	1.22%	40.83%	14	75%	28	825
2020	33,770	87,874	6,743,066	1.30%	38.43%	14	75%	28	905
2030	37,415	97,359	7,470,966	1.30%	38.43%	14	75%	28	1,002

Table 25: Cherokee County - Field's Landing Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	835	3.66	3.28	3.11	82	48	-34
2012	825	3.66	3.28	3.11	81	48	-33
2020	905	3.66	3.28	3.11	89	48	-41
2030	1,002	3.66	3.28	3.11	98	48	-50

Table 26: Cherokee County - J.J. Biello Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	14,047	52,767	6,245,913	0.84%	26.62%	14	75%	28	376
2012	25,258	84,808	6,175,062	1.37%	29.78%	14	75%	28	677
2020	21,091	74,788	6,743,066	1.11%	28.20%	14	75%	28	565
2030	23,368	82,861	7,470,966	1.11%	28.20%	14	75%	28	626

Table 27: Cherokee County - J.J. Biello Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	376	4.35	2.76	1.91	71	1,244	1,173
2012	677	4.35	2.76	1.91	128	1,244	1,116
2020	565	4.35	2.76	1.91	107	1,244	1,137
2030	626	4.35	2.76	1.91	119	1,244	1,125

Table 28: Cherokee Presbytery - Camp Cherokee Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	1,440	7,486	6,245,913	0.12%	19.24%	14	75%	28	39
2012	1,129	3,388	6,175,062	0.05%	33.32%	14	75%	28	30
2020	1,548	5,891	6,743,066	0.09%	26.28%	14	75%	28	41
2030	1,715	6,527	7,470,966	0.09%	26.28%	14	75%	28	46

Table 29: Cherokee Presbytery - Camp Cherokee Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	39	4.35	2.76	1.91	7	8	1
2012	30	4.35	2.76	1.91	6	8	2
2020	41	4.35	2.76	1.91	8	8	0
2030	46	4.35	2.76	1.91	9	8	-1

Table 30: City of Canton - Boling Park Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	262,834	719,658	6,245,913	11.52%	36.52%	14	75%	28	7,040
2012	208,263	566,142	6,175,062	9.17%	36.79%	14	75%	28	5,578
2020	255,692	697,579	6,743,066	10.35%	36.65%	14	75%	28	6,849
2030	283,294	772,881	7,470,966	10.35%	36.65%	14	75%	28	7,588

Table 31: City of Canton - Boling Park Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	7,040	3.66	6.00	3.11	377	272	-105
2012	5,578	3.66	6.00	3.11	299	272	-27
2020	6,849	3.66	6.00	3.11	367	272	-95
2030	7,588	3.66	6.00	3.11	407	272	-135

Table 32: Clark Creek North Campground Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	7,895	11,234	6,245,913	0.18%	70.28%	14	75%	28	211
2012	7,503	9,205	6,175,062	0.15%	81.51%	14	75%	28	201
2020	8,417	11,090	6,743,066	0.16%	75.89%	14	75%	28	225
2030	9,325	12,287	7,470,966	0.16%	75.89%	14	75%	28	250

Table 33: Clark Creek North Campground Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	211	1.49	8.05	3.44	8	30	22
2012	201	1.49	8.05	3.44	7	30	23
2020	225	1.49	8.05	3.44	8	30	22
2030	250	1.49	8.05	3.44	9	30	21

Table 34: Clark Creek South Ramp Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	13,767	28,537	6,245,913	0.46%	48.24%	14	75%	28	369
2012	29,102	58,889	6,175,062	0.95%	49.42%	14	75%	28	780
2020	23,222	47,557	6,743,066	0.71%	48.83%	14	75%	28	622
2030	25,729	52,691	7,470,966	0.71%	48.83%	14	75%	28	689

Table 35: Clark Creek South Ramp Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	369	3.66	3.28	3.11	36	70	34
2012	780	3.66	3.28	3.11	76	70	-6
2020	622	3.66	3.28	3.11	61	70	9
2030	689	3.66	3.28	3.11	68	70	2

Table 36: Cobb County - Acworth Regional Park Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	79,401	273,626	6,245,913	4.38%	29.02%	14	75%	28	2,127
2012	103,481	256,770	6,175,062	4.16%	40.30%	14	75%	28	2,772
2020	99,784	287,897	6,743,066	4.27%	34.66%	14	75%	28	2,673
2030	110,555	318,975	7,470,966	4.27%	34.66%	14	75%	28	2,961

