APPENDIX F

LAKE TEXOMA WATER SUPPLY REALLOCATION REPORT

REPORT FOR THE
WATER SUPPLY STORAGE REALLOCATION PROJECT
AT
LAKE TEXOMA RESERVOIR
OKLAHOMA AND TEXAS

US Army Corps
of Engineers ®
Tulsa District

October 2005

TABLE OF CONTENTS

Section	Title	Page No.
	Abbreviations and Acronyms	iv
	EXECUTIVE SUMMARY	v
1.0	PURPOSE	1
2.0	PROJECT BACKGROUND	2
2.1	Authorization and Construction	2
2.2	Project Location, Purposes, and Outputs	3
2.3	Previous Storage Reallocations and Repayment Agreements	7
2.4	Sedimentation Projection	9
2.5	Additional Project Information	11
3.0	PLAN FORMULATION	12
4.0	ECONOMIC ANALYSIS	18
4.1	Water Supply Demand Analysis	18
4.2	Analysis of Water Supply Alternatives	20
5.0	DERIVATION OF USER COST	24
5.1	Hydropower Benefits Foregone	24
5.2	Hydropower Revenues Foregone	25
5.3	Hydropower Replacement Costs	25
5.4	Updated Cost of Storage	26
5.5	User Cost	28
6.0	OTHER CONSIDERATIONS	28
6.1	Test of Financial Feasibility	28
7.0	COST ACCOUNT ADJUSTMENTS – NORTH TEXAS MUNICIPAL WATER DISTRICT	30
7.1	Payment	30
7.2	Credits for Hydropower Revenues Foregone	30
7.3	HAC and SWPA Methodology Differences for Determining Credits for Hydropower Revenue Forgone	30
8.0	ENVIRONMENTAL CONSIDERATIONS	31
9.0	CONCLUSIONS	32
10.0	RECOMMENDATION	33

TABLE OF CONTENTS (Continued)

Section	Title	Page No.
11.0	APPENDICES	34
11.1	WRDA 1986 SEC 838 Denison Dam (Lake Texoma), Red River, Texas and Oklahoma Authorization	
11.2	Letter from Oklahoma Water Resources Board to U.S. Army Corps of Engineers Regarding proposed reallocation apportionment	
11.3	H&H Storage/Yield Analysis	
11.4	Water Supply Demand Analysis	
11.5	Denison Dam & Powerhouse, Lake Texoma, Red River, Oklahoma & Texas- Water Supply Storage Reallocation Power Benefits Foregone Study, Prepared by Hydropower Analysis Center, U.S. Army Corps of Engineers Dated April 2005, and Appendix A dated August 2005.	
11.6	Southwestern Power Administration (SWPA) Letters	
11.7	National Environmental Policy Act (NEPA) Documentation – Environmental Assessment (EA), Lake Texoma Storage Reallocation Study, Lake Texoma, Oklahoma and Texas	

TABLE OF CONTENTS (Continued)

TABLES AND FIGURES

TABLES

Table	Title	Page No.
1	Lake Texoma (Denison Dam), Texas and Oklahoma Pertinent Data	9
2	Conservation Pool Storages Projected From The Sediment Surveys	9
3	Reservoir Storage	10
4	Historical and Projected Water Demand by Selected Counties, Texas State Water Plan 2006	20
5	Sources of Water Supply and Water Demand by Decade, Recommended Water Management Strategies	23
6	Sources of Water Supply and Water Demand by Decade, Costs of Recommended Water Management Strategies	24
7	Annual Hydropower Benefits Foregone Due to Reallocation From Conservation Pool Storage in Lake Texoma	25
8	Hydropower Revenues Foregone Due to Reallocation From Conservation Pool Storage in Lake Texoma	25
9	Annual Credit Due Power Marketing Agency Due to Reallocation From Conservation Pool Storage in Lake Texoma (Denison Dam)	26
10	Storage Cost Up6date for FY 2005	27
11	Lower Bois D'Arc Creek Reservoir Site Project Cost and Annual Costs	29

TABLES AND FIGURES

FIGURES

Figure	Title	Page No.
1	Vicinity Map, Lake Texoma Storage Reallocation Project	5
2	Denison Dam and Power Intake Structure	6
3	Hydropower Facility and Outlet Works at Denison Dam	6

Abbreviations and Acronyms

CWCCIS	Civil Works Construction Cost Index System
cfs	cubic feet per second
DWU	Dallas Water Utilities
EA	Environmental Assessment
ENR	Engineering News Record
FONSI	Finding of No Significant Impact
FY	Fiscal year
GTUA	Greater Texoma Utility Authority
kW	Kilowatt
mgd	million gallons per day
MW	Megawatt
NED	National Economic Development
NEPA	National Environmental Policy Act
NGVD	National Geodetic Vertical Datum
NTMWD	North Texas Municipal Water District
O&M	Operation and maintenance
PMA	power marketing administration
RRAT	Red River Authority of Texas
SWPA	Southwestern Power Administration
TRA	Trinity River Authority
TRWD	Tarrant Regional Water District
TXU	Texas Utilities
UOF	Use of Facilities
USGS	U.S. Geological Survey
UTRWD	Upper Trinity River Water District
WRDA	Water Resources Development Act

REPORT FOR THE

WATER SUPPLY STORAGE REALLOCATION PROJECT

AT LAKE TEXOMA RESERVOIR

OKLAHOMA AND TEXAS

OCTOBER 2005

EXECUTIVE SUMMARY

This study will identify up to 300,000 acre feet of storage (295 million gallons a day yield) in Lake Texoma that can be reallocated from hydropower to water supply storage. The Water Resources Development Act (WRDA) of 1986 authorizes the Secretary to reallocate storage from hydropower to water supply in increments as needed, up to an additional 150,000 acre-feet each for Oklahoma and Texas. Greater Texoma Utility Authority (GTUA) was specifically legislated 50,000 acre-feet in WRDA 86; however, they have not expressed an interest in using it.

The North Texas Municipal Water District (NTMWD) has requested a contract for 100,000 acre-feet of water storage. That draft contract will accompany the draft reallocation report when it goes forward for approval. No others have expressed interest in purchasing storage. Water supply storage is not considered to be reallocated until a water supply user enters into a contract with the Federal government and starts to pay for the storage; until that time, the storage may be used for hydropower production.

The State of Oklahoma has expressed concerns regarding previous allocations and whether additional contracts with entities in the State of Texas would be contrary to the terms of the Red River Compact. Corps legal review determined that the proposed reallocation does not provide a basis for altering existing allocations or contracts with any Oklahoma or Texas entity, nor do the existing contracts with Texas provide a basis to diminish the amount of the reallocation made available to entities in the State of Texas for future water supply storage contracts to less than that specified in WRDA 86.

The present value of the 300,000 acre-feet of water supply storage is considerably more than the present worth of hydropower revenues foregone. The 300,000 acre-feet of water supply storage is valued at $96,199,693. The total annual hydropower revenues foregone with a 300,000 acre-feet reallocation is $1,402,400. The cost of the allocation to the NTMWD for 100,000 acre-feet of storage is $32,066,564.

Because of negative impacts, hydropower will be compensated for revenues forgone. The Corps calculates revenues foregone by using National Economic Development standards as specified in Corps of Engineers policy and guidance. Southwestern Power Administration (SWPA) measures the benefits lost based on market-based benefits lost. The United States Army Corps of Engineers (USACE) Hydropower Analysis Center (HAC) has prepared an appendix to their report acknowledging this difference and illustrating the market based benefits lost. The final

report, while illustrating the different calculation methods, will follow existing Corps regulations in calculating power revenues foregone.

There will be no impacts to flood control, recreational facilities, archaeological sites, or the environment since there is no rise in conservation pool elevation. The Environmental Assessment determined that no cumulative impacts are anticipated to occur as a result of the proposed reallocation action. We expect a finding of no significant impact to be signed in November 2005.

REPORT FOR THE
WATER SUPPLY STORAGE REALLOCATION PROJECT
AT LAKE TEXOMA RESERVOIR
OKLAHOMA AND TEXAS

OCTOBER 2005

1.0 PURPOSE

The purpose of this report is to furnish the information required by Chapter 3, paragraph 3-8b5 and Appendix E, Section VIII (Water Supply), Paragraph E-57d of Engineer Regulation 1105-2-100, dated 22 April 2000, to identify for reallocation up to 300,000 acre feet of storage from hydropower to water supply in Lake Texoma, for Oklahoma and Texas, pursuant to the Water Resources Development of Act (WRDA) of 1986 passed by Congress (Public Law 99-662). Section 838 (Appendices 10.1) of the 1986 WRDA authorizes the Secretary of the Army to reallocate from hydropower storage to water supply storage, in increments as needed, up to an additional 150,000 acre-feet each for Oklahoma and Texas for municipal, industrial, and agricultural water uses (a total reallocation of 300,000 acre-feet). Water supply storage is not considered reallocated until a water supply user enters into a contract with the Federal government and starts to pay for the storage. About 148,485 acre feet of storage is pending contract or under contract for water supply. All contracts for reallocated water supply storage will be made pursuant to the Water Supply Act of 1958 (Public Law 85-500). Section 838(d)(1) of the 1986 WRDA states:

> All contracts entered into by the Secretary under this section shall be under terms in accordance with section 301(b) of the Water Supply Act of 1958 (Public Law 85-500), as amended by section 932 of this Act.

Further, Section 838(d)(2) of the 1986 WRDA states:

> No payment shall be required from and no interest shall be charged to users in the States of Oklahoma or Texas for the reallocation authorized by this section until such time as the water supply storage reserved under such reallocation is actually first used. Any contract entered into for the use of the water received under this section shall require the contracting entity to begin principal and interest payments on that portion of the water allocated under the contract at the time the entity begins the use of such water. Until such time, storage for which reallocation is authorized in this section may be used for hydropower production.

Prior to the 1986 authorization, all the water supply storage was under contract in Texas. After reallocation, total usable conservation storage of 986,730 acre-feet includes 450,000 acre feet for water supply and 536,730 acre feet for hydropower under PL 99-662, section 838, as shown in Table 3. The reallocation of storage from hydropower storage to water supply storage is necessary to meet expanding municipal and industrial water supply demands that are a result of

population growth in the region. The reallocation will provide total water supply storage of 450,000 acre feet, which will yield about 442 million gallons a day (mgd) of water supply. With the water supply storage of 450,000 acre feet, about 537,000 acre feet of storage will be available to hydropower. The reallocation study is being accomplished at the request of several municipalities and water users in north Texas and Oklahoma near Lake Texoma.

Section 838(c) of the 1986 WRDA provides:

> For that portion of the water storage reserved for users in the State of Texas, the Secretary shall contract, in increments as needed, for 50,000 acre-feet with the Greater Texoma Utility Authority and 100,000 acre-feet with other qualified individuals, entities, or water utility systems.

For example, the North Texas Municipal Water District (NTMWD) has requested a 100,000 acre-foot contract from the reallocated storage apportioned to the State of Texas. A draft water storage agreement with the NTMWD is included in the report submittal package. Other nearby communities that may be interested in future additional water supply include Sherman, Denison, Pottsboro, and Gordonville, Texas; and Durant and Kingston, Oklahoma.

Reallocating hydropower storage to water supply will have some impact on hydropower production. Compensation for future hydropower production will need to be made for future loss of power as a result of the reallocation. Section 838(d)(3) of the 1986 WRDA states:

> With respect to any water supply contract entered into by the Secretary under this section after June 1, 1985, the Secretary shall determine (A) the amount of hydropower lost, if any, as a result of the implementation of such contract, and (B) the replacement cost of the hydropower lost (where replacement cost is defined as the cost to purchase power from existing alternative sources). If hydropower is lost as a result of the implementation of such contract, the Secretary shall provide credits to the Southwestern Power Administration of amounts equal to such replacement costs. Such credits shall be against sums required to be paid by the Southwestern Power Administration for costs of the project allocated to hydropower. In each such case the Southwestern Power Administration shall reimburse each preference customer for an amount equal to the customer's actual replacement cost for hydropower lost as a result of the implementation of such contract, less the costs such customer would have had to pay to the Southwestern Power Administration for such hydropower.

Other project purposes are not expected to be adversely affected by the reallocation.

2.0 PROJECT BACKGROUND

2.1 <u>Authorization and Construction</u>. Lake Texoma (Denison Dam), Oklahoma and Texas was authorized for flood control and power by the Flood Control Act approved June 28, 1938, Project Document HD 541, 75th Congress, 3d Session. Public Law 868, 76th Congress, 3d Session, was approved October 17, 1940, to improve navigation, regulate flow of the Red River, control floods, and add other beneficial purposes. Public Law 454, 78th Congress, 2d Session, approved September 30, 1944, designated the name of the impoundment as Lake Texoma.

Public Law 273, 83rd Congress, 1st Session, approved August 14, 1953, added water supply storage for the city of Denison, Texas. Public Law 146, 85th Congress, 1st Session, approved August 14, 1957, Project Document HD 541 75th Congress, 3d Session, set aside 22,600 acre-feet of storage for municipal and industrial water supply for the city of Sherman, Texas. Public Law 662, 99th Congress, 2d Session, approved November 17, 1986, added recreation as a project purpose and authorized the reallocation of an additional 300,000 acre-feet of storage for water supply.

Construction of the dam, spillway, and outlet works was started in August 1939 and completed in February 1944. The project was first available to operate for full flood control without any restrictions in January 1944. The first hydroelectric turbine was placed on line in March 1945 and the second in September 1949. Construction of a highway bridge across Lake Texoma at the Willis Ferry site started on April 24, 1958, and was completed on October 30, 1960. The 5,426-foot-long bridge replaces a former crossing south of Woodville, Oklahoma, on Oklahoma State Highway 99 and Texas State Highway 91. The roadway surface is about 37 feet above the top of the power pool.

The structure is a rolled earth-filled embankment with a rock-protected upstream slope. Total length along the crest, including the spillway, is 17,200 feet. The main embankment is 15,200 feet long. The maximum height of the structures is 165 feet above the streambed. A rolled earth-filled dike 3,870 feet long and 15 feet high is located in the vicinity of Platter, Oklahoma. The Cumberland levee is 23,480 feet long with a crest elevation of 647.0 feet. This levee is part of the project.

The uncontrolled spillway is a concrete, gravity, chute-type structure, 2,000 feet long, located in a saddle on the right bank. Spillway capacity at maximum pool (elevation 666.4) is 1,050,000 cubic feet per second (cfs). The outlet works consist of three 20-foot-diameter concrete conduits through the embankment and six 9-by-19-foot vertical lift gates and one emergency gate. Capacity of the outlet works is 67,500 cfs at the top of the flood control pool and 60,120 cfs at the top of the power pool. Limiting channel capacity below Denison Dam is about 50,000 cfs. The power intake structure will permit future installation of three additional power units.

2.2 <u>Project Location, Purposes, and Outputs</u>. Denison Dam is located on the Red River at river mile 725.9, 5 miles northwest of Denison in Grayson County, Texas (see Figure 1). The dam, which impounds the Red River to form Lake Texoma, is located on the borders of Texas and Oklahoma. The topography surrounding the lake varies from gently sloping flats to rocky and precipitous cliffs and steep, wooded hillsides.

Five power penstocks were included in the original dam construction (see Figure 2). The first of two existing hydroelectric generating units was placed in operation in 1945; the second in 1949 (see Figure 3). Authorized project purposes are flood control, hydroelectric power, improving navigation, regulating Red River flows, water supply, and recreation. The project also provides habitat for a variety of fish and wildlife species and encompasses several historical and archeological sites.

Current estimates of project outputs include cumulative flood damages prevented in the amount of $178 million as of September 2004. Recreational use of the lake and land resources, including

fish and wildlife, is estimated to be about 6 million visitors in Fiscal Year 2005. A seasonal pool plan at Lake Texoma implemented in April 1992 enhances flood control, hydropower generation, fish and wildlife, and recreation. The GTUA, acting for the City of Sherman, is the only full-time user of Lake Texoma for water supply. All other customers use Lake Texoma water when other water resources are impacted due to low flow periods or as mixing water in other lakes. Because of this, water supply withdrawals from the lake are relatively small compared to the amount of storage under agreement. However, population growth has forced the States of Texas and Oklahoma to secure future water supplies. This significant interest in developing and identifying sufficient water sources for the north-central region of Texas resulted in passage of Texas Senate

Figure 1. Vicinity Map, Lake Texoma Storage Reallocation Project

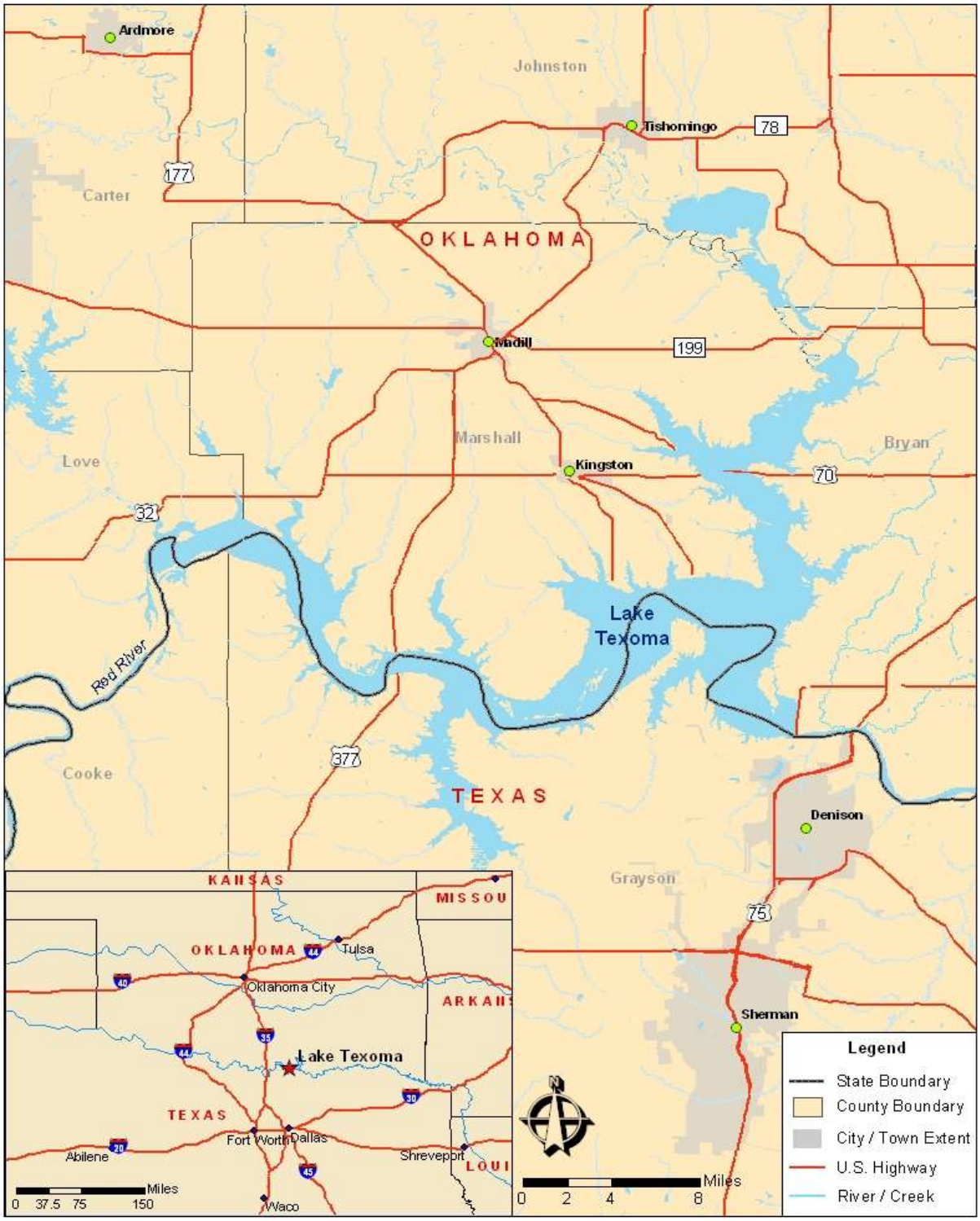

Figure 2. Denison Dam And Power Intake Structure

Figure 3. Hydropower Facility and Outlet Works At Denison Dam

Bill 1 and a determination that another large reallocation of conservation storage from hydropower to water supply was necessary. The impacts of this reallocation on hydropower and other authorized uses were analyzed using the Corps SUPER modeling tool as part of the hydropower benefits forgone evaluation in 2004. The SUPER modeling tool is a suite of computer programs written for use in the Southwestern Division of the U.S. Army Corps of Engineers to model hydraulic operations of multi-purpose reservoir systems for flood control, hydropower, navigation, and other project purposes.

2.3 Previous Storage Reallocations and Repayment Agreements.

The Water Supply Act of 1958 authorizes the reassignment of the usuage of existing storage space in a reservoir project of a higher and better use. Authority for the Corps to reallocate to municipal and industrial water supply is contained in Public Law 85-500, Title III, Water Supply Act of 1958, as amended. Guidance for reallocations is found in ER 1105-2-100.

(1) 1983 Reallocation. In August 1983, 72,600 acre-feet was reserved for water supply in an integrated hydropower and water supply conservation pool between elevations 590.0 and 617.0 feet National Geodetic Vertical Datum (NGVD). This amount included 50,000 acre-feet that had been contracted for water supply use under the Chief of Engineer's discretionary authority and 22,600 acre-feet reserved for the city of Sherman, Texas, by Public Law 85-146, approved in August 1957.

(2) 1985 Reallocation. A reallocation of 77,400 acre-feet of hydropower storage to water supply storage was approved by the Assistant Secretary of the Army (Civil Works) in December 1985. This reallocation report addressed the impacts of reallocating up to a total of 150,000 acre-feet, inclusive of the 72,600 acre-feet, and served as the basis for a 75,000 acre-foot storage agreement with the NTMWD. The 1985 report addressed the impacts of the total reallocation (150,000 acre-feet) on the project to ascertain if the last added increment of water supply storage would seriously affect the purpose for which the project was constructed or if major structural or operational changes would have been necessary. It was determined that the reallocation neither seriously affected other project purposes nor were any structural or operational changes needed.

(3) 1992 Reallocation. The 1992 supplemental reallocation report addressed the impacts of reallocating 5,500 acre-feet of Sherman's authorized 22,600 acre-feet of storage. National Environmental Policy Act (NEPA) documentation and public comment were accomplished under the 1985 Environmental Assessment (EA) and Finding of No Significant Impact (FONSI) for Regulatory Permit Application No. TXR3001311.

(4) 1997 Reallocation. In 1997, a supplemental reallocation report was accomplished to address not only the impacts of reallocating an additional 5,500 acre-feet of Sherman's authorized storage but to also address the impacts of reallocating the remaining 11,600 acre-feet. NEPA documentation in the form of an EA that included, public comments, and a hydrologic analysis for the entire 22,600 acre-feet was accomplished for that report and concluded in a FONSI. Coordination with the U.S. Fish and Wildlife Service, the Oklahoma Department of Wildlife Conservation, the Oklahoma and Texas Historical Societies, and the Oklahoma Archeological Survey concluded that there would be no impacts due to reallocation of the entire 22,600 acre-feet of storage. This reallocation did not require operation changes or construction modifications to the project. Pertinent data for Lake Texoma, representing elevations, area, capacity, and equivalent runoff, are shown in Table 1.

(5) 2004 Reallocation. In 2002, the GTUA requested that the last Sherman's 11,600 acre-feet of storage be placed under agreement. A supplemental reallocation report was accomplished and a determination made that there have been no significant changes in the project since the 1997 reallocation. A draft agreement is currently under review. Once this agreement is finalized, all of Sherman's congressionally set aside storage will be under agreement. If GTUA requires additional storage in the future it will come from the storage set aside for them in Public Law 99-662

TABLE 1

LAKE TEXOMA (DENISON DAM), TEXAS AND OKLAHOMA
PERTINENT DATA

Feature	Elevation (feet)	Area (acres)	Capacity (acre-feet)	Equivalent Runoff (1) (inches)
Top of dam	670.0	--	--	--
Top of flood control pool	640.0	141,418	5,061,062 (2)	2.81
Top of conservation pool	617.0	74,686	2,516,232 (3)	1.40
Bottom of active conservation pool	590.0	40,434	1,048,949(3)	0.58
Conservation storage	590.0-617.0	--	1,467,283(3)	0.81
Flood control storage	617.0-640.0	--	2,544,830(2)	1.41

NOTE: Data are based on 2002 sedimentation survey.
(1) From 39,719 square miles of drainage area upstream from dam.
(2) Includes storage in Cumberland pool.
(3) Excludes storage in Cumberland pool because the Cumberland storage is not accessible for conservation storage purposes.

2.4 Sedimentation Projection. Sedimentation surveys have been completed at Lake Texoma in 1969, 1985, and 2002. Table 2 summarizes the results of those sediment surveys.

TABLE 2

CONSERVATION POOL STORAGES PROJECTED FROM THE SEDIMENT SURVEYS

Year Sediment Survey Was Conducted	Projected Acre-Feet of Storage in Conservation Pool in 2044 (617.0 – 590.0)
1969	880,000
1985	1,114,909
2002	986,730

The storages for each water supply user and project purpose have been adjusted in accordance with contract or authorizing language as a result of the 2002 sediment survey. This information and data is summarized in Table 3. The U.S. Army Corps of Engineers, Tulsa District currently has three draft water storage agreements in the approval process which includes a draft agreement for 100,000 acre-feet of storage with the NTMWD that accompanies this report. Assuming that all the agreements are approved for final negotiations, the remaining balance of storage identified for reallocation for future water supply for Texas and Oklahoma communities will be 201,515 acre-feet which represents 20.422% of the conservation storage. Hydropower will have use of the un-contracted storage until it is reallocated and placed under contract. When all storage identified for reallocation under this study is under contract, 54.4% of the remaining conservation usable storage will be available for hydropower generation.

TABLE 3

RESERVOIR STORAGE
Based on 2002 Sediment Survey

Feature	Elevation (feet, NGVD)	Usable Storage (acre feet) (1)	Percent of Usable Storage	Percent of Conservation Storage
Flood Control	640-617	2,611,438	72.577	
Conservation	617-590	986,730	27.423	100
Water Supply				
Denison		21,300	0.592	2.159
TP&L		16,400	0.456	1.662
RRAT		450	0.013	0.046
RRAT		2,054	0.057	0.208
NTMWD		85,406	2.374	8.656
GTUA (2)		5,500	0.153	0.557
GTUA (2)		5,500	0.153	0.557
GTUA (Pending) (2)		11,600	0.322	1.176
OTRD (Pending)		275	0.008	0.028
NTMWD (Pending)		100,000	2.778	10.135
Future Agreements (3)		201,515	5.600	20.422
Water Supply Total		450,000	12.506	45.605
Power		536,730	14.917	54.395
Total Usable Storage		3,598,168		

(1) Storage remaining after 100 years sedimentation from the date the project became Operational based on the 2002 sediment survey.
(2) Public Law 85-146 rights to storage for Sherman, Texas. Actual law states 41,000 acre-feet, but withdrawal is limited. Amount shown reflects the conservation storage required for the withdrawal limitation during critical period.
(3) Section 838 of Public Law 99-662 authorizes the Secretary of the Army to reallocate up to 300,000 acre-feet of storage for water supply from hydropower. Total allocated available water supply is 450,000.

2.5 Additional Project Information. The NTMWD has requested a 100,000 acre-foot water storage agreement from the Texas allocation under Public Law 86-662, Section 838. The only other storage available under the Texas allocation is 50,000 acre-feet specifically set aside for the GTUA. The GTUA has not made a formal request for its additional storage because they have a draft storage agreement in the process for the remaining 11,600 acre-feet congressionally set aside for the City of Sherman, Texas. The GTUA acts as Sherman's agent for that storage. The city of Dallas, Texas, has contacted the U.S. Army Corps of Engineers, Tulsa District on numerous occasions concerning available storage from Lake Texoma, but has been informed that there is no additional storage available from the Texas allocation. Oklahoma has shown very little interest in contracting for any of the storage set aside for its use.

2.5.1 Texas and Oklahoma Apportionment. A related issue being addressed in the reallocation is the apportionment of water supply between Oklahoma and Texas. The Oklahoma Water Resources Board's letter to the Corps of Engineers dated May 25, 2004, addressed the issue of apportionment and is enclosed in appendix 10.2.

Section 838(a) of the 1986 WRDA specifically authorizes the reallocation from hydropower storage to water supply storage, in increments as needed, up to 150,000 additional acre-feet for users in the State of Texas and 150,000 additional acre-feet for users in the State of Oklahoma. With regards to the Texas portion of that reallocation, the statute further specifies at 838(c) that the Secretary "shall contract, in increments as needed, for 50,000 acre-feet with the Greater Texoma Utility Authority and 100,000 acre-feet with other qualified individuals, entities, or water utility systems." The statute contains no language that could be construed as limiting the amounts specified for reallocation. The language of Section 838 provides no alternative but to provide each State with up to the 150,000 acre-foot reallocation specified therein. Previous allocations or actual contracts entered into for water supply storage do not effect the amount to be made available to each State under the reallocations specified in Section 838. Conversely, the reallocations specified in Section 838 do not affect or alter the allocations previously made and/or contracts previously entered into with any entity. In other words, the contracts that already exist with Texas cannot be used as a basis to limit the amount made available under the reallocation to less than 150,000 acre-feet, nor can the requirement to reallocate up to 150,000 acre-feet be used as justification by the Corps to abrogate or amend earlier storage supply contracts.

Section 838(e) of the 1986 WRDA states that "[n]othing in this section shall be construed as amending or altering in any way the Red River Compact." Section 4.04 of the Red River Compact provides that, with regard to the main stem of the Red River and Lake Texoma, water storage therein is apportioned among the signatory states with 200,000 acre-feet for Oklahoma and 200,000 acre-feet for Texas, and any additional quantities at a ratio of 50% for Oklahoma and 50% for Texas. The Corps is not "amending or altering" the terms of the Red River Compact by complying with the Congressional mandate of reallocating equal amounts of water to each state from hydropower to water supply storage. What may occur, should Texas contract for the totality of storage specified to be made available in Section 838, is that Texas will exceed the parameters set out in the Red River Compact. However, the Red River Compact is an agreement only between the signatory states. The United States is not a signatory to it. Accordingly, the U.S. is not responsible for the administration or the enforcement thereof. If Texas attempts to take actions that are contrary to the Red River Compact, it will be the responsibility of States to address those actions.

In regards to the repayment of storage costs, the Corps of Engineers policy on pricing storage reallocated from one authorized project purpose to another is based on the "Use of Facilities" (UOF) method. The price of one (1) acre-foot of the total storage is established as the highest of the benefits or revenues foregone, the replacement costs, or the updated cost of storage. Storage is not considered to be reallocated until a water supply user signs a contract and starts to make payments. Until such time, the authorized project purpose will retain use of the storage. The cost of reallocated storage changes each

government fiscal year. Section 932 of the 1986 WRDA changed the number of years to repay storage investment costs from 50 years to 30 years; did away with the 10-year interest free period which would not affect reallocated storage; and requires recalculation of the interest rate at 5-year intervals. The only way costs would have been more favorable on the first 150,000 acre-feet of reallocated storage at Lake Texoma would have been if a user contracted for storage at an earlier date.

2.5.2 Hydrologic Data Information. The determination of dependable water supply yield was calculated using the Corps SUPER Model. The SUPER modeling tool can simulate flood control operations and conservation pool operations, including hydropower, water supply, water quality, diversions, and returns. In addition to modeling dependable yield, it also was used for baseline data in calculating hydropower energy changes. This hydrologic information was used by the U.S. Army Corps of Engineers Northwestern Division Hydropower Analysis Center in its Power Benefits Foregone Water Supply Storage Reallocation Report. Findings of the SUPER model simulation indicated that a critical dependable yield of 442 million gallons per day (mgd) would be available from the proposed 300,000 acre-foot reallocation. The Hydrologic SUPER model H&H Storage Yield Analysis report is attached as Appendix 10.3.

3.0 PLAN FORMULATION

3.0.1 Preliminary Alternatives. During plan formulation the goal was to identify and perform an initial evaluation of preliminary alternatives for the reallocation of hydropower storage to water supply at Lake Texoma. Consideration of all reasonable alternatives is required under the National Environmental Policy Act (NEPA) to create a better decision-making process for implementing projects and programs that could adversely impact the environment. The NEPA requires Federal agencies to incorporate environmental considerations in their planning and decision-making process and requires the use of a systematic and interdisciplinary approach. The Planning Guidance Notebook, Engineering Regulation (ER 1105-2-100), dated April 2000, requires the formulation and evaluation of a full range of reasonable alternative plans. Alternative plans are formulated to take into account the overall problems, needs, and opportunities afforded by the proposed action. Those plans are assessed in a manner consistent with the national objective of contributing to National Economic Development (NED) and protecting the Nation's Environment, Federal laws, and regulations. The NED objective is to provide a cost-effective water supply source to meet the region's future municipal and industrial requirements. In this case, the proposed action is the reallocation of Lake Texoma storage from hydropower to water supply.

Economic development problems in the region include insufficient sources of municipal and industrial water supply at affordable costs to meet future municipal and industrial needs. Due to the planning and implementation time required to evaluate the issues of storage reallocation and near term need, completion of this Reallocation Report at this point is a high priority for water marketers in Texas. The reallocation opportunity would provide a source of water supply of sufficient quantity and cost to meet future water demands as the need arises. However, the water available at Lake Texoma for water supply will not meet all the expected future demand for water in the region. Other sources of water supply would be required to meet future demands as well. In addition the lower quality of water at Lake Texoma for municipal and industrial water supply will require blending or additional treatment.

The basis for water supply evaluations in Texas is found in the "Initially Prepared Texas State Water Plan, Region C, 2006", draft version dated June 2005. This report discusses in detail the problems and needs for additional water supply in Region C by water user group, community, and water utility. Future water demands and the availability of existing and potential sources of water supply are presented and evaluated along with water management strategies of major water providers and communities in the North Texas region. These strategies relate to existing and future demand and use of all existing and potential

sources of water supply, including Lake Texoma. For Oklahoma, water supply and demand information is taken from studies completed by the Tulsa District for the Oklahoma Water Resources Board (OWRB) in support of the Oklahoma State Water Plan. This study indicates that existing and potential sources of water supply are available to meet future municipal and industrial needs.

The identified need examined in the 2005 Reallocation Report is the request by the North Texas Municipal Water District (NTMWD) for additional water supply storage of 100,000 acre-feet in Lake Texoma. The letter request is shown as an appendix to the reallocation report. The Greater Texoma Utility Authority (GTUA) also desires reallocated water supply storage. The Water Resource Development Act (WRDA) of 1986 (Public Law 99-662) is the authorization that provides opportunity to address the need and allows the Secretary of the Army the authority to reallocate a total of 300,000 acre-feet of conservation storage to water supply.

The Denison Dam-Lake Texoma Restudy, Oklahoma and Texas, feasibility Report', completed by the Corps of Engineers in September 1990, evaluated whether Lake Texoma should be modified to deal with present and projected water resource problems and needs in the region with the focus on increased hydropower production. Although the Restudy focused on increasing hydropower production at Denison Dam, the Restudy is useful in the plan formulation and evaluation of alternative plans regarding changes in the size of the conservation pool and the flood pool.

No Action Alternative

The Council on Environmental Quality (CEQ) regulations implementing the provisions of NEPA requires Federal agencies to consider a No Action Alternative. These regulations define the No Action Alternative as the continuation of existing conditions and their effects on the environment, without implementation of, or in lieu of, a proposed action. The No Action Alternative represents the existing condition, would not result in any project-related environmental impacts, and serves as the baseline against which to compare the effects of the other alternatives. The Corps considers the option of "No Action" as one of the alternatives in order to comply with the requirements of the NEPA. The No Action alternative is the condition reasonably expected to prevail over the period of analysis, given current conditions and trends, and assuming that no project would be implemented by the Federal government to achieve the planning objectives. The No Action alternative, which is synonymous with the Without-Project Condition, forms the basis from which all other alternative plans are measured. This alternative would not address the intent of Public Law 99-662, Section 838, which authorized the Secretary of the Army to reallocate from hydropower storage to water supply storage, in increments as needed, up to an additional 300,000 acre feet, for municipal, industrial, and agricultural water users in the States of Texas and Oklahoma. The No Action Alternative would not reduce the current need for additional water supply to meet the expanding municipal and industrial water supply demands that are a result of population growth in the region.

Under the No Action Alternative, the storage allocation for all major purposes would be maintained at the current level. The reallocation of 300,000 acre-feet of additional storage from hydropower to water supply would not occur, and the existing allocation of 150,000 acre-feet for water supply would remain. Essentially all of the current water supply storage is being used and North Texas currently is in need of additional water. With the No Action Alternative, this need would not be met. In accordance with Section 4.04 of Article IV of the Red River Compact, division of the flows from the main stem of the Red River into Lake Texoma between the states of Oklahoma and Texas will continue to be in effect.

Action Alternatives

Potential non-structural solutions include those that would alter the demand for increased water supply in the future. These alternatives would at least partially address some of the problems and needs in the region. The non-structural alternative is to conserve water to reduce the need for additional sources of water supply. Water conservation can include altering the demand for water by water rationing and pricing methods. Communities and major water user groups, such as the NTMWD and the GTUA, already have plans to reduce water consumption as discussed in the "Initially Prepared Region C Texas Water Plan". Water reuse is also a viable non-structural alternative that has been implemented in many areas where permitted. Reuse water in the region is not expected to be more than about 100,000 acre-feet per year by 2060. Those communities and major water utilities that have undertaken steps to reuse water where feasible are shown in the Region C water plan. Where available, reuse water is utilized prior to development of other sources of water supply.

Potential structural and/or operational solutions to the need for additional water supply are:

Change the upper and/or lower limits of the conservation pool to provide additional water supply. This alternative was evaluated in the 1990 Restudy. Raising the upper limits of the conservation pool would allow higher operating heads for hydropower (when not used for water supply) and higher pool levels for recreation. The need for water supply storage still exists. To address the need for additional water supply, storage would have to be reallocated from hydropower. Recreation was added as a project purpose by the WRDA of 1986. In response to requests to provide a more reliable pool operation for recreation during the high recreation season, a seasonal pool operation was put into effect. Raising both the upper and lower limits of the conservation storage pool would benefit hydropower and water supply and recreation; however, flood control storage would be reduced approximately 46% and existing recreation and wildlife areas around the lake would be adversely impacted. Reduction in flood control storage at Lake Texoma by encroaching on the flood pool would not be acceptable to those in the floodplain downstream of Denison Dam. Although Lake Texoma now controls the 45-year flood event, cumulative flood damages prevented by Lake Texoma is about $178.4 million through Fiscal Year 2004. Raising the lower limits of the conservation pool would restrict hydropower operations and limit water supply although it might be beneficial to recreation users of the lake. The 1990 Restudy also found that enlarging the flood control capability of the existing project was not feasible due to its adverse in-pool impacts on recreation facilities, wildlife, and cultural resources.

New reservoirs above Lake Texoma. New reservoirs above Lake Texoma on the Red River and the Washita River were evaluated in the 1990 Restudy. Both the Marietta site on the Red River and the Durwood site on the Washita River were found to be not economically feasible for development for flood control operation due to high costs relative to economic benefits and adverse environmental effects. These projects would compensate for loss of flood control storage at Lake Texoma if the upper limits of the conservation pool were increased for hydropower and /or water supply storage.

New groundwater wells. In some counties in Region C, current use of groundwater exceeds or is near the estimate of long-term reliable groundwater supply. The Region C water plan indicates that water suppliers will need to develop alternate sources of water supply since groundwater resources are overused by temporary over drafting. Some entities in the region rely on groundwater to meet existing and future water needs. These users tend to need smaller quantities of water. However, with large users, the quantity of water available from new groundwater wells would not be sufficient to meet long-term future needs for reliable water supply in the region. Temporary over drafting of groundwater can be used only as an interim measure until other supplies are developed.

Existing surface water sources. The Region C water plan, as a guide to utilization of existing sources of water supply, discusses all existing sources of surface water supply currently used and expected to be used in the region to 2060 to meet future water demands. The water management strategy in Region C is to use those sources of supply that are most cost effective and viable alternatives to meet expected municipal and industrial demands. Institutional considerations, such as joint use with other water using entities, also must be taken into account.

New Surface water sources. The Region C water plan discusses all new sources of surface water supply currently used and expected to be used in the region to 2060 to meet future water demands. In addition, the water management strategy and institutional problems are presented by decade and source of supply for the major water users along with their estimated costs of development. In some cases, several water using entities combine their resources to develop a new source of water supply for a shared use. The reallocation report discusses the water management strategy for the NTMWD and the GTUA regarding existing and new surface sources of water supply.

Downstream Red River Diversion. The 1990 Restudy addressed pumped storage hydropower facilities at Lake Texoma with an afterbay dam constructed about 7 miles downstream of the existing dam. That study concluded that the afterbay pool would increase the tailwater elevation at the existing units and reduce their efficiency. This option was not economically feasible. Downstream re-regulation dams and offsite storage would be required with the Red River Diversion. Construction of a downstream dam was considered at the Kiamichi River but was removed from further study because evaporation and seepage would result in losses of up to approximately 25% between there and the Denison Dam. Water quality releases from Hugo Dam into the Kiamichi River could not be withdrawn for water supply without increased releases from Hugo to replace water quality flows. This would result in a faster drawdown of Hugo Lake. Releases of water from Lake Texoma would have to be increased by the amount lost to evaporation and seepage which would result in a faster drawdown of Lake Texoma. Withdrawal of water from the Red River below Denison would require communities located in the upper reaches of Lake Texoma to construct extensive pipeline facilities to transport water greater distances rather than withdrawing water from intake structures located much closer within the lake. Downstream water rights would also be an issue. Downstream Red River Diversions were removed from further study.