Table 37: Cobb County 0 Acworth Regional Park Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	2,127	3.66	3.28	3.11	209	188	-21
2012	2,772	3.66	3.28	3.11	272	188	-84
2020	2,673	3.66	3.28	3.11	262	188	-74
2030	2,961	3.66	3.28	3.11	290	188	-102

Table 38: Cooper Branch Day Use Area #1 Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	49,122	124,646	6,245,913	2.00%	39.41%	14	75%	28	1,316
2012	42,118	91,678	6,175,062	1.48%	45.94%	14	75%	28	1,128
2020	50,075	117,339	6,743,066	1.74%	42.68%	14	75%	28	1,341
2030	55,480	130,006	7,470,966	1.74%	42.68%	14	75%	28	1,486

Table 39: Cooper Branch Day Use Area #1 Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,316	3.66	3.28	3.11	129	84	-45
2012	1,128	3.66	3.28	3.11	111	84	-27
2020	1,341	3.66	3.28	3.11	132	84	-48
2030	1,486	3.66	3.28	3.11	146	84	-62

Table 40: Cooper's Furnace Day Use Area Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	20,264	59,128	6,245,913	0.95%	34.27%	14	75%	28	543
2012	22,277	46,155	6,175,062	0.75%	48.27%	14	75%	28	597
2020	23,572	57,117	6,743,066	0.85%	41.27%	14	75%	28	631
2030	26,116	63,283	7,470,966	0.85%	41.27%	14	75%	28	700

Table 41: Cooper's Furnace Day Use Area Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	543	3.66	3.28	3.11	53	124	71
2012	597	3.66	3.28	3.11	59	124	65
2020	631	3.66	3.28	3.11	62	124	62
2030	700	3.66	3.28	3.11	69	124	55

Table 42: Cushing Memorial Park Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	50,428	115,925	6,245,913	1.86%	43.50%	14	75%	28	1,351
2012	28,023	60,322	6,175,062	0.98%	46.46%	14	75%	28	751
2020	42,959	95,511	6,743,066	1.42%	44.98%	14	75%	28	1,151
2030	47,597	105,822	7,470,966	1.42%	44.98%	14	75%	28	1,275

Table 43: Cushing Memorial Park Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,351	4.07	2.95	2.71	169	200	31
2012	751	4.07	2.95	2.71	94	200	106
2020	1,151	4.07	2.95	2.71	144	200	56
2030	1,275	4.07	2.95	2.71	160	200	40

Table 44: Dallas Landing Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	24,507	39,116	6,245,913	0.63%	62.65%	14	75%	28	656
2012	47,544	71,521	6,175,062	1.16%	66.48%	14	75%	28	1,274
2020	38,845	60,165	6,743,066	0.89%	64.56%	14	75%	28	1,040
2030	43,038	66,659	7,470,966	0.89%	64.56%	14	75%	28	1,153

Table 45: Dallas Landing Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	656	4.07	2.95	2.71	82	400	318
2012	1,274	4.07	2.95	2.71	159	400	241
2020	1,040	4.07	2.95	2.71	130	400	270
2030	1,153	4.07	2.95	2.71	144	400	256

Table 46: Etowah Yacht Club Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	5,324	13,180	6,245,913	0.21%	40.39%	14	75%	28	143
2012	4,180	11,475	6,175,062	0.19%	36.43%	14	75%	28	112
2020	5,139	13,380	6,743,066	0.20%	38.41%	14	75%	28	138
2030	5,694	14,824	7,470,966	0.20%	38.41%	14	75%	28	153

Table 47: Etowah Yacht Club Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	143	4.35	2.76	1.91	27	15	-12
2012	112	4.35	2.76	1.91	21	15	-6
2020	138	4.35	2.76	1.91	26	15	-11
2030	153	4.35	2.76	1.91	29	15	-14

Table 48: Galts Ferry Day Use Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	57,446	107,672	6,245,913	1.72%	53.35%	14	75%	28	1,539
2012	45,573	90,916	6,175,062	1.47%	50.13%	14	75%	28	1,221
2020	55,755	107,761	6,743,066	1.60%	51.74%	14	75%	28	1,493
2030	61,774	119,393	7,470,966	1.60%	51.74%	14	75%	28	1,655

Table 49: Galts Ferry Day Use Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,539	3.66	3.28	3.11	151	194	43
2012	1,221	3.66	3.28	3.11	120	194	74
2020	1,493	3.66	3.28	3.11	146	194	48
2030	1,655	3.66	3.28	3.11	162	194	32

Table 50: Georgia Department of Natural Resources - Red Top Mountain Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	332,484	763,395	6,245,913	12.22%	43.55%	14	75%	28	8,906
2012	262,775	567,939	6,175,062	9.20%	46.27%	14	75%	28	7,039
2020	324,332	722,169	6,743,066	10.71%	44.91%	14	75%	28	8,687
2030	359,343	800,126	7,470,966	10.71%	44.91%	14	75%	28	9,625

Table 51: Georgia Department of Natural Resources - Red Top Mountain Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	8,906	3.00	4.00	3.44	647	644	-3
2012	7,039	3.00	4.00	3.44	512	644	132
2020	8,687	3.00	4.00	3.44	631	644	13
2030	9,625	3.00	4.00	3.44	700	644	-56

Table 52: Glade Marina Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	39,520	105,233	6,245,913	1.68%	37.55%	14	75%	28	1,059
2012	39,766	99,021	6,175,062	1.60%	40.16%	14	75%	28	1,065
2020	43,080	110,869	6,743,066	1.64%	38.86%	14	75%	28	1,154
2030	47,731	122,837	7,470,966	1.64%	38.86%	14	75%	28	1,279

Table 53: Glade Marina Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,059	3.67	3.27	2.87	113	138	25
2012	1,065	3.67	3.27	2.87	114	138	24
2020	1,154	3.67	3.27	2.87	123	138	15
2030	1,279	3.67	3.27	2.87	136	138	2

Table 54: Harbour Town Marina Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	55,949	161,166	6,245,913	2.58%	45.19%	14	75%	28	1,951
2012	51,820	120,732	6,175,062	1.96%	42.92%	14	75%	28	1,388
2020	67,372	152,916	6,743,066	2.27%	44.06%	14	75%	28	1,805
2030	74,644	169,423	7,470,966	2.27%	44.06%	14	75%	28	1,999

Table 55: Harbour Town Marina Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,951	3.67	3.27	2.87	208	224	16
2012	1,388	3.67	3.27	2.87	148	224	76
2020	1,805	3.67	3.27	2.87	192	224	32
2030	1,999	3.67	3.27	2.87	213	224	11

Table 56: His Camp - Camp Gideon Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	2,309	6,679	6,245,913	0.11%	34.57%	14	75%	28	62
2012	1,488	4,502	6,175,062	0.07%	33.05%	14	75%	28	40
2020	2,050	6,063	6,743,066	0.09%	33.81%	14	75%	28	55
2030	2,271	6,718	7,470,966	0.09%	33.81%	14	75%	28	61

Table 57: His Camp - Camp Gideon Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	62	4.35	2.76	1.91	12	25	13
2012	40	4.35	2.76	1.91	8	25	17
2020	55	4.35	2.76	1.91	10	25	15
2030	61	4.35	2.76	1.91	12	25	13

Table 58: Knox Bridge Day Use Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	10,747	18,036	6,245,913	0.29%	59.59%	14	75%	28	288
2012	8,400	16,090	6,175,062	0.26%	52.21%	14	75%	28	225
2020	10,352	18,521	6,743,066	0.27%	55.90%	14	75%	28	277
2030	11,470	20,520	7,470,966	0.27%	55.90%	14	75%	28	307

Table 59: Knox Bridge Day Use Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	288	3.66	3.28	3.11	28	25	-3
2012	225	3.66	3.28	3.11	22	25	3
2020	277	3.66	3.28	3.11	27	25	-2
2030	307	3.66	3.28	3.11	30	25	-5

Table 60: Leon E. Williams - Holiday Marina Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	73,825	219,265	6,245,913	3.51%	33.67%	14	75%	28	1,977
2012	59,011	139,853	6,175,062	2.26%	42.20%	14	75%	28	1,581
2020	73,861	194,717	6,743,066	2.89%	37.93%	14	75%	28	1,978
2030	81,834	215,737	7,470,966	2.89%	37.93%	14	75%	28	2,192

Table 61: Leon E. Williams - Holiday Marina Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,977	3.67	3.27	2.87	211	65	-146
2012	1,581	3.67	3.27	2.87	168	65	-103
2020	1,978	3.67	3.27	2.87	211	65	-146
2030	2,192	3.67	3.27	2.87	234	65	-169

Table 62: Little River Landing Marina Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	101,218	328,086	6,245,913	5.25%	30.85%	14	75%	28	2,711
2012	86,483	210,430	6,175,062	3.41%	41.10%	14	75%	28	2,317
2020	105,044	291,993	6,743,066	4.33%	35.97%	14	75%	28	2,814
2030	116,383	323,513	7,470,966	4.33%	35.97%	14	75%	28	3,117

Table 63: Little River Landing Marina Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	2,711	3.67	3.27	2.87	289	197	-92
2012	2,317	3.67	3.27	2.87	247	197	-50
2020	2,814	3.67	3.27	2.87	300	197	-103
2030	3,117	3.67	3.27	2.87	332	197	-135