The following evaluation matrix displays the screening of preliminary alternatives. The matrix displays potential study alternatives. The alternative of reallocating storage from the existing conservation pool to water supply was found to be the only reasonable alternative. A complete evaluation of alternatives and assumptions used in this analysis can be found in the water supply storage reallocation report which accompanies this EA. This report and its findings are incorporated by reference.

Evaluation Matrix of Preliminary Alternatives.

Alternative	Potential Study Alternatives	Screening Results								Conclusion	Appropriate for
		Meet Future Water Demands	Hydropower Impacts	Environmental Impacts	Flood Control Impacts	Recreation Impacts	Economic Costs	Legislative Direction (WRDA 1986)	Evaluated in Previous Studies		
2	New Reservoirs above Lake Texoma	Yes	None	High	None	None	High	No	Yes	Difficult to justify based on high costs and environmental impacts	No
3	New Groundwater Wells	No	None	None	None	None	High	No	Yes	Production not sufficient to meet high municipal and industrial demands.	No
4	Existing Surface Water Sources	Yes	None	None	None	None	High	No	Yes	Accounted for in Texas State Water Plan, Region C	Yes
5	New Surface Water Sources	Yes	None	High	Yes	Yes	High	No	Yes	Accounted for in Region C water management strategy in Texas State Water Plan	Yes
6	Downstream Red River Diversion	Yes	None	Medium	None	Yes	High	No	Yes	Economically unfeasible, excessive water loss, extensive pipeline construction.	No
7	Reallocation from Existing Conservation Pool	Yes	High	Low	None	None	Low	Yes	Yes	Legislative mandate to reallocate hydropower storage to water supply storage.	Yes

Selected Alternative. The selected alternative would require no change in pool elevations at Lake Texoma. In accordance with the Water Resources Development Act of 1986, 300,000 acre-feet of water currently in hydropower storage would be reallocated to water supply storage, creating a total of 450,000 acre-feet of water supply. The reallocation would provide up to 150,000 additional acre-feet for municipal, industrial, and agricultural water users in the state of Oklahoma and up to 150,000 additional acre-feet for municipal, industrial, and agricultural water users in the state of Texas. This apportionment of the reallocation is consistent with Section 4.04 of Article IV of the Red River Compact, which states that water storage in Lake Texoma, as well as flow from the main stem of the Red River into Lake Texoma, will be divided equally between the states of Oklahoma and Texas.

Water supply at Lake Texoma was not an original project purpose. Several special congressional authorizations have made storage available to users throughout the years. When the Federal government realized that there was an increasing demand for water supply storage, studies were conducted (in 1983 and 1985) to reallocate a total of 150,000 acre-feet of storage from the hydropower purpose to water supply. The cost charged to the user for the storage is based on the highest either of benefits or revenues foregone, replacement costs (as a result of reallocating hydropower storage), or updated cost of storage. The cost of the storage that has been identified as being available for reallocation, but not currently under contract, will continue to increase in value annually until a water storage contract is signed. Storage is not considered to be reallocated from its original purpose until a water storage contract is entered into, and the user starts to pay for and use the storage.

4.0 ECONOMIC ANALYSIS

4.1 Water Supply Demand Analysis.

4.1.1 Study Area. The study area includes the counties and water systems or districts in the North Texas region that are currently using Lake Texoma water or may use Lake Texoma water in the future. The basis for evaluation of water supply and demands for the region is the "Initially Prepared Texas State Water Plan for Region C 2006", June 2005 draft. Region C includes Grayson County adjacent to Lake Texoma mainly in the Red River Basin and the Dallas-Fort Worth metropolitan area, lying mostly in the Trinity River Basin. Appendix 10.4 presents more detailed water supply demand analysis information for both Texas and Oklahoma. The Oklahoma information was developed by the U.S. Army Corps of Engineers, Tulsa District and others for the 2005 update of the Oklahoma State Water Plan.

There are over 34 reservoirs in Region C with conservation storage over 5,000 acre-feet. Additional reservoirs outside the region provide water supply to the region. Although use of groundwater has been decreasing, the Trinity Aquifer supplies most of the groundwater used in this region, mainly in rural areas. Ninety percent of the total water supplied in the region is from surface sources. Municipal supply accounts for about 85% of current water use. Little wastewater is treated and returned for use although municipalities are considering reuse as a source of future supply. In addition to the GTUA serving the Sherman-Denison communities in Grayson County, there are five major water providers in the region. They are: a) the NTMWD, b) the GTUA; c) the DWU, d) the TRWD, e) the city of Fort Worth, and f) the Trinity River Authority (TRA). Since the NTMWD has requested additional water supply storage at Lake Texoma, existing and potential sources of water supply for the NTMWD are discussed below.

4.1.2 Water Demand. Although all 16 counties in Region C are evaluated in the State Water Plan, 5 counties (Collin, Dallas, Denton, Grayson, and Tarrant) stand out for comparative purposes relative to

probable future use of Lake Texoma water. There are 35 wholesale water providers and 351 water user groups in Region C. Major water providers serve all or portions of other counties as well. These counties have as their major providers of water the NTMWD (Collin County), the Dallas Water Utilities (DWU) (Dallas County), and the GTUA (Grayson County). Two other counties, Denton (DWU) and Tarrant (Tarrant Regional Water District [TRWD]), also account for expected large future municipal water demands. Water conservation is also built into the demand projections. Currently implemented water conservation strategies and water conservation assumption are implicit in the water demand projections for the region.

Table 4 shows historical and future water demand for selected counties in Region C.

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TABLE 4

HISTORICAL AND PROJECTED WATER DEMAND BY SELECTED COUNTIES
(acre-feet)

County	Year				
	1996	**2000**	**2020**	**2040**	**2060**
Collin	89,230	138,306	287,247	402,383	526,315
Dallas	505,423	623,535	785,788	879,106	1,055,030
Denton	65,075	93,982	212,211	307,951	406,700
Grayson	29,152	32,478	45,954	55,613	66,715
Tarrant	291,406	331,066	451,536	559,650	718,098
Total	980,286	1,219,367	1,782,736	2,204,703	2,772,858
Region C Total	1,126,621	1,380,556	2,100,519	2,622,513	3,311,217
Municipal	946,454	1,196,452	1,828,831	2,294,491	2,915,773

Source: Initially Prepared Texas State Water Plan 2006, June 2005.

4.2. <u>North Texas Municipal Water District</u>. The NTMWD is comprised of Collin County and portions of Kaufman, Rockwall, and Dallas counties in north-central Texas. The NTMWD provides wholesale water and wastewater service to communities within its boundary. The cities of Plano, Richardson, Garland, Mesquite, and McKinney are a few of the larger municipalities receiving all or part of their service from the NTMWD. Water demand is expected to double between 2010 and 2060, with a shortage of about 100,000 acre-feet by 2010, increasing to 534,000 acre-feet by 2060. The main water treatment plant for the NTMWD is located near Lake Lavon. The district receives its surface water supply from three primary sources, Lake Lavon, Cooper Lake, and Lake Texoma.

Lake Texoma has 986,730 acre-feet of conservation storage. The Red River Authority of Texas (RRAT), the GTUA, the city of Denison, the NTMWD, and Texas Utilities (TXU) have water rights in Lake Texoma. Lake Texoma water is pumped and then gravity flowed to Lake Lavon and blended for subsequent use. The NTMWD has contractual rights to divert up to 85,406 acre-feet or about 75.0 mgd of water from Lake Texoma. Other entities that have storage at Lake Texoma are the GTUA, acting for the city of Sherman, Texas; 22,600 acre-feet; the city of Denison, 21,300 acre-feet; the TXU, 16,400 acre-feet; and the RRAT, 2,504 acre-feet.

Groundwater sources for the NTMWD area are of poor quality or limited quantity and, therefore, are not considered adequate potential sources of water supply.

4.2.1 Potential Sources of Water Supply. There are no reservoirs proposed for construction in this region. Major regional wholesale water providers, such as the NTMWD, the DWU, the TRWD, and the Upper Trinity River Water District (UTRWD), have similar strategies. These strategies include water conservation, reuse water, installation of connections to existing sources already under contract, connection to other existing sources, and development of new reservoirs. Marvin Nichols Reservoir, Toledo Bend Reservoir, and Oklahoma water are possible sources of new supply for the NTMWD as well as for the other major providers. New Bonham Reservoir, George Parkhouse, and Marvin C. Nichols Reservoir are under consideration by the NTMWD as possible water supply sources outside the area. Oklahoma water remains a promising source of supply for the North Texas region although the Oklahoma legislature has a current moratorium on export of water from the state. Although the long term (year 2060) recommended strategy in the Water Plan is to consider Oklahoma water as an additional source of

water supply for the TRWD and the NTMWD, discussions with the State of Oklahoma have precluded this water being available to meet immediate needs. Oklahoma water is also considered an alternate strategy for the DWU and the city of Irving if the water becomes available in the future.

4.2.2 Water Supply Alternatives. Water supply alternatives other than those joint efforts discussed above are:

- **NTMWD Conservation.** Conservation is the projected conservation savings for the NTMWD's existing and potential customers based on the Region C recommended water conservation program.

- **Interim Treated Water Purchase from Dallas Water Utilities.** The NTMWD is negotiating with the DWU to purchase an annual average of up to 10 mgd (11,210 acre-feet per year) of treated water.

- **Additional Wilson Creek Reuse Project.** The NTMWD currently has a water right allowing the reuse of up to 35,941 acre-feet per year (32 mgd) of actual discharges from the Wilson Creek Wastewater Treatment Plant.

- **East Fork Reuse Project.** The NTMWD has applied for a water right to divert treated wastewater from the East Fork of the Trinity River near Crandall. The estimated supply available from this project will increase with increasing wastewater flows to 102,000 acre-feet per year.

- **Additional Lake Lavon Yield.** The NTMWD currently has a water right allowing the diversion of up to 104,000 acre-feet per year from Lake Lavon (in addition to water delivered to the lake from return flows, Lake Texoma, and Lake Chapman).

- **Interim Purchase of Lake Texoma Water from GTUA/Sherman.** The NTMWD has reached an agreement with the city of Sherman and the GTUA to purchase surplus Lake Texoma water.

- **Upper Sabine Basin Supply.** The NTMWD is negotiating with the Sabine River Authority to divert water from Lake Tawakoni or Lake Fork on an interim basis.

- **Fannin County Water Supply System.** The NTMWD would cooperate with Fannin County entities to develop a treated water supply system for Fannin County water users after the Lower Bois d'Arc Creek Reservoir is developed in 2020.

4.2.3 Summary of Water Supply Alternatives. Nearly 790,000 acre-feet per year of new supplies are recommended in the Region C water plan for the NTMWD, leading to a total supply of 1.02 million acre-feet per year in 2060. A summary of current water supplies and potential water management alternatives or strategies and projected demand is presented in Table 5. Some existing sources of water supply would diminish over time due to sedimentation. Projected demands exceed current available supplies as shown in Table 5 requiring the consideration of alternative water management strategies over time. Costs for

the alternative strategies are shown in Table 6. The water management strategy for Region C prepared for the Region C Water Planning Group by Freese and Nichols, Consulting Engineers, and others, anticipates new Lake Texoma water would be required by year 2015. Capital costs for the projects in Table 6 are typically financed by 30-year bonds. Pre-amortization costs refer to the 30 year period during which debt service payments on the bonds are being made. Post-amortization costs refer to the period after the bonds are paid off in which there are no debt service costs.

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TABLE 5

SOURCES OF WATER SUPPLY AND WATER DEMAND BY DECADE
RECOMMENDED WATER MANAGEMENT STRATEGIES
North Texas Municipal Water District

	Year					
Source	**2010**	**2020**	**2030**	**2040**	**2050**	**2060**
Current Available Supplies						
Lake Lavon	104,000	104,000	104,000	104,000	104,000	104,000
Lake Texoma	77,300	77,300	77,300	77,300	77,300	77,300
Lake Chapman	49,976	49,150	48,324	47,498	46,672	45,843
Wilson Creek Reuse (permitted)	35,941	35,941	35,941	35,941	35,941	35,941
Lake Bonham	5,340	5,340	5,340	4,850	4,250	3,650
Total Current Available Supplies	272,557	271,731	270,905	269,589	268,163	266,734
Water Management Strategies						
Conservation	12,366	32,071	45,646	58,274	70,220	83,096
Interim DWU Supply	11,210	11,210	0	0	0	0
Wilson Creek Reuse (new)	26,956	35,941	35,941	35,941	35,941	35,941
East Fork Reuse	81,400	96,400	102,000	102,000	102,000	102,000
Additional Lake Lavon Yield	11,000	10,000	9,000	8,000	7,000	6,000
Interim GTUA Supply	20,000	0	0	0	0	0
Upper Sabine Basin	50,000	30,000	20,000	10,000	10,000	10,000
New Lake Texoma	0	38,250	57,105	54,105	100,460	112,460
Lower Bois d'Arc Creek Reservoir	0	123,000	121,000	119,000	117,000	115,000
Marvin Nichols Reservoir	0	0	87,420	87,420	174,840	174,840
Toledo Bend Phase 1	0	0	0	0	100,000	100,000
Oklahoma Water	0	0	0	0	0	50,000
Treatment and Distribution Losses	-10,028	-17,240	-21,623	-20,823	-32,362	-35,312
Total Supplies from Strategies	212,932	376,872	478,112	474,740	717,461	789,337
Total Current and Strategy Supplies	475,461	631,363	727,394	723,506	953,262	1,020,759
Total from Reuse and Conservation	156,663	200,353	219,528	232,156	244,102	256,978
Percent from Reuse and Conservation	32.9%	31.7%	30.2%	32.1%	25.6%	25.2%
Projected Demands	370,499	482,185	567,185	649,440	721,491	801,513

Source: Initially Prepared Texas State Water Plan 2006, June 2005.

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TABLE 6

SOURCES OF WATER SUPPLY AND WATER DEMAND BY DECADE COSTS OF RECOMMENDED WATER MANAGEMENT STRATEGIES
Texas State Water Plan 2006
North Texas Municipal Water District
(2002 Price Levels)

Water Management Strategies	Develop Dates	Quantity for NTMWD (acre-feet/year)	(mgd)	NTMWD Share of Capital Cost($)	Unit Cost($/kGal) Pre-Amort	Post-Amort
Treatment and Distribution Improvements	2005-2060	N/A	N/A	1,290,523,000	N/A	N/A
Interim DWU Supply	2006	11,210	10	1,350,000	$0.75	$0.72
Wilson Creek Reuse (new)	2005	35,491	32	1,150,000	$0.01	$0.00
East Fork Reuse	2010	102,000	91	288,879,000	$0.92	$0.21
Additional Lake Lavon Yield	2006	11,000	10	270,000	$0.01	$0.00
Interim GTUA Supply	2006	20,000	18	104,000	$0.09	$0.09
Upper Sabine Basin	2010	50,000	45	60,232,000	$0.52	$0.25
New Lake Texoma	2015	113,000	101	201,829,000	$0.58	$0.18
Lower Bois d'Arc Creek Reservoir	2020	123,000	110	399,190,000	$0.87	$0.14
Fannin County Water Supply System	2020	0	0	55,458,000	$1.96	$0.52
Marvin Nichols Reservoir	2030	174,840	156	534,125,000	$0.94	$0.26
Toledo Bend Phase 1	2050	200,000	179	886,002,000	$1.56	$0.57
Oklahoma Water	2060	50,000	45	128,898,000	$0.95	$0.37
Total Capital Costs				3,848,010,000		

Source: Initially Prepared Texas State Water Plan 2006, June 2005.

5.0 DERIVATION OF USER COST

5.1 **Hydropower Benefits Foregone**. The loss of project benefits that would result from the reallocation of 300,000 acre-feet of storage is computed based on current price levels, interest rates, and conditions projected for the remaining economic life of the project. Benefits were calculated assuming a 70-megawatt (MW) power capacity at 5-3/8% interest for a 50-year period of analysis. The annual energy loss based on SWD-SUPER stream flow data for 1938-2000 is 23,792 MWh. (See Table 3-1, Water Supply Storage Reallocation Power Benefits Foregone report dated April 2005, Appendix 10.5). The annual hydropower benefits foregone is the sum of annual energy benefits foregone and annual capacity benefits foregone. The total annual benefits foregone with a 450,000 acre-feet reallocation is $1,402,400. Annual hydropower benefits foregone for a 150,000 acre-feet and 300,000 acre-feet water supply reallocation (300,000 and 450,000 acre-feet of total water supply) are outlined in Table 7. A 150,000 acre-feet reallocation was calculated since water supply needs in Oklahoma is for meeting long-term water supply needs. The 300,000 acre-feet reallocation satisfies the water supply demands of the Texas communities.

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TABLE 7

ANNUAL HYDROPOWER BENEFITS FOREGONE DUE TO REALLOCATION FROM CONSERVATION POOL STORAGE IN LAKE TEXOMA*

Allocation Alternatives	300,000 Acre-Feet	450,000 Acre-Feet
Annual Energy Losses (MWh)	11,995	23,792
Energy Value ($/MWh)	$33.23	$33.23
Annual Energy Benefit Foregone	$398,600	$790,600
Capacity Losses (kW)	2,310	5,472
Capacity Value ($/kW)	$111.80	$111.80
Annual Capacity Benefit Foregone	$258,300	$611,800
Total Annual Benefits Foregone	$656,900	$1,402,400

* Total water supply reallocation for Texoma.

5.2 **Hydropower Revenues Foregone**. The hydropower revenues that would be lost because of the storage reassignment were evaluated based on the value of lost power that is based on current Southwestern Power Administration (SWPA) system rates. The rates that are in effect are as follows:

Energy Charge: 8.25 mills/kWh
Capacity Charge: $23.52/kW-year

The annual revenues foregone for a 300,000 acre-feet reallocation (450,000 acre-feet of total water supply) is $861,000. A summary of hydropower revenues foregone assuming 300,000 and 450,000 acre-feet of total available water supply is outlined in Table 8.

TABLE 8

HYDROPOWER REVENUES FOREGONE DUE TO REALLOCATION FROM CONSERVATION POOL STORAGE IN LAKE TEXOMA*

Allocation Alternatives	300,000 Acre-Feet	450,000 Acre-Feet
Annual Energy Losses (MWh)	11,995	23,792
Energy Charge ($/MWh)	$8.25	$8.25
Annual Energy Revenues Foregone	$99,000	$196,300
Capacity Losses (kW)	12,730	28,263
Capacity Charge ($/kW)	$23.52	$23.52
Annual Capacity Revenues Foregone	$299,400	$664,700
Total Annual Revenues Foregone	$398,400	$861,000

* Total hydropower reallocated for Texoma.

5.3 **Hydropower Replacement Costs**. The replacement cost of power as used for computing the cost of reallocated storage is an economic or National Economic Development (NED) cost. In the case of hydropower, the NED cost of replacement power is, by definition, identical to the power benefits foregone. An exception to this rule is where there are existing Federal contracts. In such cases, replacement costs will be actual costs incurred to fulfill the Federal government's obligations during the duration of the contracts and will revert to benefits foregone for the remaining period of analysis.

Contract information provided by the SWPA indicated that current contracts for all power marketed will expire in 2015. For this reason, the cost of replacement power was the basis for SWPA credit until the

present contracts expire in 2015. The SWPA credit in the following years was based on revenues foregone for the remaining economic life of the project. Table 9 is a summary of credit due the power marketing administration (PMA) for the 300,000 acre-feet and 450,000 acre-feet total water supply alternatives. NOTE: The PMA has already received or will receive full credit for the 150,000 acre-feet of hydropower storage reallocated in 1983, 1985, 1992, 1997, and 2004.

TABLE 9

ANNUAL CREDIT DUE POWER MARKETING AGENCY DUE TO REALLOCATION FROM CONSERVATION POOL STORAGE IN LAKE TEXOMA (DENISON DAM)

Allocation Alternative	300,000 Acre-Feet	450,000 Acre-Feet
Energy Credit	$240,500	$477,800
Capacity Credit	$280,000	$642,400
Annual Credit to PMA	$520,500	$1,120,200

5.4 **Updated Cost of Storage**. The value of the entire 300,000 acre-feet of storage being identified for reallocation in this report is estimated at $96,199,693 based on the updated cost of storage. The value of the storage was determined by first computing the cost at the time of construction by using the use of facilities cost allocation procedure as follows:

$$\frac{\text{(Project joint-use const. cost x Storage reallocated (acre-feet)}}{\text{Total usable storage}}$$

The cost allocated to the storage on this basis is then to be escalated to present day price levels using the estimated 2004 Civil Works Construction Cost Index System. Computations to determine the value of the reallocated storage follow:

($1,153,888,600 (Fiscal Year [FY] 2005)) (300,000 acre-feet/3,598,168 acre-feet) = $96,199,693

A storage cost update for FY 2005 for Denison Dam is shown in Table 10.

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TABLE 10
UPDATED STORAGE COSTS FOR FY2005 ($1,000)

Project, Denison Dam - Construction Initiated, August 1939; Construction Completed, June 1944; Construction Mid-point, January 1942

	Actual Joint-Use As of January1942	Mid-point January 1942 ENR Index	October 1967 ENR Index	Update Factor	October 1967 Joint Use Costs	October (1) ENR or (2) CWCCIS 1967 Index	October (1) ENR or (2) CWCCIS 2004 Index	Update Factor	October 2004 Joint Use Costs
Lands and Damages	6,442.0	268	1,096	4.0896	26,345.2	100 (2)	598 (3)	5.982	157,597.0
Relocations	13,670.1	268	1,096	4.0896	55,905.2	1,096 (1)	7314 (1)	6.673	373,055.4
Reservoir	3,703.9	268	1,096	4.0896	15,147.5	100 (2)	633 (2)	6.330	95,883.7
Dam and Spillway	15,622.7	268	1,096	4.0896	63,890.6	100 (2)	579 (2)	5.790	369,926.6
Outlet Works	0.0	268	1,096	4.0896	0.0	100 (2)	579 (2)	5.790	0.0
Roads	271.3	268	1,096	4.0896	1,109.5	100 (2)	601 (2)	6.010	6,668.1
Levees	5,633.5	268	1,096	4.0896	23,038.8	100 (2)	599 (2)	5.990	138,002.4
Buildings, grounds, and utilities	258.0	268	1,096	4.0896	1,055.1	1,096	7314	6.673	7,040.7
Permanent operating equipment	209.4	268	1,096	4.0896	856.4	1,096	7314	6.673	5,714.8
TOTAL	45,810.9								1,153,888.6
Specific Costs Water Supply Conduit	0.0	268	1,096	4.0896	0.0	100	579	5.790	0.0

(1) Engineering News Record Index
(2) Civil Works Construction Cost Index System
(3) Updated by the weighted average of other project features

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5.5 **User Cost**. The present worth of the 300,000 acre-feet of water supply storage is considerably more than the present worth of hydropower benefits or revenues foregone. The total reallocated water supply storage of 300,000 acre-feet is valued at $96,199,693, which equals an annual payment of $3,023,656 per year for 30 years if water supply agreements for the full reallocation were signed by one water supply user. At the present time NTMWD has applied for a water supply agreement for 100,000 acre-feet of storage. Based on a 30 year repayment at the water supply interest rate of 5.125%, the annual payment would be $2,012,645, and the estimated annual operation and maintenance cost of $58,941 for fiscal year 2005.

6.0 OTHER CONSIDERATIONS

6.1 Test of Financial Feasibility.

6.1.1 Most Likely, Least Costly Alternative. Upon review of the No Action existing condition alternative, it is evident that reallocation of 300,000 acre-feet of hydropower storage from Lake Texoma is the most likely, least costly alternative. The No Action alternative will not meet future water demand of the area communities served by the NTMWD and is not consistent with the Texas State Water Plan.

6.1.2 Alternative Non-Federal Project. The reallocation of storage to water supply requires a test of financial feasibility. This test is a comparison of the annual cost of storage of Lake Texoma to the annual cost of the most likely, least costly alternative that would provide an equivalent quality and quantity of water which the non-Federal sponsor would develop in the absence of utilizing the Federal project at Lake Texoma. The water at Lake Texoma has relatively high concentration of chlorides compared to other water sources in the region. The Region C Texas State Water Plan evaluated water management strategies for the major providers and estimated the capital costs required to implement that strategy. As discussed in the economic analysis, the next most likely alternative for the NTMWD in the time frame the water is required is the reservoir project on the Lower Bois d'Arc Creek in Fannin County, Texas. Table 6 in this report refers to the time frame when water is needed and shows estimated costs for each alternative.

6.1.2.2 Cost of Lower Bois d'Arc Creek Reservoir and Conveyance Facilities. Cost estimates for the new reservoir project and conveyance facilities on the Lower Bois d'Arc Creek have two components:

- Project or capital costs for the dam and reservoir, the pipeline, pumping, and storage facilities include construction, land acquisition, mitigation, engineering, and contingency costs. The project costs for the Lower Bois d'Arc Creek Reservoir project are updated from 2002 price levels as found in the Initially Prepared 2006 Region C Water Plan, Table U-49. Those detailed costs were consolidated and updated to 2005 price levels using the Civil Works Construction Cost Index System (CWCCIS). Detailed costs are shown in the Region C Water Plan. Interest during construction is also a cost for the utilization of capital over the estimated 3-year construction period. Interest during construction was calculated at the FY 2005 Federal discount rate of 5-3/8% interest using Corps of Engineers methodologies.

- Average annual costs represent annual operation and maintenance costs and debt service. Annual costs were calculated based on a 100-year amortization period for major reservoir projects at 5-3/8% interest.

Table 11 shows the consolidated project costs for the dam and reservoir, pipeline, pumps, and

storage facilities along with other mitigation costs at 2005 price levels. Also shown are the annualized costs at 2005 price levels.

TABLE 11

LOWER BOIS D'ARC CREEK RESERVOIR SITE
PROJECT COST AND ANNUAL COSTS

PROJECT COSTS	**Cost** ($1,000)
Category	
Dam and Reservoir	$64,711
Land Acquisition	$38,010
Conflicts	$19,950
Conveyance Facilities	
Pipeline	$179,766
Intake Pump Station	$39,163
Terminal Storage Facilities	$20,802
Mitigation/Permitting	$54,959
Total Project Cost	$417,361
ANNUAL COSTS	
Total Project Cost	**$417,361**
Interest During Construction	$34,511
Total Gross Investment	$451,872
Annual Charges	
Interest & Amortization	$24,418
Operation & Maintenance	$7,093
Major Replacement	$0
Total Annual Charges	**$31,511**
UNIT COSTS	
Quantity	123,000 acre-feet/year
Unit Costs per acre-foot	$256
Unit Costs per thousand gallons	$0.79

Note: Price levels at 2nd quarter 2005.
Difference in annual costs attributed to 100-year period of analysis instead of 30-year, as found in the Region C Water Plan.

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7.0 COST ACCOUNT ADJUSTMENTS - NORTH TEXAS MUNICIPAL WATER DISTRICT

7.1 **Payment**. NTMWD will initially contract for 100,000 acre-feet of the 300,000 acre-feet of storage being reallocated. The cost to the NTMWD for 100,000 acre-feet of storage is estimated as follows:

Storage*
100,000/3,598,168 = 2.779% * $1,153,888,600 = $32,066,564

Annual Operation and Maintenance (FY 05)
Joint-use 100,000/3,598,168 = 2.779% x $2,120,931 = 58,941**

Replacement and Rehabilitation (FY 05)
Joint-use 100,000/3,598,168 = 2.779% x $0 = 0

* See Table of Updated Costs. To be adjusted to reflect the Civil Works Construction Cost Index System at the beginning of the fiscal year in which the first payment on the storage is made.
** Joint-Use Operation and Maintenance costs are an annual reimbursement.

7.2 **Credits for Hydropower Revenues Foregone**. All the funds received from the sale of the 100,000 acre-feet of storage will be deposited into the U.S. Treasury by the Corps of Engineers. Those revenues that represent hydropower revenues foregone, in accordance with section 4.2 of this report, will be credited to the project's hydropower income account. The SWPA will be provided an amortization of credits for the 30-year repayment period by the NTMWD. The SWPA will be notified in writing within 30 days after the agreement between the United States of America and any future water supply user. When the proposed water supply contract with NTMWD is signed, SWPA will be notified in writing within 30 days of the amount that will be credited to the hydropower income account. If the revenues representing hydropower revenues foregone exceed the projects annual operation and maintenance (O&M) allocated to hydropower, the excess revenues will be applied to other hydropower projects in the U.S. Army Corps of Engineers, Tulsa District as directed by the SWPA.

7.3 HAC and SWPA Methodology Differences for Determining Credits for Hydropower Revenue Forgone

SWPA and the Corps of Engineers Hydropower Analysis Center (HAC) have had numerous discussions concerning the appropriate methodologies used for evaluating impacts to energy and capacity benefits when hydropower storage is reallocated to other uses. Differences center primarily on three issues: 1) the computation of dependable capacity; 2) the energy value used to compute power benefits foregone; and 3) SWPA's contract rates used to compute revenue forgone. Attached in Appendix 10.6 are comments supplied by Southwestern Power which outline SWPA concerns regarding compensation for lost hydropower from the proposed water storage reallocation.

Appendix A of the HAC report (appendix 10.5), uses alternative methodologies similar to those used by SWPA in calculating annual energy and capacity benefits foregone. The primary concern of the SWPA involves the amount and compensation credit for hydropower revenue foregone and the procedures for how that compensation is determined. The HAC report dated April 2005 used Corps policy and procedures in determining the credits that are due. Appendix A to that report used methodologies similar to those proposed by SWPA to determine the credits that are due.

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Appendix A calculations presents an alternative approach to quantifying power benefits foregone based on comments received (Appendix 10.6) from SWPA and may not exactly follow the procedures and values used by SWPA. The total annual power benefits foregone for the reallocation storage of 300,000 acre feet is $1.7 million for energy from combustion turbines only and $1.4 million for energy from both the combined cycle and combustion turbine alternative. For a 450,000 acre feet reallocation these values would range from $3.5 million for energy from the combustion turbine alternative, and $2.9 million for energy from both the combined combustion turbine and combustion turbine alternative. The computation of benefits shown in Appendix A does not follow current Corps of Engineers policy and guidelines. Appendix A was not used, nor is it recommended in this report.

8.0 ENVIRONMENTAL CONSIDERATION

The NEPA of 1969 requires all Federal agencies to address the environmental impacts of any major Federal action on the natural and human environment. A supplemental EA was completed in 2005 to assure that the proposed storage reallocation project complies with the intent of the NEPA. (Appendix 10.7) The EA 30-day public review process was coordinated with Federal, State, and/or local interests affected by reallocation that had legislative and administrative responsibilities for environmental protection. This EA determined that no cumulative impacts are anticipated to occur as a result of the proposed reallocation action.

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9.0 CONCLUSIONS

Reallocation of 300,000 acre-feet from hydropower to water supply is the most efficient means to satisfy the projected water demands in Texas and Oklahoma. The rapid growth in the North Texas Region C as expressed in Texas Senate Bill 1 Regional Water Plan identified the need for establishing future water sources because of a projected 50% population increase within the region. The demand for additional water supply sources resulted in Congressional authorization through the 1986 WRDA passed by Congress (Public Law 99-662). Section 838 of the 1986 WRDA authorized the Secretary of the Army to reallocate 150,000 acre-feet each for Oklahoma and Texas for municipal, industrial, and agricultural water uses. A total reallocation of 300,000 acre-feet was directed from the congressional authorization. This would bring the identified total water supply storage to 450,000 acre-feet. A reallocation of water supply storage from hydropower storage does not occur until water supply agreements are signed by all parties and the water supply user starts to pay for the storage. Storage identified for reallocation but not under contract is still considered hydropower storage; however, it no longer becomes a dependable source of power.

The study to reallocate 300,000 acre-feet of storage from hydropower to water supply complies with NEPA. An EA was conducted and a determination made that no significant impacts are anticipated to occur as a result of the proposed reallocation action.

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10.0 RECOMMENDATION

Based on the 2005 Environmental Assessment and pursuant to the 1986 Water Resources Development Act, Public Law 99-662, Section 838, it is recommended that 150,000 acre-feet each for Oklahoma and Texas for municipal, industrial, and agricultural water uses (a total reallocation of 300,000 acre-feet) be reallocated from hydropower storage to water supply. It is recommended that 300,000 acre-feet between elevations 590.0 and 617.0 feet NGVD in Lake Texoma be reallocated from hydropower storage to water supply to meet the municipal and industrial needs of Oklahoma and Texas communities.

The recommendations contained herein reflect the information available at this time and current Departmental policies governing formulation of individual projects. They do not reflect program and budgeting priorities inherent in the formulation of a national Civil Works program nor the perspective of higher review levels within the Executive Branch. Consequently, the recommendations may be modified before they are transmitted to the Congress as proposals for authorization and implementation funding. However, prior to transmittal to the Congress, the sponsor, the States, interested Federal agencies, and other parties will be advised of any modifications and will be afforded an opportunity to comment further.

DRAFT

11.0 APPENDICES

11.1 WRDA 1986, PL 99-662, SEC 838, Denison Dam (Lake Texoma), Red River, Texas and Oklahoma Authorization

11.2 Letter from Oklahoma Water Resources Board to U.S. Army Corps of Engineers regarding proposed reallocation

11.3 H&H Storage/Yield Analysis

11.4 Water Supply Demand Analysis

11.5 Denison Dam & Powerhouse, Lake Texoma, Red River, Oklahoma & Texas - Water Supply Storage Reallocation Power Benefits Foregone Study, April 2005(revised) Prepared by Hydropower Analysis Center, U.S. Army Corps of Engineers.

11.6 Southwestern Power Administration Water Storage Reallocation Hydropower Impacts Executive Summary

11.7 NEPA Documentation – Environmental Assessment, Lake Texoma Storage Reallocation Study, Lake Texoma, Oklahoma and Texas.

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APPENDIX 11.1

WATER RESOURCES DEVELOPMENT ACT OF 1986
PUBLIC LAW 99-662-NOVEMBER 17, 1986

SECTION 838

DENISON DAM (LAKE TEXOMA), RED RIVER, TEXAS AND OKLAHOMA

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(a) The project for Denison Dam (Lake Texoma), Red River, Texas and Oklahoma, authorized by the Flood Control Act approved June 28, 1938 (52 Stat. 1219), is modified to provide that the Secretary is authorized to reallocate from hydropower storage to water supply storage, in increments as needed, up to an additional 150,000 acre-feet for municipal, industrial, and agricultural water users in the State of Texas and up to 150,000 acre-feet for municipal, industrial and agricultural water users in the State of Oklahoma.

(b) For that portion of the water storage reserved for users in the State of Oklahoma, the Secretary may contract, in increments as needed, with qualified individuals, entities, or water utility systems for use within the Red River Basin; except that for any portion of that water to be utilized outside the Red River Basin, the Secretary shall contract with the Red Ark Development Authority.

(c) For that portion of the water storage reserved for users in the State of Texas, the Secretary shall contract, in increments as needed, for 50,000 acre-feet with the Greater Texoma Utility Authority and 100,000 acre-feet with other qualified individuals, entities, or water utility systems. Nothing in the preceding sentence shall supersede any requirement of State law with respect to the use of any water subject to a contract.

(d) (1) All contracts entered into by the Secretary under this section shall be under terms in accordance with section 301(b) of the Water Supply Act of 1958 (Public Law 85-500), as amended by section 932 of this Act.

(2) No payment shall be required from and no interest shall be charged to users in the States of Oklahoma or Texas for the reallocation authorized by this section until such time as the water supply storage reserved under such reallocation is actually first used. Any contract entered into for the use of the water received under this section shall require the contracting entity to begin principal and interest payments on that portion of the water allocated under the contract at the time the entity begins the use of such water. Until such time; storage for which reallocation is authorized in this section may be used for hydropower production.

(3) With respect to any water supply contract entered into by the Secretary under this section after June 1, 1985, the Secretary shall determine (A) the amount of hydropower lost, if any, as a result of the implementation of such contract, and (B) the replacement cost of the hydropower lost (where replacement cost is defined as the cost to purchase power from existing alternative sources). If hydropower is lost as a result of the implementation of such contract, the Secretary shall provide credits to the Southwestern Power Administration of amounts equal to such replacement costs. Such credits shall be against sums required to be paid by the Southwestern Power Administration for costs of the project allocated to hydropower. In each such case the Southwestern Power Administration shall reimburse each preference customer for an amount equal to the customer's actual replacement cost for hydropower lost as a result of the implementation of such contract, less the cost such customer would have had to pay the Southwestern Power Administration for such hydropower.

(4) The Secretary may not increase payments of water users under a water supply contract under this section on account of the credits and reimbursement required to be provided under this section.

(e) Nothing in this section shall be construed as amending or benefits in connection with such reallocation and usage of municipal, industrial, and agricultural water, all benefits that can be assigned to the Red River chloride control project, Texas and Oklahoma, or the Red River and tributaries multipurpose study, Oklahoma, Texas, Arkansas, and Louisiana, and any individual projects arising from such study, shall be reserved for such projects. Nothing in this section shall affect water rights under the laws of the State of Texas and Oklahoma.

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(f) Such project is further modified to include recreation as a project purpose.

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Appendix 11.2 Letter from Oklahoma Water Resources Board to U.S. Army Corps of Engineers Regarding Proposed Reallocation Apportionment

DUANE A. SMITH
EXECUTIVE DIRECTOR

BRAD HENRY
GOVERNOR

STATE OF OKLAHOMA
WATER RESOURCES BOARD
www.owrb.state.ok.us

May 25, 2004

Mr. Larry Hogue, P.E.
Chief, Planning, Environmental,
and Regulatory Division
Environmental Analysis and Compliance Branch
Department of the Army
Corps of Engineers, Tulsa District
Tulsa, OK 74128-4609

Re: Proposed reallocation – Lake Texoma

Dear Mr. Hogue:

Thank you for the opportunity to comment on the proposed reallocation of the storage at Lake Texoma.

As you know, the State of Oklahoma is a party to the Red River Compact. Accordingly, the State of Oklahoma has a significant interest in ensuring compliance with the apportionment provisions of the Red River Compact. Article IV of the Compact, specifically Section 4.04, apportions the water of the mainstem of the Red River and Lake Texoma between the State of Oklahoma and the State of Texas. Basically, the Compact apportions the storage of Lake Texoma and flow of the mainstem of the Red River into Lake Texoma on a 50/50 basis between Oklahoma and Texas. Any reallocation of storage at Lake Texoma must be consistent with the apportionment provisions of the Compact.

Unfortunately, the Compact Commission has not finalized rules to implement the apportionment provisions of the Compact. Until such rules are adopted by the Commission, it will not be possible to determine whether a proposed reallocation of storage is consistent with the Compact's apportionment provisions. The Oklahoma Commissioners and Texas Commissioners of the Red River Compact Commission are aware of the need for rules, and we hope to consider proposed rules at the Commission's annual meeting scheduled during April, 2005. Staff of the Corps' Tulsa District are routinely invited to the Commission's annual meetings, and therefore, will be notified of the Commission's determination regarding the apportionment rules.

A related issue that should be addressed in the reallocation study is the costs of the water supply storage. It is our understanding that the original water supply storage allocation for Lake Texoma was 150,000 acre-feet. Therefore, under the terms of the 50/50 apportionment provision, the Compact apportions 75,000 acre-feet of the original water supply storage

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Lonnie L. Farmer • Mark Nichols • Bill Secrest • Harry Currie • Richard C. Sevenoaks • Jack Keeley

allocation to Oklahoma and the other 75,000 acre-feet to Texas. Based on plain readings of the Water Supply Act of 1986 and the Red River Compact, we believe that Oklahoma users remain entitled to enter into contracts for up to a total of 75,000 acre-feet of water supply storage under terms and conditions available prior to the Water Supply Act of 1986. An explanation is in order.

Section 838 of the Water Resources Development Act of 1986 provides authority for the Corps to reallocate 300,000 acre-feet of storage in Lake Texoma from hydropower to water supply, with 150,000 acre-feet for Oklahoma users and 150,000 acre-feet for Texas users (this is consistent with the 50/50 apportionment provision of the Compact). Paragraph (d)(1) of Section 838 then indicates that all contracts for the reallocated storage shall be under the new water supply contract terms set forth in Section 932, which terms are substantially less favorable than terms in contracts entered pursuant to the Water Supply Act of 1958. However, paragraph (e) of Section 838 controls the situation by providing that nothing in Section 838 of the Water Resources Development Act of 1986 shall be construed as amending or altering in any way the Red River Compact. As noted above, the Red River Compact split the storage at Lake Texoma and flow from the mainstem of the Red River on a 50/50 basis, as follows: "Oklahoma 200,000 acre-feet and Texas to 200,000 acre-feet, which quantities shall include existing allocations and uses" (emphasis added). The emphasized language in the Compact makes it clear that the 50/50 apportionment provision of the Compact applies to the original 150,000 acre-feet allocation for water supply storage. Therefore, Oklahoma users are entitled to contract for up to 75,000 acre-feet of the original allocation amount without triggering less favorable repayment terms that will apply to contracts for the reallocated storage.