Table 64: McKaskey Creek Campground Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	29,846	69,395	6,245,913	1.11%	43.01%	14	75%	28	799
2012	11,599	17,647	6,175,062	0.29%	65.73%	14	75%	28	311
2020	25,604	47,094	6,743,066	0.70%	54.37%	14	75%	28	686
2030	28,368	52,178	7,470,966	0.70%	54.37%	14	75%	28	760

Table 65: McKaskey Creek Campground Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	799	3.49	3.44	3.53	66	65	-1
2012	311	3.49	3.44	3.53	26	65	39
2020	686	3.49	3.44	3.53	57	65	8
2030	760	3.49	3.44	3.53	63	65	2

Table 66: McKinney Campground Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	33,004	87,691	6,245,913	1.40%	37.64%	14	75%	28	884
2012	31,509	72,793	6,175,062	1.18%	43.29%	14	75%	28	844
2020	35,234	87,080	6,743,066	1.29%	40.46%	14	75%	28	944
2030	39,037	96,480	7,470,966	1.29%	40.46%	14	75%	28	1,046

Table 67: McKinney Campground Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	884	3.49	3.44	3.53	73	108	35
2012	844	3.49	3.44	3.53	70	108	38
2020	944	3.49	3.44	3.53	78	108	30
2030	1,046	3.49	3.44	3.53	86	108	22

Table 68: Minuteman Recreation Association Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	4,096	12,972	6,245,913	0.21%	31.58%	14	75%	28	110
2012	3,184	13,796	6,175,062	0.22%	23.08%	14	75%	28	85
2020	3,972	14,535	6,743,066	0.22%	27.33%	14	75%	28	106
2030	4,401	16,104	7,470,966	0.22%	27.33%	14	75%	28	118

Table 69: Minuteman Recreation Association Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	110	4.35	2.76	1.91	21	10	-11
2012	85	4.35	2.76	1.91	16	10	-6
2020	106	4.35	2.76	1.91	20	10	-10
2030	118	4.35	2.76	1.91	22	10	-12

Table 70: Northwest Georgia Girl Scout Council - Camp Pine Acres Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	745	2,089	6,245,913	0.03%	35.66%	14	75%	28	20
2012	650	1,852	6,175,062	0.03%	35.10%	14	75%	28	17
2020	757	2,139	6,743,066	0.03%	35.38%	14	75%	28	20
2030	838	2,370	7,470,966	0.03%	35.38%	14	75%	28	22

Table 71: Northwest Georgia Girl Scout Council - Camp Pine Acres Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	20	4.35	2.76	1.91	4	94	90
2012	17	4.35	2.76	1.91	3	94	91
2020	20	4.35	2.76	1.91	4	94	90
2030	22	4.35	2.76	1.91	4	94	90

Table 72: Northwest Georgia Council, Boy Scouts of America - Camp Westin Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	371	1,043	6,245,913	0.02%	35.57%	14	75%	28	10
2012	325	913	6,175,062	0.01%	35.60%	14	75%	28	9
2020	378	1,062	6,743,066	0.02%	35.58%	14	75%	28	10
2030	418	1,176	7,470,966	0.02%	35.58%	14	75%	28	11

Table 73: Northwest Georgia Council, Boy Scouts of America - Camp Westin Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	10	4.35	2.76	1.91	2	30	28
2012	9	4.35	2.76	1.91	2	30	28
2020	10	4.35	2.76	1.91	2	30	28
2030	11	4.35	2.76	1.91	2	30	28

Table 74: Old Hwy 41 #1 Day Use Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	11,994	14,454	6,245,913	0.23%	82.98%	14	75%	28	321
2012	12,846	20,907	6,175,062	0.34%	61.44%	14	75%	28	344
2020	13,877	19,217	6,743,066	0.28%	72.21%	14	75%	28	372
2030	15,375	21,292	7,470,966	0.28%	72.21%	14	75%	28	412

Table 75: Old Hwy 41 #1 Day Use Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	321	3.66	3.28	3.11	32	114	82
2012	344	3.66	3.28	3.11	34	114	80
2020	372	3.66	3.28	3.11	36	114	78
2030	412	3.66	3.28	3.11	40	114	74

Table 76: Old Hwy 41 #3 Campground Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	14,417	19,207	6,245,913	0.31%	75.06%	14	75%	28	386
2012	11,557	14,791	6,175,062	0.24%	78.14%	14	75%	28	310
2020	14,128	18,444	6,743,066	0.27%	76.60%	14	75%	28	378
2030	15,653	20,435	7,470,966	0.27%	76.60%	14	75%	28	419

Table 77: Old Hwy 41 #3 Campground Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	386	1.49	8.05	3.44	14	61	47
2012	310	1.49	8.05	3.44	26	61	35
2020	378	1.49	8.05	3.44	32	61	29
2030	419	1.49	8.05	3.44	35	61	26

Table 78: Payne Campground Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	40,758	89,362	6,245,913	1.43%	45.61%	14	75%	28	1,092
2012	35,427	79,389	6,175,062	1.29%	44.62%	14	75%	28	949
2020	41,320	91,583	6,743,066	1.36%	45.12%	14	75%	28	1,107
2030	45,780	101,469	7,470,966	1.36%	45.12%	14	75%	28	1,226

Table 79: Payne Campground Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,092	3.66	3.28	3.11	107	175	68
2012	949	3.66	3.28	3.11	93	175	82
2020	1,107	3.66	3.28	3.11	109	175	66
2030	1,226	3.66	3.28	3.11	120	175	55

Table 80: Proctor Landing Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	16,313	22,922	6,245,913	0.37%	71.17%	14	75%	28	437
2012	16,840	22,184	6,175,062	0.36%	75.91%	14	75%	28	451
2020	18,006	24,486	6,743,066	0.36%	73.54%	14	75%	28	482
2030	19,950	27,129	7,470,966	0.36%	73.54%	14	75%	28	534

Table 81: Proctor Landing Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	437	3.66	3.28	3.11	43	263	220
2012	451	3.66	3.28	3.11	44	263	219
2020	482	3.66	3.28	3.11	50	263	213
2030	534	3.66	3.28	3.11	55	263	208

Table 82: PS Marina 3 - Allatoona Landing Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	93,456	280,068	6,245,913	4.48%	33.37%	14	75%	28	2,503
2012	126,340	233,579	6,175,062	3.78%	54.09%	14	75%	28	3,384
2020	121,878	278,712	6,743,066	4.13%	43.73%	14	75%	28	3,265
2030	135,034	308,799	7,470,966	4.13%	43.73%	14	75%	28	3,617

Table 83: PS Marina 3 - Allatoona Landing Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	2,503	3.67	3.27	2.87	267	633	366
2012	3,384	3.67	3.27	2.87	361	633	272
2020	3,265	3.67	3.27	2.87	348	633	285
2030	3,617	3.67	3.27	2.87	385	633	248

Table 84: Riverside Day Use Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	31,923	112,063	6,245,913	1.79%	41.14%	14	75%	28	1,235
2012	30,407	83,386	6,175,062	1.35%	36.47%	14	75%	28	814
2020	41,136	106,019	6,743,066	1.57%	38.80%	14	75%	28	1,102
2030	45,577	117,464	7,470,966	1.57%	38.80%	14	75%	28	1,221

Table 85: Riverside Day Use Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,235	3.66	3.28	3.11	121	243	122
2012	814	3.66	3.28	3.11	80	243	163
2020	1,102	3.66	3.28	3.11	108	243	135
2030	1,221	3.66	3.28	3.11	120	243	123

Table 86: South Cherokee Recreation Association Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	18,815	87,877	6,245,913	1.41%	21.41%	14	75%	28	504
2012	18,485	78,665	6,175,062	1.27%	23.50%	14	75%	28	495
2020	20,296	90,386	6,743,066	1.34%	22.45%	14	75%	28	544
2030	22,487	100,143	7,470,966	1.34%	22.45%	14	75%	28	602

Table 87: South Cherokee Recreation Association Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	504	4.35	2.76	1.91	96	375	279
2012	495	4.35	2.76	1.91	94	375	281
2020	544	4.35	2.76	1.91	103	375	272
2030	602	4.35	2.76	1.91	114	375	261

Table 88: Stamp Creek Day Use Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	19,695	42,204	6,245,913	0.68%	46.67%	14	75%	28	528
2012	14,609	34,663	6,175,062	0.56%	42.15%	14	75%	28	391
2020	18,521	41,707	6,743,066	0.62%	44.41%	14	75%	28	496
2030	20,520	46,210	7,470,966	0.62%	44.41%	14	75%	28	550

Table 89: Stamp Creek Day Use Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	528	3.66	3.28	3.11	52	50	-2
2012	391	3.66	3.28	3.11	38	50	12
2020	496	3.66	3.28	3.11	49	50	1
2030	550	3.66	3.28	3.11	54	50	-4