The Environmental Assessment should address both the apportionment rules to be adopted by the Compact Commission and the costs of the storage.

Please keep us informed of the progress of the Environmental Assessment work. Thank you again for the opportunity to provide input.

Sincerely,

Duane A. Smith
Executive Director

cc: Secretary Miles Tolbert
Charles Dobbs, Oklahoma Commissioner
Mark Nichols
Gordon W. Fassett, Federal Commissioner
William A. Abney, Texas Commissioner
Randy Young, Arkansas Commissioner

APPENDIX 11.3

Red River SUPER Model, Texoma Yield Analysis, and Water Supply Reallocation at Texoma

There has been significant interest in developing and identifying sufficient water sources for the north-central region of Texas due to continued population growth and development in the region. Also, the passage of Texas Senate Bill 1, which is a comprehensive water resource planning initiative the State of Texas has undertaken, has also created an interest in future water supply availability. Due to the current and future interest in municipal and industrial water supply in the region, it was determined that another large reallocation of conservation storage from hydropower to water supply use was appropriate at Lake Texoma. This current reallocation will be for a total of 300,000 acre-feet of conservation storage. A total of 150,000 acre-feet will be set aside for Oklahoma use, and the remaining 150,000 acre-feet will be designated for Texas use. The impacts of this reallocation on hydropower and other authorized uses will need to be determined. SUPER was chosen as the modeling tool to provide yield and impact analysis.

Overview of SUPER Model

The SUPER Model is a suite of computer programs written for use in the Southwestern Division of the U.S. Army Corps of Engineers to model multi-purpose reservoir system regulation. The programs were developed over a 30-year period by Ronald L. Hula, primarily as a planning tool to perform period-of-record analysis to evaluate changes in operational scenarios. The model has the ability to simulate flood control operations and conservation pool operations, including hydropower, water supply, water quality, diversions, and returns. In addition to period-of-record analysis, it has the capability to perform conservation pool yield analysis and firm energy analysis. It also has the capability to develop unregulated conditions models, simulating systems with some or all reservoirs “dummied” out or non-existent. Besides system modeling, SUPER can perform economic analyses of impacts between plans. It can also provide a wide variety of output from which to evaluate scenarios including tabular or graphical formats of hydrographs, duration plots, and frequency curves at all reservoirs and control points within the system model.

SUPER is a daily simulation model that assumes all reservoirs are in place for the entire period of record specified for each model, based on data availability. For each SUPER model, a complex set of intervening area flows is developed for the entire period of record. This is the culmination of the pre-processing of data, before any simulation is done. When simulation is begun, headwater reservoir inflows and subsequent derived releases based on current and future forecast conditions are then routed through the system on a daily basis. These routed flows are combined with intervening area flows at all control point locations. Reservoir releases are made for flood control, hydroelectric power generation, water supply requirements, and stream flow requirements such as water quality and irrigation. Other regulating considerations include channel capacities and bank stability. All releases are analyzed to determine their impact on current and future forecasted conditions and are adjusted as needed to meet predefined system constraints. In addition to the above requirements, SUPER works to achieve a target uniform balance between all competing reservoirs during the draw down of system flood storage, and a target uniform balance in system conservation storage remaining during a conservation pool draw down. SUPER has evolved to meet the complex challenge of modeling system operations while meeting system and local constraints, and balancing requirements.

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SUPER Hydrologic Development

Prior to this study, the Red River SUPER model had a hydrologic period-of-record from January 1938 to December 1990. Although there had not been any significant floods along the Red River through most of the 1990's, there had been some drier years and enough additional years of record that the model needed to be updated. The goal of this update was to extend the period of record to 2000.

This required collecting and formatting an additional 10 years of daily inflows for the 20 reservoirs within the model and daily flows for numerous flow gages used to develop the period-of-record hydrology. Monthly evaporation and precipitation at numerous locations was also collected and formatted. The data was extracted as much as possible from the USGS published data. Reservoir inflows, data for unpublished gages, and some evaporation data were taken from the internal Corps of Engineers databases. All required data were input into the Red River SUPER database.

After the Red River SUPER database was updated and complete, extensive editing of the hydrologic files was done to incorporate and utilize the additional 10 years of daily data that was available. Hydrologic building files were then run through a series of programs to develop the updated period-of-record hydrology or local flows.

With the updated hydrology files, a natural conditions run, simulating no reservoirs in place, was made. As a final check to spot errors in building the hydrology file, a volume checking program was run, which performs a volume comparison between the natural condition flows developed from SUPER and observed gaged flow data. This required building an extensive input file to perform the volume checking analysis. Problems were corrected as required.

Texoma Yield Analysis Using SUPER

With the updated SUPER model, it was desired to determine the true yield of the conservation storage available at the end of the project life. The yield of the conservation storage is required to determine the critical dependable water supply demand that will occur if the entire reallocated storage is used for water supply. This will provide a worse case demand for water supply during the critical drought. At Lake Texoma, the conservation storage lies between elevation 590 and 617. The end of the project life at Texoma is 2044. The water supply yield run was made using an updated elevation-area-capacity table based on the 2002 sediment resurvey of Lake Texoma, with projected future sedimentation to 2044. This projected future storage is considered "usable storage". The true yield of the conservation storage at Lake Texoma for the projected 2044 conditions was determined to be 1502.5 cfs. The critical dependable yield for the conservation storage allocated to water supply is determined based on the following equation:

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$$\text{Critical Dependable Yield for Yield} = \frac{\text{Total Allocated Water Supply Storage}}{\text{Total “Usable” Conservation Storage (in 2044)}} * \text{True Allocated Water Supply Storage}$$

$$\text{For the full 300,000 acre-feet reallocation, the Critical Dependable Water Supply Yield} = \frac{\text{150,000 ac-ft (past) + 300,000 ac-ft (present)}}{\text{986,730 ac-ft}} * \text{1502.5 cfs}$$

$$= \text{685.2 cfs or 442.1 mgd}$$

Current water supply contracts based on the 1985 sediment survey with sediment projections to 2044 will need to be updated to the current “usable storage” based on the 2002 sediment survey at Texoma.

Texoma Water Supply Reallocation Runs Using SUPER

Three SUPER runs were made to model impacts at Texoma due to the current reallocation of hydropower to water supply. The critical dependable water supply demand is the only input parameter that varies between the runs. The runs made are as follows:

(1) Existing conditions in which the full 150,000 acre-feet previously reallocated from hydropower to water supply at Texoma is utilized. The water supply demand modeled = 228.4 cfs

(2) Modified conditions in which the previous 150,000 acre-feet of reallocated water supply storage is utilized at Texoma plus half the current Texoma water supply reallocation of 300,000 acre-feet (150,000 acre-feet for Texas and 150,000 acre-feet for Oklahoma). Therefore, the total water supply demand for Texoma modeled in this run is 300,000 acre-feet. This modified conditions run basically models Texas fully utilizing their water supply demand. The water supply demand modeled = 456.8 cfs

(3) Modified conditions in which the previous 150,000 acre-feet of reallocated water supply storage is utilized at Texoma plus all the current Texoma water supply reallocation of 300,000 acre-feet. The total water supply demand for Texoma modeled in this run is 450,000 acre-feet. This run models fully utilized water supply conditions at Texoma or the worst case scenario, for demands on Texoma. The water supply demand modeled = 685.2 cfs.

These runs were all done with the updated 2002 Lake Texoma Elevation-Area-Capacity table, with the updated Texoma seasonal pool guide curve (see Figure 1), and the extended period of record hydrology through 2000. The water supply demand at Texoma is modeled as a constant year-round demand. Results of the runs are provided in both graphical and tabular form in the appendix.

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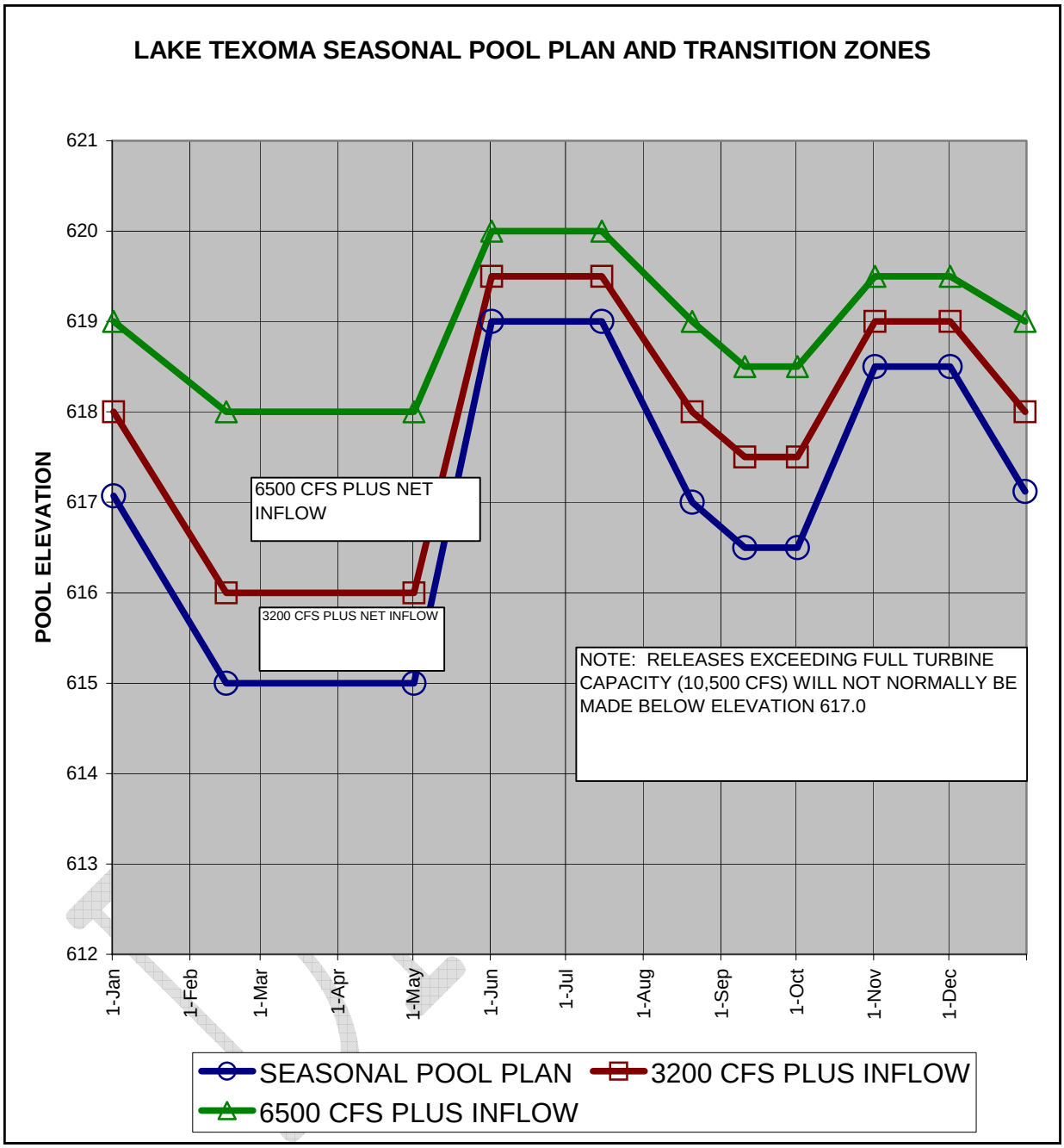
Figure 1 Texoma Seasonal Pool



10.1.2 Appendix

Figure 1 **Texoma Comparative Elevation-Frequency Curve between Super Runs A03X07, A03X08, and A03X09**

Figure 2 **Texoma Comparative Elevation-Duration Curve between Super Runs A03X07, A03X08, and A03X09**

Figure 3 **Texoma Outflow Comparative Flow-Frequency Curve between Super Runs A03X07, A03X08, and A03X09**

Figure 4 **Texoma Outflow Comparative Flow-Duration Curve between Super Runs A03X07, A03X08, and A03X09**

Figure 5 **Arthur City Comparative Flow-Frequency Curve between Super Runs A03X07, A03X08, and A03X09**

Figure 6 **Arthur City Comparative Flow-Duration Curve between Super Runs A03X07, A03X08, and A03X09**

Figure 7 **Texoma Comparative Minimum Elevation-Frequency Curve between Super Runs A03X07, A03X08, and A03X09**

Figure 8 **Arthur City Comparative Minimum Flow-Frequency Curve between Super Runs A03X07, A03X08, A03X09**

Note: Tabular Data for the above plots is provided in the following computer files:

Text Files - Note x axis on the minimum frequency files should be reversed.
TEXEL07 - Texoma elevation-frequency and elevation-duration data for run R03X07
TEXEL08 - Texoma elevation-frequency and elevation-duration data for run R03X08
TEXEL09 - Texoma elevation-frequency and elevation-duration data for run R03X09
TEXOUT07- Texoma outflow flow-frequency and flow-duration data for run R03X07
TEXOUT08- Texoma outflow flow-frequency and flow-duration data for run R03X08
TEXOUT09- Texoma outflow flow-frequency and flow-duration data for run R03X09
ARTH07 - Arthur City flow-frequency and flow-duration data for run R03X07
ARTH08 - Arthur City flow-frequency and flow-duration data for run R03X08
ARTH09 - Arthur City flow-frequency and flow-duration data for run R03X09

Excel File
TexWSReal-FreqDur – All tabular data for the three SUPER runs plus minimum frequency files with corrected x axis

Power Point File
TexomaWSRealloc – All plots shown in the figures

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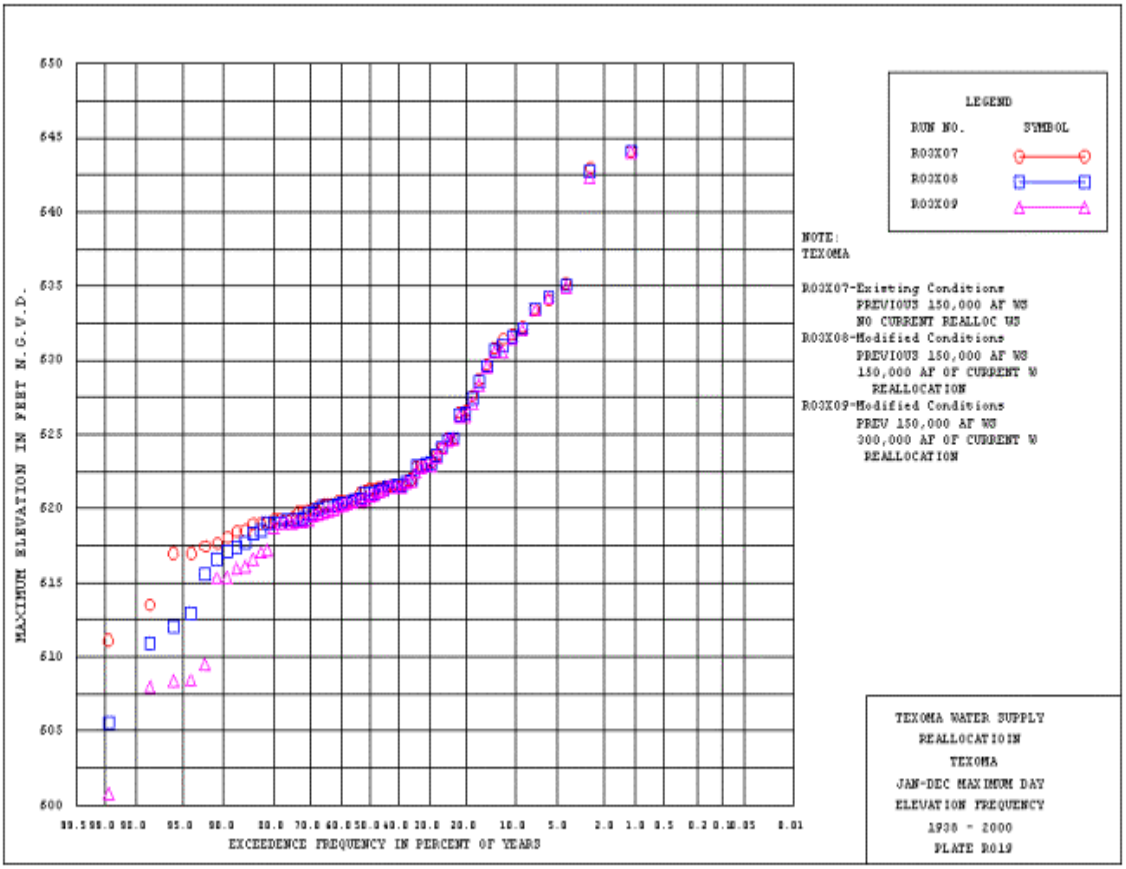
MAXIMUM ELEVATION IN FEET N.G.V.D.
650
645
640
635
630
625
620
615
610
605
600
EXCEEDENCE FREQUENCY IN PERCENT OF YEARS
LEGEND
RUN NO.
SYMBOL
R03X07
R03X08
R03X09
NOTE:
TEXOMA
R03X07-Existing Conditions
PREVIOUS 150,000 AF WS
NO CURRENT REALLOC WS
R03X08-Modified Conditions
PREVIOUS 150,000 AF WS
150,000 AF OF CURRENT W
REALLOCATION
R03X09-Modified Conditions
PREV 150,000 AF WS
300,000 AF OF CURRENT W
REALLOCATION
TEXOMA WATER SUPPLY
REALLOCATIOIN
TEXOMA
JAN-DEC MAXIMUM DAY
ELEVATION FREQUENCY
1938 - 2000
PLATE R019

Figure 1

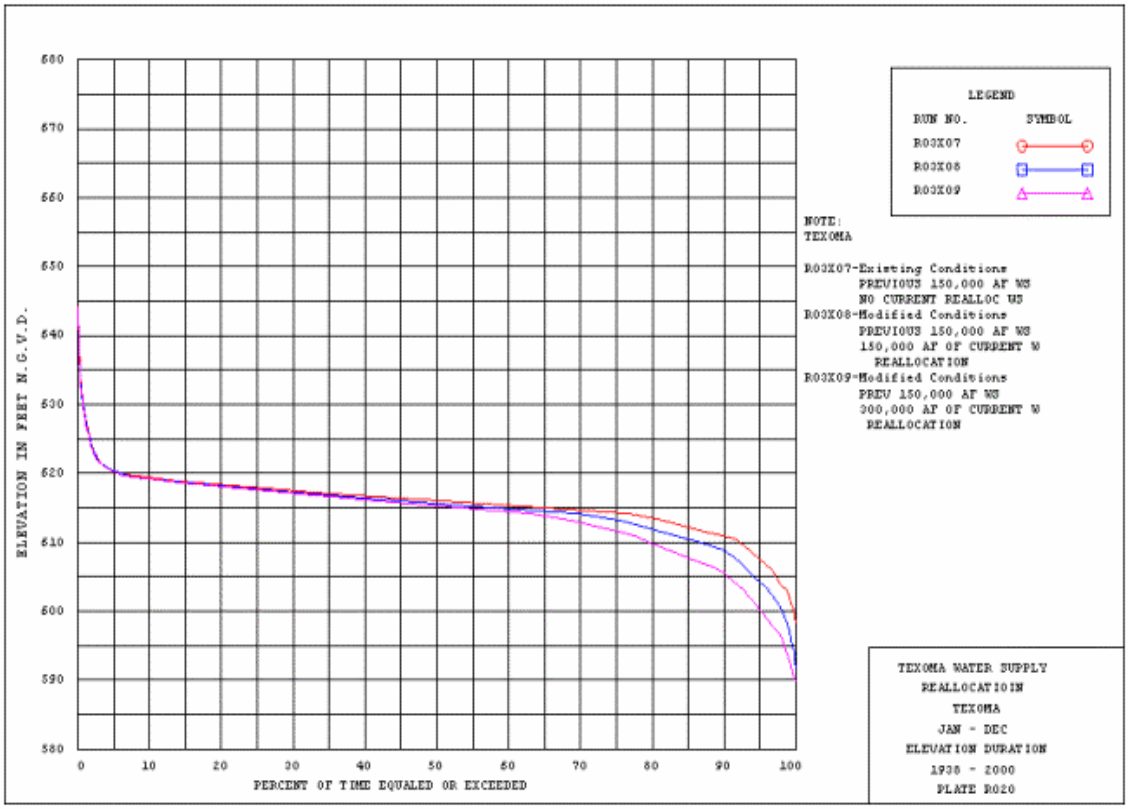
ELEVATION IN FEET N.G.V.D.
680
670
660
650
640
630
620
610
600
590
580
0
10
20
30
40
50
60
70
80
90
100
PERCENT OF TIME EQUALED OR EXCEEDED
LEGEND
RUN NO.
SYMBOL
R03X07
R03X08
R03X09
NOTE:
TEXOMA
R03X07-Existing Conditions
PREVIOUS 150,000 AF WS
NO CURRENT REALLOC WS
R03X08-Modified Conditions
PREVIOUS 150,000 AF WS
150,000 AF OF CURRENT W
REALLOCATION
R03X09-Modified Conditions
PREV 150,000 AF WS
300,000 AF OF CURRENT W
REALLOCATION
TEXOMA WATER SUPPLY
REALLOCATIOIN
TEXOMA
JAN - DEC
ELEVATION DURATION
1938 - 2000
PLATE R020

Figure 2

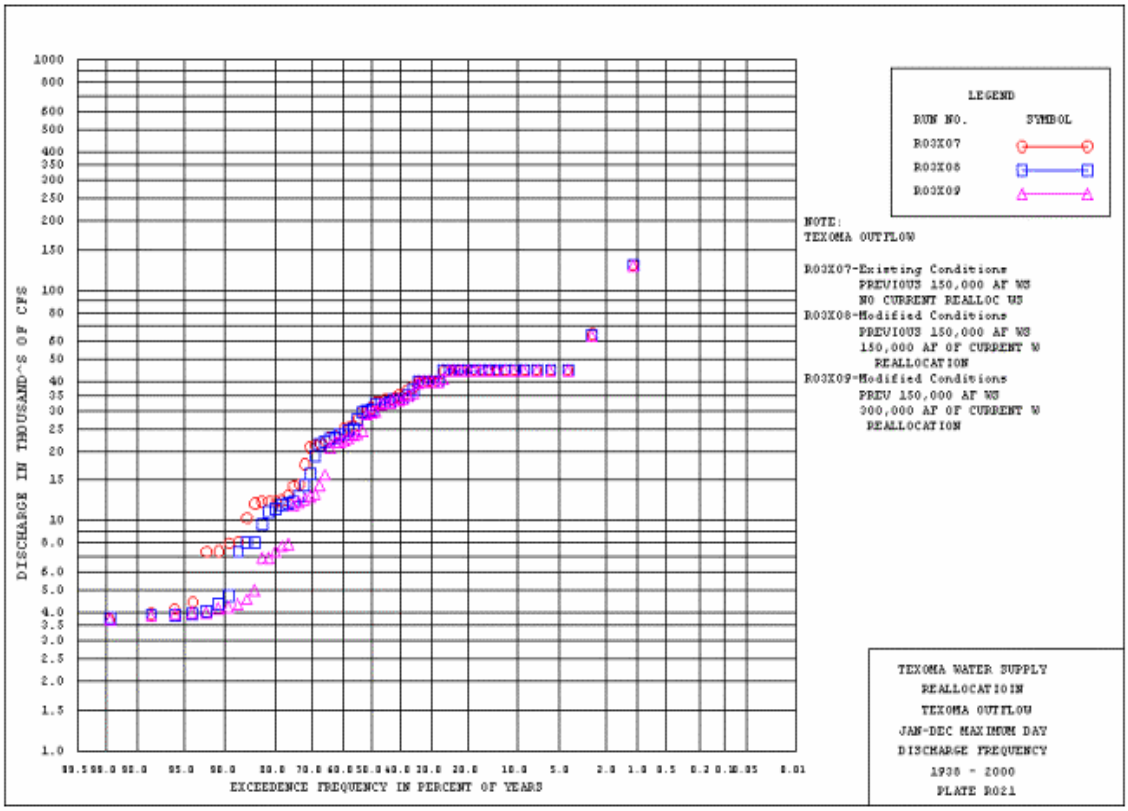
LEGEND
RUN NO.
SYMBOL
R03X07
R03X08
R03X09
NOTE:
TEXOMA OUTFLOW
R03X07-Existing Conditions
PREVIOUS 150,000 AF WS
NO CURRENT REALLOC WS
R03X08-Modified Conditions
PREVIOUS 150,000 AF WS
150,000 AF OF CURRENT W
REALLOCATION
R03X09-Modified Conditions
PREV 150,000 AF WS
300,000 AF OF CURRENT W
REALLOCATION
DISCHARGE IN THOUSAND^S OF CFS
EXCEEDENCE FREQUENCY IN PERCENT OF YEARS
TEXOMA WATER SUPPLY
REALLOCATIOIN
TEXOMA OUTFLOW
JAN-DEC MAXIMUM DAY
DISCHARGE FREQUENCY
1938 - 2000
PLATE R021

Figure 3

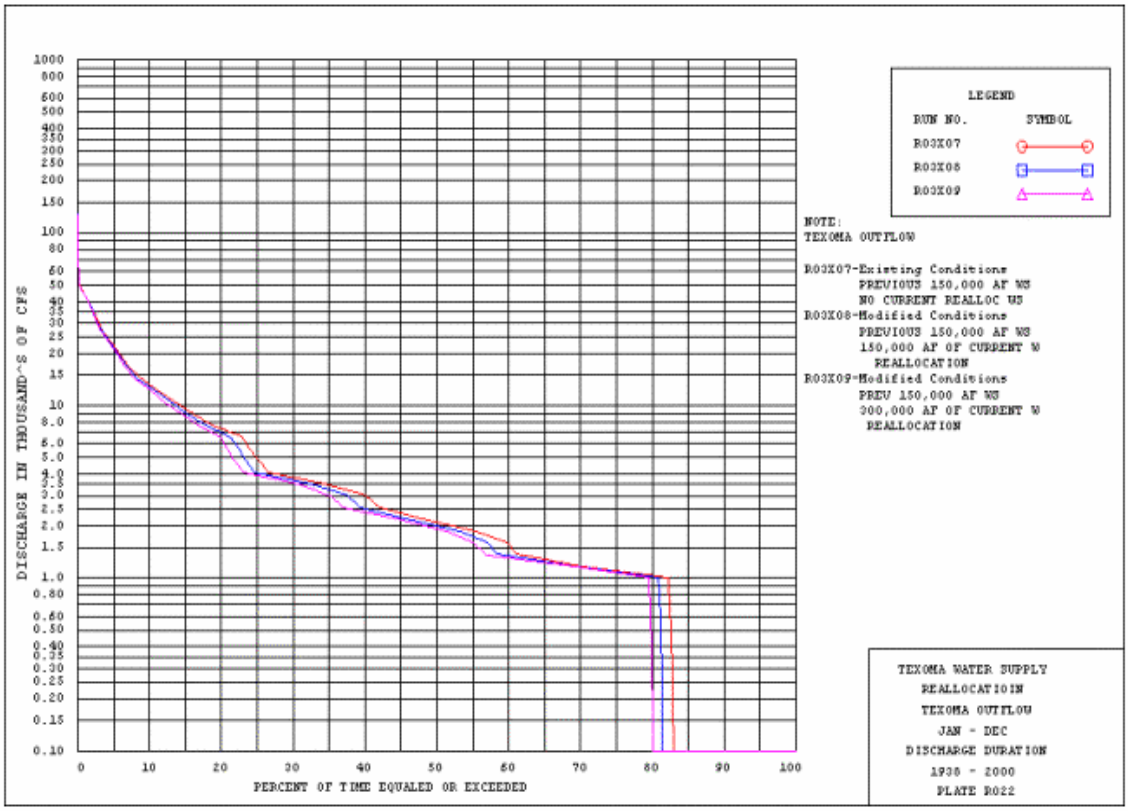
LEGEND
RUN NO.
SYMBOL
R03X07
R03X08
R03X09
NOTE:
TEXOMA OUTFLOW
R03X07-Existing Conditions
PREVIOUS 150,000 AF WS
NO CURRENT REALLOC WS
R03X08-Modified Conditions
PREVIOUS 150,000 AF WS
150,000 AF OF CURRENT W
REALLOCATION
R03X09-Modified Conditions
PREV 150,000 AF WS
300,000 AF OF CURRENT W
REALLOCATION
DISCHARGE IN THOUSAND^S OF CFS
PERCENT OF TIME EQUALED OR EXCEEDED
TEXOMA WATER SUPPLY
REALLOCATIOIN
TEXOMA OUTFLOW
JAN - DEC
DISCHARGE DURATION
1938 - 2000
PLATE R022

Figure 4

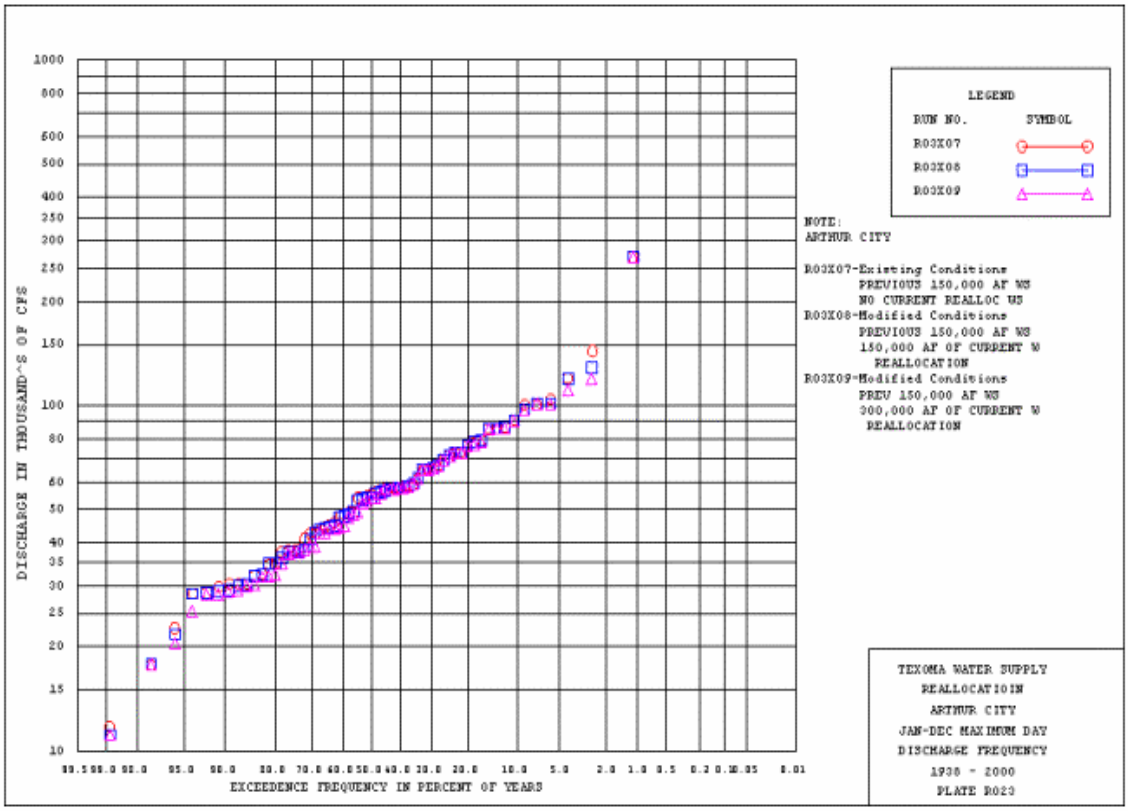
LEGEND
RUN NO.
SYMBOL
R03X07
R03X08
R03X09
NOTE:
ARTHUR CITY
R03X07-Existing Conditions
PREVIOUS 150,000 AF WS
NO CURRENT REALLOC WS
R03X08-Modified Conditions
PREVIOUS 150,000 AF WS
150,000 AF OF CURRENT W
REALLOCATION
R03X09-Modified Conditions
PREV 150,000 AF WS
300,000 AF OF CURRENT W
REALLOCATION
DISCHARGE IN THOUSAND^S OF CFS
EXCEEDENCE FREQUENCY IN PERCENT OF YEARS
TEXOMA WATER SUPPLY
REALLOCATIOIN
ARTHUR CITY
JAN-DEC MAXIMUM DAY
DISCHARGE FREQUENCY
1938 - 2000
PLATE R023

Figure 5

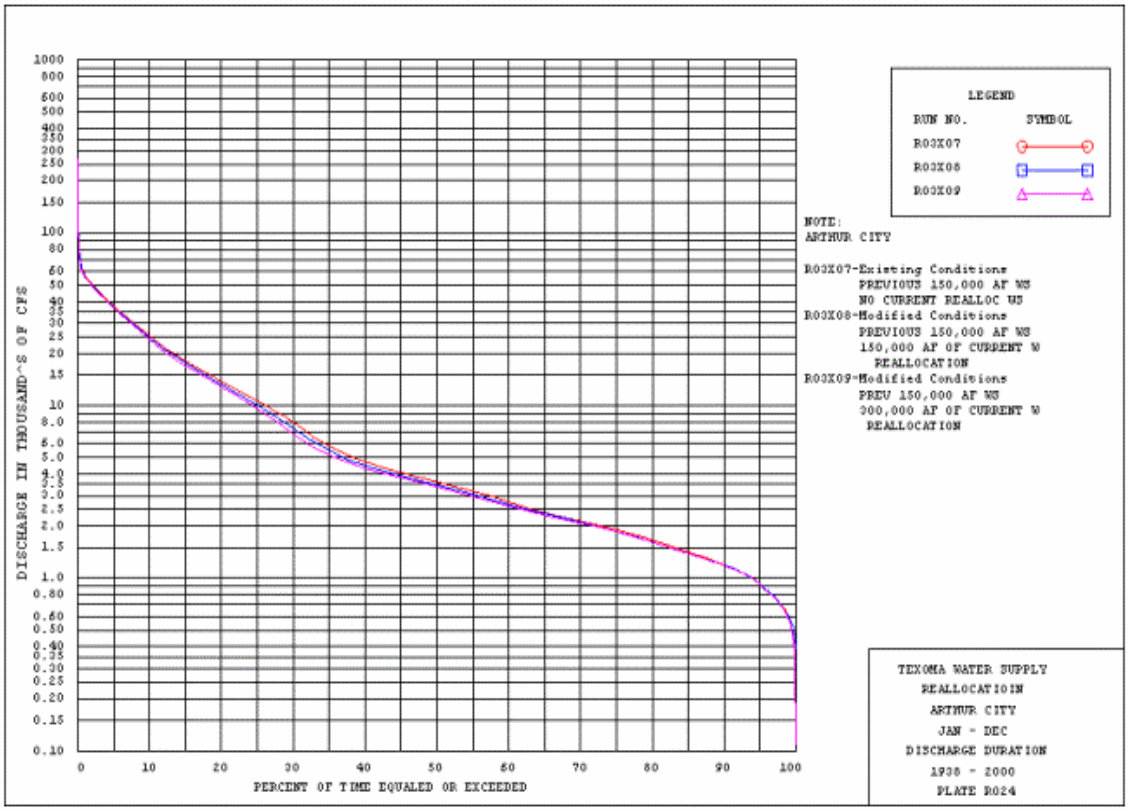
LEGEND
RUN NO.
SYMBOL
R03X07
R03X08
R03X09
NOTE:
ARTHUR CITY
R03X07-Existing Conditions
PREVIOUS 150,000 AF WS
NO CURRENT REALLOC WS
R03X08-Modified Conditions
PREVIOUS 150,000 AF WS
150,000 AF OF CURRENT W
REALLOCATION
R03X09-Modified Conditions
PREV 150,000 AF WS
300,000 AF OF CURRENT W
REALLOCATION
DISCHARGE IN THOUSAND^S OF CFS
PERCENT OF TIME EQUALED OR EXCEEDED
TEXOMA WATER SUPPLY
REALLOCATIOIN
ARTHUR CITY
JAN - DEC
DISCHARGE DURATION
1938 - 2000
PLATE R024

Figure 6

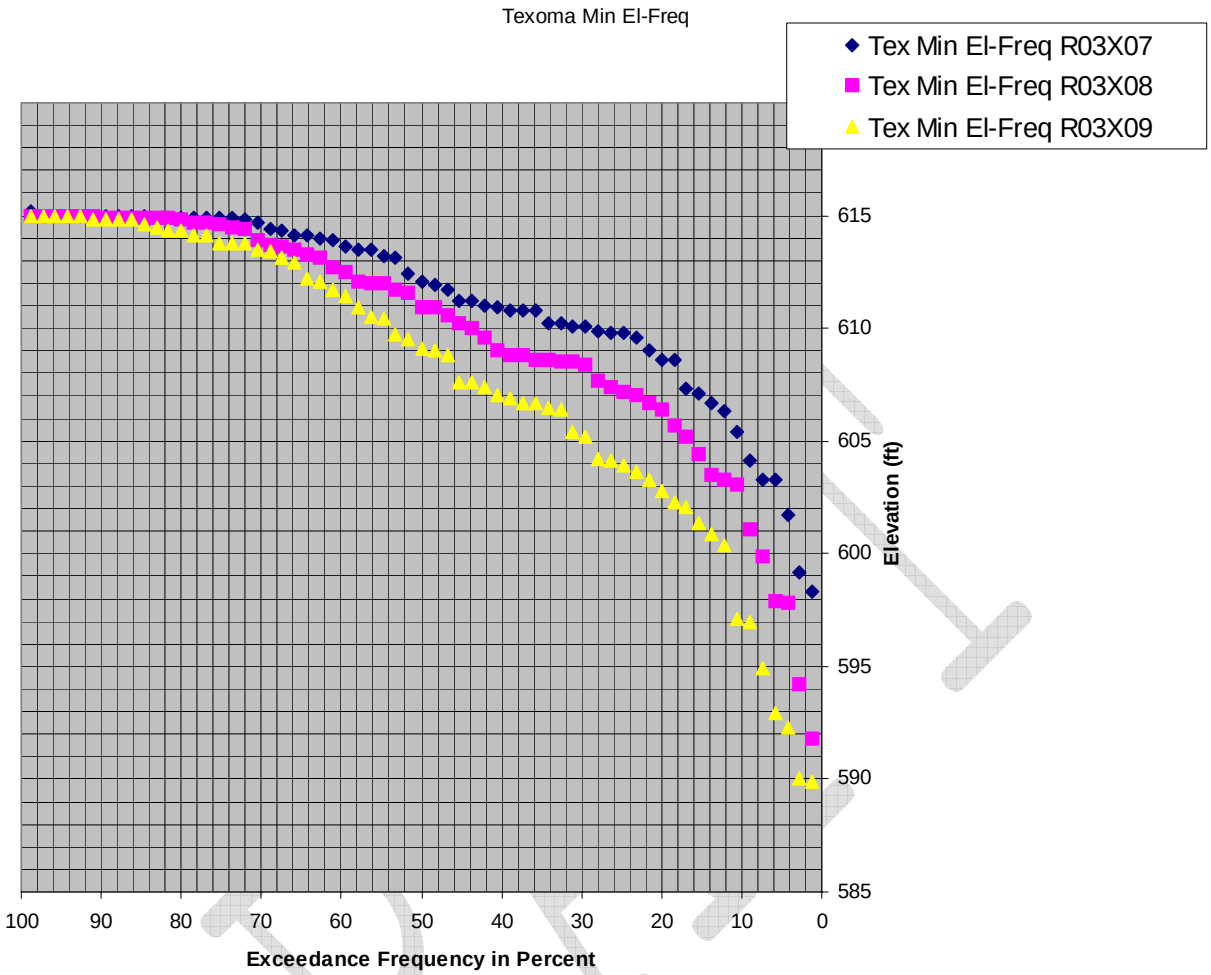
Texoma Min El-Freq
Tex Min El-Freq R03X07
Tex Min El-Freq R03X08
Tex Min El-Freq R03X09
615
610
605
600
595
590
585
Elevation (ft)
100
90
80
70
60
50
40
30
20
10
0
Exceedance Frequency in Percent

Figure 7

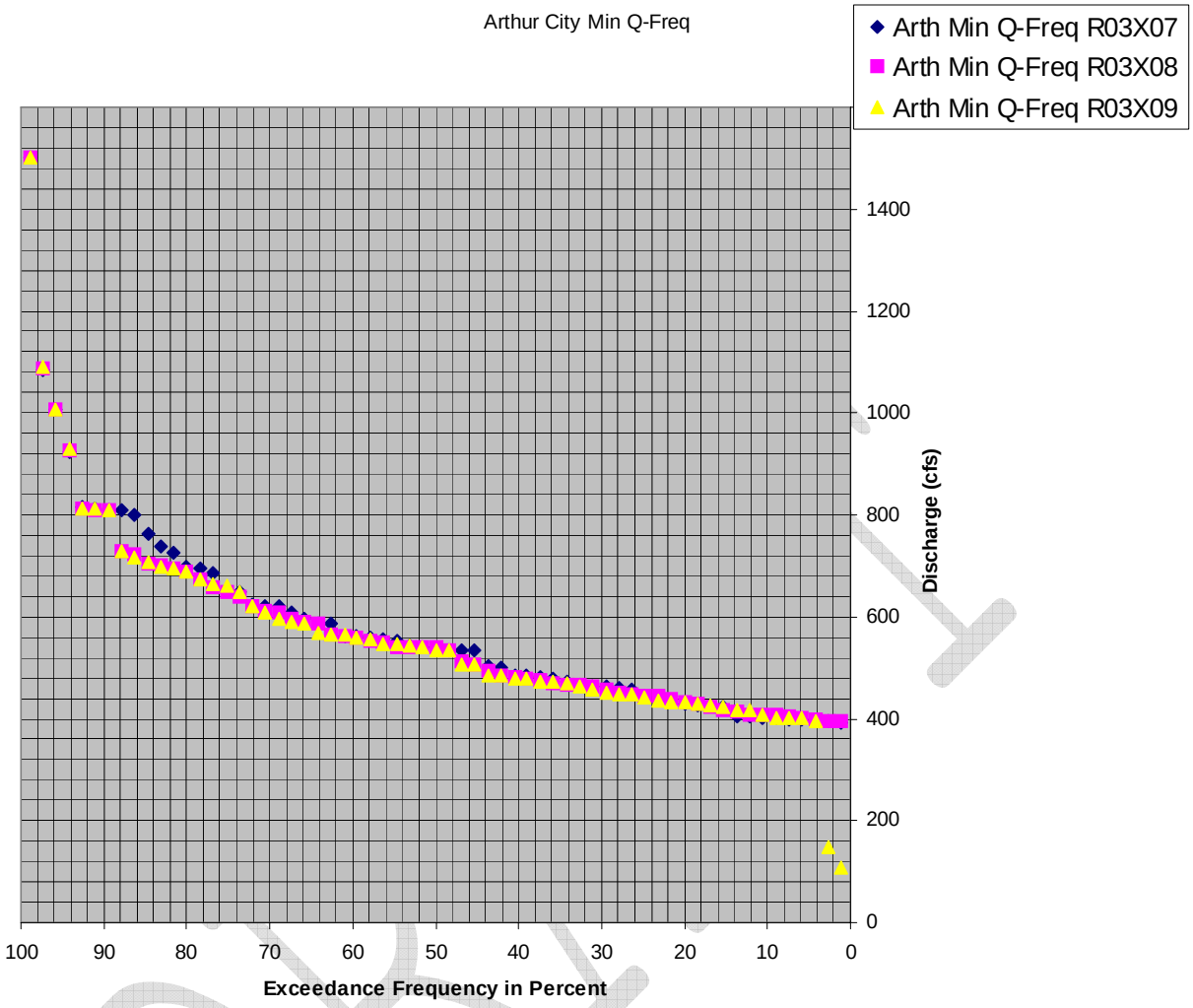
Arthur City Min Q-Freq
Arth Min Q-Freq R03X07
Arth Min Q-Freq R03X08
Arth Min Q-Freq R03X09
1400
1200
1000
800
600
400
200
0
Discharge (cfs)
100
90
80
70
60
50
40
30
20
10
0
Exceedance Frequency in Percent

Figure 8

APPENDIX 11.4
LAKE TEXOMA WATER SUPPLY DEMAND AND ANALYSIS

11.4.1 Lake Texoma Water Reallocation Study - Water Supply Demand Analysis and Analysis of Water Supply Alternatives

11.4.1.1 Introduction. The following sections discuss water supply and demand in Texas and Oklahoma, for those areas are most likely to be impacted by the availability of water supply from Lake Texoma. The Texas portion is derived, in part, from the "Initially Prepared Texas State Water Plan for Region C, 2006," dated June 2005, with the focus on the NTMWD and the GTUA. Information presented in the Oklahoma portion is taken from information developed by the U.S. Army Corps of Engineers, Tulsa District and others for the 2005 update of the Oklahoma State Water Plan.