Table 90: Sweetwater Campground Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	33,668	52,280	6,245,913	0.84%	64.40%	14	75%	28	902
2012	23,774	43,466	6,175,062	0.70%	54.70%	14	75%	28	637
2020	30,937	51,953	6,743,066	0.77%	59.55%	14	75%	28	829
2030	34,276	57,561	7,470,966	0.77%	59.55%	14	75%	28	918

Table 91: Sweetwater Campground Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	902	1.49	8.05	3.44	33	100	67
2012	637	1.49	8.05	3.44	23	100	77
2020	829	1.49	8.05	3.44	30	100	70
2030	918	1.49	8.05	3.44	33	100	67

Table 92: Sweetwater Day Use Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	10,907	14,069	6,245,913	0.23%	77.53%	14	75%	28	292
2012	9,268	13,843	6,175,062	0.22%	66.95%	14	75%	28	248
2020	10,946	15,153	6,743,066	0.22%	72.24%	14	75%	28	293
2030	12,128	16,788	7,470,966	0.22%	72.24%	14	75%	28	325

Table 93: Sweetwater Day Use Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	292	3.66	3.28	3.11	29	133	104
2012	248	3.66	3.28	3.11	24	133	109
2020	293	3.66	3.28	3.11	29	133	104
2030	325	3.66	3.28	3.11	32	133	101

Table 94: Traina Enterprises - Wilderness Camp Marina Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	43,304	99,128	6,245,913	1.59%	43.68%	14	75%	28	1,160
2012	28,192	63,982	6,175,062	1.04%	44.06%	14	75%	28	755
2020	38,803	88,443	6,743,066	1.31%	43.87%	14	75%	28	1,039
2030	42,992	97,990	7,470,966	1.31%	43.87%	14	75%	28	1,152

Table 95: Traina Enterprises - Wilderness Camp Marina Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,160	3.67	3.27	2.87	124	160	36
2012	755	3.67	3.27	2.87	80	160	80
2020	1,039	3.67	3.27	2.87	111	160	49
2030	1,152	3.67	3.27	2.87	123	160	37

Table 96: Upper Stamp Creek Campground Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	3,601	5,147	6,245,913	0.08%	69.96%	14	75%	28	96
2012	3,527	4,343	6,175,062	0.07%	81.21%	14	75%	28	94
2020	3,892	5,150	6,743,066	0.08%	75.59%	14	75%	28	104
2030	4,313	5,705	7,470,966	0.08%	75.59%	14	75%	28	116

Table 97: Upper Stamp Creek Campground Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	96	1.49	8.05	3.44	3	27	24
2012	94	1.49	8.05	3.44	3	27	24
2020	104	1.49	8.05	3.44	4	27	23
2030	116	1.49	8.05	3.44	4	27	23

Table 98: Upper Tanyard Day Use Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	14,585	19,197	6,245,913	0.31%	75.98%	14	75%	28	391
2012	5,491	7,003	6,175,062	0.11%	78.41%	14	75%	28	147
2020	10,951	14,186	6,743,066	0.21%	77.19%	14	75%	28	293
2030	12,133	15,717	7,470,966	0.21%	77.19%	14	75%	28	325

Table 99: Upper Tanyard Day Use Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	391	3.66	3.28	3.11	38	111	73
2012	147	3.66	3.28	3.11	14	111	97
2020	293	3.66	3.28	3.11	29	111	82
2030	325	3.66	3.28	3.11	32	111	79

Table 100: US Naval Air Station Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	34,520	90,133	6,245,913	1.44%	38.30%	14	75%	28	925
2012	33,122	68,950	6,175,062	1.12%	48.04%	14	75%	28	887
2020	37,254	86,300	6,743,066	1.28%	43.17%	14	75%	28	998
2030	41,276	95,616	7,470,966	1.28%	43.17%	14	75%	28	1,106

Table 101: US Naval Air Station Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	925	3.66	3.28	3.11	91	48	-43
2012	887	3.66	3.28	3.11	87	48	-39
2020	998	3.66	3.28	3.11	98	48	-50
2030	1,106	3.66	3.28	3.11	108	48	-60

Table 102: Victoria Campground Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	21,613	42,297	6,245,913	0.68%	51.10%	14	75%	28	579
2012	23,224	31,479	6,175,062	0.51%	73.78%	14	75%	28	622
2020	24,987	40,019	6,743,066	0.59%	62.44%	14	75%	28	669
2030	27,684	44,339	7,470,966	0.59%	62.44%	14	75%	28	742

Table 103: Victoria Campground Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	579	1.49	8.05	3.44	21	271	250
2012	622	1.49	8.05	3.44	53	271	218
2020	669	1.49	8.05	3.44	57	271	214
2030	742	1.49	8.05	3.44	63	271	208