11.4.1.2 Water Demand and Supply: Texas - Initially Prepared Texas State Water Plan for Region C, 2006.

11.4.1.2.1 Study Area. The study area includes the counties and water systems or districts in the North Texas region that are currently using Lake Texoma water or may use Lake Texoma water in the future. In addition to the Texas counties, those Oklahoma counties that may currently be using or expect to use Lake Texoma water in the future will be discussed. The focus will be on the Texas counties and major water systems that have an expressed need for water from Lake Texoma. The basis for the evaluation of water supply and demands for the region is the "Initially Prepared Texas State Water Plan for Region C 2006", June 2005 draft. Region C includes Grayson County adjacent to Lake Texoma mainly in the Red River Basin and the Dallas-Fort Worth metropolitan area, lying mostly in the Trinity River Basin. The population of Region C was about 5 million in 2000, with Dallas and Tarrant counties accounting for over 70% of the region's population. This area has shown strong population and economic growth over the last decade. Although Region C contains about 25% of the State's population, only about 7% of Texas' water use occurs in the region due to the lack of irrigation in the region. Figure 4 shows Region C with major water resources identified.

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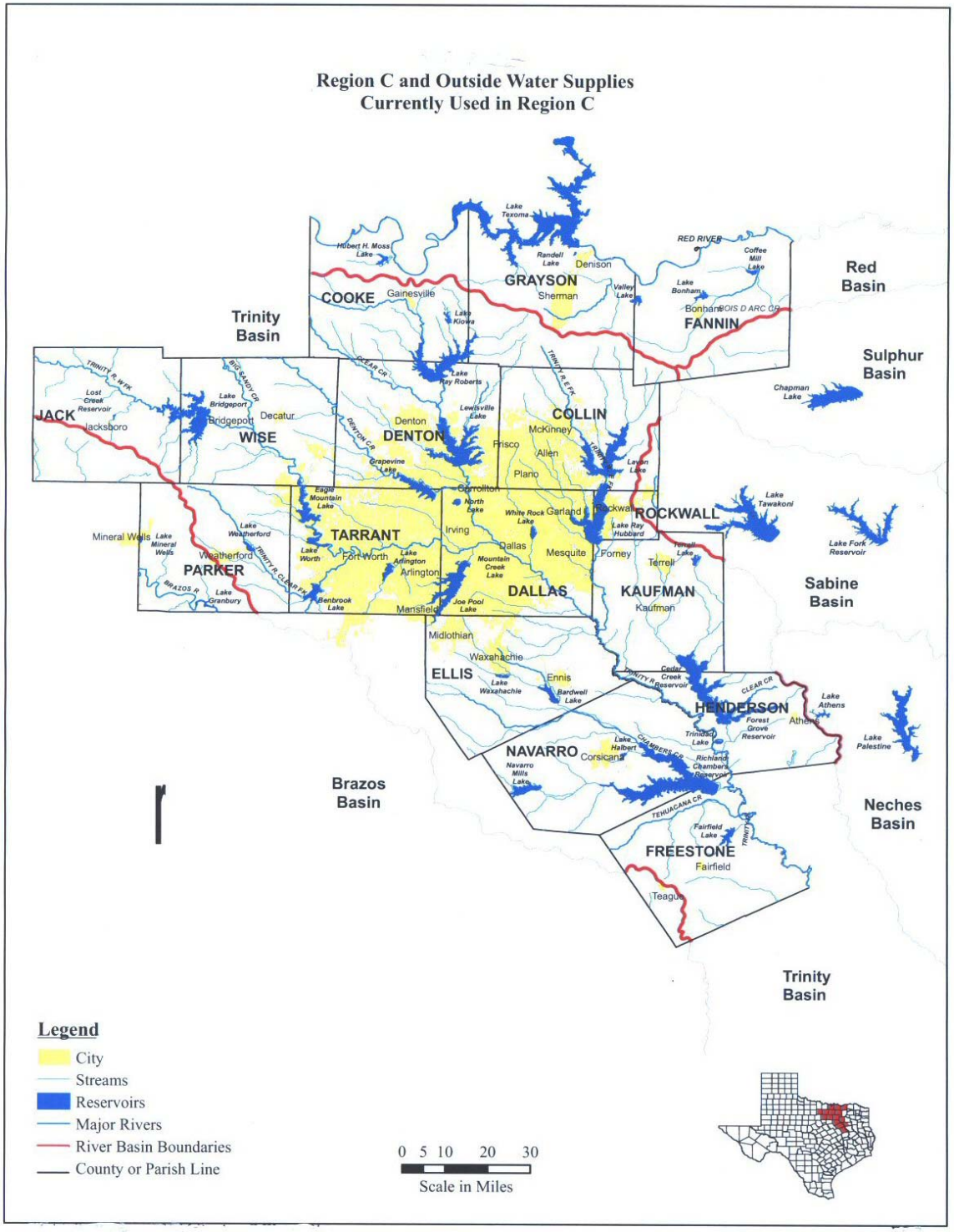

Figure 1. Region C And Outside Water Supplies Currently Used In Region C

Table 1 shows historical and future populations for selected counties in Region C. Projections are made by 20-year increments from 2020 to 2060. Although this table doesn't display all counties (the Texas State Water Plan shows all counties), it represents most of the expected population counts in the region.

TABLE 1

HISTORICAL AND POPULATION PROJECTIONS BY SELECTED COUNTIES
REGION C
TEXAS STATE WATER PLAN 2006

County	Year				
	1990	**2000**	**2020**	**2040**	**2060**
Collin	264,036	491,774	1,033,173	1,512,261	2,033,981
Dallas	1,852,810	2,218,774	2,883,564	3,338,498	4,032,056
Denton	273,525	432,976	953,668	1,392,575	1,870,472
Grayson	95,021	110,595	163,711	208,936	253,568
Tarrant	1,170,103	1,446,219	1,956,163	2,454,046	3,146,721
Total	3,655,495	4,700,338	6,990,279	8,906,316	11,336,798
Region C Total	4,077,565	5,254,722	7,966,389	10,246,795	13,087,849

Source: Initially Prepared Texas State Water Plan 2006, June 2005 draft.

11.4.1.2.2 Water Demand. Although all 16 counties in Region C are evaluated in the State Water Plan, 5 counties (Collin, Dallas, Denton, Grayson, and Tarrant) stand out for comparative purposes relative to probable future use of Lake Texoma water. There are 35 wholesale water providers and 351 water user groups in Region C. Major water providers serve all or portions of other counties as well. These counties have as their major providers of water the NTMWD (Collin County), the Dallas Water Utilities (DWU) (Dallas County), and the GTUA (Grayson County). Two other counties, Denton (DWU) and Tarrant (TRWD), also account for expected large future municipal water demands. Water demand projections for Region C were categorized by use as municipal, manufacturing, steam-electric power, mining, irrigation, and livestock. Region-wide projections are consistent with Texas Water Development Board (TWDB) planning guidelines. These projections now incorporate a substantial slowing in the rate of population growth over the next 50 years. Water conservation is also built into the demand projections. Currently implemented water conservation strategies and water conservation assumption are implicit in the water demand projections for the region. For example, by 2060 low flow plumbing devices would reduce future water demand about 5% of total regional demand. More efficient power plants will also reduce water consumption in the future.

A significant increase in per capita water use in the region occurred in 1996 and 1998 despite conservation efforts and the impact of low flow plumbing fixtures. Although per capita water use has been increasing for many communities, conservation measures will partially offset this increase. Rapid development in communities and in commercial development accounts for part of this increase. Projected municipal water demand is a function of per capita use rates and population growth. Conservation measures will also reduce the per capita use rate from 197 gallons per capita day (gpcd) in 2000 to less that 120 gpcd by 2020.

The vast majority of historical and future water use will occur in the municipal sector. The historical year 1996 use for municipal was about 947,000 acre-feet (846 mgd) out of a total of 1,127,000 acre-feet (1,006.3 mgd) for Region C. Projected municipal water demand by 2050 for the region is expected to be

2,125,000 acre feet (1,897.3 mgd) out of a total of 2,537,000 acre-feet (2,265.2 mgd). These data indicate a strong demand for water in the future, mainly for municipal purposes.

Table 2 shows historical and future water demand for selected counties in Region C. Projections are made by 20-year increments and water use category from 2020 to 2060. Although this data does not display all counties, it represents most of the future water demand in the region.

TABLE 2

HISTORICAL AND PROJECTED WATER DEMAND BY SELECTED COUNTIES
TEXAS STATE WATER PLAN 2006
(acre-feet)

County	Year				
	1996	2000	2020	2040	2060
Collin	89,230	138,306	287,247	402,383	526,315
Dallas	505,423	623,535	785,788	879,106	1,055,030
Denton	65,075	93,982	212,211	307,951	406,700
Grayson	29,152	32,478	45,954	55,613	66,715
Tarrant	291,406	331,066	451,536	559,650	718,098
Total	980,286	1,219,367	1,782,736	2,204,703	2,772,858
Region C Total	1,126,621	1,380,556	2,100,519	2,622,513	3,311,217
Municipal	946,454	1,196,452	1,828,831	2,294,491	2,915,773

Source: Initially Prepared Texas State Water Plan 2006, June 2005.

11.4.1.2.3 Existing and Potential Sources of Water Supply by Major Provider. There are over 34 reservoirs in Region C with conservation storage over 5,000 acre-feet. Additional reservoirs outside the region provide water supply to the region. Although use of groundwater has been decreasing, the Trinity Aquifer supplies most of the groundwater used in this region, mainly in rural areas. Ninety percent of the total water supplied in the region is from surface sources. Municipal supply accounts for about 85% of current water use. Little wastewater is treated and returned for use although municipalities are considering reuse as a source of future supply. In addition to the GTUA serving the Sherman-Denison communities in Grayson County, there are five major water providers in the region. They are Dallas Water Utilities (DWU), Tarrant Regional Water District (TRWD), the NTMWD, the city of Fort Worth, and the Trinity River Authority (TRA).

Total water use in Region C in 2000 was over 1.38 million acre-feet (1,231 mgd), of which about 60% came from in-region reservoirs and 28% was imported from other regions. By 2060, total water supply from reliable sources will be about 1,927,000 acre-feet (1,720 mgd). In–region reservoirs, as a source of water supply for Region C in 2060, are expected to total about 1,127,000 acre-feet (1,006 mgd), or about 58% of the total supply. Other sources of water supply in the region include 106,000 acre-feet (95 mgd) from groundwater, 44,000 acre-feet (39 mgd) from local supplies, 103,000 acre-feet (92 mgd) from reuse, and 546,000 acre-feet (487 mgd) (28% of total supply) from other regions. The expected supply from existing sources in 2060 is significantly less than expected demand. Nine of the regional wholesale water suppliers provide about 77% of the supply available to the region, and by 2060 will continue to have about 77% of the water supply currently available in the region. The amount of current water supply available to the region will decline about 4% by 2060. The Texas Region C Water Plan indicates that in 2000, Cooke, Dallas, and Parker counties show a net need for additional supplies, with additional

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supplies needing to be connected by 2010. By 2060, 11 out of 16 Region C counties show a need for the development of additional supplies to meet projected demands.

a. North Texas Municipal Water District (NTMWD). The NTMWD is comprised of Collin County and portions of Kaufman, Rockwall, and Dallas counties in north central Texas. The NTMWD provides wholesale water and wastewater service to communities within its boundary. The cities of Plano, Richardson, Garland, Mesquite, and McKinney are a few of the larger municipalities receiving all or part of their service from the NTMWD. Water demand is expected to double between 2010 and 2060, with a shortage of about 100,000 acre-feet by 2010, increasing to 534,000 acre-feet by 2060. The main water treatment plant for the NTMWD is located near Lake Lavon. The district receives its surface water supply from three primary sources, Lake Lavon, Cooper Lake, and Lake Texoma.

(1) <u>Existing Sources of Water Supply: NTMWD</u>.

Lake Lavon. Lake Lavon is located on the East Fork of the Trinity River approximately 1 mile northwest of Lavon, Texas, in Collin County. The Corps of Engineers built Lake Lavon in 1953 for flood control and water supply. The lake has conservation storage of 380,000 acre-feet with a dependable yield of about 92.0 mgd. The entire yield is allocated and contracted to the NTMWD which has a water right to 104,000 acre-feet of storage. The lake also receives up to 24.0 mgd of effluent from the Wilson Creek Wastewater Treatment Plant and is the receiving point for inter-basin transfers of water from Lake Texoma and Lake Cooper. Facilities are in place to utilize the entire available yield of Lake Lavon.

Jim Chapman Lake/Cooper Dam. Jim Chapman Lake/Cooper Dam is a Corps of Engineers reservoir on the South Sulphur River, 4 miles southeast of Cooper, Texas, in Hopkins and Delta counties. Jim Chapman Lake was completed in 1992. The reservoir has conservation storage of 273,120 acre-feet with a dependable yield of ±107.1 mgd. The NTMWD, the city of Irving, and the Sulphur River Water District (SRWD) hold water rights in Lake Chapman totaling 146,250 acre-feet per year, of which 127,320 acre-feet per year can be exported for use in Region C. The NTMWD receives 57,214 acre-feet per year; the city of Irving, 54,000 acre-feet per year; and the Upper Trinity Regional Water District (UTRWD) (purchased from the SRWD), 16,106 acre-feet per year. The SRWD has contracted a portion of its yield to the UTRWD for use in the Denton County, Texas, area. Currently available water from Lake Jim Chapman for the NTMWD is 50,802 acre-feet per year in 2000 decreasing to 45,843 acre-feet per year by 2060. The city of Irving receives 47,948 acre-feet per year in 2000 decreasing to 43,268 acre-feet in 2060. Finally, the UTMWD receives 14,301 acre-feet per year in 2000 decreasing to 12,905 acre-feet per year by 2060. Each entity is permitted to divert at a maximum rate of 122% of allocated yield. The NTMWD has facilities in place to transfer up to 110 mgd of water from Cooper Lake to Lake Lavon.

Lake Texoma. Lake Texoma, on the Red River near Denison, Texas, is the third surface water source utilized by the NTMWD. The reservoir has 2,722,000 (is this current conservation pool?) acre-feet of conservation storage (does this include the Cumberland pool? I don't think the Cumberland pool is included in the integrated hydropower and water supply pool. Otherwise I thought the conservation storage was 1,002,070 AF.) The RRAT, the GTUA, the city of Denison, the NTMWD, and Texas Utilities (TXU) have water rights in Lake Texoma. Lake Texoma water is pumped and then gravity flowed to Lake Lavon and blended for subsequent use. The NTMWD has contractual rights to divert up to 77,300 acre-feet or about 75.0 mgd of water from Lake Texoma. Other entities that have storage at Lake Texoma are the GTUA, acting for the city of Sherman, Texas; 22,600 acre-feet; the city of Denison, 21,300 acre-feet; the TXU, 16,400 acre-feet; and the RRAT, 2,473 acre-feet.

Groundwater sources for the NTMWD area are of poor quality or limited quantity and, therefore, are not considered adequate potential sources of water supply.

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(2) Potential Sources of Water Supply: Water Management Strategies. There are no reservoirs proposed for construction in this region. Major regional wholesale water providers, such as the NTMWD, the DWU, the TRWD, and the UTRWD, have similar strategies. These strategies include water conservation, reuse water, installation of connections to existing sources already under contract, connection to other existing sources, and development of new reservoirs. Marvin Nichols Reservoir, Toledo Bend Reservoir, and Oklahoma water are possible sources of new supply for the NTMWD as well as for the other major providers. New Bonham Reservoir, George Parkhouse, and Marvin C. Nichols Reservoir are under consideration by the NTMWD as possible water supply sources outside the area.

Marvin Nichols Reservoir is another potential two-stage impoundment on the Sulphur River and White Oak Creek in southwestern Bowie and Morris counties. The total yield of water supply is about 612,300 acre-feet per year, assuming that Ralph Hall Lake is senior to Marvin Nichols Reservoir and that Marvin Nichols Reservoir is operated as a system with Lake Wright Patman. With about 489,430 acre-feet available for Region C, the NTMWD share would be about 174,840 acre-feet, while the TRWD (have you identified TRWD?) would receive the largest amount at 280,000 acre-feet per year. The DWU and the city of Irving would use this reservoir as an alternate source of supply. Phase 1 would be developed by 2030 and Phase 2 by 2050. Most of the cost is in the pipelines and pump stations.

Toledo Bend Reservoir in East Texas is recommended for the TRWD and the NTMWD as a primary strategy and for the DWU and the UTRWD as an alternate strategy. The NTMWD's share would be 200,000 acre-feet per year of the total 500,000 acre-feet available by 2050. The TRWD would also receive 200,000 acre-feet per year.

Oklahoma water remains a promising source of supply for the North Texas region although the Oklahoma legislature has a current moratorium on export of water from the state. Although the long term (year 2060) recommended strategy in the Water Plan is to pursue Oklahoma water, of which 50,000 acre-feet each is for the TRWD and the NTMWD, discussion with the State of Oklahoma have precluded this water being available to meet immediate needs. Oklahoma water is also considered an alternate strategy for the DWU and the city of Irving if the water becomes available in the future.

Water management strategies other than those joint efforts discussed above are:

NTMWD Conservation. Conservation is the projected conservation savings for the NTMWD's existing and potential customers based on the Region C recommended water conservation program. Not including savings from low flow plumbing fixtures (which amount to about 5% of demand and are built into the demand projections) and not including reuse, conservation by NTMWD customers is projected to reach 84,124 acre-feet per year by 2060.

Interim Treated Water Purchase from Dallas Water Utilities (DWU). The NTMWD is negotiating with the DWU to purchase an annual average of up to 10 mgd (11,210 acre-feet per year) of treated water. The water would be delivered to the NTMWD by a connection between Dallas' water distribution system and the NTMWD treated water distribution system, and a meter would be installed.

Additional Wilson Creek Reuse Project. The NTMWD currently has a water right allowing the reuse of up to 35,941 acre-feet per year (32 mgd) of actual discharges from the Wilson Creek Wastewater Treatment Plant. The NTMWD has applied for a water right to reuse an additional 35,941 acre-feet per year of discharges from the

plant. This was a recommended water management strategy in the 2001 *Region C Water Plan.*

East Fork Reuse Project. The NTMWD has applied for a water right to divert treated wastewater from the East Fork of the Trinity River near Crandall. The water would be diverted to a constructed wetland for treatment, pumped through a pipeline to Lake Lavon, and redirected from Lake Lavon for treatment and use. The estimated supply available from this project will increase with increasing wastewater flows to 102,000 acre-feet per year. This water management strategy was added to the 2001 *Region C Water Plan* by an amendment in 2005.

Additional Lake Lavon Yield. The NTMWD currently has a water right allowing the diversion of up to 104,000 acre-feet per year from Lake Lavon (in addition to water delivered to the lake from return flows, Lake Texoma, and Lake Chapman). The Trinity River Water Availability Model [(6)] shows that the yield of Lake Lavon is greater than 104,000 acre-feet per year. The NTMWD has applied for a water right to divert up to an additional 14,840 acre-feet per year from Lake Lavon. Based on estimated area and capacity conditions in the lake, the additional supply from this measure will vary from 11,000 acre-feet per year in 2010 to 6,000 acre-feet per year in 2060.

Interim Purchase of Lake Texoma Water from GTUA/Sherman. The NTMWD has reached an agreement with the city of Sherman and the GTUA to purchase surplus Lake Texoma water. The water would be delivered through the NTMWD's existing pump station and pipeline from Lake Texoma. This supply is expected to be available for up to 20 years, and only water surplus to the in-basin needs of GTUA and Sherman would be purchased. The GTUA has applied for an interbasin transfer permit to allow the proposed sale and transfer.

Upper Sabine Basin Supply. The NTMWD is negotiating with the Sabine River Authority to divert water from Lake Tawakoni or Lake Fork on an interim basis. The NTMWD would divert only water surplus to the needs of other users and would eventually replace this water with supplies from other sources. The NTMWD would seek an interbasin transfer and would build a pump station and pipeline to deliver water from Lake Tawakoni or Lake Fork to Lake Lavon.

Fannin County Water Supply System. The NTMWD would cooperate with Fannin County entities to develop a treated water supply system for Fannin County water users after the Lower Bois d'Arc Creek Reservoir is developed in 2020. The system would involve one or more water treatment plants and a treated water distribution system.

As shown on Table 6, nearly 790,000 acre-feet per year of new supplies are recommended for the NTMWD, leading to a total supply of 1.02 million acre-feet per year in 2060. Over 30% of the projected water supply through 2040 is from reuse and conservation. This percentage reduces to 25% as new supplies are developed in 2050. The NTMWD's share of the total capital cost for the recommended plan is $3.9 billion.

The following alternative water management strategies are recommended:

- Toledo Bend Reservoir Phase 2 (accelerated to occur before 2060)
- Lake 0' the Pines
- Wright Patman Lake
- Lake Texoma with desalination rather than blending
- Ogallala groundwater in Roberts County (Region A)
- Carrizo-Wilcox groundwater in Brazos County Area (Region G)
- George Parkhouse North Reservoir
- Lake Livingston

A summary of current water supplies and potential water management strategies and projected demand is presented in Table 3.

Costs for the alternative strategies are shown in Table 4. Capital costs for the projects are financed by 30-year bonds. Pre-amortization costs refer to the 30-year period during which debt service payments on the bonds are being made. Post-amortization costs refer to the period after the bonds are paid off, in which there are no debt service costs.

b. Greater Texoma Utilities Authority (GTUA). The GTUA serves the Sherman-Denison area in Grayson County. The GTUA provides water to Sherman and manufacturing water to Grayson County. The GTUA will participate in the Grayson County Water Supply Project and the Collin-Grayson Municipal Alliance Pipeline that will provide water to 19 water user groups in Grayson and Collin counties. The GTUA will also provide the NTMWD with up to 25,000 acre-feet of raw water per year, with plans for 20,000 acre-feet per year. The GTUA has an existing water right for 25,000 acre-feet from Lake Texoma, which is currently limited by a treatment plant capacity of 11,210 acre-feet per year.

(1) <u>Existing Sources of Water Supply: GTUA</u>.

Lake Texoma. The largest impoundment in the Red River Basin is Lake Texoma, a Corps of Engineers lake completed in 1944 primarily for flood control and hydropower generation. Recreation has become a major industry at the lake. The lake currently has 150 mgd yieldFrom the 1985 150,000 acre-feet reallocation. Most of this storage was used by Texas. Less than 5 mgd of the available water was used by Oklahoma. The lake is high in total dissolved solids (TDS) and chlorides (Cl), which exceed the U.S. Environmental Protection Agency (EPA) drinking water standards for public water supplies. The water requires either desalination treatment, using the electro-dialysis reversal (EDR) method, or blending prior to conventional water treatment for potable use.

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TABLE 3

SOURCES OF WATER SUPPLY AND WATER DEMAND BY DECADE
RECOMMENDED WATER MANAGEMENT STRATEGIES
Texas State Water Plan 2006
North Texas Municipal Water District

Source	Year					
	2010	2020	2030	2040	2050	2060
Current Available Supplies						
Lake Lavon	104,000	104,000	104,000	104,000	104,000	104,000
Lake Texoma	77,300	77,300	77,300	77,300	77,300	77,300
Lake Chapman	49,976	49,150	48,324	47,498	46,672	45,843
Wilson Creek Reuse(permitted)	35,941	35,941	35,941	35,941	35,941	35,941
Lake Bonham	5,340	5,340	5,340	4,850	4,250	3,650
Total Current Available Supplies	272,557	271,731	270,905	269,589	268,163	266,734
Water Management Strategies						
Conservation	12,366	32,071	45,646	58,274	70,220	83,096
Interim DWU Supply	11,210	11,210	0	0	0	0
Wilson Creek Reuse(new)	26,956	35,941	35,941	35,941	35,941	35,941
East Fork Reuse	81,400	96,400	102,000	102,000	102,000	102,000
Additional Lake Lavon Yield	11,000	10,000	9,000	8,000	7,000	6,000
Interim GTUA Supply	20,000	0	0	0	0	0
Upper Sabine Basin	50,000	30,000	20,000	10,000	10,000	10,000
New Lake Texoma	0	38,250	57,105	54,105	100,460	112,460
Lower Bois d'Arc Creek Reservoir	0	123,000	121,000	119,000	117,000	115,000
Marvin Nichols Reservoir	0	0	87,420	87,420	174,840	174,840
Toledo Bend Phase 1	0	0	0	0	100,000	100,000
Oklahoma Water	0	0	0	0	0	50,000
Treatment and Distribution Losses	-10,028	-17,240	-21,623	-20,823	-32,362	-35,312

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TABLE 3. SOURCES OF WATER SUPPLY AND WATER DEMAND BY DECADE (Continued)

Source	Year					
	2010	2020	2030	2040	2050	2060
Total Supplies from Strategies	212,932	376,872	478,112	474,740	717,461	789,337
Total Current and Strategy Supplies	475,461	631,363	727,394	723,506	953,262	1,020,759
Total from Reuse and Conservation	156,663	200,353	219,528	232,156	244,102	256,978
Percent from Reuse and Conservation	32.9%	31.7%	30.2%	32.1%	25.6%	25.2%
Projected Demands	370,499	482,185	567,185	649,440	721,491	801,513

Source: Initially Prepared Texas State Water Plan 2006, June 2005.

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TABLE 4

SOURCES OF WATER SUPPLY AND WATER DEMAND BY DECADE
COSTS OF RECOMMENDED WATER MANAGEMENT STRATEGIES
Texas State Water Plan 2006
North Texas Municipal Water District
(2002 Price Levels)

Water Management Strategies	Develop Dates	Quantity for NTMWD (acre-feet/year)	(mgd)	NTMWD Share of Capital Cost($)	Unit Cost($/kGal) Pre-Amort	Post-Amort
Treatment and Distribution Improvements	2005-2060	N/A	N/A	1,290,523,000	N/A	N/A
Interim DWU Supply	2006	11,210	10	1,350,000	$0.75	$0.72
Wilson Creek Reuse(new)	2005	35,941	32	1,150,000	$0.01	$0.00
East Fork Reuse	2010	102,000	91	288,879,000	$0.92	$0.21
Additional Lake Lavon Yield	2006	11,000	10	270,000	$0.01	$0.00
Interim GTUA Supply	2006	20,000	18	104,000	$0.09	$0.09
Upper Sabine Basin	2010	50,000	45	60,232,000	$0.52	$0.25
New Lake Texoma	2015	113,000	101	201,829,000	$0.58	$0.18
Lower Bois d'Arc Creek Reservoir	2020	123,000	110	399,190,000	$0.87	$0.14
Fannin County Water Supply System	2020	0	0	55,458,000	$1.96	$0.52
Marvin Nichols Reservoir	2030	174,840	156	534,125,000	$0.94	$0.26
Toledo Bend Phase 1	2050	200,000	179	886,002,000	$1.56	$0.57
Oklahoma Water	2060	50,000	45	128,898,000	$0.95	$0.37
Total Capital Costs				3,848,010,000		

Source: Initially Prepared Texas State Water Plan 2006, June 2005.
Note: Capital costs for water supply projects are typically financed by 30- year bonds. Pre-amortization costs refer to the 30 year period during which debt service payments on the bonds are being made. Post-amortization costs refer to the period after the bonds are paid off, in which there are no debt service costs.

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Lake Randell. Lake Randell, with a dependable yield of 4.7 mgd, is used to regulate diversions from Lake Texoma for treatment and use by the city of Denison, and requires demineralization. Groundwater in this area is high in TDS, although some smaller communities continue to use it out of necessity and lack of alternative sources. Sherman obtains about 60% of its water from wells, with the remaining water that is desalinized by the EDR method coming from Lake Texoma. The city of Denison obtains about 0.12 mgd of its 3.5 mgd (3,920 acre-feet) average demand from wells with the capacity to transfer 6 mgd from Lake Texoma to Lake Randell.

(2) Potential Sources of Water Supply: Water Management Strategies. The Texas State Water Plan 2006 indicates that the GTUA will need to develop 6,000 acre-feet of new supply per year by 2010, and 43,000 acre-feet of new supplies per year by 2060. To meet these future needs, the Water Plan recommends the following strategies:

Conservation. Water conservation is expected to save about 4,800 acre-feet per year by 2060.

Changing permitted Lake Texoma water to municipal and industrial. The existing water right for diversion of water from Lake Texoma is 15,000 acre-feet per year for municipal/domestic purposes and 10,000 acre-feet per year for industrial purposes. The GTUA has submitted an application to the Texas Council on Environmental Quality (TCEQ) for an amendment to this water right that would allow an additional 25,000 acre-feet of water for municipal or industrial purposes. This amendment will also make water available for sale to the NTMWD as an interim supply.

Obtain additional Lake Texoma water. The GTUA has a contract with the NTMWD to provide an interim supply of up to 25,000 acre-feet per year of raw water from Lake Texoma. About 20,000 acre-feet of water will be supplied by 2010. The GTUA has applied for an interbasin transfer authorization. The GTUA will then contract with the Corps of Engineers for storage in Lake Texoma of about 50,000 acre-feet. A new water right, for about 56,000 acre-feet per year, to divert water from Lake Texoma will also be necessary from the TCEQ. This new water right will also support the Grayson County Water Supply Project.

Develop the Collin-Grayson Municipal Alliance Pipeline Project. By 2006, the GTUA will purchase water from the NTMWD for supply to customers of the Collin-Grayson Alliance Pipeline Project. This pipeline project is currently under design to meet a demand for about 15 mgd or 16,813 acre-feet of water, and will transmit water from McKinney to the customer cities. The city of McKinney will also be compensated for its pumping facilities.

Develop the Grayson County Water Supply Project. By 2020, due to limited groundwater availability, the GTUA will provide treated surface water from Lake Texoma to Grayson County customers. Phase 1 of this project to be constructed by 2020 includes

a 25-mgd water treatment plant expansion, a new 1-mgd water treatment plant in northwestern Grayson County, and a water transmission system. Phase 2 is the construction of a 20-mgd water treatment plant expansion by 2040. This strategy will use all currently permitted water under the GTUA's existing water right in Lake Texoma and would also require that the GTUA obtain an additional water right (with interbasin transfer authorization) in Lake Texoma.

Summary of Existing and Potential Sources of Water Supply. Potential water supply sources and projected demand by decade for the GTUA are shown in Table 5.

TABLE 5

RECOMMENDED WATER MANAGEMENT STRATEGIES
WATER SUPPLIES AND DEMANDS
Texas State Water Plan 2006
Greater Texoma Utility Authority (GTUA)

Source	Year					
	2010	2020	2030	2040	2050	2060
Current Available Supplies						
Lake Texoma	11,210	11,210	11,210	11,210	11,210	11,210
Water Management Strategy						
Customer Water Conservation	177	102	1,901	2,812	3,868	4,774
Change Permitted Lake Texoma Use to Municipal or Industrial	0	0	0	0	0	0
Add Lake Texoma(Interim NTMWD Supply)	20,000	0	0	0	0	0
Collin-Grayson Municipal Alliance Pipeline Project	2,408	6,935	10,523	13,705	16,813	16,813
Additional Lake Texoma						
Grayson County Water Supply Project -Phase 1	0	14,572	14,572	14,572	14,572	14,572
Grayson County Water Supply Project -Phase 2	0	0	0	11,443	11,443	11,443
Total Supplies from Strategies	22,585	21,609	26,996	42,532	46,696	47,602
Total Supplies	33,795	32,819	38,206	53,742	57,906	58,812
Projected Demand	31,357	23,158	30,534	38,749	47,930	54,038

Source: Initially Prepared Texas State Water Plan 2006, June 2005.

The anticipated capital costs and the unit costs are shown in Table 6.

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TABLE 6

RECOMMENDED WATER MANAGEMENT STRATEGIES
SUMMARY OF COSTS
Texas State Water Plan 2006
Greater Texoma Utility Authority (GTUA)
(2002 Price Levels)

Water Management Strategy	Develop Date	2060 Quantity	Capital Cost	Unit Cost ($/kGal.) Pre-Amort	Unit Cost ($/kGal.) Post-Amort.
Customer Water Conservation	2010	4,774	$0	N/A	N/A
Change Permitted Lake Texoma Use to Municipal or Industrial	2005	0	$50,000	N/A	N/A
Add Lake Texoma (Interim NTMWD Supply)	2006	20,000	$15,729,000	$0.18	$0.00
Collin-Grayson Municipal Alliance Pipeline Project	2006	16,813	$16,382,000	$1.46	$1.25
Additional Lake Texoma					
Grayson County Water Supply Project - Phase 1	2020	14,572	$168,859,000	$4.55	$1.96
Grayson County Water Supply Project - Phase 2	2040	11,557	$55,894,000	$2.40	$1.50
Total Capital Costs			$256,914,000		

Source: Initially Prepared Texas State Water Plan 2006, June 2005.

c. Dallas Water Utilities (DWU). The city of Dallas/DWU is the major water wholesale service supplier for a service area that includes most of Dallas, Denton, and portions of Rockwall and Kaufman counties. Several other wholesale water suppliers are also in these counties, including the city of Denton, the UTRWD, and the TRA. The cities of Dallas, Irving, Grand Prairie, Carrollton, and many others receive all or part of their water service from the DWU. The DWU is supplied from six major existing reservoirs, with three other existing reservoirs awaiting connection and/or completion of their transmission systems. The projected water demands on the DWU are expected to increase from 640,000 acre-feet in 2010 to 1.06 million acre-feet by 2060.

The currently available supply is about 457,000 acre-feet. By 2010, the DWU will need an additional 182,000 acre-feet per year increasing to an additional 624,000 acre-feet per year by 2060. Conservation and reuse and connections to existing sources of supply are some of the 25 water management strategies to be utilized. Other than conservation and reuse, the connections of Lake Fork, which would supply about 120,000 acre-feet by 2010, and Lake Palestine, which would provide about 114,000 acre-feet by 2020, are two major connections. Existing reservoirs will continue to be over-drafted. The DWU is expected to continue to use return flows, estimated at 50,000 acre-feet per year in 2000; however, these are not expected to be available by 2050.

The DWU is part of a group of providers that will participate in the Marvin Nichols I Reservoir, a major new reservoir in the Sulphur River (Region D) with a yield of abut 619,100 acre-feet per year of which the DWU would receive about 94,000 acre-feet per year. Cost is expected to be about $1.5 billion. The DWU will also develop the Southside Reuse project (68,300 acre-feet per year). The DWU has also shown some interest in Lake Texoma as an alternate water management strategy. This alternate water

management strategy includes future use of Lake Texoma by blending and desalination at a cost of over $800 million. Other alternate strategies include Marvin Nichols, Toledo Bend Reservoir, and Oklahoma water among others, if the recommended water management strategies are not workable.

d. Tarrant Regional Water District (TRWD). The TRWD is mainly comprised of Tarrant County, Texas, and is the predominant wholesale supplier to the city of Fort Worth, the city of Arlington, the TRA, and many other municipalities within Tarrant County. The TRWD provides water, directly or indirectly, to 104 water user groups with an additional 13 water user groups planned for the future. The projected water demand is 416,200 acre-feet per year in 2010 increasing to 863,600 acre-feet per year by 2060. The total available water supply from the TRWD system is 447,000 acre-feet per year in 2010, decreasing to 394,000 acre-feet per year by 2060 based on the operational safe yield analysis. The TRWD shortage of 82,000 acre-feet per year begins in 2020 increasing to about 500,000 acre-feet per year in 2060.

There are eight reservoirs in operation and planning documents on several more. The addition of a third transmission pipeline and booster stations will allow the additional capacity and yields from Cedar Creek Lake and Richland-Chambers Lake (115,500 acre-feet per year and 113,900 acre-feet per year, respectively) to be utilized more fully. Also, the West Fork Connection would allow water to be transferred among the existing parts of the system. Recommended water management strategies other than conservation, reuse, and the Eagle Mountain Connection, are Marvin Nichols Reservoir, Toledo Bend Reservoir, and Oklahoma water. These are multi-provider strategies. Other alternate water management strategies include Lake Wright Patman, Lakes Sam Rayburn and Steinhagen, Lake Tehuacana, and Lake Livingstone. Obtaining water from Lake Texoma is not specifically mentioned as a strategy.

e. City of Fort Worth. The city of Fort Worth obtains water from the TRWD and distributes treated water to 29 existing customers with 3 new customer groups expected to be served in the future. The shortages of 41,000 acre-feet expected in 2020 will increase to about 305,000 acre-feet by 2060. The water management strategies recommended to meet this shortfall are conservation and reuse for steam electric power, expansion of water treatment plants and transmission lines, new treatment plants, and additional supply from the TRWD. No plans include Lake Texoma as a water management strategy.

f. Trinity River Authority (TRA). The TRA currently provides water to users from its own water rights in Lakes Bardwell, Navarro Mills, Joe Pool, and Livingstone. The TRA also supplies water to Tarrant County entities by purchase from the TRWD. The TRA provides raw water for steam-electric power in Freestone County and reuse water to entities in Dallas and Ellis counties. The TRA has contracts with the TRWD and Ellis County users to supply water through the Ellis County Project. The TRA also owns and operates wastewater treatment plants and has plans to develop a number of direct and indirect reuse projects. Water management strategies for TRA include conservation, direct and indirect reuse projects, expansion of the Tarrant County Water Supply System, and development of the Ellis County Project. There are no plans to utilize Lake Texoma water in the future.

11.4.2 Oklahoma Water Demand, Water Supply, and Net Needs – Southern Regional Water Planning District

11.4.2.1 Overview. The Oklahoma Water Resources Board (OWRB) and the U.S. Army Corps of Engineers, Tulsa District are in the process of determining future demands for water and sources of water supply for inclusion in the 2005 Oklahoma State Water Plan. Portions of that study are summarized below. This study contains an estimate of supply and demand for water from 2000 to 2060, with 2000 representing the base year and 2010 to 2060 designated as a

50-year planning horizon.

The state was reconfigured from 8 water planning regions as described in previous State water plans into 11 sub-state regional water planning districts that represented the Oklahoma Council of Government (COG) statewide planning districts or regions. The Southern Region sub-state regional water planning districts represents the region around Lake Texoma. The Southern Regional Water Planning District, represented by the Southern Oklahoma Development Authority (SODA), consists of Atoka, Bryan, Carter, Coal, Garvin, Johnston, Love, Marshall, Murray, and Pontotoc counties. Figure 2 depicts this region.

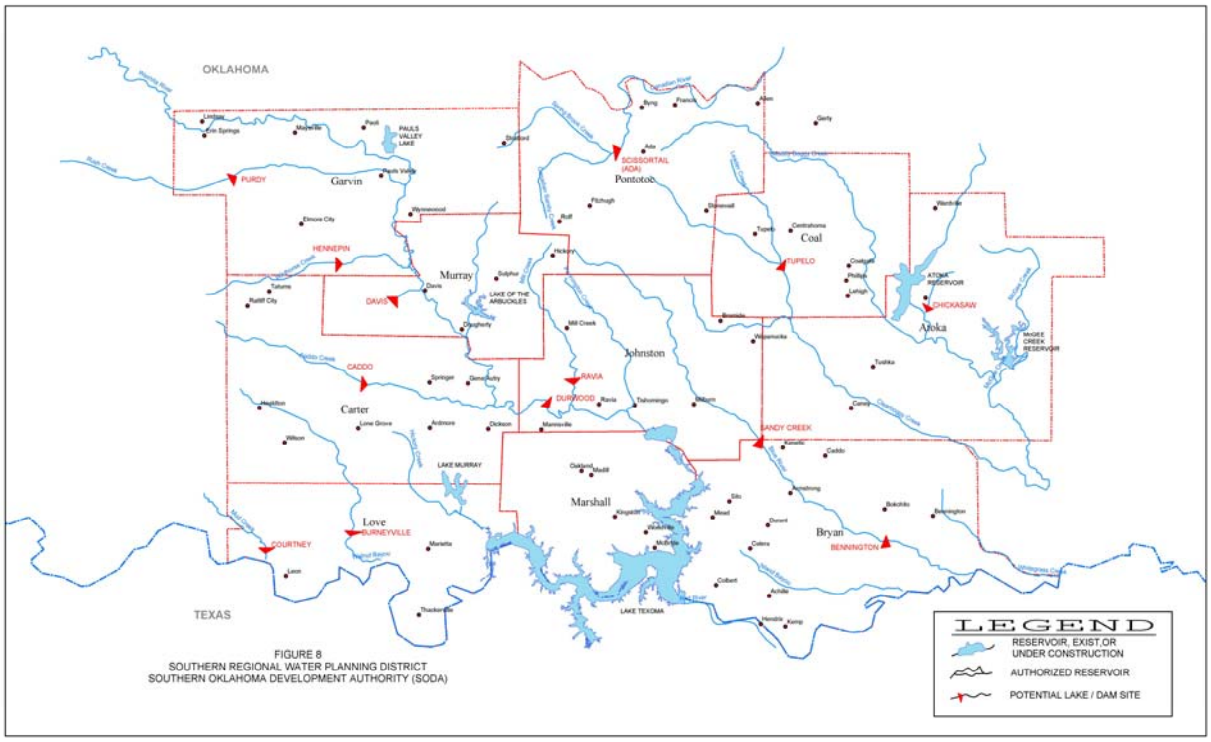

FIGURE 8
SOUTHERN REGIONAL WATER PLANNING DISTRICT
SOUTHERN OKLAHOMA DEVELOPMENT AUTHORITY (SODA)

Figure 2. Southern Regional Water Planning District

11.4.2.2 <u>Regional Description</u>. The Southern Regional Water Planning District (Southern Oklahoma Development Authority (SODA) covers approximately 9.8% of the state (6,724 square miles). This region lies at the eastern edge of the Southern Great Plains. The region's terrain varies from lush pastures in the river bottoms to sparsely vegetated oil fields and to the rugged foothills of the Arbuckle Mountains. Stream and surface water sources are abundant in the eastern portions of the region; however, they are relatively scarce in the western portions.

The region's climate is mild with annual mean temperatures varying from 61 °Fahrenheit (F) to 64 °F. Annual evaporation within the region ranges from 63 inches per year in the western areas to 55 inches per year in the eastern areas. Rainfall averages 30 inches per year in the western areas and approaches 39 inches per year in the eastern areas. Ardmore, Ada, and Durant are the largest cities within the region.

11.4.2.3 <u>Water Demands</u>. Along with data obtained from the survey, water use data from the U.S. Geological Survey (USGS) and the OWRB were used to calibrate the IWR-MAIN

model to 2000 water use. An attempt was made to calibrate the IWR-MAIN model to actual 2000 data with discrepancies indicated in the unaccounted column. In some cases, unaccounted water reflects the fact that water is being transported to or from other regions, such as Atoka, Oklahoma, and Tulsa counties.

11.4.2.4 **Municipal and Industrial Water Demand.** Estimates of the quantities of water that will be used in the future require the use of appropriate econometric models to make projections of future water use that are statistically consistent for long-term water supply planning. One approach to forecast municipal and industrial (M&I) water demand is to use the IWR-MAIN software. The IWR-MAIN Water Demand Management Suite is a Windows-based PC software package that uses econometric water demand models for translating existing demographic, housing, and business statistics into estimates of existing water demands for cities, counties, or service areas. These estimates are then used to fine tune the water use equations for translating the official long-term projections of population, housing, and employment into disaggregated forecasts of water use. A survey was conducted to collect data on all known water supply purveyors in the State of Oklahoma. The questionnaire collected basic information regarding water use, pricing, conservation, source of water, and other parameters, such as unaccounted for water due to system losses. Some of these parameters are used to calibrate the IWR-MAIN model to 2000 actual water use to assist in adjusting the model to simulate actual conditions in 2000. Projected population and employment variables along with other data, such as housing units, can then be used to develop estimates of future demand for M&I users. The data also provided some information on the geographic distribution of systems particularly in dealing with systems that are in more than one planning district.

11.4.2.4.1 Demographic Parameters.

Population. One key parameter used by the IWR-MAIN model to project residential water demand is population. In 2002, the Oklahoma Department of Commerce, under contract with the OWRB, expanded their 2000-2030 projections of the resident population of Oklahoma by county. The projections were made using a cohort component projection. With this method, each component of the population, births, deaths, and migration, is projected separately based on algorithms developed by the U.S. Bureau of the Census. The base population used is April 1, 2000, the date of the U.S. Census of Population and Housing count of the United States resident population. Fertility, death, and migration rates are applied to that base population to arrive at the near year projection period. Six migration assumptions were used in developing these projections. These include:

- Very Low - negative migration for 10 years, then zero migration for the remaining years
- Low - zero migration
- Medium - 5,000 in-migration per year
- High - 10,000 in-migration per year
- Very High - 15,000 in-migration per year
- Special - 5,000 in-migration per year for 15 years and 2,000 in-migration for the remaining years

For this analysis, the medium set of assumptions of 5,000 in-migration per year was used. Year 2005 was interpolated between 2000 and 2010.

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Employment. Commercial and industrial water use represents a very large part of current and future demand for water in the state. The IWR-MAIN model for projecting water demand for commercial, industrial, and public use categories relies on the number of persons employed in a county by each Standard Industrial Classification (SIC) category and, since 1997, the North American Industry Classification System (NAICS) code. Data used in the IWR-MAIN model utilizes the NAICS system. National water use survey data were used to provide water use coefficients for each industrial sector, by two- or three-digit code, based on the number of employees. The number of employees serves as a proxy for production activity in a given industrial sector and the associated amount of water required to support that activity. To project future industrial water demand, the model utilizes a linear relationship using employment and water use per employee by NAICS code. Specific codes are consolidated into the general categories of commercial, industrial, and public use.

Housing. Another parameter used by the IWR-MAIN model to project future residential water use is housing units. Data from the U.S. Bureau of Census and Housing were used to develop housing units for the 2000 base year. It is assumed that the person-per-household ratio will remain constant over the entire projection range. The algorithm used in the projection of residential water demand uses persons per household, population divided by number of housing units, as well as housing density. The housing density variable is a parameter used to characterize the outdoor component of water use for the summer season.

11.4.2.4.2 Forecast Manager Overview. The forecasting algorithm of Forecast Manager is built to operate on data corresponding to study areas, water use sectors/sub-sectors, months, and forecast years. The needs and data available dictated the degree of detail required to use the model. The methodology utilized is known as the "Driver Times Rate of Use" approach. In other words, for a given study area, sector, month, and forecast year, water use can be calculated as a product of the number of users, the rate of use, and the number of days in the given month. This allows the disaggregation of a water demand forecast and permits unit water use rate, such as gallons per household, gallons per employee, etc., to be assumed or predicted via the water use model.

Four different methods can be used to generate water demand forecasts in IWR-MAIN, from the simple to the more complex depending on the availability of data and time and cost constraints. The first method is to use constant use rates, which depends on the make-up of the study area, such as the number of customers. The second method is to build a model by adjusting per unit rates of use. Unit rates of use for a user class are defined, and these rates are modified over time by specific variables. These variables may include price, income, employment, productivity, land use, or other factors. The third and fourth options are to specify or customize a model for water demand by using specific statistical information related to water use models, such as values for intercept terms, model variables, and associated coefficients and elasticities in the algorithms. This method may be either a multiplicative or linear predictive model.

The second method, building a forecasting model using explanatory variables, was utilized for most counties. This method uses selected explanatory variables, such as median household income, persons per household, housing density, marginal price of water, maximum temperature, and precipitation, to adjust per unit usage rates. The base year per unit water use rate is calculated from the base year water use and the number of counting units for the sub-sector. This calculated rate of use is then adjusted by the relationship between sub-sector water use and those explanatory variable selected for the sub-sector, which are selected by the user and may

change over time. Year to year changes in water use are explained by the change in the selected explanatory variables and the counting units. Counting units are driver variables, such as employee counts, housing units, acres, etc., associated with each sub-sector.

Residential Water Usage. Daily residential water usage for each county will be estimated by the following equation:

$$Q^R = N * q$$

where N is the number of housing units and q is the daily residential water usage given by the multiplicative model:

$$q = e^{\alpha} (Inc)^{\beta^1} (HsgDensity)^{\beta^2} (HshldSize)^{\beta^3} (MP)^{\beta^4} (MaxTemp)^{\beta^5} (Precip)^{\beta^6}$$

where: e^{α} is the model intercept in natural log form
Inc is median household income
HsgDensity is housing units per acre
HshldSize is person per household
MP is marginal price
MaxTemp is average daily maximum temperature
Precip is total precipitation

$\beta^1 - \beta^6$ are the elasticities taken from the IWR-MAIN recommended range. The midpoint of the range is used for each term. Selection of these model variables and variable elasticities provides a rational model of residential water demand that may be calibrated to average daily use in each region.

Non-residential Water Usage. Daily non-residential water usage for each sub-sector was estimated by the following equation:

$$Q^{NR} = N * q$$

where N is the number of employees in a sector and q is the daily water usage for the sub-sector given by the linear model:

$$q = GED$$

where q is the gallons/per employee/per day (GED) that has been developed outside the model. This method of estimation makes the assumption that the main driver of changes of water demand within a given sector is change in the number of employees rather than change in weather, pricing, or other variables.

The advantage of an average usage/per unit/per day method of estimating residential and non-residential water usage, which is based on housing units and employees, is that it accounts for usage by both public and private water suppliers.

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Unaccounted Water Usage/System Losses. For each county, the amount was calculated by taking a weighted average of the estimated losses of all providers that have returned questionnaires (weighted by the relative number of accounts they serve). This county average was then scaled down based on the percentage of the population within the county that is served by a public system (available from the 1990 census data). This method is based on the assumption that private systems will have a lower loss rate (via leakage, etc.) and little or no unaccounted usage (i.e., hydrants). In addition, when major discrepancies occurred between a county's total M&I water use as reported in 2000 and the output of the IWR-MAIN model, an adjustment to total water use as generated in the model was made in the unaccounted for sector.

11.4.2.5 Thermo-Electric Power Forecasts. The basis for projecting future water use based on nation-wide data from the Department of Energy is assumed to be a linear relationship between the amount of electricity generated and the amount of water used. This indicates that total electricity demand is projected to grow by 1.9% per year from 2001 through 2020, and 1.8% per year from 2001 to 2025. This nationwide average was applied to Oklahoma. After 2025, an increase of 1.8% per year was assumed over the base year. The Oklahoma Corporation Commission showed an increase in peak demand but not generation. If it is assumed that there is a direct correlation between peak demand and electrical generation, future water use could be calculated with this alternative method.

11.4.2.6 Agricultural Water Demand Forecasts. Initial agricultural water demand forecasts were prepared in March 2003 by the Bureau of Reclamation (BR), Great Plains Regional Office for irrigated land and livestock. The base year is 2000 with water demand forecast by decade to 2060. Major livestock groups that were evaluated were beef and dairy cattle (cattle), sheep and lambs (sheep), hogs, and broiler and laying chickens (chickens). Others groups were not evaluated since they were not major water users. Year 2000 data were obtained from the United States Department of Agriculture (USDA) for nine major agricultural areas.

Major irrigated crop groups that were evaluated were grain corn (corn), sorghum, wheat, cotton, soybeans, peanuts, alfalfa, hay, corn silage, and vegetables. Other crop groups are minor water users. The 1997 USDA Agricultural Census provided data on county irrigated acreages. These were deemed representative for 2000. The highest reported irrigated acres from agricultural census years 1978 to 1997 were used to project irrigated acres in 2060 for most counties. Ten-year increments from 2000 to 2060 were developed by straight-line interpolation. A composite or weighted average crop irrigation requirement (CIR) for each county was developed. The CIR is that portion of total water requirements other than natural precipitation. The weighted CIR is calculated by summing the product of the individual CIR and the irrigated crop acres in each county, and then dividing this summed product by the sum of the acres. Future irrigated water demands are determined by multiplying irrigated land values by the weighted average CIR for each county.

The percentage of acres irrigated by each method of irrigation for each county was obtained from 2000 OWRB Water Use Reports and USGS preliminary water use data for Oklahoma for 2000 (see Appendix 5). These percentages by irrigation method and applicable field application efficiencies were applied to the BR's calculations of water demand for irrigated land. For example, gross irrigation water requirement or the amount of water to be withdrawn (by diversion or pumping) and applied to the irrigation scheme was calculated as follows:

(% acres by irrigation method * net water demand)
Field application efficiency

Gross irrigation water requirement thus includes net irrigation water requirement plus water losses. The above methodology was used to compute and aggregate irrigation water demands for each county and was extrapolated for each decade.

11.4.2.7 Water Resources.

11.4.2.7.1 Stream Water. The region's major streams include the Red River and the upper Washita River, along with Mud Creek and Walnut Bayou in the western portions of the region. Stream water is not a dependable supply source within the western region due to the intermittent flow and/or water quality problems. The region's other major streams to the north and east includes Blue River, Clear Boggy Creek, Muddy Boggy Creek, and the lower Washita River. With the exception of the Red River below Lake Texoma, the eastern region's streams contain good quality water. Overall, the water is suitable for all uses.

The Red River is the major stream within the Southern Regional Water Planning District, forming the southern border. The water is highly mineralized above Lake Texoma with chlorides and dissolved solids exceeding EPA limits most of the time. The Red River Chloride Control Project is an extensive project by the Corps of Engineers to reduce the naturally occurring chloride pollution in the river and its tributaries. The project, consisting of nine smaller projects involving the use of low flow dams, brine lakes, pump stations, and pipelines, hopes to prevent 409 tons per day of chloride from reaching the river. The result would reduce chloride levels in Lake Texoma to within EPA limits ±15% of the time. Several of the projects have been completed to date; however, budgetary and environmental concerns threaten completion of the project. The water has high levels of dissolved solids and chlorides through much of Bryan and Choctaw counties. After confluence with the Blue River, Boggy Creek(s), and Kiamichi Rivers, the water is of acceptable quality for most uses.

The Washita River flows through the northern portion of the region before joining the Red River in Lake Texoma. The Washita River is also highly mineralized. The tributary streams of the Washita improve overall stream quality in the lower reaches to make it suitable for most uses.

The Blue River flows southeasterly through Pontotoc, Johnston, and Bryan counties to its confluence with the Red River. The river's drainage basin is ±80 miles long and contains 676 square miles. There are no impoundments on the river. The water is classified as hard with moderate levels of inorganic turbidity.

The Boggy Creek Basin consists of Clear Boggy Creek and Muddy Boggy Creek. The drainage basin contains 2,400 square miles of Pontotoc, Coal, Atoka, Bryan, and Choctaw counties. Atoka Lake and McGee Creek Lake are the impoundments in the river basin. The water in upper Muddy Boggy Creek is generally hard with high chloride and moderate sulfate concentrations. Downstream of Atoka the water becomes moderately hard with lower sulfate and chloride levels. High turbidity and nutrient levels exist along the entire branch. Water in Clear Boggy Creek is relatively hard with moderate turbidity, chlorides, and sulfates.

Stream Water Development. Table 7 lists the existing and proposed reservoirs within the region. There are four major impoundments within the Southern Regional Water Planning District. The largest of these impoundments is Lake Texoma on the Oklahoma-Texas border in Love and Marshall counties. This Corps of Engineers project was constructed in 1944 for flood control, water supply, recreation, navigation, and hydropower. The flood control storage of 2,613,777 acre-feet is credited with preventing over $101 million in flood related damages since becoming operational. The lake is located on the main stem of the

Red River and is subject to the Red River Compact, which equally allocates water supplies to Texas and Oklahoma from the lake. Each state is allocated a dependable water supply yield of 168,000 acre-feet/year (150.0 mgd). Lake Texoma has power pool storage of 1,010,170 acre-feet and installed hydro-turbine capacity of 70,000 kW. The water is of poor quality and is not suitable for most M&I uses without treatment or blending. Water within the Washita arm of the lake is generally suitable for most uses.

The BR constructed Lake of the Arbuckles in 1967. Located on Rock Creek, a tributary of the Washita River in Murray County, the impoundment provides water supply, flood control, recreation, and fish and wildlife mitigation. The reservoir has 36,400 acre-feet of flood control storage and 62,600 acre-feet of conservation storage, which yields 24,000 acre-feet/year (±21.4 mgd). The entire available yield is allocated to the Arbuckle Master Conservancy District which provides water to the cities of Ardmore, Davis, Sulpher, Wynnwood, and Dougherty. The water is classified as good and is suitable for all uses.

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TABLE 7

STREAM WATER DEVELOPMENT, SOUTHERN REGION

Name of Source/County	Stream	Purpose	Flood Control Storage (acre-feet)	Water Supply Storage (acre-feet)	Water Supply Yield (acre-feet/year)
Existing					
Atoka Lake/Atoka	North Boggy Creek	ws, r	-	123,500	700 (1)
McGee Creek Lake/Atoka	McGee Creek	ws, fc, r	85,340	107,980	31,800 (2)
Arbuckle Lake/Murray	Rock Creek	ws, fc, r	36,400	62,600	24,000
Ardmore City Lake	Tributary of Caddo Creek	ws, r	-	2,300	560
Ardmore Mountain Lake	Tributary of Caddo Creek	ws, r	-	4,650	2,800
R. C. Longmire (NRCS)/ Garvin	Keel Sandy Creek	ws, fc, r	4,142	13,162	3,360
Lake Murray/Love	Tributary of Hickory Creek	r	-	153,250	-
Jean Neustadt (NRCS 13)/ Carter	Tributary of Caddo Creek	ws, fc, r	4,357	4,542	2,150
Pauls Valley Lake/ Garvin	Washington Creek	ws, r	-	8,500	4,000
Rock Creek (NRCS 18)/ Carter	Tributary of Caddo Creek	ws, r	1,634	2,573	1,220
Lake Texoma/Marshall	Red River	ws, fc, p	2,613,777	150,000	168,000 (3)
Subtotal			2,745,650	633,057	238,590
Potential					
Parker/Coal	Muddy Boggy Creek	ws, fc, r	100,300	109,940	45,900
Burneyville/Love	Walnut Bayou	ws, r, p	576,580	150,000	25,000
Caddo/Carter	Caddo Creek	ws, r, p	73,980	260,000	40,000
Courtney/Love	Mud Creek	ws, r, p	79,000	224,100	45,100
Davis/Murray	Colbert Creek	ws	4,400	10,760	2,800

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TABLE 7. STREAM WATER DEVELOPMENT, SOUTHERN REGION (Continued)

Name of Source/County	Stream	Purpose	Flood Control Storage (acre-feet)	Water Supply Storage (acre-feet)	Water Supply Yield (acre-feet/year)
Gainesville/Love	Red River	ws, p, r, fw, i	47,151	35,000	8,750 (4)
Hennepin/Garvin	Wildhorse Creek	ws, p	27,000	180,000	30,000
Purdy/Garvin	Rush Creek	ws, fc, r	62,500	140,000	20,000
Bennington (Durant)/ Bryan	Blue River	ws, fc, r	359,590	287,420	179,000
Chickasaw/Atoka	Chickasaw Creek	ws, fc, r, p	158,940	36,320	17,900
Durwood/Johnston	Mill Creek	ws, r, fw	51,600	100,800	25,300
Sandy Creek/Bryan	Blue River	ws, p	88,080	16,920	10,800
Scissortail (Ada)/ Pontotoc	Sandy Creek	ws, r	-	88,200	32,000
Tupelo/Coal	Clear Boggy Creek	ws, fc, r, fw, i	177,300	280,000	93,000
Subtotal			2,051,651	2,039,190	807,550
Total			4,797,301	2,672,247	1,046,140

* ws-municipal water supply, fc-flood control, wq-water quality, p-power, r-recreation, fw-fish & wildlife, i-irrigation, n-navigation

(1) Total yield is 65,000 acre-feet/year of which 64,300 acre-feet/year is allocated to the city of Oklahoma City (West Central Region) and 700 acre-feet/year is allocated to the Southern Region. Water from McGee Creek is pumped in Atoka for transfer to Stanley Draper Lake via the Atoka Pipeline (90 mgd capacity).

(2) Total yield is 71,800 acre-feet/year of which 40,000 acre-feet/year is allocated to the city of Oklahoma City in the West Central Region.

(3) Lake Texoma is subject to the Red River Compact Agreement between the States of Oklahoma and Texas. Under the terms of the Agreement, Oklahoma has the right to use one-half of the total water supply yield or 168,000 acre-feet/year (150 mgd) each.

(4) Site is located on an interstate stream subject to the Red River Compact Agreement. Total yield is projected to be 17,500 acre-feet/year of which 8,750 acre-feet/year would be available to Oklahoma.

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Atoka Lake, located on North Boggy Creek in Atoka County, is a water supply lake owned by the city of Oklahoma City. Built in 1964, the reservoir provides 125,000 acre-feet of conservation storage yielding 65,000 acre-feet/year (±58 mgd) of good quality water. The water is transferred via pipeline to Lake Stanley Draper in the West Central Region for use by Oklahoma City. The pipeline has a capacity of 90 mgd.

Lake Murray is a State-owned lake constructed in 1937 for recreational purposes only. The lake is located on Hickory Creek in Love County. The lake has 153,250 acre-feet of conservation storage; however, none of the conservation storage is for water supply. Several permits have been issued for recreation, fish and wildlife mitigation, and irrigation uses. The lake remains one of southern Oklahoma's major tourist attractions, second only to Lake Texoma.

McGee Creek Reservoir is a BR project on McGee Creek, a tributary of Muddy Boggy Creek, in Atoka County. Completed in 1987, the project's purposes include water supply, water quality control, flood control, recreation, and fish and wildlife mitigation. The reservoir has a drainage area of 171 square miles and has 85,340 acre-feet of flood control storage. Conservation storage of 107,980 acre-feet yields 71,800 acre-feet/year (±64 mgd) of water supply. Oklahoma City in the West Central Planning Region has the allocation rights to 40,000 acre-feet/year (±35.7 mgd) of the yield. Atoka, Atoka County, and the Southern Oklahoma Development Trust have allocations totaling 20,000 acre-feet/year (±17.9 mgd).

There are several large municipal lakes within the Southern Regional Water Planning District. Ardmore City Lake is one of the oldest impoundments in Oklahoma, constructed in 1910. The impoundment is on a tributary of Caddo Creek, approximately 4 miles north of the city of Ardmore in Carter County. Its primary use is now recreation; however, it can provide 560 acre-feet/year (±0.5 mgd) of water supply from its 2,300 acre-feet of conservation storage if needed.

Ardmore Mountain Lake is an impoundment on Hickory Creek in north-central Carter County approximately 21 miles northwest of Ardmore. The lake is owned by the city of Ardmore and is primarily used for recreation and water supply. The lake has 4,650 acre-feet of conservation storage and a dependable yield of 2,800 acre-feet/year (±2.5 mgd).

Coalgate City Lake (SCS-#2) is used by the city of Coalgate for water supply, flood control, and recreation. The lake is located on Coon Creek in Coal County. The lake was built in 1965 and contains 3,437 acre-feet of conservation storage.

Pauls Valley Lake is a 750-surface-acre impoundment in Garvin County. Located on Washington Creek, the lake provides water supply and recreation for the city of Pauls Valley. The lake has 8,500 acre-feet of conservation storage, which yields 4,000 acre-feet/year (±3.6 acre-mgd) of water supply.

Lake R.C. Longmire (SCS-17M) is a Natural Resources Conservation Service (NRCS) project completed in 1990 for water supply, flood control, and recreation in Garvin County on Keel Sandy Creek. The lake is owned by the city of Pauls Valley and has 4,142 acre-feet of flood control storage and 13,162 acre-feet of conservation storage, which yields 3,360 acre-feet/year (±3 mgd).

Rock Creek Reservoir (SCS #18) is a multi-purpose project on a tributary of Caddo Creek in Carter County approximately 7 miles northwest of Ardmore. The reservoir, with 248 surface acres, has 1,634 acre-feet of flood control storage. The 2,573 acre-feet of conservation storage yields 1,220 acre-feet/year (±1.1 mgd) of water supply for the city of Ardmore.

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There are numerous other NRCS projects, small municipal lakes, and private reservoirs within the Southern Regional Water Planning District. These small lakes provide municipal supplies, irrigation water, and recreational opportunities. Healdton (3,766 acre-feet storage and 413 acre-feet/year yield) in Carter County, Carter Lake (990 acre-feet) in Marshall County, and Veterans Lake (600 acre-feet) in Murray County are some of the larger impoundments in this category. The values in parenthesis indicate the approximate conservation storage of these impoundments.

Potential Development. Several sites in the Southern Regional Water Planning District have potential for development of new water supply projects. Of the sites identified in Table 9, several have been extensively studied. To date, no local sponsors exist for any of these projects.

Parker Lake is a proposed impoundment authorized by the Water Resources Development Act of 1986 for Muddy Boggy Creek in Coal County. The lake is authorized for flood control, water supply, recreation, and fish and wildlife mitigation. The lake is estimated to have a drainage area of 164 square miles and would provide 100,300 acre-feet of flood control storage and 109,940 acre-feet of conservation storage yielding 45,900 acre-feet/year (±41 mgd) of good quality water. Pre-construction engineering and design have been completed for the project. The lake construction is on hold until a local sponsor for the water supply storage is secured.

Burneyville Lake is proposed for development on Walnut Bayou in Love County. The 8,500-acre project is proposed to provide water supply and hydropower. The potential yield is estimated at 25,000 acre-feet/year (±22.3 mgd) with 150,000 acre-feet of conservation storage. An additional 576,580 acre-feet of flood control storage is possible at this site.

Caddo Lake is a proposed multi-purpose impoundment on Caddo Creek in Carter County. The lake is proposed to have 260,000 acre-feet of conservation storage yielding 40,000 acre-feet/year (±35.7 mgd). Additionally 73,980 acre-feet of flood control storage are planned.

Courtney Reservoir is a potential project on Mud Creek in western Love County. The potential yield of 45,100 acre-feet/year (±40.3 mgd) would be developed from 224,100 acre-feet of conservation storage. Flood control storage of 79,000 acre-feet is also possible.

Purdy Reservoir is a potential impoundment on Rush Creek in western Garvin County. Conservation storage of 140,000 acre-feet is proposed to yield 20,000 acre-feet/year (±17.9 mgd). The site can also provide 62,500 acre-feet of flood control storage.

Ravia Reservoir is a potential impoundment on Mill Creek in Johnston County. The reservoir is intended to provide 51,600 acre-feet of flood control storage and 100,800 acre-feet of conservation storage with a firm yield of 25,300 acre-feet/year (±22.6 mgd).

Scissortail Reservoir is a potential project on Canadian Sandy Creek, a Canadian River tributary, in Pontotoc County. Formally known as the potential Ada Reservoir, the lake would provide municipal water supply, recreation, and fish and wildlife enhancement. The site is anticipated to provide 88,200 acre-feet of conservation storage and an average annual yield of 32,000 acre-feet/year (±28.6 mgd). The BR has extensively evaluated the project as a possible water supply source for the city of Ada.

Durwood Reservoir is a potential multi-purpose site on the Washita River in Johnston County. Potential uses include water supply, flood control, hydropower, irrigation, and recreation. The reservoir is anticipated to provide 245,230 acre-feet of flood control storage and 119,730 acre-feet of conservation storage yielding 232,000 acre-feet/year (±207.1 mgd).

Tupelo, in Coal County, did not pass BR screening criteria for potential hydropower, flood control, recreation, and/or water supply projects during their last review. Bennington (Durant) Reservoir and Sandy Creek Reservoir, both in Bryan County, were recommended as long-term potential projects since they did not meet the BR selection criteria as viable projects for short-term development.

Stream Water Rights. The OWRB had issued stream water allocation permits totaling 315,286 acre-feet of water per year from lakes, rivers, and streams within the Southern Regional Water Planning District. Table 8 provides a breakdown of the stream water allocations within the region.

11.4.2.7.2 Groundwater. The Southern Regional Planning District overlays four principal groundwater aquifers: the Arbuckle-Simpson Group, the Oscar Formation, the Antlers Formation, and the alluvium and terrace deposits. Groundwater is the principal supply for most irrigation demands as well as the major supply for many of the smaller communities in the region.

The Arbuckle-Simpson Group is a limestone, dolomite, and sandstone formation found in portions of Carter and Murray counties. Formation thicknesses vary between 5,000 and 9,000 feet. Well depths are commonly between 100 and 2,500 feet with yields between 100 and 500 GPM. The water is a calcium magnesium bicarbonate type and is very hard. Dissolved solids are generally within acceptable limits and the water is suitable for most uses.

The Oscar Formation is an interbedded shale, sandstone, and limestone conglomerate aquifer. The formation is 300 to 400 feet thick and is found in western Stephens, southwestern Garvin and Carter, and eastern Jefferson County. Wells range from 600 to 400 GPM. The water quality is suitable for most uses.

The Antlers Sandstone is a friable sandstone, silt, clay, and shale formation with average thicknesses of 450 feet. The formation is found in Love, Marshall, Bryan, and southern Carter, Johnston, and Atoka counties. Well depths range between 200 and 800 feet with yields between 100 and 500 gpm. The water is generally of the sodium or calcium bicarbonate type with dissolved solids generally less than 1,000 mg/l. The dissolved solids can exceed 3,000 mg/l in some areas. The aquifer is largely undeveloped with an estimated 32 million acre-feet in storage.

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TABLE 8

STREAM WATER RIGHTS, SOUTHERN REGION
(acre-feet)

County	Allocations							
	Municipal	Industrial	Agricultural	Commercial	Recreation and Fish & Wildlife	Power	Other	Total
Atoka	142,161	12,000	2,055	-	535	285	-	157,036
Bryan	13,281	644	14,195	5	6,626	-	-	34,751
Carter	8,027	175	2,959	-	12,161	-	-	23,322
Coal	3,566	-	6,217	-	1	-	-	9,784
Garvin	4,453	182	8,159	10	1,452	-	-	14,256
Johnston	1,290	1,246	9,366	25	2,356	-	-	14,283
Love	-	2	2,776	667	372	-	-	3,817
Marshall	6,581	-	5,117	2	148	-	111	11,959
Murray	27,135	2,276	1,384	10	2,483	-	-	33,288
Pontotoc	8,700	17	3,907	23	143	-	-	12,790
Total	215,194	16,542	56,135	742	26,277	285	111	315,286

Note: Municipal is Public Supply. Agricultural includes Irrigation and Livestock. Mining is included in Industrial.
Source of data: Oklahoma Water Resources Board, May 2003.

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Groundwater.

The Southern Regional Planning District overlays four principal groundwater aquifers: the Arbuckle-Simpson Group, the Oscar Formation, the Antlers Formation, and the alluvium and terrace deposits. Groundwater is the principal supply for most irrigation demands as well as the major supply for many of the smaller communities in the region.

The Arbuckle-Simpson Group is a limestone, dolomite, and sandstone formation found in portions of Carter and Murray counties. Formation thicknesses vary between 5,000 and 9,000 feet. Well depths are commonly between 100 and 2,500 feet with yields between 100 and 500 GPM. The water is a calcium magnesium bicarbonate type and is very hard. Dissolved solids are generally within acceptable limits and the water is suitable for most uses.

The Oscar Formation is an interbedded shale, sandstone, and limestone conglomerate aquifer. The formation is 300 to 400 feet thick and is found in western Stephens, southwestern Garvin and Carter, and eastern Jefferson County. Wells range from 600 to 400 GPM. The water quality is suitable for most uses.

The Antlers Sandstone is a friable sandstone, silt, clay, and shale formation with average thicknesses of 450 feet. The formation is found in Love, Marshall, Bryan, and southern Carter, Johnston, and Atoka counties. Well depths range between 200 and 800 feet with yields between 100 and 500 gpm. The water is generally of the sodium or calcium bicarbonate type with dissolved solids generally less than 1,000 mg/l. The dissolved solids can exceed 3,000 mg/l in some areas. The aquifer is largely undeveloped with an estimated 32 million acre-feet in storage.
The alluvial and terrace deposit aquifers are usually found around the two major rivers in the region, the Red River and the Washita River. Wells in this formation range from 200 gpm to 500 gpm. The formation deposits average 70 feet in thickness. The formation consists of silt and clays downgrading into fine to coarse sand. The water is hard to very hard with the water generally calcium magnesium bicarbonate type. Total Dissolved Solids values are usually less than 1,000 mg/l within the Washita River Basin and less than 2,000 mg/l within the Red River Basin. The water levels have generally declined in recent years.

Groundwater Development. Development of groundwater supplies continues within the Southern Regional Water Planning District despite the low yields and poor water quality in the aquifers. Some communities have developed the Oscar formation as their principal supply. Most irrigation within the region is done with groundwater. No costs have been calculated regarding the development of groundwater. For groundwater to be a viable and dependable source of supply, costs would have to be developed to determine it's feasibility for a particular user.

Groundwater Rights. The OWRB had issued groundwater allocation permits totaling 217,309 acre-feet of water per year from aquifers within the Southern Regional Water Planning District. Table 9 provides a breakdown of the groundwater allocations within the region.

11.4.2.8 Supply and Demand Analysis. Table 10 summarizes the surface and groundwater sources of water supply within the Southern Regional Water Planning District by decade beginning in year 2000 to year 2060. The Southern Regional Water Planning District is the dividing line between the part of the state with ample water and the part with too little. The western portions of the region may have local shortages without the development of future sources. Water quality is also a problem in the western areas. Table 11 reflects the available surplus water within the region and indicates the availability of water from existing sources. The long-range projections for M&I water demand in 2060 is 67,648 acre-feet/year. Agricultural demands are estimated at 73,350 acre-feet/year by year 2060. The water is moderately turbid and is classified as soft. Table 11 shows existing and projected supply and demand for water in this region for selected decades to 2060.

11.4.2.8.1 Summary of Water Demand and Supply. In a comparison of water demands to water supply in this region, it would appear that quantities of supply are much greater than demands. This is due to the estimate of the large amount of groundwater in the aquifers in this region. However, the quantity of groundwater available does not necessarily reflect the quality of groundwater or the estimated costs of obtaining and delivering groundwater to users. Most of the groundwater is utilized for agricultural irrigation activities. Some municipalities depend on groundwater to varying degrees to meet current and future residential, commercial, industrial, and public water demands. The demand for water for power is not significant in this region. The feasibility of obtaining water supply from sources of supply, both surface and groundwater, and a water management strategy for this region would require a more detailed analysis of the cost of developing the water supply as well as the conveyance of the water to a user. A regional analysis would require the evaluation of sources of supply and demands in other regions, particularly those with less expensive sources of supply or those with large municipal and industrial demands as in large metropolitan areas.

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TABLE 9

GROUNDWATER RIGHTS, SOUTHERN REGION
(acre-feet)

County	Allocations							
	Municipal	Industrial	Agricultural	Commercial	Recreation and Fish & Wildlife	Power	Other	Total
Atoka	182	-	420	2,698	20	-	-	3,320
Bryan	3,829	273	6,768	0	20	-	-	10,890
Carter	2,619	1,768	14,211	70	-	-	-	18,668
Coal	783	-	34	-	-	-	-	817
Garvin	4,922	12,471	7,716	43	33	-	5	25,190
Johnston	4,810	2,062	1,936	4	240	-	-	9,052
Love	3,338	555	21,082	100	510	-	-	25,585
Marshall	5,670	180	3,060	-	100	-	-	9,010
Murray	22,045	1,875	10,783	-	200	2,214	-	37,117
Pontotoc	53,121	6,991	14,124	794	30	2,600	-	77,660
Total	101,319	26,175	80,134	3,709	1,153	4,814	5	217,309

Note: Municipal is Public Supply. Agricultural includes Irrigation and Livestock. Mining is included in Industrial.
Source of data: Oklahoma Water Resources Board, May 2003.