Table 104: Victoria Day Use Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	46,337	79,201	6,245,913	1.27%	58.51%	14	75%	28	1,241
2012	44,427	90,719	6,175,062	1.47%	48.97%	14	75%	28	1,190
2020	49,593	92,284	6,743,066	1.37%	53.74%	14	75%	28	1,328
2030	54,946	102,246	7,470,966	1.37%	53.74%	14	75%	28	1,472

Table 105: Victoria Day Use Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,241	3.66	3.28	3.11	122	199	77
2012	1,190	3.66	3.28	3.11	117	199	82
2020	1,328	3.66	3.28	3.11	130	199	69
2030	1,472	3.66	3.28	3.11	144	199	55

Table 106: Victoria Harbour Marina Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	67,569	168,874	6,245,913	2.70%	40.01%	14	75%	28	1,810
2012	55,511	123,878	6,175,062	2.01%	44.81%	14	75%	28	1,487
2020	67,347	158,794	6,743,066	2.35%	42.41%	14	75%	28	1,804
2030	74,617	175,936	7,470,966	2.35%	42.41%	14	75%	28	1,999

Table 107: Victoria Harbour Marina Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	1,810	3.67	3.27	2.87	193	276	83
2012	1,487	3.67	3.27	2.87	158	276	118
2020	1,804	3.67	3.27	2.87	192	276	84
2030	1,999	3.67	3.27	2.87	213	276	63

Table 108: Wildlife Action Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	3,077	10,043	6,245,913	0.16%	30.64%	14	75%	28	82
2012	2,429	8,964	6,175,062	0.15%	27.10%	14	75%	28	65
2020	2,978	10,315	6,743,066	0.15%	28.87%	14	75%	28	80
2030	3,299	11,429	7,470,966	0.15%	28.87%	14	75%	28	88

Table 109: Wildlife Action Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	82	4.35	2.76	1.91	16	93	77
2012	65	4.35	2.76	1.91	12	93	81
2020	80	4.35	2.76	1.91	15	93	78
2030	88	4.35	2.76	1.91	17	93	76

Table 110: YMCA of Metro Atlanta - Cherokee YMCA Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	96,728	190,751	6,245,913	3.05%	50.71%	14	75%	28	2,591
2012	133,375	221,137	6,175,062	3.58%	60.31%	14	75%	28	3,573
2020	124,182	223,706	6,743,066	3.32%	55.51%	14	75%	28	3,326
2030	137,587	247,855	7,470,966	3.32%	55.51%	14	75%	28	3,685

Table 111: YMCA of Metro Atlanta - Cherokee YMCA Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	2,591	4.35	2.76	3.00	313	86	-227
2012	3,573	4.35	2.76	3.00	432	86	-346
2020	3,326	4.35	2.76	3.00	402	86	-316
2030	3,685	4.35	2.76	3.00	445	86	-359

Table 112: YMCA of Metro Atlanta - Camp High Harbour Design Load

Year	Peak Season (June-Aug)	Annual Visits	Total Project Visitation	Area of Total Visitation	Peak Season Visitation % of Total	Weekends in Peak Season	Percent of Visitation Occurring on Weekends	Number of Weekend Days	Design Load
2010	16,536	32,489	6,245,913	0.52%	50.90%	14	75%	28	443
2012	6,320	16,122	6,175,062	0.26%	39.20%	14	75%	28	169
2020	11,866	26,340	6,743,066	0.39%	45.05%	14	75%	28	318
2030	13,147	29,183	7,470,966	0.39%	45.05%	14	75%	28	352

Table 113: YMCA of Metro Atlanta - Camp High Harbour Parking Demand

Year	Design Load	Day Use Hours per Visitor	Turnover (12/Day Use Hours per Visitor)	Visitors Per Vehicle	Parking Space Demand	Existing Parking Space Supply	Net Differences
2010	443	4.35	2.76	1.91	84	84	0
2012	169	4.35	2.76	1.91	32	84	52
2020	318	4.35	2.76	1.91	60	84	24
2030	352	4.35	2.76	1.91	67	84	17

5 Boating Density Analysis

A boating density analysis was undertaken to evaluate the possible need for adding additional boat slips at Allatoona Lake.

5.1 Methodology

The methods used to complete this study drew, in part, on the information and data gathered from other sources. This included use of established Recreation Opportunity Spectrum (ROS) classifications, current boater density safety standards, and current optimum carrying capacities for outdoor recreation activities; best management practices (BMPs); environmental considerations for development; and other industry standards. This information and data were correlated to existing recreation facilities relative to current recreation use and anticipated future recreation use. The standards listed in Table 114 were used to evaluate the boating density.