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TABLE 10

WATER SUPPLY SOURCES BY YEAR AND COUNTY, SOUTHERN REGION
(acre-feet per year)

Source: Year 2000	County										
	Atoka	**Bryan**	**Carter**	**Coal**	**Garvin**	**Johnston**	**Love**	**Marshall**	**Murray**	**Pontotoc**	**Total**
Major Reservoirs & M&I Lakes											
Atoka Lake	700	0	0	0	0	0	0	0	0	0	700
McGee Creek Lake	31,800	0	0	0	0	0	0	0	0	0	31,800
Arbuckle Lake	0	0	18,240	0	4,320	0	0	0	1,440	0	24,000
Rock Creek (SCS 18)	0	0	1,220	0	0	0	0	0	0	0	1,220
Lake Texoma	0	0	0	0	0	0	0	168,000	0	0	168,000
Other M&I Lakes & NRCS Structures*											
Blue River 1-6	0	2,400	0	245	0	0	0	0	0	949	3,594
Canadian River Subsystem 2-6-1	1,400	0	0	0	638	0	0	0	0	2,005	4,043
Muddy Boggy River 1-4	3,780	0	0	5,115	0	2,497	0	270	0	0	11,662
Red River 1-9	0	0	0	0	0	0	0	1,500	0	0	1,500
Walnut Bayou Creek 1-10	0	0	1,715	0	0	0	1,123	0	0	0	2,838
Washita River Subsystem 1-8-1	0	0	7,068	0	11,464	1,449	0	2,394	2,307	356	25,038
Washita River Subsystem 1-8-2	0	0	0	0	864	0	0	0	0	0	864
Total Impounded Surface Water Yield	37,680	2,400	28,243	5,360	17,286	3,946	1,123	172,164	3,747	3,310	275,259
Groundwater: Recoverable Water											
A&T of Canadian River	0	0	0	0	0	0	0	0	0	197,010	197,010
A&T of Red River	0	922,169	0	0	0	0	544,620	0	0	0	1,466,789
A&T of Washita River	0	0	0	0	729,638	0	0	0	178,723	0	908,361

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TABLE 10. WATER SUPPLY SOURCES BY YEAR AND COUNTY, SOUTHERN REGION (Continued)

Source: Year 2000	County										
	Atoka	**Bryan**	**Carter**	**Coal**	**Garvin**	**Johnston**	**Love**	**Marshall**	**Murray**	**Pontotoc**	**Total**
Antlers	2,045,970	9,963,162	283,290	0	0	769,545	2,164,823	5,531,045	0	0	20,757,835
Arbuckle-Simpson	0	0	504,963	0	0	3,905,709	0	0	2,966,265	2,053,557	9,430,494
Gerty	0	0	0	0	66,262	0	0	0	0	156,569	222,831
Total Groundwater Recoverable	2,045,970	10,885,331	788,253	0	795,900	4,675,254	2,709,443	5,531,045	3,144,988	2,407,136	32,983,320
Total Water Supply Year 2000	2,083,650	10,887,731	816,496	5,360	813,186	4,679,200	2,710,566	5,703,209	3,148,735	2,410,446	33,258,579
Total Water Supply Year 2010	2,083,650	10,887,731	816,496	5,360	813,186	4,679,200	2,710,566	5,703,209	3,148,735	2,410,446	33,258,579
Total Water Supply Year 2020	2,083,650	10,887,731	816,496	5,360	813,186	4,679,200	2,710,566	5,703,209	3,148,735	2,410,446	33,258,579
Total Water Supply Year 2030	2,083,650	10,887,731	816,496	5,360	813,186	4,679,200	2,710,566	5,703,209	3,148,735	2,410,446	33,258,579
Total Water Supply Year 2040	2,083,650	10,887,731	816,496	5,360	813,186	4,679,200	2,710,566	5,703,209	3,148,735	2,410,446	33,258,579
Total Water Supply Year 2050	2,083,650	10,887,731	816,496	5,360	813,186	4,679,200	2,710,566	5,703,209	3,148,735	2,410,446	33,258,579
Total Water Supply Year 2060	2,083,650	10,887,731	816,496	5,360	813,186	4,679,200	2,710,566	5,703,209	3,148,735	2,410,446	33,258,579
***Includes estimated yields for structures containing more than 100 acre-feet of storage.**											

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TABLE 11

WATER DEMAND AND SUPPLY BY YEAR, COUNTY, AND CATEGORY
SOUTHERN REGION
(acre-feet per year)

Year 2000 County	Water Demand M&I	Power	Agriculture	Total Demand	Total Supply	Balance
Atoka	2,273	0	2,477	4,750	2,083,650	2,078,900
Bryan	7,440	0	14,835	22,275	10,887,731	10,865,456
Carter	9,464	0	2,857	12,321	816,496	804,175
Coal	800	0	1,402	2,202	5,360	3,158
Garvin	9,447	0	4,510	13,957	813,186	799,229
Johnston	1,727	0	3,127	4,854	4,679,200	4,674,346
Love	1,107	0	7,435	8,542	2,710,566	2,702,024
Marshall	7,828	0	2,603	10,431	5,703,209	5,692,778
Murray	2,253	0	3,300	5,553	3,148,735	3,143,182
Pontotoc	7,120	616	7,447	15,183	2,410,446	2,395,263
Total	49,459	616	49,993	100,068	33,258,579	33,248,148

Year 2010 County	Water Demand M&I	Power	Agriculture	Total Demand	Total Supply	Balance
Atoka	2,557	0	2,540	5,097	2,083,650	2,078,553
Bryan	8,391	0	16,209	24,600	10,887,731	10,863,131
Carter	10,114	0	2,948	13,062	816,496	803,434
Coal	824	0	1,635	2,459	5,360	2,901
Garvin	9,929	0	5,402	15,331	813,186	797,855
Johnston	1,913	0	3,376	5,289	4,679,200	4,673,911
Love	1,350	0	7,458	8,808	2,710,566	2,701,758
Marshall	10,496	0	3,275	13,771	5,703,209	5,689,438
Murray	2,542	0	3,353	5,895	3,148,735	3,142,840
Pontotoc	7,438	733	7,691	15,862	2,410,446	2,394,584
Total	55,554	733	53,887	110,174	33,258,579	33,244,808

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TABLE 11. WATER DEMAND AND SUPPLY BY YEAR, COUNTY, AND CATEGORY, SOUTHERN REGION (Continued)

Year 2020 County	Water Demand M&I	Power	Agriculture	Total Demand	Total Supply	Balance
Atoka	2,799	0	2,602	5,401	2,083,650	2,078,249
Bryan	8,979	0	17,583	26,562	10,887,731	10,861,169
Carter	10,419	0	3,038	13,457	816,496	803,039
Coal	936	0	1,868	2,804	5,360	2,556
Garvin	9,654	0	6,295	15,949	813,186	797,237
Johnston	2,099	0	3,624	5,723	4,679,200	4,673,477
Love	1,548	0	7,481	9,029	2,710,566	2,701,537
Marshall	12,142	0	3,947	16,089	5,703,209	5,687,120
Murray	2,668	0	3,406	6,074	3,148,735	3,142,661
Pontotoc	7,503	850	7,935	16,288	2,410,446	2,394,158
Total	58,747	850	57,779	117,376	33,258,579	33,242,490

Year 2060 County	Water Demand M&I	Power	Agriculture	Total Demand	Total Supply	Balance
Atoka	3,917	0	2,853	6,770	2,083,650	2,076,880
Bryan	11,802	0	23,079	34,881	10,887,731	10,852,850
Carter	12,123	0	3,401	15,524	816,496	800,972
Coal	1,458	0	2,800	4,258	5,360	1,102
Garvin	9,509	0	9,865	19,374	813,186	793,812
Johnson	3,004	0	4,619	7,623	4,679,200	4,671,577
Love	2,375	0	7,572	9,947	2,710,566	2,700,619
Marshall	19,811	0	6,634	26,445	5,703,209	5,676,764
Murray	3,466	0	3,618	7,084	3,148,735	3,141,651
Pontotoc	8,068	1,305	8,909	18,282	2,410,446	2,392,164
Total	75,533	1,305	73,350	150,188	33,258,579	33,232,134

11.4.3 Analysis of Water Supply Alternatives.

11.4.3.1 **No Action**. Under the No Action Alternative existing condition, approximately 150,000 acre-feet of water supply storage would remain available to water users in Oklahoma and Texas. The No Action alternative represents the existing condition baseline against which to compare the effects of other alternatives.

The no action alternative would remove a large potential water source for meeting future water demand that was projected in Texas Senate Bill 1. The No Action alternative would not satisfy the expanding municipal and industrial water supply demands that are a result of population growth in the region. Additional water requests made by the NTMWD, the GTUA, the RRAT,

the Marshall County Water District, and the states of Texas and Oklahoma and the surrounding communities would not be met.

Additional water supply storage at Lake Texoma would not be made available to the GTUA as required under Public Law 85-146, thereby prompting the city of Sherman and the GTUA to obtain water contracts elsewhere and attempt to manage water demands with existing resources. This would likely result in long-term failure to meet local area municipal and industrial water supply needs. It would also require development of another alternative water source, which is not feasible.

11.4.3.2 **Action Alternative**. Only one alternative was identified. That alternative is the Proposed Action. Other alternatives were eliminated from further consideration based on language in the authorizing legislation. Public Law 99-662, Section 838 (a) states that, "The project for the Denison Dam (Lake Texoma), Red River, Texas and Oklahoma, authorized by the Flood Control Act approved June 28, 1938, is modified to provide that the Secretary is authorized to reallocate from hydropower storage to water supply storage, in increments as needed, up to an additional 150,000 acre-feet for municipal, industrial and agricultural water users in the State of Texas and up to an additional 150,000 acre-feet for municipal, industrial and agricultural water users in the State of Oklahoma."

In accordance with the Water Resources Development Act of 1986, 300,000 acre-feet of water currently authorized for hydropower storage would be reallocated to water supply storage. The reallocation would provide up to 150,000 additional acre-feet for municipal, industrial, and agricultural water users in the state of Oklahoma and 150,000 additional acre-feet for municipal, industrial, and agricultural water users in the state of Texas.

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US Army Corps of Engineers ®
Northwestern Division

DENISON DAM & POWERHOUSE
LAKE TEXOMA
RED RIVER
OKLAHOMA & TEXAS

WATER SUPPLY STORAGE REALLOCATION

POWER BENEFITS FOREGONE

APRIL 2005
(revised)

Prepared for

U.S. Army Corps of Engineers
Tulsa District
Tulsa, Oklahoma

PREPARED BY
HYDROPOWER ANALYSIS CENTER

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LAKE TEXOMA
DENISON DAM, RED RIVER
OKLAHOMA & TEXAS

WATER SUPPLY STORAGE REALLOCATION

POWER BENEFITS FOREGONE

APRIL 2005
(*revised)*

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TABLE OF CONTENTS

1.0 INTRODUCTION 1

1.1 Purpose and Scope 1
1.2 Project Description 1
1.3 Study Participants 2
1.4 The Cost of Water Supply Storage Reallocation 3
1.5 Power Benefits Foregone 3
1.6 Revenues Foregone 4
1.7 Replacement Cost of Power 4

2.0 POWER BENEFITS FORGONE 5

2.1 General 5
2.2 Power Unit Values 5
2.3 Interest Rate 5
2.4 Period of Analysis 5
2.5 Price Level 6
2.6 Most Likely Thermal Generation Alternative 6
2.7 Revised Simulations with SWD-SUPER Streamflow Routing Model 7
2.8 Generator Rewind Study 7

3.0 ENERGY BENEFITS FOREGONE 8

3.1 General 8
3.2 Water Supply Withdrawal Alternatives Considered 9
3.3 Study Assumptions 9
3.4 Computation of Energy Losses 10
3.5 Input Revision to the SUPER model 12
3.6 General Basis for Computing Energy Benefits 12
3.7 Procedure for Computing Energy Unit Value 13
3.8 PROSYM Production Cost Model 13
3.9 Power Market Area and Loads 14
3.10 System Loads 14
3.11 PROSYM Input Data 14
3.12 Fuel Prices, Variable O&M Costs, Heat Rates 16
3.13 PROSYM Computer Runs 16
3.14 Annual Energy Values 16
3.15 Energy Unit Value 16

4.0 CAPACITY BENEFITS FOREGONE 18

4.1 General 18
4.2 Dependable Capacity 18
4.3 Dependable Capacity Evaluation Method 18
4.4 Dependable Capacity vs. Marketable Capacity 19
4.5 Computation of Dependable Capacity 19
4.5.1 Hydrologic Period of Analysis 19
4.5.2 Criteria for Computing Dependable Capacity 20
4.5.3 Computation Procedure for Supportable Capacity 21
4.6 Dependable Capacity Looses 22

DRAFT

4.7 Capacity Values 25
4.7.1 Most Likely Thermal Generating Alternative 25
4.7.2 Capacity and Energy Values Used in Screening Curve Analysis 25
4.7.3 Screening Curve Analysis 27
4.7.4 Least-Cost Thermal Mix 29
4.7.5 Composite Capacity Unit Value 29
4.8 Capacity Benefits Foregone 31

5.0 TOTAL BENEFITS FOREGONE 32

5.1 General 32
5.2 Summary of Power Benefits Foregone 32

6.0 REVENUES FOREGONE 34

6.1 General 34
6.2 Energy Revenue Foregone 34
6.3 Capacity Revenue Foregone 34
6.4 Loss in Marketable Capacity 34
6.5 Marketable Capacity vs. Dependable Capacity 35
6.6 Total Revenues Foregone 35

7.0 CREDIT TO POWER MARKETING AGENCY 36

7.1 General 36
7.2 Remaining Period of Contract 37
7.3 Computation of Credit to Power Marketing Agency 37
7.4 Summary of Credits 40

8.0 SUMMARY OF RESULTS 41

8.1 Power Benefits Foregone 41
8.2 Replacement Cost 41
8.3 Revenues Foregone 42
8.4 SWPA Credit 42

DRAFT

LIST OF TABLES

Table 1-1: Water Supply Storage Allocation in Lake Texoma 2
Table 2-1: Pertinent Study Data Hydropower and Economic Parameters..... 6
Table 3-1: Annual Energy Loss Due to Reallocation 11
Table 3-2: Average Annual Energy..... 12
Table 3-3: Annualized Energy Value Computation..... 17
Table 4-1: Lake Texoma Dependable Capacity Parameters..... 20
Table 4-2: Dependable Capacity Calculation - 300,000 AF..... 23
Table 4-3: Dependable Capacity Calculation - 450,000 AF..... 24
Table 4-4: Capacity Unit Values 26
Table 4-5: Energy Unit Values..... 27
Table 5-1: Annual Hydropower Benefits Foregone..... 25
Table 6-1: Hydropower Revenues Foregone..... 25
Table 7-1: SWPA Annual Capacity and Energy Credit 300,000 AF 38
Table 7-2: SWPA Annual Capacity and Energy Credit 450,000 AF 39
Table 7-3: Annual Credit Due Power Marketing Agency 26
Table 8-1: Annual Power Benefits Foregone..... 10
Table 8-2: Annual Revenue Foregone..... 10
Table 8-3: Annual SWPA Credit 10

LIST OF FIGURES

Figure 4-1: Thermal Screening Curve 28
Figure 4-2: Total hourly Generation Duration Curve for 1998 29

LIST OF ATTACHMENTS

ATTACHMENT A – FERC POWER VALUES ……..……A-1
ATTACHMENT B – PROSYM OUTPUT SUMMARY ……..……B-1

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1.0 INTRODUCTION

1.1 Purpose and Scope

This report, prepared by the Hydropower Analysis Center (HAC) for the Tulsa District (SWT), Corps of Engineers, presents details of the hydropower benefits and economic analysis associated with the proposed reallocation of an additional 300,000 acre-feet (AF) from Lake Texoma (Denison Dam) on the Red River. Analysis of hydropower impacts for reallocating hydropower storage to water supply storage in Lake Texoma includes the computation of the following values:

- power benefits foregone
- revenues foregone
- credit to the Federal Power Marketing Agency (Southwestern Power Administration)

Values were computed for each of these parameters for the proposed reallocation of reservoir storage.

1.2 Project Description

The Denison Dam (Lake Texoma) is located on the Red River at river mile 725.9 on the Oklahoma-Texas border in Bryan County, 5 miles northwest of Denison in Grayson County. The authorized purposes of the project are flood control, navigation, hydropower, water supply and recreation.

The project was constructed during the years 1939 to 1944. The powerhouse has two generating units – two 35 MW units for a total installed capacity of 70 MW. These units generate an estimated average of 235 gigawatt-hours (GWh) yielding an average annual plant factor of about 38 percent. Lake Texoma has a total of 5,194,164 AF of storage, of which 1,570,216 AF (elevation 590 ft to 617 ft) is reserved for power (conservation) storage.

The Water Supply Act of 1958 established a Federal policy of cooperation in development of municipal water supplies by reallocating reservoir storage among riginal authorized purposes to include municipal water supply. Currently, the allocation for water supply storage in Lake Texoma is 150,000 AF made in 1983 and 1985. Existing water supply users are listed in Table 1-1. The total storage shown in Table 1-1 exceeds the 150,000 AF by approximately 8,000 AF due to a yield study done in 1992 and the new storages were distributed based on percentages in the contracts.

Table 1-1: Water Supply Storage Allocation in Lake Texoma

Entity	Storage
City of Denison	21,300 AF
Texas Power & Light	16,400 AF
Red River Authority of Texas	2,736 AF
North Texas Municipal	95,023 AF
Buncombe Creek	1 AF
Greater Texoma Utility Authority	22,600 AF

Reallocation of an additional 300,000 acre-feet of hydropower storage to water supply was authorized in Section 838 of PL 99-662. This legislation provides 150,000 acre-feet of storage for Texas and 150,000 acre-feet for Oklahoma. Of the 150,000 acre-feet of storage for Texas - 50,000 acre-feet of it is specifically set aside for the Greater Texoma Utility Authority.

1.3 Study Participants

This report was prepared by the Hydropower Analysis Center (HAC) of the Northwestern Division, North Pacific Region, Corps of Engineers. The primary HAC point of contact is Kamau Sadiki, HAC Technical Manager, at telephone: (503) 808-3980; e-mail: kamau.b.sadiki@usace.army.mil. HAC engineer, Dinh Quan performed the power values and benefit impact analyses. Russ Davidson, HAC hydropower engineer, performed technical writing and power analyses. Kamau Sadiki performed the Independent Technical Review and served as overall study coordinator for HAC. Ms. Cynthia Kitchens was the Project Manager and Ms. Janet Hotubbee of the Tulsa District (SWT) served as study manager (telephone: (910) 251-4762. Mr. Jim Sullivan, economist, Tulsa District, performed life-cycle economic evaluations for the overall Lake Texoma Water Supply study. Ms. Mary Ann Duke of the Tulsa District performed hydrologic engineering studies using the SWD-SUPER model.

1.4 The Cost of Water Supply Storage Reallocation

The procedures for computing the cost of storage reallocation addressed in this study are outlined in Appendix E, paragraph E-57, d(2) of ER 1105-2-100, *Planning Guidance Notebook* (22 April 2000). These procedures require that the reallocation cost of the water supply customers be the highest of the following;

- power benefits foregone
- power revenues foregone
- replacement costs of power
- updated cost of storage

Although reservoir storage reallocations could result in impacts to other project purposes this report determines the impacts to hydropower. Therefore, power benefits foregone in this evaluation are a power related impact. The revenue foregone and replacement cost of power are also power-related. The updated cost of storage is non-power related and Tulsa District will compute the updated cost of storage based on the storage necessary to yield the requested withdrawals. In Sections 1.5 through 1.7 are descriptions of each of these power-related values.

1.5 Power Benefits Foregone

Hydropower benefits are normally based on the cost of the most likely alternative thermal source of power. When conservation storage is reallocated for water supply the lost hydropower will be replaced with the most likely alternative thermal source of power.

The power benefits foregone can be divided into two components, lost energy and lost capacity benefits. In the case of water supply withdrawals, there is usually a loss of energy benefits, which are based on the loss in generation (both at-site and downstream) as a result of water being diverted from the reservoir for water supply rather than passing through the hydropower plant. In addition, there could be a loss of capacity benefits as a result of a loss in dependable capacity at the project. Loss of dependable capacity could be a result of:

- a loss in head due to lower post-withdrawal reservoir elevations
- a reduction in the usability of the capacity due to inadequate energy to support the full capacity during low-flow periods

The details of energy benefit computations are described in Section 3, and capacity benefit computations are shown in Section 4.

1.6 Revenues Foregone

The second power-related cost is the revenues foregone. This is the value of the lost hydropower based on the power marketing agency's current energy rates. The calculations for revenues foregone are contained in Section 6.

1.7 Replacement Cost of Power

The third power-related cost is the cost of replacement power. This is a National Economic Development (NED) cost similar to power benefits foregone, and is therefore a redundant value in the case of hydropower. NED power benefits foregone are based on the cost of the most likely alternative, which in fact is the cost of replacement power. Replacement cost is included in the guidance as one of the four alternative cost methods to be evaluated because it has meaning when storage is reallocated from functions other than hydropower. For example, if the objective is to reallocate flood control storage to water supply, the replacement cost of flood control storage would have to be considered, because this storage would have an entirely different value than the flood control benefits foregone. However, for a hydropower/conservation storage reallocation, the replacement cost of hydropower is identical to the power benefits foregone.

Note that Appendix E, paragraph d(2)(c)(3), *Planning Guidance Notebook* (22 April 2000), also discusses a replacement cost based on financial or actual market prices, but this is an entirely different value than the replacement cost discussed in the paragraph above. The market-based replacement cost is to be used to compute a possible credit to the power marketing agency. If the water supply reallocation results in less hydropower being available to the marketing agency for delivery to its customers, the marketing agency will receive a credit to offset additional costs that they might incur and to reduce their repayment obligation. The calculation of this value is described in Section 7.

2.0 POWER BENEFITS FORGONE

2.1 General

The details of energy and capacity benefit computation are described in Section 3 and Section 4, respectively. This section describes some of the terminology, methodology, and basic assumptions required for computing power benefits foregone.

2.2 Power Unit Values

The power benefits foregone are computed by applying power unit values to the loss in average annual generation and dependable capacity at Lake Texoma (Denison Dam). The capacity unit value, applied to the dependable capacity loss, represents the unit cost of constructing an increment of thermal capacity to replace the lost hydropower capacity. The energy unit value, the unit cost of producing replacement energy in the area power system, is applied to the loss in average annual generation.

These values were derived using NED economic criteria, in accordance with the U.S. Water Resources Council's Economics and Environmental Principles and Guidelines for Water and Related Land Resources Implementation Studies, previously referenced as ER 1105-2-100, *Planning Guidance Notebook* (22 April 2000).

2.3 Interest Rate

The interest rate used in computing power benefits foregone due to water supply storage reallocation is the current (Fiscal Year 2005) Federal interest rate of 5-3/8 percent.

2.4 Period of Analysis

The economic period of analysis for this study is 50 years. The “Period of Analysis” as defined in *Planning Guidance Notebook*, Section 2-4j, for a multiple-purpose reservoir project, is not to exceed 100 years. In section E-63 i(1)(a)(1), “Benefits Foregone”, defines the period of analysis for storage reallocations as the greater of (a) the remaining economic life of the project, or (b) 50 years. Benefits foregone for this analysis are computed assuming the water supply contract will be implemented in 2005. The power on-line date, total economic life, and remaining economic life for the project are shown in Table 2-1

Table 2-1: Pertinent Study Data Hydropower and Economic Parameters

Power	
Installed capacity	70 MW
Economic	
Power on-line (POL)	1944
Total Project life	100 yrs
Remaining life	40 yrs
Interest Rate	5-3/8%
Period of Analysis	50 yrs

2.5 Price Level

The capacity unit value and fuel prices used in determining the energy unit value, was based on 2005 price levels. Real fuel cost escalation was not utilized in developing levelized energy values. Therefore, 2005 level fuel prices were applied over the entire period of analysis1.

2.6 Most Likely Thermal Generation Alternative

The type of alternative plants considered were coal-fired steam (base loads displacement), gas-fired combined cycle (intermediate loads displacement), and gas-fired combustion turbine (peak loads displacement). As described in Section 4.7.1, the most likely thermal generation alternatives to the Lake Texoma (Denison Dam) generation are natural gas-fired combined cycle and natural gas-fired combustion turbine, determined by using a screening curve methodology. Thermal generation replacement alternatives are used in power system modeling to displace the Lake Texoma (Denison Dam) hydropower capacity.

1 2003 fuel prices were indexed to 2005 prices using WEFA, Inc U.S. Energy Outlook for West South Central region fuel cost data. Refer to Attachment B for additional information.

2.7 Revised Simulations with SWD-SUPER Streamflow Routing Model

The SWD-SUPER streamflow routing model was used to simulate the operation of Lake Texoma (Denison Dam) reservoir on a daily time-step according to existing guidelines for reservoir and system operation. The simulations used in the analysis were based on a period of record of 63 years, from 1938 through 2000, and models three alternative storage reallocations of 150,000, 300,000 and 450,000 acre-feet (AF). See Section 3.2 for an explanation of alternatives considered in this analysis.

In the April 2004 report prepared by the HAC, the original load schedule obtained from the Southwestern Power Administration (SWPA), occasionally emptied Lake Texoma's conservation storage under the SUPER simulated condition of a water supply allocation alternative of 450,000 AF. The exhaustion of conservation storage in this alternative simulation was due to over commitment of the available storage. The generating units in the Denison Dam powerhouse do not operate when the pool drops below Elevation 602 because generator efficiency rapidly decreases below this pool elevation. Therefore, to realistically model how the pool would operate under the 450,000 AF alternative, SWPA modified the load schedule to reduce the storage commitment to avoid exhausting the available conservation storage for an extended period of time.

2.8 Generator Rewind Study

A generator rewind study was preformed by HAC for the Denison powerhouse units in July 2003. The powerhouse capacity would increase from 70 MW to 88 MW if the units were rewound. The rewound units were not included in the SUPER simulations due to the uncertainty of when the generator rewind project would actually be implemented.

3.0 ENERGY BENEFITS FOREGONE

3.1 General

Energy benefits foregone have traditionally been computed as the product of the energy loss (in megawatt-hours) and an energy unit value ($/MWh). The energy unit value is based on the cost of energy from the alternative thermal generating plant that would replace the lost energy from the hydropower plant due to operational and/or structural changes.

The value of lost energy benefits can be calculated using several methods, but for this analysis, an hourly system production cost model was used to calculate the value of the lost energy. This approach better accounts for the manner in which hydropower is used in the particular power system being considered, providing a more accurate measure of the energy benefits foregone. The PROSYM system production cost model was used in this study to compute the value of lost hydropower generation. The difference in system production costs (between the "with" and "without" Lake Texoma, Denison Dam, hydropower plant) was converted into an energy unit value that is used to compute energy benefits foregone due to withdrawal at the project.

The basic procedure for estimating energy unit value is as follows:

- Determine the average annual energy from the SWD-SUPER model output, for the base case and reallocation alternatives,

- Compute the difference in energy (kWh) between the base case and reallocation alternatives,

- Simulate the operation of the power system with and without the hydropower energy from Lake Texoma (Denison Dam) using the PROSYM system production cost model,

- Determine the value of the lost hydropower energy by subtracting (a) the cost of operating the system with the losses from (b) the cost of operating the system without losses,

- Divide the resulting cost by the energy loss to obtain the energy unit value ($/MWh) for Lake Texoma (Denison Dam) generation.

These procedures are used to compute an energy value for five future load years, at five-year increments, starting with the project-on-line year. The energy value for intermediate years is computed using linear interpolation. Beyond 25 years, the energy value is held constant due to uncertainty. The 50 annual energy values are brought to a present value using present-worth methods and amortized to an annualized value. The product of the annualized energy value and energy losses due to water withdrawals represents the annual energy benefits foregone for that alternative.

3.2 Water Supply Withdrawal Alternatives Considered

To date there are various water supply contracts in force as listed in Table 1-1. The full use of existing water supply contracts are accounted for in the base case alternative. Tulsa District requested the Hydropower Analysis Center to evaluate the following alternatives:

- Base Case Alternative. Current operations with full use of existing water supply allocation of 150,000 AF.

- 300,000 AF Alternative. Base case alternative with an additional 150,000 AF reallocated from hydropower (conservation) storage for water supply.

- 450,000 AF Alternative. Base case alternative with an additional 300,000 AF reallocated from hydropower (conservation) storage for water supply.

Congress provides discretionary authority to the Commander, US Army, Corps of Engineers to approve storage reallocation requests if the reallocation of storage in a Federal reservoir does not have a severe effect on other project authorized purposes. Additionally, the Commander, USACE, has Congressional authority to reallocate storage to water supply from other purposes in amounts up to 15 percent of total storage capacity allocated to all authorized project purposes or 50,000 acre-feet, whichever is less. In the case of Lake Texoma, 15 percent of the total storage capacity is 779,100 acre-feet. Therefore, the Commander, USACE can reallocate up to 50,000 acre-feet of storage in the reservoir. Existing reallocated storage amounts in the reservoir already exceeds the discretionary limit (see Table 1.1). Therefore, any additional storage reallocation in Lake Texoma would require Congressional authority.

3.3 Study Assumptions

The evaluation of energy benefits foregone due to water supply withdrawals from Lake Texoma was performed based on the following assumptions.

- Water supply withdrawals are considered “consumptive use,” implying that none of the withdrawal amount taken from Lake Texoma (Denison Dam) reservoir will be returned to either the reservoir or the stream reach below the reservoir.

- The seasonal water supply withdrawal rates from Lake Texoma (Denison Dam) are made at a uniform rate through out the year.

The impact on hydropower benefits from reallocating storage for water supply will only be evaluated for storage reallocations in the conservation or hydropower pool. The Tulsa District eliminated evaluation of storage reallocations in the flood control pool based on language in the authorizing legislation. Public Law 99-662, Section 838 (a) states that, “The project for the Denison Dam (Lake Texoma), Red River, Texas and Oklahoma, authorized by the Flood Control Act approved June 28, 1938, is modified to provide that the Secretary is authorized to reallocate from hydropower storage to water supply storage, in increments as needed, up to an additional 150,000 acre-feet for municipal, industrial and agricultural water users in the State of Texas and up to an

additional 150,000 acre-feet for municipal, industrial and agricultural water users in the State of Oklahoma."

3.4 Computation of Energy Losses

Energy losses associated with the reallocation of storage alternatives at Lake Texoma (Denison Dam) were computed by the Tulsa District using the stream flows from the historical period of record (1938–2000) in the SWD-SUPER streamflow routing model. Lake Texoma (Denison Dam) average annual energy loss was computed between the base case and 300,000 AF alternative and the base case and 450,000 AF alternative shown in Table 3-1.

Table 3-1: Annual Energy Loss Due to Reallocation

Year	Existing (MWh)	300K Withdrawal (MWh)	Loss (MWh)	450K Withdrawal (MWh)	Loss (MWh)
1938	287,639	278,839	-8,800	268,290	-19,349
1939	67,938	53,792	-14,146	41,823	-26,115
1940	112,434	96,292	-16,142	79,076	-33,358
1941	467,160	458,024	-9,136	449,533	-17,627
1942	354,380	342,748	-11,632	330,486	-23,894
1943	224,046	212,346	-11,700	203,282	-20,764
1944	125,872	117,902	-7,970	106,463	-19,409
1945	344,665	328,694	-15,971	313,696	-30,969
1946	268,478	256,054	-12,424	243,865	-24,613
1947	245,095	239,962	-5,133	230,747	-14,348
1948	182,353	165,694	-16,659	151,967	-30,386
1949	168,439	157,574	-10,865	153,563	-14,876
1950	352,142	339,374	-12,768	324,252	-27,890
1951	189,865	180,035	-9,830	171,576	-18,289
1952	103,360	86,114	-17,246	62,294	-41,066
1953	87,270	69,469	-17,801	57,855	-29,415
1954	161,475	152,084	-9,391	141,144	-20,331
1955	191,021	179,629	-11,392	171,627	-19,394
1956	73,716	58,695	-15,021	48,741	-24,975
1957	278,949	268,383	-10,566	255,966	-22,983
1958	186,555	177,539	-9,016	166,370	-20,185
1959	183,731	167,541	-16,190	153,112	-30,619
1960	252,519	239,903	-12,616	227,860	-24,659
1961	230,537	215,717	-14,820	201,081	-29,456
1962	229,679	216,547	-13,132	204,869	-24,810
1963	99,823	85,655	-14,168	71,157	-28,666
1964	66,133	53,796	-12,337	43,824	-22,309
-	-	-	-	-	-
-	-	-	-	-	-
-	-	-	-	-	-
1995	412,693	403,221	-9,472	392,603	-20,090
1996	263,096	249,621	-13,475	236,512	-26,584
1997	383,762	373,017	-10,745	362,118	-21,644
1998	295,197	288,347	-6,850	279,884	-15,313
1999	169,668	156,956	-12,712	145,907	-23,761
2000	189,077	171,495	-17,582	154,810	-34,267
Average	232,084	220,089	-11,995	208,292	-23,792

The average annual generation loss for each alternative is summarized in Table 3-2.

Table 3-2: Average Annual Energy

(1938 – 2000)

LAKE TEXOMA	Average Annual Energy	Average Annual Energy Loss
Base Case (MWh)	232,084	---
300,000 AF Alternative (MWh)	220,089	11,995
450,000 AF Alternative (MWh)	208,292	23,792

3.5 Input Revision to the SUPER model

The SUPER model simulation of the 450,000 AF reallocation alternative using the original generation load schedule from SWPA caused the conservation pool to be completely evacuated for a short time in the period of simulation. The conservation pool was over committed. This did not occur for the 150,000 AF reallocation or the 300,000 AF simulations. The efficiency of the generators decreases when the pool drops below Elevation 602. Therefore, generation is not normally scheduled when the pool drops below this elevation. To realistically model how the pool would be operated under the three alternatives, the generation loads were modified by SWPA. In the resulting model output, the conservation pool does not fully evacuate during any period.

3.6 General Basis for Computing Energy Benefits

The energy benefits for a hydropower project are based on the area power system cost of producing the same amount of thermal replacement energy as the proposed hydropower project. To obtain these values, a power system analysis was performed in which the area power system was modeled under two different conditions, one that included the proposed hydropower project or hydropower project modification, and one in which the proposed hydropower project or hydropower project modification was removed. The total systems energy production cost was computed using the differences between the conditions mentioned above. The hydropower energy unit value is then determined by dividing the difference in system operating costs for the two conditions by the hydropower project's annual energy output.

Hydropower generation from the Denison powerhouse is distributed to two preference customers of SWPA, the Rayburn Country and Tex-La Electric Co-operatives. The reliability and security of electricity transmission in Texas is ensured by the Electric Reliability Council of Texas (ERCOT) system. The ERCOT, one of 10 regional reliability councils in the North American Electric Reliability Council (NERC) organization, borders the Southwest Power Pool (SPP) to the south.

The Denison project is operated primarily as a peaking project. Its power generation generally fluctuates daily to meet a relatively constant load pattern. Power generation at Denison powerhouse contributes about 275 gigawatt-hours (GWh) annually to SWPA.

The Denison powerhouse operates independently from SWPA's power system and is not considered a firm resource to meet their system power obligations. The energy generated at Denison is delivered directly to the Rayburn Country and Tex-La Electric Cooperatives.

3.7 Procedure for Computing Energy Unit Value

The value of energy used in this analysis was based on the cost of thermal generations that would be generated in the ERCOT area power system to replace the energy generated from Denison. Since energy benefits are computed by utilizing an average (levelized) energy value over the project economic life, a single energy unit value representing the entire period of analysis was developed for use in computing the Denison energy benefits.

The hydropower energy unit value was computed using the PROSYM system production cost model. Two scenario were analyzed, one with the current hydro operation and one without the hydro generation from Denison. This approach yields a generalized power value for energy from Denison. Because the system generation resource mix changes with time, simulations were performed for the five representative load years: 2005, 2010, 2015, 2020 and 2025. PROSYM modeling of the area power system was limited to every five years due to the amount of effort required to model the system for a single year. Linear interpolation was used to compute energy values for the intermediate years. The use of linear interpolation for the intermediate years does not significantly affect the accuracy of the levelized unit energy value. Also, due to the high degree of uncertainty in projecting power market conditions in the future (such as system load demand, fuel costs and changes in technology), power system simulations were not performed beyond the year 2025. Instead, the PROSYM results for the year 2025 were utilized for the remainder of the period of analysis.

Once the yearly energy unit values were developed utilizing output from PROSYM, they were adjusted to a present-worth value at beginning of the period of analysis and then amortized over the project economic life by applying the appropriate amortization factor. These last results were used to develop the levelized unit energy value. Sections 3.8 through 3.14 describe the PROSYM model and studies, and Section 3.15 describes the process to determine levelized unit energy unit values.

3.8 PROSYM Production Cost Model

To develop system operating costs, the ERCOT area power system was modeled using the PROSYM production cost model, a proprietary model that was developed and is maintained by Henwood Energy Services of Sacramento, California. PROSYM is a chronological hourly production cost model that is used throughout the power industry. The HAC has used this model for more than seventeen years.

The PROSYM model dispatches system generating resources to meet hourly system loads in the same manner as a power system dispatcher would in actual system operation, thereby developing system operating costs for the specified load and resource conditions. In PROSYM, one load year is analyzed at a time, with the model dispatching resources hour-by-hour over one-week periods. PROSYM was used to model the "with" and "without" Denison scenarios for this study.

3.9 Power Market Area and Loads

As mention above, a discussion with SWPA indicated that the power generated at Denison would be marketed to customers located throughout the ERCOT region. The State of Texas makes up this region and is divided into four ERCOT zones, North (ERCTN), South (ERCTS), West (ERCTW) and Houston (ERCTH).

The utilities that make up these zones are:

ERCOT Houston Zone
Frontier Energy Centers - ERCOT
ERCOT Dallas Fort -Worth Area
ERCOT North Zone - ERCOT
Gateway Energy - ERCOT
Kiamichi Energy Zone
ERCOT West Zone

3.10 System Loads

Current and projected ERCOT system load were extracted from Henwood's National Electric Reliability Council (NERC) database. Compilations of Electricity Supply and Demand Projection (EIA-411) and information gathered from the utilities makes up the ERCOT Henwood's load data. For this analysis, Henwood NERC database version 6.6.0 was used, last updated in July of 2003.

The LOADFARM subroutine of the PROSYM model was used to project the hourly load shape for future years. The hourly loads for the base year (average load data from 1996 to 2001) were adjusted by the percentage change in the loads. For the purpose of this study, a 10 percent capacity reserve margin criterion was used. This percentage represents the average reserve capacity of the generating supply over demand for the 2005 through 2025 time period.

3.11 PROSYM Input Data

The basic PROSYM input data set used for the Denison analysis was configured by using EMSS and a database composed of NERC data collected by Henwood. Henwood uses the most current and reliable sources of data in the compilation of their regional database, including sources from government agencies, private utilities, industry publications, and other respected information gathering companies.

Additional generating resources had to be scheduled to insure that loads were met beyond the period covered by the EIA-411 report. Resources were added to the system so that load plus additional 10 percent reserve was met through 2025, base on ERCOT planning criteria. Using projected data from EIA Energy Outlook 2003 (www.eia.doe.gov/oiaf/aeo/supplement/index.html), of Table 61 "Electric Power Projections for EMM Region Eastern Electric Reliability Council" and examining current utility practices, a system future thermal resource mix of 75 percent gas-fired combined cycle (CC) and 25 percent gas-fired combustion turbine (CT) capacity, was used through

out the study years. The characteristics of these assumed new plants were based on the most recent heat rates, efficiencies and the average plant size of currently planned units.

PROSYM accounted for conventional hydropower plants in the system and were modeled as individual hydro-plants. Denison Dam input data was provided for each week of the year, including the weekly capacity output and the weekly energy output. A number of hydropower projects in addition to Denison are operated in ERCOT system, most of which are Corps of Engineers projects. There are several small hydropower projects that are owned by utilities. Denison weekly generation data for 1992 was developed, using output from the generation study and substituted for PROSYM data. Tulsa District has indicated that 1992 was a typical operating year for the Red River system.

3.12 Fuel Prices, Variable O&M Costs, Heat Rates

All fuel prices for individual generation plants within the ERCOT region as well as all generic fuel prices were brought to 2005 price levels. Henwood collected these fuel prices from EIA publications for the NERC database. In accordance with Section 2-4i of ER 1105-2-100, Guidance for Conducting Civil Works Planning Studies (22 Apr 2000), this study did not utilize real fuel cost escalation, and the 2005 level fuel prices were assumed to apply over the entire period of analysis.

3.13 PROSYM Computer Runs

PROSYM simulations were preformed for expected load conditions in the ERCOT region for each of the study years. Hydropower generation replacement for the without scenario, was replaced by screening curve mix of 50% CT generation and 50% CC generation.

3.14 Annual Energy Values

Two PROSYM simulations were performed for each of the five simulated load years in order to determine the system operating costs for the base and alternate conditions. Interpolation used to derive energy values for intermediate years, and the year 2025 value was assumed to be representative of future years beyond that point. A present-worth and amortization procedure was used to derive an amortized energy value over the 50 years life of the project. For each load year, the difference in system operating costs for the two conditions was divided by the annual energy output of the Denison project in order to derive an annual energy value for that year.

3.15 Energy Unit Value

The PROSYM summaries in Attachment B show tables for both with and without project condition, for the selected study year. The tables summarized the ERCOT system operation by plant types. System cost increases for the with-project condition as a result of an increment of hydropower generation being withdrawn and replaced with thermal generation. This cost is divided by the hydropower project average annual generation in order to arrive at the hydropower energy unit value. An examination of these tables will show that, in most years, the hydro generation was replaced primarily by gas-fired combustion turbines and gas-fired steam. The incremental increases in gas-fired steam replaced the intermediate and base load hydro while the gas combustion turbine replaces the peaking hydropower generation.

Table 3-3 shows how these energy unit values were used to determine an annualized energy unit value.

The annualized energy unit value was applied to the generation loss for each withdrawal alternative shown in Table 3.2 to obtain the energy benefits foregone. These computations are summarized in Section 5.

Table 3-3: Annualized Energy Value Computation

Interest Rate (%)	5.375%
Lake Texoma water supply reallocation date	2005
Lake Texoma project economic life of 50 years	
End of Lake Texoma project economic life	2054

Year	Present-Worth Factor	Energy Value ($/Mwh)	Present-Worthed Values Energy Value ($/Mwh)
2005	0.9490	28.43	26.98
2006	0.9006	28.51	25.67
2007	0.8546	28.58	24.43
2008	0.8111	28.66	23.24
2009	0.7697	28.73	22.12
2010	0.7304	28.81	21.04
2011	0.6932	29.70	20.58
2012	0.6578	30.58	20.12
2013	0.6243	31.47	19.65
2014	0.5924	32.36	19.17
2015	0.5622	33.25	18.69
2016	0.5335	33.75	18.00
2017	0.5063	34.25	17.34
2018	0.4805	34.75	16.70
2019	0.4560	35.25	16.07
2020	0.4327	35.75	15.47
2021	0.4106	36.04	14.80
2022	0.3897	36.33	14.16
2023	0.3698	36.62	13.54
2024	0.3510	36.91	12.95
2025	0.3331	37.20	12.39
2026	0.3161	37.20	11.76
2027	0.2999	37.20	11.16
2028	0.2846	37.20	10.59
2029	0.2701	37.20	10.05
2030	0.2563	37.20	9.54
to	---	---	124.20
2054	0.0730	37.20	2.71
		Total	573.12
		Annualizing Factor @ 5.375, 50 years	0.058
		Annualized Value	**33.23**

4.0 CAPACITY BENEFITS FOREGONE

4.1 General

Capacity benefits foregone are defined as the product of the loss in dependable capacity and a capacity unit value, which represent the capital cost of constructing replacement thermal capacity.

4.2 Dependable Capacity

A hydropower project's dependable capacity 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 capacity can be considered dependable. In some cases even the overload capacity is dependable.

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

4.3 Dependable Capacity Evaluation Method

Dependable capacity can be computed in several ways. The method that is most appropriate for evaluating a hydropower plant’s dependable capacity in a predominantly thermal-based power system is the average availability method, as described in Section 6-7g of EM 1110-2-1701, *Hydropower*, dated 31 December 1985. The occasional unavailability of a portion of hydro project's generating capacity due to hydrologic variations should be treated in the same manner as the occasional unavailability of all or part of a thermal plant's generating capacity due to forced outages.

This assumption is not appropriate in power systems where hydropower is a majority resource, because adverse hydrology can affect all of the hydropower projects in a system simultaneously, with a resulting long-term reduction in capacity at all projects. In such systems, hydropower dependable capacity must be based on the capacity available under adverse hydrologic conditions or critical period.

This is not the case in a large, diverse power system, where hydropower represents only a small portion of the region's generating resources. When defining a hydropower project contribution to meeting peak loads in this type of system, random hydrologic variations can be considered equivalent to random thermal generating plant forced outages. ERCOT is primarily a thermal-based power system with only a small amount of hydropower. Therefore, average availability method is the most appropriate method for measuring dependable capacity for this analysis.