Table 114: Water Recreation Opportunity Spectrum Classification Summary and Associated Boating Density Standard

Setting (Classification)	Generalized Description Summary of the Recreation Experiences by WROS Class	Standard (Acres per Boat)
Urban	Limited opportunities to see, hear, or smell the natural resources exist due to the extensive level of development, human activity, and natural resource modification. Meeting other visitors is expected, and socializing with family and friends is important. A diverse range of visitors and activities, including groups and special events, is probable. Convenience is central and dominant.	1-10
Suburban	Limited or rare opportunities to see, hear, or smell the natural resources exist due to the widespread and prevalent level of development, human activity, and natural resource modification. Meeting other visitors is expected, and socializing with family and friends is important. A diverse range of visitors and activities is probable. Convenience is central and dominant.	10-20

Setting (Classification)	Generalized Description Summary of the Recreation Experiences by WROS Class	Standard (Acres per Boat)
Rural Developed	Occasional or periodic opportunities to see, hear, or smell the natural resources exist due to the common and frequent level of development, human activity, and natural resource modification. Brief periods of solitude are likely although the presence of other visitors is expected. A diverse range of visitors and activities is probable. Moderate levels of comfort and convenience are expected.	20-50
Rural Natural	Frequent opportunities exist to see, hear, or smell the natural resources due to an occasional or periodic level of development, human activity, and natural resource modification. Independence and freedom with a moderate level of management presence are important. A diverse range of visitors and activities is probable although experiences tend to be more resource-dependent. Comfort and convenience are not important or expected.	50-110
Semi-primitive	Widespread and prevalent opportunities exist to see, hear, or smell the natural resources due to a rare or minor level of development, human activity, and natural resource modification. Solitude through the lack of contact with other visitors and managers is important. Opportunities exist for more adventure-based enthusiasts and overnight visitors. Sensations of challenge, adventure, risk, and self-reliance are important.	110-480
Primitive	Extensive opportunities abound to see, hear, or smell the natural resources due to the rare and very minor level of development, human activity, and natural resource modification. Solitude and lack of the site, sound, and smells of others are important. Opportunities are plentiful for human-powered activities (for example, canoeing, fly-fishing, and backpacking). Sensations of solitude, peacefulness, tranquility, challenge, adventure, risk, testing skills, orienteering, and self-reliance are important.	480-3,200

Source: TVA, Accessed 2015.

5.2 Existing Facilities

Currently, there are 8 marinas, which have 3147 wet slips and 1294 dry slips. There are also a number of boat ramps located at the USACE-operated recreation areas with a total of 1262 spaces for boat trailer parking.

5.3 Analysis

To determine the appropriate classification for each condition, the usable surface area of Allatoona Lake was calculated as well as the boating utilization assumptions. Tables 115 and 116 display the inputs used for this analysis. The average summer weekend day was used as the decision criteria for the boating density classification based on full pool surface of 11,800 acres.

Table 115: Boating Facilities

	Existing Estimated Boating Units
Commercial Wet Slips	3147
Commercial Dry Slips	1294
Subtotal Boating Units	4441
	Existing Estimated Parking Spaces for Boating Units
Public Ramp Parking	643
Private Community Ramp Parking	619
Subtotal Parking Spaces	1262

Source: USACE, 2016.

Table 116: Boating Utilization

	Estimated % Boating Units In Use		
	Average Summer Weekday %	**Average Summer Weekend Day %**	**Peak Holiday Summer %**
Commercial Wet & Dry Slips	15%	25%	35%
Public/Private Ramp Parking	20%	60%	75%

Source: USACE, 2016.

5.4 Boating Density Classification

Based on the analysis of the existing facilities assumption, an average of 6.319 acres per boat in use during average summer weekend days and 4.718 acres per boat in use for peak summer holidays classifies the setting as Urban. Summer weekday conditions are classified as Suburban with approximately 12.846 acres per boat in use (Table 117). Any proposed additions to boating facilities, including additional car parking, do not significantly alter the user experience since it is already considered a highly urbanized project.

Table 117: Boating Density Classification

	Average Summer Weekday – Existing
Est. Boating Units in Use	919
Surface Acres Per Boating Unit	12.846
Classification	Suburban
	Average Summer Weekend Day - Existing
Est. Boating Units in Use	1867
Surface Acres Per Boating Unit	6.319
Classification	Urban
	Peak Holiday Summer – Existing
Est. Boating Units in Use	2501
Surface Acres Per Boating Unit	4.718
Classification	Urban

Source: USACE, 2016.