4.4 Dependable Capacity vs. Marketable Capacity

The average availability method differs from the method used by Southwestern Power Administration (SWPA) in defining the amount of firm hydropower capacity that it can market. SWPA uses a method based on adverse water, because hydropower is its only generating resource. SWPA can only guarantee delivery of hydropower capacity that it can support during adverse water conditions, because it has no thermal generating plants to back up its hydropower resources. SWPA sometimes purchases thermal power generation on the open market during periods of low stream flows, but cannot afford to do this very often and still meet its repayment obligations to the Federal treasury.

However, even though SWPA uses a method based on a year of adverse hydrologic conditions to determine the marketable capacity of the Lake Texoma (Denison Dam) project, that does not mean the method is appropriate for measuring the loss in NED capacity benefits at this project. The objective of NED benefits is to measure the gain or loss of benefits to the nation as a whole, not to a single entity (such as SWPA) or to a small group of entities (SWPA's customers).

4.5 Computation of Dependable Capacity

Under the average availability method the Lake Texoma (Denison Dam) may occasionally lose capacity due to loss of head or due to inadequate energy to support the available capacity. Similarly, there are periods when the full peaking capacity is both available and usable. The average availability method attempts to measure the average capacity available during the peak demand periods of the year.

4.5.1 Hydrologic Period of Analysis

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 can be used, but 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.

A reliable alternative method is the use of a period-of-record computer simulation of system operation. As described in Section 2.7, the Tulsa District provided a daily simulation of the Red River projects over the period 1938 to 2000 (63 years). This simulation, which was performed using the SWD-SUPER streamflow routing model, served as the basis of this study's dependable capacity computations.

4.5.2 Criteria for Computing Dependable Capacity

The SWPA criterion for sustained capacity at Lake Texoma (Denison Dam) has been approximated by examining the project's contribution to meeting total system capacity requirements in the water year 1964—the year SWPA uses to measure system marketable capacity. Dependable capacity is normally based on the amount of capacity that can be supported in the peak demand period of June through August in the ERCOT region according to SWPA. Table 4-1 list the dependable capacity parameters used in computing dependable capacity at Lake Texoma (Denison Dam).

Table 4-1: Lake Texoma Dependable Capacity Parameters

Critical period:	June-August 1964
Marketed capacity:	70 MW
Machine capability:	80 MW
Number of hrs/day on peak:	7 hours

The average weekly energy output at Lake Texoma (Denison Dam) during June-August 1964 was obtained from the SWD-SUPER streamflow routing model simulation for the Base Case Alternative. The number of hours that the project is required to support was then determined by dividing the average weekly energy by the amount of capacity that SWPA markets from the Lake Texoma (Denison Dam) project.

Thus, based on water available during the 1964 peak demand period of June-August, the number of hours of weekly peaking that the Lake Texoma (Denison Dam) powerhouse can support under the base condition with no new withdrawals for water supply is as follows:

(1)	average June-August 1964 weekly energy,	2,261 MWh
(2)	SWPA marketable capacity:	70.0 MW
(3)	1964 machine capability:	78.7 MW
(4)	Hours on peak per week [(1)/(2)]	32.30 hours

4.5.3 Computation Procedure for Supportable Capacity

Using 32.30 hours per week for sustainable capacity, as computed above and which approximates the SWPA criterion of 7 hours per weekday, the average weekly energy for the peak demand period was computed for each year and divided by 32.30 hours in order to determine how much capacity could be supported during the peak demand months of each year.

For each year, a comparison was made between the “potential” supportable capacity and the project machine capability for that year. In all cases, the capacity that could actually be supported was limited to that portion of the potential supportable capacity that did not exceed project machine capability.

The following example summarizes the computations that were performed to determine average supportable (usable) capacity during the peak demand months of June-August 1964.

Computed from project data for operation without diversion for water supply:

- Average weekly energy during June-August 1964 without diversion is 2,261 MWh
- Average weekly machine capability during June-August 1964 is 78.7 MW
- Potential support capacity during June-August 1964 is 2,261 MWh / 32.30 hours or 70 MW
- Actual supportable capacity during June-August is the minimum of machine capability or potential support capacity or MIN (78.7 MW, 70.0 MW) = 70 MW

4.6 Dependable Capacity Looses

Compared to the existing condition, Table 4-2 and 4-3 show the dependable capacity computations for the 300,000 AF and 450,000 AF reallocation alternatives, respectively. Columns 1-5 of Tables 4-2 and 4-3, ”Calculations - Before Withdrawals”, show how the above procedure was followed to compute each project’s dependable capacity without water supply withdrawals. Columns 6-10, “Calculation - After Withdrawals”, shows the project’s dependable capacity with water supply withdrawals. Notes at the bottom of the tables show how the values in each column were computed. The dependable capacity lost computed in Tables 4-2 and 4-3 are summarized in Table 5-1.

Table 4-2: Dependable Capacity Calculation - 300,000 AF

	Calculations Before Withdrawals					Calculations After Withdrawals				
	1	2	3	4	5	6	7	8	9	10
Year	Required Hours On Peak	Average Weekly Energy Jun-Aug (MWh)	Potential Support Capacity (MW)	Machine Capability (MW)	Actual Support Capacity (MW)	Average Weekly Energy Jun-Aug (MWh)	Potential Support Capacity (MW)	Machine Capability (MW)	Actual Support Capacity (MW)	Lost Capacity (MW)
1964	32.30	2261	70.00	78.7	70.0	1,850	57.27	78.6	57.3	12.73
1938	32.30	6,017	186.3	80.0	80.0	5,952	184.3	80.0	80.0	0.00
1939	32.30	2,262	70.0	80.0	70.0	1,850	57.3	80.0	57.3	12.74
1940	32.30	4,576	141.7	80.0	80.0	4,098	126.9	80.0	80.0	0.00
1941	32.30	9,890	306.2	80.0	80.0	9,730	301.3	80.0	80.0	0.00
1942	32.30	7,057	218.5	80.0	80.0	6,835	211.6	80.0	80.0	0.00
1943	32.30	5,419	167.8	80.0	80.0	5,345	165.5	80.0	80.0	0.00
1944	32.30	3,894	120.6	80.0	80.0	3,771	116.8	80.0	80.0	0.00
1945	32.30	8,191	253.6	80.0	80.0	8,127	251.6	80.0	80.0	0.00
1946	32.30	4,942	153.0	80.0	80.0	4,753	147.2	80.0	80.0	0.00
1947	32.30	6,538	202.4	80.0	80.0	6,474	200.4	80.0	80.0	0.00
1948	32.30	5,740	177.7	80.0	80.0	5,629	174.3	80.0	80.0	0.00
1949	32.30	5,908	182.9	80.0	80.0	5,850	181.1	80.0	80.0	0.00
1950	32.30	10,219	316.4	80.0	80.0	9,963	308.5	80.0	80.0	0.00
1951	32.30	7,239	224.1	80.0	80.0	7,134	220.9	80.0	80.0	0.00
1952	32.30	3,164	97.9	80.0	80.0	3,035	94.0	80.0	80.0	0.00
1953	32.30	2,234	69.2	80.0	69.2	1,824	56.5	79.9	56.5	12.72
1954	32.30	5,070	157.0	80.0	80.0	4,880	151.1	80.0	80.0	0.00
1955	32.30	6,352	196.7	80.0	80.0	6,225	192.7	80.0	80.0	0.00
1956	32.30	2,262	70.0	80.0	70.0	1,849	57.3	80.0	57.3	12.77
1957	32.30	9,843	304.8	80.0	80.0	9,748	301.8	80.0	80.0	0.00
1958	32.30	3,509	108.7	80.0	80.0	3,256	100.8	80.0	80.0	0.00
1959	32.30	5,065	156.8	80.0	80.0	4,513	139.7	80.0	80.0	0.00
1960	32.30	4,548	140.8	80.0	80.0	4,329	134.0	80.0	80.0	0.00
1961	32.30	4,999	154.8	80.0	80.0	4,753	147.2	80.0	80.0	0.00
1962	32.30	7,311	226.4	80.0	80.0	7,122	220.5	80.0	80.0	0.00
1963	32.30	2,280	70.6	80.0	70.6	1,863	57.7	80.0	57.7	12.91
1964	32.30	2,261	70.0	78.7	70.0	1,850	57.3	78.6	57.3	12.73
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
1990	32.30	7,545	233.6	80.0	80.0	7,592	235.1	80.0	80.0	0.00
1991	32.30	7,279	225.4	80.0	80.0	7,034	217.8	80.0	80.0	0.00
1992	32.30	9,484	293.6	80.0	80.0	9,395	290.9	80.0	80.0	0.00
1993	32.30	7,289	225.7	80.0	80.0	7,107	220.1	80.0	80.0	0.00
1994	32.30	5,974	185.0	80.0	80.0	5,821	180.2	80.0	80.0	0.00
1995	32.30	11,909	368.7	80.0	80.0	11,814	365.8	80.0	80.0	0.00
1996	32.30	2,950	91.3	80.0	80.0	2,622	81.2	80.0	80.0	0.00
1997	32.30	7,852	243.1	80.0	80.0	7,621	235.9	80.0	80.0	0.00
1998	32.30	2,504	77.5	80.0	77.5	2,206	68.3	80.0	68.3	9.23
1999	32.30	5,708	176.7	80.0	80.0	5,584	172.9	80.0	80.0	0.00
2000	32.30	3,273	101.3	80.0	80.0	3,072	95.1	80.0	80.0	0.00
Average Actual Supportable Capacities (MW) :					**78.24**				**75.93**	**2.310**

Explanation of Calculations:
Col (1): Required hours peak from section 4.5.2. **Col (2)**: Ave weekly energy before water supply withdrawals is based on the output from the Kerr-Philpott model for Jun-Aug.**Col (3):** Col (2)/Col(1).
Col (4) & Col (8): Machine Capability specified in table 4-1**Col (5):** Lesser of Col (3) and Col (4).
Col (6): Ave weekly energy after water supply withdrawals is based on the data in Col (2) minus the energy losses computed using thepower equation. **Col (7):** Col (6)/Col (1).
Col (9): The lesser of Col (7) and Col (8). **Col (10):** Col (5) - Col (9)

Table 4-3: Dependable Capacity Calculation - 450,000 AF

	Calculations Before Withdrawals					Calculations After Withdrawals				
	1	2	3	4	5	6	7	8	9	10
Year	Required Hours On Peak	Average Weekly Energy Jun-Aug (MWh)	Potential Support Capacity (MW)	Machine Capability (MW)	Actual Support Capacity (MW)	Average Weekly Energy Jun-Aug (MWh)	Potential Support Capacity (MW)	Machine Capability (MW)	Actual Support Capacity (MW)	Lost Capacity (MW)
1964	32.30	2,261	70.0	78.7	70.0	1348	41.7	78.3	41.7	28.26
1938	32.30	6,017	186.3	80.0	80.0	5,896	182.6	80.0	80.0	0.00
1939	32.30	2,262	70.0	80.0	70.0	1,349	41.8	79.9	41.8	28.28
1940	32.30	4,576	141.7	80.0	80.0	3,406	105.5	80.0	80.0	0.00
1941	32.30	9,890	306.2	80.0	80.0	9,596	297.1	80.0	80.0	0.00
1942	32.30	7,057	218.5	80.0	80.0	6,583	203.8	80.0	80.0	0.00
1943	32.30	5,419	167.8	80.0	80.0	5,284	163.6	80.0	80.0	0.00
1944	32.30	3,894	120.6	80.0	80.0	3,600	111.5	80.0	80.0	0.00
1945	32.30	8,191	253.6	80.0	80.0	8,027	248.5	80.0	80.0	0.00
1946	32.30	4,942	153.0	80.0	80.0	4,617	142.9	80.0	80.0	0.00
1947	32.30	6,538	202.4	80.0	80.0	6,386	197.7	80.0	80.0	0.00
1948	32.30	5,740	177.7	80.0	80.0	5,527	171.1	80.0	80.0	0.00
1949	32.30	5,908	182.9	80.0	80.0	5,794	179.4	80.0	80.0	0.00
1950	32.30	10,219	316.4	80.0	80.0	9,765	302.3	80.0	80.0	0.00
1951	32.30	7,239	224.1	80.0	80.0	7,068	218.8	80.0	80.0	0.00
1952	32.30	3,164	97.9	80.0	80.0	2,175	67.4	80.0	67.4	12.65
1953	32.30	2,234	69.2	80.0	69.2	1,331	41.2	79.8	41.2	27.96
1954	32.30	5,070	157.0	80.0	80.0	4,579	141.8	80.0	80.0	0.00
1955	32.30	6,352	196.7	80.0	80.0	6,018	186.3	80.0	80.0	0.00
1956	32.30	2,262	70.0	80.0	70.0	1,348	41.8	79.9	41.8	28.28
1957	32.30	9,843	304.8	80.0	80.0	9,724	301.1	80.0	80.0	0.00
1958	32.30	3,509	108.7	80.0	80.0	3,000	92.9	80.0	80.0	0.00
1959	32.30	5,065	156.8	80.0	80.0	4,178	129.4	80.0	80.0	0.00
1960	32.30	4,548	140.8	80.0	80.0	4,087	126.6	80.0	80.0	0.00
1961	32.30	4,999	154.8	80.0	80.0	4,505	139.5	80.0	80.0	0.00
1962	32.30	7,311	226.4	80.0	80.0	7,002	216.8	80.0	80.0	0.00
1963	32.30	2,280	70.6	80.0	70.6	1,359	42.1	80.0	42.1	28.52
1964	32.30	2,261	70.0	78.7	70.0	1,348	41.7	78.3	41.7	28.26
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-
1990	32.30	7,545	233.6	80.0	80.0	7,343	227.4	80.0	80.0	0.00
1991	32.30	7,279	225.4	80.0	80.0	6,903	213.7	80.0	80.0	0.00
1992	32.30	9,484	293.6	80.0	80.0	9,305	288.1	80.0	80.0	0.00
1993	32.30	7,289	225.7	80.0	80.0	6,923	214.3	80.0	80.0	0.00
1994	32.30	5,974	185.0	80.0	80.0	5,721	177.1	80.0	80.0	0.00
1995	32.30	11,909	368.7	80.0	80.0	11,707	362.5	80.0	80.0	0.00
1996	32.30	2,950	91.3	80.0	80.0	2,271	70.3	80.0	70.3	9.70
1997	32.30	7,852	243.1	80.0	80.0	7,382	228.6	80.0	80.0	0.00
1998	32.30	2,504	77.5	80.0	77.5	1,808	56.0	80.0	56.0	21.53
1999	32.30	5,708	176.7	80.0	80.0	5,437	168.3	80.0	80.0	0.00
2000	32.30	3,273	101.3	80.0	80.0	2,605	80.7	80.0	80.0	0.00
Average Actual Supportable Capacities (MW) :					**78.24**				**72.77**	**5.472**

Explanation of Calculations:
Col (1): Required hours peak from section 4.5.2. **Col (2)**: Ave weekly energy before water supply withdrawals is based on the output from the Kerr-Philpott model for Jun-Aug **Col (3):** Col (2)/Col(1).
Col (4) & Col (8): Machine Capability specify in table 4-1. **Col (5):** Lesser of Col (3) and Col (4).
Col (6): Ave weekly energy after water supply withdrawals is based on the data in Col (2) minus the energy losses computed using thepower equation. **Col (7):** Col (6)/Col (1).
Col (9): The lesser of Col (7) and Col (8). **Col (10):** Col (5) - Col (9)

4.7 Capacity Values

Hydropower benefits are based on the cost of the most likely thermal generation alternative that would carry the same increment of load as the proposed hydropower project or modification. Capacity benefits are intended to measure the investment cost of thermal generating plant capacity that would be needed to replace the lost capacity due to the water withdrawals from the reservoir. Capacity benefits are computed as the product of the dependable capacity loss and a capacity unit value, which is based on the unit cost of constructing the most likely thermal generating alternative.

4.7.1 Most Likely Thermal Generating Alternative

A screening curve analysis was conducted to determine the mix of thermal resources that would be the most likely, least-cost generation plant alternative to the Lake Texoma (Denison Dam) project. The type of alternative plants considered were coal-fired steam (base loads displacement), gas-fired combined cycle (intermediate loads displacement), and gas-fired combustion turbine (peak loads displacement). The screening curve analysis for Lake Texoma (Denison Dam) is described in Section 4.7.3.

4.7.2 Capacity and Energy Values Used in Screening Curve Analysis

Capacity unit values for coal-fired steam, gas-fired combined cycle and combustion turbine plants were computed using procedures developed by the Federal Energy Regulatory Commission (FERC). Capacity values were computed for the Texas region based on a 5-3/8 percent interest rate and 2005 price levels. Computed capacity values are shown in Table 4-4. 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*, Chapter 9-5c for further discussion on the capacity value FERC adjustments.

Unit capacity values 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 Texas.

The adjusted FERC capacity value (CV_{FERC}) incorporates the unadjusted capacity value (CV), the ratio of availability (HMA/TMA) and the flexibility adjustment (1+F).

$$CV_{FERC} = (CV)\left(\frac{HMA}{TMA}\right)(1+F) \qquad \text{(Eq. C-1)}$$

where: CV = unit cost of the most likely thermal alternative, in $/kW-year (also

sometimes called the unadjusted unit capacity value)

HMA = mechanical/electrical availability of the hydro generating unit (computed as 1 - FOR, where FOR = unit forced-outage rate)

TMA = mechanical/electrical availability of the thermal alternative

F = operational flexibility adjustment factor

The ratio of availability accounts for the relative mechanical/electrical reliability of hydropower compared to the thermal alternative, while the flexibility adjustment accounts for the added operational flexibility of hydropower compared to the thermal alternative.

The adjusted and unadjusted unit capacity values, based on a Federal interest rate of 5.375 percent and 2005 price levels, are shown in Table 4-4. A summary of the input data used in computing the adjusted capacity values is included in Attachment A. Also included in Attachment A are copies of the FERC model output where adjusted capacity and energy values were calculated for Texas.

Table 4-4: Capacity Unit Values

Thermal Alternative Plant Type	Adjusted Capacity Value ($/kW-yr)	FERC Adjustments			Unadjusted Capacity Value ($/kW-yr)
		HMA	TMA	F	
Coal-Fired Steam	**235.87**	**0.98**	**0.85**	**0.05**	**194.84**
Combined Cycle	**118.67**	**0.98**	**0.9**	**0.025**	**106.32**
Combution Turbine	**63.00**	**0.98**	**0.9**	**0.025**	**56.45**

Energy unit values 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 2005 price levels, are shown in Table 4-5. 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 4-5: Energy Unit Values

Thermal Alternative Plant Type	Energy Value ($/MWh)
Coal-Fired Steam	20.05
Combined Cycle	38.08
Combustion Turbine	59.73

4.7.3 Screening Curve Analysis

Adjusted capacity values shown in Table 4-4 were used to develop a screening curve for Texas for each of the thermal generating alternatives. A screening curve is a plot of total plant cost (fixed plus variable) versus annual plant factor. Energy unit values in Table 4-5 represent the plant's variable cost.

A screening curve analysis consists of the following steps:

- Construct a total plant cost (in $/kW-year) versus annual plant factor (in percent) diagram (screening curve) which includes a curve for each type of thermal generating plant available for addition to the system; this screening curve will show which type of plant is least costly in each plant factor range.

- Construct an hourly load-duration curve, based on loads for a typical operating year, for the increment of load being analyzed.

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

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

The plot for each thermal generating alternative was developed by computing the annual plant cost for various plant factors ranging from zero to 100 percent. The annual costs were computed using the following equation:2

[2] The product 0.0876 * PF is the factor used to convert EV from $/MWh to $/kW-year so that CV and EV have the same units.

$$AC = CV + (EV * 0.0876 * PF) \qquad \text{(EQ 3)}$$

where: AC = thermal generating plant total cost ($/kW-year)
CV = thermal generating plant capacity value ($/kW-year)
EV = thermal generating plant energy value ($/MWh)
PF = annual plant factor (percent)

The resulting Screening Curve is shown in Figure 4-1. Figure 4-2 shows an hourly duration for 1998, which was considered by the Tulsa District to be a typical operating year for the Denison powerhouse.

Figure 4-1: Thermal Screening Curve

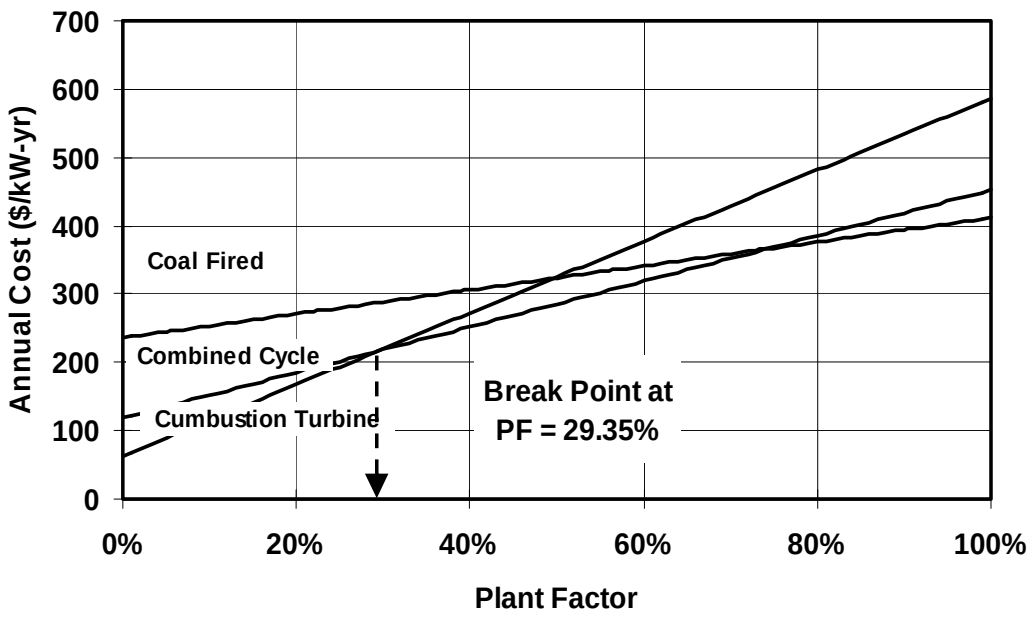
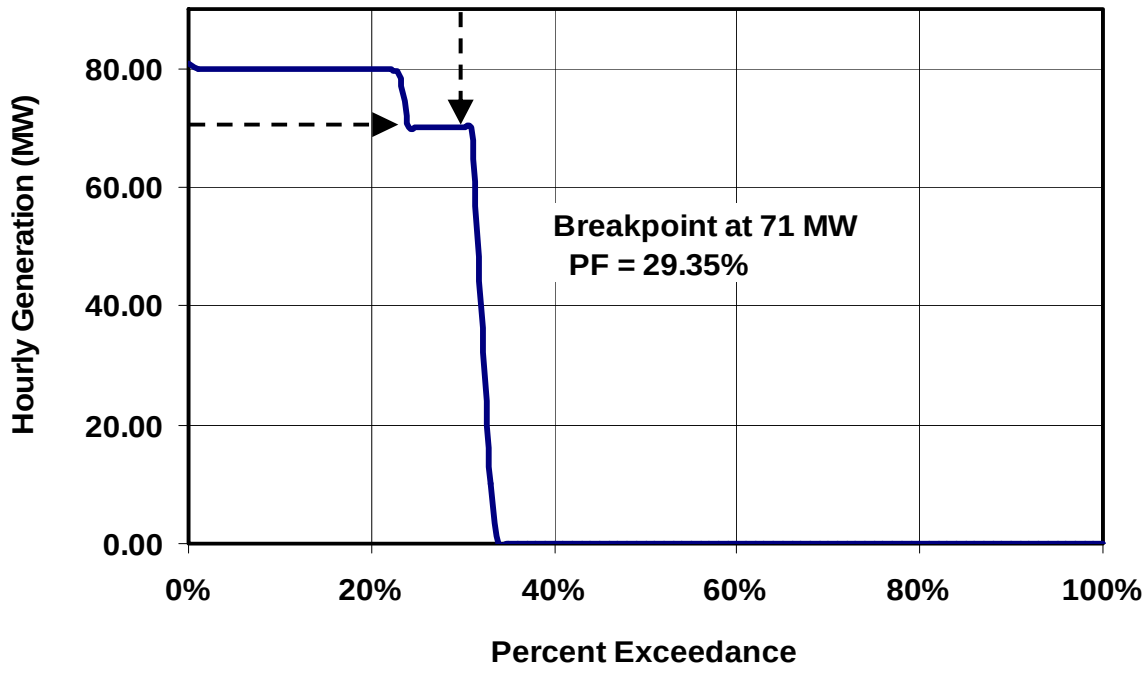


Figure 4-2: Total hourly Generation Duration Curve for 1998



4.7.4 Least-Cost Thermal Mix

From Figure 4-1 a breakpoint plant factor of 29.35% is obtained between the combustion turbine and combined-cycle plant. This plant factor was matched to the percent exceedence on the 1998 hourly generation-duration curve in Figure 4-2. The Tulsa District considers 1998 to be a representative year of operation in terms of both power generation and river flows. A generation value of 71 MW was obtained for the breakpoint. This generation value was then used to divide the generation-duration curve into two components: a 10 MW (81 MW – 71 MW) combustion-turbine (upper) component, a 71 MW combined-cycle component. Thus, the most likely, least-cost thermal alternative to the Lake Texoma hydropower plant would be 10 MW of gas-fired combustion turbine, 71 MW of gas-fired combined cycle power plant, because the project is operated at a relatively low plant factor. This is the most likely least cost generation alternative to the Lake Texoma (Denison Dam) hydro-generation.

4.7.5 Composite Capacity Unit Value

The composite unit capacity value was derived by applying the capacity components of the least-cost thermal alternative as weighting factors to the corresponding adjusted capacity values from Table 4-4. The calculation of the composite unit capacity value is shown below.

CC Capacity Value (Weighted) = $118.67/kW-yr * [71 MW / (71MW + 10 MW)]

= $104.02/kW-yr

CT Capacity Value (Weighted) = $63.00/kW-yr * [10MW / (71MW + 10 MW)]

= $7.78/kW-yr

Summarizing:

Composite Unit Capacity Value = $104.02/kW-yr + $7.78/kW-yr

=$111.80/kW-yr

Based on the Screening Curve analysis results, the FERC adjusted capacity value for gas-fired combustion turbine thermal generating plant for Lake Texoma (Denison Dam) project is $111.80/kW-yr. This capacity unit value will be used to compute capacity benefits foregone for each allocation alternative.

4.8 Capacity Benefits Foregone

The capacity unit value is then applied to the respective capacity losses in Section 4.6 to obtain the loss in capacity benefits for each case. These computations are summarized in Section 5.

5.0 TOTAL BENEFITS FOREGONE

5.1 General

One of the objectives of this study was to identify power benefits foregone due to the proposed storage allocation of 300,000 AF and 450,000 AF in the Lake Texoma (Denison Dam) reservoir (hydropower/conservation) pool. Annual energy losses were computed and then multiplied by the energy unit value to arrive at annual energy benefits foregone. Annual capacity losses were computed and then multiplied by the composite capacity unit value to arrive at annual capacity benefits foregone. Capacity benefits foregone were then added to energy benefits foregone to arrive at total hydropower benefits foregone due to water supply withdrawals.

5.2 Summary of Power Benefits Foregone

Table 5-1 summarizes total hydropower benefits foregone due to allocating 300,000 AF and 450,000 AF of hydropower (conservation) storage to water supply in Lake Texoma (Denison Dam) reservoir. The data in Table 5-1 is derived from information developed in prior sections of this report. Table 3-1 provides the lost energy due to diversion for water supply from the hydropower (conservation) zone in Lake Texoma (Denison Dam) reservoir and Table 3-3 provides the unit value of the energy lost. Capacity losses shown in Tables 4-2 and 4-3 are for diversion from the hydropower (conservation) zone. The unit value for generation capacity is found in Section 4.7.5.

Table 5-1: Annual Hydropower Benefits Foregone

Due to Reallocation from Conservation Pool Storage in Lake Texoma

Allocation Alternatives	**300,000 AF**	**450,000 AF**
Annual Energy Losses (MWh)	11,995	23,792
Energy value ($/MWh)	$33.23	$33.23
Annual energy benefit foregone	**$398,600**	**$790,600**
Capacity Losses (kW)	2,310	5,472
Capacity value ($/kW)	$111.80	$111.80
Annual capacity benefit foregone	**$258,300**	**$611,800**
Total Annual Benefits Foregone	**$656,900**	**$1,402,400**

6.0 REVENUES FOREGONE

6.1 General

Revenues foregone are based on the current contract rates of the Southwestern Power Administration (SWPA), the power marketing administration for Lake Texoma (Denison Dam) project power generation. The rates that are in effect are as follows:

Energy charge:	8.25 mills/kWh
Capacity charge:	$23.52/kW-year

To compute revenues foregone, the energy charge is applied to the average annual energy losses calculated in Section 3. The capacity charge is applied to the loss in dependable capacity in 1964, SWPA's most critical operating year, calculated in Section 4. The results are summarized in Tables 6-1.

6.2 Energy Revenue Foregone

SWPA's average annual energy revenue foregone would be the product of the average annual energy loss under each allocation alternative (Table 2-2) and SWPA's energy charge shown above in Section 6.1**.** Energy revenue foregone is shown in Table 6.1.

6.3 Capacity Revenue Foregone

SWPA's annual capacity revenue foregone would be the product of the loss of marketable capacity during the peak demand period of 1964 (Tables 4-2 and 4-3) and the capacity charge. Capacity revenue foregone is shown in Table 6-1.

6.4 Loss in Marketable Capacity

Under SWPA's current marketing procedures, the amount of marketable capacity at Denison Dam (Lake Texoma) is based on the capacity that can be supported during the 1964 peak demand period. As shown in Table 4-2 and 4-3, the loss in marketable capacity for the 300,000 AF and 450,000 AF allocations alternatives is 12,730 kW and 28,263 kW, respectively.

6.5 Marketable Capacity vs. Dependable Capacity

The 1964 critical water year was designated by SWPA and the marketable capacity loss computation for that year is shown in Table 4-2 and 4-3. Also, shown in these tables is the dependable capacity loss. The difference between the two parameters measures different quantities. The dependable capacity is an NED value, which is intended to measure the economic impact on the region as a whole, while the marketable capacity is a financial parameter that applies only to a single entity, SWPA. Dependable capacity is computed based on the critical period average of historical period years, while marketable capacity is computed based on adverse water conditions and peak power demand during a single year.

6.6 Total Revenues Foregone

The computation of total revenues foregone for the allocation alternatives from Lake Texoma (Denison Dam) is shown in Table 6-1.

Table 6-1: Hydropower Revenues Foregone

Due to Reallocation from the Conservation Pool Storage in Lake Texoma

Allocation Alternatives	**300,000 AF**	**450,000 AF**
Annual Energy Losses (MWh)	11,995	23,792
Energy charge ($/MWh)	$8.25	$8.25
Annual energy revenues foregone	**$99,000**	**$196,300**
Capacity Losses (kW)	12,730	28,263
Capacity charge ($/kW)	$23.52	$23.52
Annual capacity revenues foregone	**$299,400**	**$664,700**
Total Annual Revenues Foregone	**$398,400**	**$861,000**

7.0 CREDIT TO POWER MARKETING AGENCY

7.1 General

Project costs originally allocated to hydropower are being repaid through power revenues which are based on rates designed by the Federal power marketing agency (SWPA) 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, SWPA'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 2000) 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."

For purposes of estimating what this cost will be, the energy and marketable capacity values and energy and capacity charges from Section 6 will be used. No annual escalation rate will be applied to the energy and capacity charges to cover SWPA's estimated real increase in rates in the future, in accordance with paragraph 4-32d(2)(b) of ER 1105-2-100 cited above.

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 actually lost or the replacement costs actually incurred (and documented) by the power marketing agency.

However, for purposes of providing an estimate of this credit, the cost of replacement power will be based on the same power values and energy and average capacity losses as were used in the benefits foregone calculations.

7.2 Remaining Period of Contract

The length of time remaining under the current power sales contracts had to be identified to determine how many years the SWPA credit would be based on cost of replacement power. Contract information provided by SWPA indicated that current contracts for all power marketed from the Lake Texoma (Denison Dam) project will expire in 2015. For this reason, the cost of replacement power will be the basis for the SWPA credit until the present contracts expire in 2015. Following this year, the SWPA credit will be based on revenue foregone for the remaining economic life of the project.

7.3 Computation of Credit to Power Marketing Agency

Tables 7-1 and 7-2 show the computation of SWPA capacity and energy credits. Lost energy and dependable capacity and the power values were taken from Table 5-1. The lost marketable capacity and current SWPA unit energy and capacity charges were taken from Tables 6-1. Following are explanations of the columns in Tables 7-1 and 7-2;

- Column 1 - end of the Lake Texoma (Denison Dam)'s economic life is the year 2055
- Column 2 - capacity benefit is from Table 5-1.
- Column 3 - capacity revenue is from Table 6-1.
- Column 4 - power from this project is marketed under a contract that will expire in 2015. Capacity credits are based upon capacity benefits until 2015, and capacity revenues foregone from 2015 to the end of project economic life.
- Column 5 - energy benefit is from Table 5-1.
- Column 6 - energy revenue is from Table 6-1.
- Column 7 - energy credits are calculated as described in Column (4).
- Column 8 - amortization factor at 5-3/8 percent interest
- Column 9 - column 4 x column 8
- Column 10 - column 7 x column 8
- Column 11 - column 9 + column 10

Following is the calculation of the expected average annual SWPA credit for the alternative storage reallocations in Lake Texoma (Denison Dam) analyzed in this report.

Table 7-1: SWPA Annual Capacity and Energy Credit 300,000 AF

Reallocation from Lake Texoma Conservation Zone

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
Year	Capacity Benefit ($)	Capacity Revenue ($)	Annual Capacity Credit ($)	Energy Benefit ($)	Energy Revenue ($)	Annual Energy Credit ($)	Present-Worth Factor	Present-Worthed Capacity Credit ($)	Present-Worthed Energy Credit ($)	Total Power Credit ($)
2005	$258,300	----	$258,300	$398,600	----	$398,600	0.9490	$245,125	$378,268	$623,393
2006	$258,300	----	$258,300	$398,600	----	$398,600	0.9006	$232,621	$358,973	$591,594
2007	$258,300	----	$258,300	$398,600	----	$398,600	0.8546	$220,756	$340,663	$561,418
2008	$258,300	----	$258,300	$398,600	----	$398,600	0.8111	$209,495	$323,286	$532,781
2009	$258,300	----	$258,300	$398,600	----	$398,600	0.7697	$198,809	$306,796	$505,605
2010	$258,300	----	$258,300	$398,600	----	$398,600	0.7304	$188,668	$291,147	$479,815
2011	$258,300	----	$258,300	$398,600	----	$398,600	0.6932	$179,045	$276,296	$455,340
2012	$258,300	----	$258,300	$398,600	----	$398,600	0.6578	$169,912	$262,202	$432,114
2013	$258,300	----	$258,300	$398,600	----	$398,600	0.6243	$161,245	$248,828	$410,073
2014	$258,300	----	$258,300	$398,600	----	$398,600	0.5924	$153,020	$236,136	$389,156
2015	$258,300	----	$258,300	$398,600	----	$398,600	0.5622	$145,215	$224,091	$369,306
2016	----	$299,400	$299,400	----	$99,000	$99,000	0.5335	$159,735	$52,818	$212,554
2017	----	$299,400	$299,400	----	$99,000	$99,000	0.5063	$151,587	$50,124	$201,712
2018	----	$299,400	$299,400	----	$99,000	$99,000	0.4805	$143,855	$47,567	$191,423
2019	----	$299,400	$299,400	----	$99,000	$99,000	0.4560	$136,517	$45,141	$181,658
2020	----	$299,400	$299,400	----	$99,000	$99,000	0.4327	$129,554	$42,838	$172,392
2021	----	$299,400	$299,400	----	$99,000	$99,000	0.4106	$122,946	$40,653	$163,599
2022	----	$299,400	$299,400	----	$99,000	$99,000	0.3897	$116,674	$38,580	$155,254
2023	----	$299,400	$299,400	----	$99,000	$99,000	0.3698	$110,723	$36,612	$147,335
2024	----	$299,400	$299,400	----	$99,000	$99,000	0.3510	$105,075	$34,744	$139,819
2025	----	$299,400	$299,400	----	$99,000	$99,000	0.3331	$99,715	$32,972	$132,687
2026	----	$299,400	$299,400	----	$99,000	$99,000	0.3161	$94,629	$31,290	$125,919
2027	----	$299,400	$299,400	----	$99,000	$99,000	0.2999	$89,802	$29,694	$119,496
2028	----	$299,400	$299,400	----	$99,000	$99,000	0.2846	$85,222	$28,179	$113,401
2029	----	$299,400	$299,400	----	$99,000	$99,000	0.2701	$80,875	$26,742	$107,617
2030	----	$299,400	$299,400	----	$99,000	$99,000	0.2563	$76,749	$25,378	$102,127
2031	----	$299,400	$299,400	----	$99,000	$99,000	0.2433	$72,834	$24,084	$96,918
2032	----	$299,400	$299,400	----	$99,000	$99,000	0.2309	$69,119	$22,855	$91,974
2033	----	$299,400	$299,400	----	$99,000	$99,000	0.2191	$65,594	$21,689	$87,283
2034	----	$299,400	$299,400	----	$99,000	$99,000	0.2079	$62,248	$20,583	$82,831
2035	----	$299,400	$299,400	----	$99,000	$99,000	0.1973	$59,073	$19,533	$78,606
2036	----	$299,400	$299,400	----	$99,000	$99,000	0.1872	$56,059	$18,537	$74,596
2037	----	$299,400	$299,400	----	$99,000	$99,000	0.1777	$53,200	$17,591	$70,791
2038	----	$299,400	$299,400	----	$99,000	$99,000	0.1686	$50,486	$16,694	$67,180
2039	----	$299,400	$299,400	----	$99,000	$99,000	0.1600	$47,911	$15,842	$63,753
2040	----	$299,400	$299,400	----	$99,000	$99,000	0.1519	$45,467	$15,034	$60,502
2041	----	$299,400	$299,400	----	$99,000	$99,000	0.1441	$43,148	$14,267	$57,415
2042	----	$299,400	$299,400	----	$99,000	$99,000	0.1368	$40,947	$13,540	$54,487
2043	----	$299,400	$299,400	----	$99,000	$99,000	0.1298	$38,858	$12,849	$51,707
2044	----	$299,400	$299,400	----	$99,000	$99,000	0.1232	$36,876	$12,194	$49,070
2045	----	$299,400	$299,400	----	$99,000	$99,000	0.1169	$34,995	$11,572	$46,567
2046	----	$299,400	$299,400	----	$99,000	$99,000	0.1109	$33,210	$10,981	$44,192
2047	----	$299,400	$299,400	----	$99,000	$99,000	0.1053	$31,516	$10,421	$41,938
2048	----	$299,400	$299,400	----	$99,000	$99,000	0.0999	$29,909	$9,890	$39,798
2049	----	$299,400	$299,400	----	$99,000	$99,000	0.0948	$28,383	$9,385	$37,768
2050	----	$299,400	$299,400	----	$99,000	$99,000	0.0900	$26,935	$8,906	$35,842
2051	----	$299,400	$299,400	----	$99,000	$99,000	0.0854	$25,561	$8,452	$34,014
2052	----	$299,400	$299,400	----	$99,000	$99,000	0.0810	$24,258	$8,021	$32,279
2053	----	$299,400	$299,400	----	$99,000	$99,000	0.0769	$23,020	$7,612	$30,632
2054	----	$299,400	$299,400	----	$99,000	$99,000	0.0730	$21,846	$7,224	$29,070
								$4,829,026	$4,147,775	$8,976,802
				Years of Analysis				50	50	50
				Annualization Factor				0.05798	0.05798	0.05798
				Annualized Credit				**$280,000**	**$240,500**	**$520,500**

Table 7-2: SWPA Annual Capacity and Energy Credit 450,000 AF

Reallocation from Lake Texoma Conservation Zone

(1) Year	(2) Capacity Benefit ($)	(3) Capacity Revenue ($)	(4) Annual Capacity Credit ($)	(5) Energy Benefit ($)	(6) Energy Revenue ($)	(7) Annual Energy Credit ($)	(8) Present-Worth Factor	(9) Present-Worthed Capacity Credit ($)	(10) Present-Worthed Energy Credit ($)	(11) Total Power Credit ($)
2005	$611,800	----	$611,800	$790,600	----	$790,600	0.9490	$580,593	$750,273	$1,330,866
2006	$611,800	----	$611,800	$790,600	----	$790,600	0.9006	$550,978	$712,003	$1,262,981
2007	$611,800	----	$611,800	$790,600	----	$790,600	0.8546	$522,874	$675,685	$1,198,558
2008	$611,800	----	$611,800	$790,600	----	$790,600	0.8111	$496,203	$641,219	$1,137,422
2009	$611,800	----	$611,800	$790,600	----	$790,600	0.7697	$470,892	$608,512	$1,079,404
2010	$611,800	----	$611,800	$790,600	----	$790,600	0.7304	$446,873	$577,472	$1,024,345
2011	$611,800	----	$611,800	$790,600	----	$790,600	0.6932	$424,079	$548,017	$972,095
2012	$611,800	----	$611,800	$790,600	----	$790,600	0.6578	$402,447	$520,063	$922,510
2013	$611,800	----	$611,800	$790,600	----	$790,600	0.6243	$381,919	$493,536	$875,455
2014	$611,800	----	$611,800	$790,600	----	$790,600	0.5924	$362,438	$468,361	$830,799
2015	$611,800	----	$611,800	$790,600	----	$790,600	0.5622	$343,951	$444,471	$788,421
2016	----	$664,700	$664,700	----	$196,300	$196,300	0.5335	$354,629	$104,730	$459,359
2017	----	$664,700	$664,700	----	$196,300	$196,300	0.5063	$336,540	$99,387	$435,928
2018	----	$664,700	$664,700	----	$196,300	$196,300	0.4805	$319,374	$94,318	$413,692
2019	----	$664,700	$664,700	----	$196,300	$196,300	0.4560	$303,083	$89,507	$392,590
2020	----	$664,700	$664,700	----	$196,300	$196,300	0.4327	$287,623	$84,941	$372,565
2021	----	$664,700	$664,700	----	$196,300	$196,300	0.4106	$272,952	$80,609	$353,561
2022	----	$664,700	$664,700	----	$196,300	$196,300	0.3897	$259,029	$76,497	$335,526
2023	----	$664,700	$664,700	----	$196,300	$196,300	0.3698	$245,817	$72,595	$318,412
2024	----	$664,700	$664,700	----	$196,300	$196,300	0.3510	$233,278	$68,892	$302,170
2025	----	$664,700	$664,700	----	$196,300	$196,300	0.3331	$221,379	$65,378	$286,757
2026	----	$664,700	$664,700	----	$196,300	$196,300	0.3161	$210,087	$62,043	$272,130
2027	----	$664,700	$664,700	----	$196,300	$196,300	0.2999	$199,371	$58,878	$258,249
2028	----	$664,700	$664,700	----	$196,300	$196,300	0.2846	$189,201	$55,875	$245,076
2029	----	$664,700	$664,700	----	$196,300	$196,300	0.2701	$179,550	$53,025	$232,575
2030	----	$664,700	$664,700	----	$196,300	$196,300	0.2563	$170,392	$50,320	$220,712
2031	----	$664,700	$664,700	----	$196,300	$196,300	0.2433	$161,700	$47,754	$209,454
2032	----	$664,700	$664,700	----	$196,300	$196,300	0.2309	$153,452	$45,318	$198,770
2033	----	$664,700	$664,700	----	$196,300	$196,300	0.2191	$145,625	$43,006	$188,631
2034	----	$664,700	$664,700	----	$196,300	$196,300	0.2079	$138,197	$40,812	$179,009
2035	----	$664,700	$664,700	----	$196,300	$196,300	0.1973	$131,148	$38,731	$169,878
2036	----	$664,700	$664,700	----	$196,300	$196,300	0.1872	$124,458	$36,755	$161,213
2037	----	$664,700	$664,700	----	$196,300	$196,300	0.1777	$118,110	$34,880	$152,990
2038	----	$664,700	$664,700	----	$196,300	$196,300	0.1686	$112,085	$33,101	$145,186
2039	----	$664,700	$664,700	----	$196,300	$196,300	0.1600	$106,368	$31,413	$137,780
2040	----	$664,700	$664,700	----	$196,300	$196,300	0.1519	$100,942	$29,810	$130,752
2041	----	$664,700	$664,700	----	$196,300	$196,300	0.1441	$95,793	$28,290	$124,083
2042	----	$664,700	$664,700	----	$196,300	$196,300	0.1368	$90,907	$26,847	$117,754
2043	----	$664,700	$664,700	----	$196,300	$196,300	0.1298	$86,270	$25,477	$111,747
2044	----	$664,700	$664,700	----	$196,300	$196,300	0.1232	$81,870	$24,178	$106,047
2045	----	$664,700	$664,700	----	$196,300	$196,300	0.1169	$77,693	$22,945	$100,638
2046	----	$664,700	$664,700	----	$196,300	$196,300	0.1109	$73,730	$21,774	$95,505
2047	----	$664,700	$664,700	----	$196,300	$196,300	0.1053	$69,970	$20,664	$90,633
2048	----	$664,700	$664,700	----	$196,300	$196,300	0.0999	$66,401	$19,609	$86,010
2049	----	$664,700	$664,700	----	$196,300	$196,300	0.0948	$63,014	$18,609	$81,623
2050	----	$664,700	$664,700	----	$196,300	$196,300	0.0900	$59,799	$17,660	$77,459
2051	----	$664,700	$664,700	----	$196,300	$196,300	0.0854	$56,749	$16,759	$73,508
2052	----	$664,700	$664,700	----	$196,300	$196,300	0.0810	$53,854	$15,904	$69,759
2053	----	$664,700	$664,700	----	$196,300	$196,300	0.0769	$51,107	$15,093	$66,201
2054	----	$664,700	$664,700	----	$196,300	$196,300	0.0730	$48,501	$14,323	$62,824
2055	----	$664,700	$664,700	----	$196,300	$196,300	0.0692	$46,027	$13,593	$59,619
								$11,079,321	$8,239,911	$19,319,232
				Years of Analysis				50	50	50
				Annualization Factor				0.05798	0.05798	0.05798
				Annualized Credit				**$642,400**	**$477,800**	**$1,120,200**

7.4 Summary of Credits

Table 7-3 is a summary of credit due the power marketing administration for the 300,000 AF Alternative and 450,000 AF Alternative reallocations in Lake Texoma (Denison Dam).

Table 7-3: Annual Credit Due Power Marketing Agency

Due to Reallocation from the Conservation Pool Storage in Lake Texoma (Denison Dam)

Allocation Alternative	**300,000 AF**	**450,000 AF**
Energy Credit	$240,500	$477,800
Capacity Credit	$280,000	$642,400
Annual Credit to PMA	**$520,500**	**$1,120,200**

8.0 SUMMARY OF RESULTS

Power benefits foregone, which are equivalent to replacement costs of power, and power revenues foregone were considered over a 50-year evaluation period in order to determine the cost of the storage reallocation being requested. The non-power related updated cost of storage was not evaluated in this report, but will be determined by the Tulsa District. The reallocation cost to the water supply customers will be the highest cost for each of these different components.

8.1 Power Benefits Foregone

Summarizing the data developed in Sections 2 through 5, power benefits foregone for the 300,000 AF Alternative and 450,000 AF Alternative reallocations in Lake Texoma (Denison Dam) are as follows (from Table 5-1):

Table 8-1: Annual Power Benefits Foregone

Allocation Alternative	**300,000 AF**	**450,000 AF**
Annual Energy Benefit Foregone	$398,600	$790,600
Capacity Benefit Foregone	$258,300	$611,800
Annual Benefit Foregone	**$656,900**	**$1,402,400**

8.2 Replacement Cost

As noted in Section 1.7, the replacement cost of power as used in determining the cost of the reallocation to the water supply customer is identical in each case to the hydropower benefits foregone presented in Section 5.2.

8.3 Revenues Foregone

Summarizing the data developed in Sections 6 and in Table 6-1, the power revenues foregone for 300,000 AF Alternative and 450,000 AF Alternative reallocations in Lake Texoma (Denison Dam) are as follows.

Table 8-2: Annual Revenue Foregone

Allocation Alternative	**300,000 AF**	**450,000 AF**
Annual Energy Revenue Foregone	$99,000	$196,300
Capacity Revenue Foregone	$299,400	$664,700
Annual Revenue Foregone	**$398,400**	**$861,000**

8.4 SWPA Credit

Summarizing the data developed in Section 7, the 300,000 AF Alternative and 450,000 AF Alternative estimated SWPA credits for the project are as follows (from Table 7-3).

Table 8-3: Annual SWPA Credit

Allocation Alternative	**300,000 AF**	**450,000 AF**
Energy Credit	$240,500	$477,800
Capacity Credit	$280,000	$642,400
Annual Credit to PMA	**$520,500**	**$1,120,200**

ATTACHMENT A

FERC Power Values

Date Run

COAL-FIRED STEAM POWER VALUE

02/10/05

PROJECT NAME: Lake Texoma WS Study
LOCATION: Texas
FINANCING: FEDERAL @ 5.375%

Capacity Value	$235.87	per kW-yr
Energy Value	$20.05	per MWh

PROGRAM INPUT DATA

Cost Level Date	1/1/2005
Single unit capacity	600
Capacity factor	0.65
Trans Voltage	345
Transformer MVA	200
No of Trans	6
No of Trans Pos	2
Single or Three Phase	1
Length Line 1	50
Length Line 2	0
Line 1: Total Circuits	3
No of Single Circ	1
No of Double Circ	1
Line 2: Total Circuits	0
No of Single Circ	0
No of Double Circ	0
Cost of Money (%)	5.375
Plant Life	30
Substation Life	30
Trans (towers) Life	50
Trans (poles) life	30
Plant insurance (%)	0.25
Trans Insurance (%)	0.10
Sub insurance (%)	0.25

State Index Number	44
State Location	TX
H-W Index Reg No	4
ROW ($/acre)	2479
Clearing % of ROW	0.60
Rec Sub Land Cost	23318
Plant Invest	1551
FC Mov-Ave Time Frame	60
Fuel Cost	125.1
Heat Rate	10730
Variable O&M	6.63
Fixed O&M	64.24
O&M update	2.95
Plant update	2.70
Transmission update	2.36
Depreciation Plant (%)	1.41
Deprec Sub (%)	1.41
Deprec Trans Tower (%)	0.42
Deprec Trans Pole (%)	1.41
Fed Inc Tax (%)	0.000
Fed Misc Tax (%)	0.000
State & Local Tax (%)	0.000
Hydro Flex Adjust	0.050
Alt Mechanical Avail	0.850
Hydro Mech Avail	0.980
Mech Avail Adjust	0.153

Date Run

COMBINED CYCLE POWER VALUE

02/10/05

PROJECT NAME: Lake Texoma WS Study
LOCATION: TX
FINANCING: FEDERAL @ 5.375%

Capacity Value	$118.67	per kW-yr
Energy Value	$38.08	per MWh

PROGRAM INPUT DATA

Cost Level Date	1/1/2005
Single unit capacity	150
Capacity factor	0.20
Trans Voltage	230
Transformer MVA	200
No of Trans	1
No of Trans Positions	1
Single or Three Phase	3
Length Line 1	0
Length Line 2	0
Line 1: Total Circuits	0
No of Single Circ	0
No of Double Circ	0
Line 2: Total Circuits	0
No of Single Circ	0
No of Double Circ	0
Cost of Money (%)	5.375
Plant Life	30
Substation Life	30
Trans (towers) Life	50
Trans (poles) life	30
Plant insurance (%)	0.25
Trans Insurance (%)	0.10
Sub insurance (%)	0.25

State Index Number	44
State Abbr. (exact)	TX
H-W Index Reg No	4
ROW ($/acre)	2479
Clearing % of ROW	0.60
Rec Sub Land Cost	23318
Plant Invest	764
FC Mov-Ave Time Frame	60
Fuel Cost	462.0
Heat Rate	8030
Variable O&M	0.98
Fixed O&M	47.67
O&M update	2.95
Plant update	2.70
Transmission update	2.36
Depreciation Plant (%)	1.41
Deprec Sub (%)	1.41
Deprec Trans Tower (%)	0.42
Deprec Trans Pole (%)	1.41
Fed Inc Tax (%)	0.000
Fed Misc Tax (%)	0.000
State & Local Tax (%)	0.000
Hydro Flex Adjust	0.025
Alt Mechanical Avail	0.900
Hydro Mech Avail	0.980
Mech Avail Adjust	0.089

Date Run

COMBUSTION TURBINE POWER VALUE

02/10/05

PROJECT NAME: Lake Texoma WS Study
LOCATION: Texas
FINANCING: FEDERAL @ 5.375%

Capacity Value	$63.00	per kW-yr
Energy Value	$59.73	per MWh

PROGRAM INPUT DATA

Cost Level Date	1/1/2005
Single unit capacity	100
Capacity Factor	0.10
Transmission Voltage	230
Transformer MVA	125
No of Trans	2
No of Trans Pos	2
Single or Three Phase	3
Length Line 1	0
Length Line 2	0
Line 1: Total Circuits	2
No of Single Circ	2
No of Double Circ	0
Line 2: Total Circuits	0
No of Single Circ	0
No of Double Circ	0
Cost of Money (%)	5.375
Plant Life	30
Substation Life	30
Trans (towers) Life	50
Trans (poles) life	30
Plant insurance (%)	0.25
Trans Insurance (%)	0.10
Sub insurance (%)	0.25

State Index Number	44
State Location	TX
H-W Index Reg No	4
ROW ($/acre)	2319
Clearing % of ROW	0.60
Rec Sub Land Cost	21869
Plant Invest	473
FC Mov-Ave Time Frame	60
Fuel Cost	462.2
Heat Rate	12870
Variable O&M	0.25
Fixed O&M	15.64
O&M update	2.95
Plant update	2.70
Transmission update	2.36
Depreciation Plant (%)	1.41
Deprec Sub (%)	1.41
Deprec Trans Tower (%)	0.42
Deprec Trans Pole (%)	1.41
Fed Inc Tax (%)	0.000
Fed Misc Tax (%)	0.000
State & Local Tax (%)	0.000
Hydro Flex Adjust	0.025
Alt Mechanical Avail	0.900
Hydro Mechanical Avail	0.980
Mech Avail Adjust	0.089

ATTACHMENT B

PROSYM OUTPUT SUMMARY

LAKE TEXOMA WATER SUPPLY REALLOCATION, FUEL PRICE UPDATE

New fuel price estimates for oil, natural gas, and coal were used to update the energy values for the Lake Texoma Water Supply Study for years 2005, 2010, 2015, 2020 and 2025. Old fuel prices were taken from our earlier PROSYM model runs – 2003 data. Both the updated and original PROSYM summary tables are included in this attachment.

The updated fuel prices are the historical average (2003-2005) from WEFA, INC., US Energy Outlook. Annual values for fuel costs to electric generators for West South Central region were used. In keeping with the policy of no real fuel price escalation, fuel prices were projected as constant for the years 2005, 2010, 2020 and 2025. The table below compares the old and current fuel prices.

Fuel	$2003/MMbtu	$2005/MMbtu Current Projection
Coal	1.21	1.25
Natural Gas	5.38	5.50
Petroleum	6.22	7.40

These current fuel prices were used to update the PROSYM Summary Tables of the Lake Texoma, 2005 Water Supply Reallocation Study. The summary tables have a column that displays the cost of the resource in mills/kWh for each type of plant. In this column, the fuel prices were indexed up for those plant types (coal, natural gas, and oil) that would be utilized if the hydropower plant was unavailable. The update factor was only applied to the fuel cost component of costs (about 93% of costs). Variable costs are assumed to remain the same. These changes result in new hydropower energy values for years 2005, 2010, 2015, 2020 and 2025 as shown in the Table below. The new energy values were then used along with the current Federal discount rate (5 3/8%) to derive a new levelized energy value of $33.23/Mwh.

Year	Former Hydropower Energy Value (mills/kWh)	Updated Hydropower Energy Value (mills/kWh)
2005	27.15	28.43
2010	27.53	28.81
2015	31.80	33.25
2020	34.05	35.75
2025	35.76	37.20

LAKE TEXOMA : GENSUM TABLE
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STUDY YR. JAN 2005

	Base Case	Alt Case	Diff.	Delta
System Cost ($1000)	10,171,362.0	10,173,078	1,716.0	
FuelCost	8571881	8572707	826	
VOM Cost	560288	560220	-68	
Unserved Energy Cost	0	0	0	
System Generation (GWh)	294,798.1	294,797.4	-0.7	
Peak Load (MW)	71971	71971	0	
Peak Resources (MW)	81939	81972	33	
Reserve Margin (%)	10.52	10.58	0.06	

System with Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 NG Reliant	58,715.7	2,466,029	42.00	16,845	39.9%
2 NG TMPP	15,460.4	595,488	38.52	4,125	42.9%
3 INTLOAD	0.0	0	0.00	0	0.0%
4 Coal-ERCOT	112,320.1	1,961,469	17.46	15,547	82.7%
5 NG TXU-EAST	57,324.4	2,315,487	40.39	18,027	36.4%
6 Uranium	38,700.6	535,034	13.82	4,738	93.5%
7 FO#2-ERCOT	0.1	272	2,720.28	0	0.0%
8 Wind	2,374.9	25,518	10.74	272	100.0%
9 NG WETU	1,704.9	91,161	53.47	981	19.9%
10 NG TXU-WEST	13,435.9	550,179	40.95	3,835	40.1%
11 NG CPSA	4,824.5	225,551	46.75	2,953	18.7%
12 NG CP&L	16,297.5	629,496	38.63	5,812	32.1%
13 NG LCRA	26,030.2	983,508	37.78	5,093	58.5%
14 NG ST&M	3,964.4	145,645	36.74	816	55.6%
15 NG AUST	2,998.3	136,414	45.50	1,865	18.4%
16 HydroStudy	77.2	386	5.00	80	11.0%
17 Hydro	511.1	2,556	5.00	427	13.7%
18 Transaction	-1,226.4	0	0.00	-140	100.0%
Totals	294,798.1	10,664,194	36.17	64,432	52.2%
Unserved Energy	0.0	0	0.00	--	--
Net Total	294,798.1	10,664,194	36.17	--	--

	System Thermal Res. Add. 2005 MW	Total System Thermal Res. Add. To date MW	Hydro Capacity Removed MW	Hydro Capacity Replaced MW
CT	0	0		
CC	0	0		
CO	0	0		0
Total	0	0	80	

System without Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh	% C Sav	% E Sav	mills/kWh component
1 NG Reliant	58,716.3	2,466,032	42.00	16,845	39.9%	0.6	-3.1	-5.25	0	-600	0.00
2 NG TMPP	15,441.1	595,172	38.54	4,169	42.4%	-19.3	-316.0	16.37	-14	19,300	0.00
3 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0.0	0.00	0	0	0.00
4 Coal-ERCOT	112,324.3	1,961,528	17.46	15,547	82.7%	4.2	58.1	13.84	3	-4,200	-550.00
5 NG TXU-EAST	57,524.8	2,322,544	40.37	18,090	36.4%	200.4	7,056.7	35.21	321	-200,400	-67210.00
6 Uranium	38,700.6	535,034	13.82	4,738	93.5%	0.0	0.0	0.00	0	0	0.00
7 FO#2-ERCOT	0.1	273	2,732.48	0	0.0%	0.0	1.2	0.00	0	0	0.00
8 Wind	2,374.9	25,518	10.74	272	100.0%	0.0	0.0	0.00	0	0	0.00
9 NG WETU	1,695.5	90,781	53.54	980	19.8%	-9.4	-380.1	40.43	-17	9,400	3620.00
10 NG TXU-WEST	13,351.6	546,687	40.95	3,840	39.8%	-84.3	-3,492.1	41.43	-159	84,300	33260.00
11 NG CPSA	4,827.0	225,754	46.77	2,955	18.7%	2.5	203.7	81.48	9	-2,500	-1940.00
12 NG CP&L	16,304.1	629,736	38.62	5,814	32.1%	6.6	239.4	36.27	11	-6,600	-2280.00
13 NG LCRA	26,011.2	982,613	37.78	5,090	58.5%	-19.0	-895.6	47.14	-41	19,000	8530.00
14 NG ST&M	3,963.6	145,623	36.74	816	55.6%	-0.8	-22.0	27.56	-1	800	210.00
15 NG AUST	2,993.9	136,165	45.48	1,873	18.3%	-4.4	-248.8	56.55	-11	4,400	2370.00
16 HydroStudy	0.0	0	0.00	0	0.0%	-77.2	0.0	0.00	0	0	0.00
17 Hydro	511.1	2,556	5.00	427	13.7%	0.0	0.0	0.00	0	0	0.00
18 Transaction	-1,226.4	0	0.00	-140	100.0%	0.0	0.0	0.00	0	0	0.00
Totals	294,797.4	10,666,016	36.18	64,470	52.2%	-0.1	2,201		100	-76,500	-23990.00
Unserved Energy	0.0	0	0.00	--	--	0.0	0	0.00		--	--
Net Total	294,797.4	10,666,016	36.18	--	--	-0.1				--	--

HYDROPOWER ENERGY VALUE: 28.51 mills/kWh Fuel &VarCostUpdated

HYDROPOWER ENERGY BENEFIT: 2,201

28.43 mills/kWh **Fuel Only CostUpdated**

LAKE TEXOMA : GENSUM TABLE

2005 Updated Fuel Costs
STUDY YR. JAN 2010

System with Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 NG Reliant	56,936.8	1,952,211	34.29	16,669	39.1%
2 NG TMPP	15,876.1	504,638	31.79	4,443	40.9%
3 INTLOAD	0.0	0	0.00	0	0.0%
4 Coal-ERCOT	112,671.0	1,908,337	16.94	15,539	83.0%
5 NG TXU-EAST	54,777.2	1,812,986	33.10	17,417	36.0%
6 Uranium	37,974.1	518,346	13.65	4,740	91.7%
7 FO#2-ERCOT	0.3	296	988.08	34	0.1%
8 Wind	2,374.9	25,518	10.74	272	100.0%
9 NG WETU	2,425.4	101,941	42.03	1,102	25.2%
10 NG TXU-WEST	12,876.5	432,945	33.62	3,722	39.6%
11 NG CPSA	5,055.0	191,957	37.97	2,823	20.5%
12 NG CP&L	16,180.4	513,092	31.71	5,596	33.1%
13 NG LCRA	26,635.1	824,292	30.95	5,368	56.8%
14 NG ST&M	4,064.0	122,969	30.26	816	57.0%
15 NG AUST	2,827.4	103,126	36.47	1,491	21.7%
16 HydroStudy	77.2	386	5.00	80	11.0%
17 Hydro	511.1	2,556	5.00	427	13.7%
18 Transaction	-1,182.6	0	0.00	-135	100.0%
Totals	293,143.1	9,015,598	30.75	63,736	52.5%
Unserved Energy			0.00	--	--
Net Total	293,143.1	9,015,598	30.75	--	--

System without Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh	% C Sav	% E Sav	mills/kWh component
1 NG Reliant	56,920.4	1,951,531	34.29	16,664	39.1%	-16.4	-680.4	41.49	-31	-16,400	0.00
2 NG TMPP	15,868.6	504,842	31.81	4,496	40.4%	-7.5	203.7	-27.16	9	-7,500	2036.91
3 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0.0	0.00	0	0	0.00
4 Coal-ERCOT	112,669.1	1,908,328	16.94	15,539	83.0%	-1.9	-8.5	4.45	0	-1,900	-84.55
5 NG TXU-EAST	54,967.5	1,818,185	33.08	17,478	36.0%	190.3	5,199.4	27.32	233	190,300	51993.59
6 Uranium	37,974.1	518,346	13.65	4,740	91.7%	0.0	0.0	0.00	0	0	0.00
7 FO#2-ERCOT	0.2	293	1,463.83	23	0.1%	-0.1	-3.7	0.00	0	-100	0.00
8 Wind	2,374.9	25,518	10.74	272	100.0%	0.0	0.0	0.00	0	0	0.00
9 NG WETU	2,404.4	101,213	42.09	1,101	25.0%	-21.0	-727.6	34.65	-33	-21,000	-7276.16
10 NG TXU-WEST	12,825.8	431,747	33.66	3,717	39.5%	-50.7	-1,198.0	23.63	-54	-50,700	-11979.95
11 NG CPSA	5,051.0	191,827	37.98	2,820	20.5%	-4.0	-130.2	32.55	-6	-4,000	-1301.94
12 NG CP&L	16,189.8	513,330	31.71	5,599	33.1%	9.4	237.3	25.24	11	9,400	2372.89
13 NG LCRA	26,615.9	823,674	30.95	5,364	56.8%	-19.2	-617.4	32.15	-28	-19,200	-6173.71
14 NG ST&M	4,063.1	122,931	30.26	816	57.0%	-0.9	-37.8	42.00	-2	-900	-377.98
15 NG AUST	2,826.7	103,120	36.48	1,491	21.7%	-0.7	-6.3	9.00	0	-700	-63.00
16 HydroStudy	0.0	0	0.00	0	0.0%	-77.2	0.0	0.00	0	0	0.00
17 Hydro	511.1	2,556	5.00	427	13.7%	0.0	0.0	0.00	0	0	0.00
18 Transaction	-1,182.6	0	0.00	-135	100.0%	0.0	0.0	0.00	0	0	0.00
Totals	350,080.0	9,017,443	25.76	80,412	49.7%	0.1	2,231	27.53	100	93,700	27760.00
Unserved Energy	0.0	0	0.00	--	--	0.0	0	0.00		--	--
Net Total	350,080.0	9,017,443	25.76	--	--	0.1	2,231	27.53		--	--

HYDROPOWER ENERGY VALUE: 28.89 mills/kWh Fuel & VarCostUpdated HYDROPOWER ENERGY BENEFIT: 2,231

28.81 mills/kWh Fuel Only CostUpdated

LAKE TEXOMA : GENSUM TABLE
2005 Updated Fuel Prices
STUDY YR. JAN 2015

System with Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 NG Reliant	55,775.2	1,881,261	33.73	16,497	38.7%
2 NG TMPP	26,792.2	847,167	31.62	8,071	38.0%
3 INTLOAD	0.0	0	0.00	0	0.0%
4 Coal-ERCOT	111,418.1	1,843,999	16.55	15,535	82.1%
5 NG TXU-EAST	80,057.5	2,554,363	31.91	22,189	41.3%
6 Uranium	37,566.6	512,784	13.65	4,736	90.8%
7 FO#2-ERCOT	0.1	273	2,732.48	0	0.0%
8 Wind	2,374.9	25,518	10.74	272	100.0%
9 NG WETU	5,895.2	233,525	39.61	2,026	33.3%
10 NG TXU-WEST	12,948.3	424,467	32.78	3,423	43.3%
11 NG CPSA	4,258.9	160,218	37.62	2,526	19.3%
12 NG CP&L	15,154.4	481,528	31.77	5,821	29.8%
13 NG LCRA	43,982.4	1,346,859	30.62	8,405	59.9%
14 NG ST&M	3,822.2	115,541	30.23	816	53.6%
15 NG AUST	2,525.5	92,321	36.56	1,490	19.4%
16 HydroStudy	77.2	386	5.00	80	11.0%
17 Hydro	511.1	2,556	5.00	427	13.7%
18 Transaction	-1,182.6	0	0.00	-135	100.0%
Totals	346,202.0	10,522,766	30.39	75,682	52.2%
Unserved Energy	0.0	0	0.00	--	--
Net Total	346,202.0	10,522,766	30.39	--	--

System without Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh	% C Sav	% E Sav	mills/kWh component
1 NG Reliant	55,816.6	1,882,537	33.73	16,467	38.8%	41.4	1,275.7	29.35	49	54	15.74
2 NG TMPP	26,763.1	846,810	31.64	8,105	37.8%	-29.1	-357.0	11.68	-14	-38	0.00
3 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0.0	0.00	0	0	0.00
4 Coal-ERCOT	111,418.1	1,844,002	16.55	15,535	82.1%	0.0	3.2	0.00	0	0	0.00
5 NG TXU-EAST	80,254.8	2,560,267	31.90	22,244	41.3%	197.3	5,903.9	28.50	229	256	72.84
6 Uranium	37,565.9	512,775	13.65	4,736	90.8%	-0.7	-9.6	7.14	0	-1	-0.06
7 FO#2-ERCOT	0.1	277	2,769.07	0	0.0%	0.0	3.7	0.00	0	0	0.00
8 Wind	2,374.9	25,518	10.74	272	100.0%	0.0	0.0	0.00	0	0	0.00
9 NG WETU	5,838.5	231,544	39.66	2,031	32.9%	-56.7	-1,981.3	33.28	-77	-73	-24.44
10 NG TXU-WEST	12,857.2	421,637	32.79	3,423	43.0%	-91.1	-2,829.6	29.58	-110	-118	-34.91
11 NG CPSA	4,263.6	160,408	37.62	2,529	19.3%	4.7	190.0	38.51	7	6	2.34
12 NG CP&L	15,142.8	481,157	31.77	5,817	29.8%	-11.6	-370.6	30.43	-14	-15	-4.57
13 NG LCRA	44,001.5	1,347,489	30.62	8,395	60.0%	19.1	630.0	31.41	24	25	7.77
14 NG ST&M	3,822.7	115,537	30.22	816	53.6%	0.5	-4.2	-8.00	0	1	-0.05
15 NG AUST	2,528.9	92,441	36.55	1,492	19.4%	3.4	119.7	33.53	5	4	1.48
16 HydroStudy	0.0	0	0.00	0	0.0%	-77.2	0.0	0.00	0	0	0.00
17 Hydro	511.1	2,556	5.00	427	13.7%	0.0	0.0	0.00	0	0	0.00
18 Transaction	-1,182.6	0	0.00	-135	100.0%	0.0	0.0	0.00	0	0	0.00
Totals	401,977.2	10,524,954	26.18	92,152	49.8%	0.0	2,574	31.80	100	46	20.39
Unserved Energy	0.0	0	0.00	--	--	0.0	0	0.00		--	--
Net Total	401,977.2	10,524,954	26.18	--	--	0.0	2,574	31.80		--	--

HYDROPOWER ENERGY VALUE: 33.34 mills/kWh Fuel & VarCostUpdated

HYDROPOWER ENERGY BENEFIT: 2,574

33.25 mills/kWh **Fuel Only CostUpdated**

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LAKE TEXOMA : GENSUM TABLE
2005 Updated Fuel Costs
STUDY YR. JAN 2020

System with Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 NG Reliant	54,925.6	1,905,732	34.70	16,811	37.4%
2 NG TMPP	36,233.0	1,185,454	32.72	12,057	34.4%
3 INTLOAD	0.0	0	0.00	0	0.0%
4 Coal-ERCOT	110,986.5	1,796,253	16.18	15,588	81.5%
5 NG TXU-EAST	109,464.6	3,517,722	32.14	27,783	45.1%
6 Uranium	38,564.9	500,958	12.99	4,752	92.9%
7 FO#2-ERCOT	0.0	0	0.00	0	0.0%
8 Wind	2,382.2	25,596	10.74	273	100.0%
9 NG WETU	12,526.2	503,772	40.22	3,773	38.0%
10 NG TXU-WEST	12,112.7	408,747	33.75	3,432	40.4%
11 NG CPSA	3,842.8	146,052	38.01	2,279	19.3%
12 NG CP&L	14,666.4	480,631	32.77	5,850	28.7%
13 NG LCRA	60,388.6	1,891,014	31.31	11,043	62.6%
14 NG ST&M	3,909.4	120,031	30.70	694	64.5%
15 NG AUST	2,608.4	96,447	36.98	1,493	20.0%
16 HydroStudy	77.2	386	5.00	80	11.0%
17 Hydro	511.3	2,557	5.00	427	13.7%
18 Transaction	-1,185.8	0	0.00	-136	100.0%
Totals	407,088.4	12,581,354	30.91	89,388	52.0%
Unserved Energy	0.0	0	0.00	--	--
Net Total	407,088.4	12,581,354	30.91	--	--

System without Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh	% C Sav	% E Sav	mills/kWh component
1 NG Reliant	54,952.3	1,906,478	34.69	16,819	37.4%	26.7	745.5	26.59	27	35	9.18
2 NG TMPP	36,202.2	1,184,963	32.73	12,117	34.2%	-30.8	-491.4	15.19	-18	-40	0.00
3 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0.0	0.00	0	0	0.00
4 Coal-ERCOT	110,991.8	1,796,317	16.18	15,589	81.5%	5.3	64.5	11.51	2	7	0.79
5 NG TXU-EAST	109,686.1	3,525,017	32.14	27,840	45.1%	221.5	7,295.1	31.37	264	287	89.88
6 Uranium	38,565.9	500,971	12.99	4,752	92.9%	1.0	13.0	5.00	0	1	0.06
7 FO#2-ERCOT	0.0	0	0.00	0	0.0%	0.0	0.0	0.00	0	0	0.00
8 Wind	2,382.2	25,596	10.74	273	100.0%	0.0	0.0	0.00	0	0	0.00
9 NG WETU	12,423.2	500,017	40.25	3,772	37.7%	-103.0	-3,754.6	34.72	-136	-133	-46.26
10 NG TXU-WEST	12,052.9	407,028	33.77	3,432	40.2%	-59.8	-1,718.8	27.37	-62	-77	-21.18
11 NG CPSA	3,852.0	146,460	38.02	2,273	19.4%	9.2	407.4	42.17	15	12	5.02
12 NG CP&L	14,648.9	480,061	32.77	5,843	28.7%	-17.5	-570.1	31.03	-21	-23	-7.02
13 NG LCRA	60,403.1	1,891,351	31.31	11,045	62.6%	14.5	337.0	22.14	12	19	4.15
14 NG ST&M	3,909.6	120,017	30.70	693	64.6%	0.2	-14.7	-70.00	-1	0	-0.18
15 NG AUST	2,618.4	96,903	37.01	1,491	20.1%	10.0	455.7	43.40	17	13	5.61
16 HydroStudy	0.0	0	0.00	0	0.0%	-77.2	0.0	0.00	0	0	0.00
17 Hydro	511.3	2,557	5.00	427	13.7%	0.0	0.0	0.00	0	0	0.00
18 Transaction	-1,185.8	0	0.00	-136	100.0%	0.0	0.0	0.00	0	0	0.00
Totals	462,014.1	12,583,736	27.24	106,230	49.6%	0.1	2,768	34.05	100	65	30.88
Unserved Energy	0.0	0	0.00	--	--	0.0	0	0.00		--	--
Net Total	462,014.1	12,583,736	27.24	--	--	0.1	2,768	34.05		--	--

HYDROPOWER ENERGY VALUE: 35.86 mills/kWh Fuel & VarCostUpdated

HYDROPOWER ENERGY BENEFIT: 2,768

35.75 mills/kWh Fuel Only CostUpdated

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LAKE TEXOMA : GENSUM TABLE
2005 Updated Fuel Costs
STUDY YR. JAN 2025

System with Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 NG Reliant	51,921.6	1,808,675	34.83	14,821	40.1%
2 NG TMPP	43,839.2	1,459,865	33.30	16,453	30.5%
3 INTLOAD	0.0	0	0.00	0	0.0%
4 Coal-ERCOT	112,184.3	1,815,629	16.18	15,547	82.6%
5 NG TXU-EAST	147,831.4	4,771,087	32.27	36,787	46.0%
6 Uranium	37,411.3	484,476	12.95	4,737	90.4%
7 Wind	2,374.9	25,518	10.74	272	100.0%
8 NG WETU	19,261.3	777,789	40.38	5,596	39.4%
9 NG TXU-WEST	10,913.6	367,504	33.67	2,912	42.9%
10 NG CPSA	2,785.8	102,045	36.63	1,405	22.7%
11 NG CP&L	13,092.1	438,817	33.52	5,854	25.6%
12 NG LCRA	84,715.4	2,681,464	31.65	15,271	63.5%
13 NG ST&M	3,656.9	114,089	31.20	692	60.5%
14 NG AUST	2,169.7	84,159	38.79	1,487	16.7%
15 FO#2-ERCOT	0.0	0	0.00	0	0.0%
16 HydroStudy	77.2	386	5.00	80	11.0%
17 Hydro	511.1	2,556	5.00	427	13.7%
18 Transaction	-1,182.6	0	0.00	-135	100.0%
Totals	479,641.6	14,934,058	31.14	107,385	51.0%
Unserved Energy	0.0	0	0.00	--	--
Net Total	479,641.6	14,934,058	31.14	--	--

System without Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh	% C Sav	% E Sav	mills/kWh component
1 NG Reliant	51,900.5	1,808,142	34.84	14,815	40.1%	-21.1	-532.3	24.03	-18	-27	0.00
2 NG TMPP	43,894.1	1,462,129	33.31	16,528	30.4%	54.9	2,263.7	39.27	78	71	27.89
3 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0.0	0.00	0	0	0.00
4 Coal-ERCOT	112,172.1	1,815,494	16.18	15,545	82.6%	-12.2	-135.3	10.49	-5	-16	-1.66
5 NG TXU-EAST	148,074.8	4,778,789	32.27	36,768	46.1%	243.4	7,701.4	30.14	266	315	94.89
6 Uranium	37,408.7	484,443	12.95	4,737	90.4%	-2.6	-33.7	5.38	-1	-3	-0.18
7 Wind	2,374.9	25,518	10.74	272	100.0%	0.0	0.0	0.00	0	0	0.00
8 NG WETU	19,097.1	771,658	40.41	5,591	39.1%	-164.2	-6,131.7	-58,400.00	-212	-212	124052.78
9 NG TXU-WEST	10,871.5	366,332	33.70	2,914	42.7%	-42.1	-1,171.7	26.51	-40	-54	-14.44
10 NG CPSA	2,770.2	101,402	36.60	1,403	22.6%	-15.6	-642.6	39.23	-22	-20	-7.92
11 NG CP&L	13,066.0	438,031	33.52	5,842	25.6%	-26.1	-785.4	28.66	-27	-34	-9.68
12 NG LCRA	84,779.2	2,683,856	31.66	15,283	63.5%	63.8	2,392.8	35.72	83	83	29.48
13 NG ST&M	3,659.7	114,165	31.20	691	60.6%	2.8	76.6	26.07	3	4	0.94
14 NG AUST	2,166.0	84,036	38.80	1,485	16.7%	-3.7	-122.8	31.62	-4	-5	-1.51
15 FO#2-ERCOT	0.0	0	0.00	0	0.0%	0.0	0.0	0.00	0	0	0.00
16 HydroStudy	0.0	0	0.00	0	0.0%	-77.2	0.0	0.00	0	0	0.00
17 Hydro	511.1	2,556	5.00	427	13.7%	0.0	0.0	0.00	0	0	0.00
18 Transaction	-1,182.6	0	0.00	-135	100.0%	0.0	0.0	0.00	0	0	0.00
Totals	531,563.3	14,936,551	28.10	122,166	49.7%	0.1	2,879	35.76	100	127	124170.61
Unserved Energy	0.0	0	0.00	--	--	0.0	0	0.00		--	--
Net Total	531,563.3	14,936,551	28.10	--	--	0.1	2,879	35.76		--	--

HYDROPOWER ENERGY VALUE: 37.29 mills/kWh Fuel & VarCostUpdated

HYDROPOWER ENERGY BENEFIT: 2,879

37.20 mills/kWh Fuel Only CostUpdated

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LAKE TEXOMA : GENSUM TABLE
1/12/2004
STUDY YR. JAN 2015

System with Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 NG Reliant	55,775.2	1,791,760	32.12	16,497	38.7%
2 NG TMPP	26,792.2	806,863	30.12	8,071	38.0%
3 INTLOAD	0.0	0	0.00	0	0.0%
4 Coal-ERCOT	111,418.1	1,744,749	15.66	15,535	82.1%
5 NG TXU-EAST	80,057.5	2,432,839	30.39	22,189	41.3%
6 Uranium	37,566.6	505,192	13.45	4,736	90.8%
7 FO#2-ERCOT	0.1	224	2,240.00	0	0.0%
8 Wind	2,374.9	25,518	10.74	272	100.0%
9 NG WETU	5,895.2	222,415	37.73	2,026	33.3%
10 NG TXU-WEST	12,948.3	404,273	31.22	3,423	43.3%
11 NG CPSA	4,258.9	152,596	35.83	2,526	19.3%
12 NG CP&L	15,154.4	458,619	30.26	5,821	29.8%
13 NG LCRA	43,982.4	1,282,782	29.17	8,405	59.9%
14 NG ST&M	3,822.2	110,044	28.79	816	53.6%
15 NG AUST	2,525.5	87,929	34.82	1,490	19.4%
16 HydroStudy	77.2	386	5.00	80	11.0%
17 Hydro	511.1	2,556	5.00	427	13.7%
18 Transaction	-1,182.6	0	0.00	-135	100.0%
Totals	346,202.0	10,028,745	28.97	75,682	52.2%
Unserved Energy	0.0	0	0.00	--	--
Net Total	346,202.0	10,028,745	28.97	--	--

System without Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh	% C Sav	% E Sav	mills/kWh component
1 NG Reliant	55,816.6	1,792,975	32.12	16,467	38.8%	41.4	1,215	29.35	49	54	15.74
2 NG TMPP	26,763.1	806,523	30.14	8,105	37.8%	-29.1	-340	11.68	-14	-38	0.00
3 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0	0.00	0	0	0.00
4 Coal-ERCOT	111,418.1	1,744,752	15.66	15,535	82.1%	0.0	3	0.00	0	0	0.00
5 NG TXU-EAST	80,254.8	2,438,462	30.38	22,244	41.3%	197.3	5,623	28.50	229	256	72.84
6 Uranium	37,565.9	505,187	13.45	4,736	90.8%	-0.7	-5	7.14	0	-1	-0.06
7 FO#2-ERCOT	0.1	227	2,270.00	0	0.0%	0.0	3	0.00	0	0	0.00
8 Wind	2,374.9	25,518	10.74	272	100.0%	0.0	0	0.00	0	0	0.00
9 NG WETU	5,838.5	220,528	37.77	2,031	32.9%	-56.7	-1,887	33.28	-77	-73	-24.44
10 NG TXU-WEST	12,857.2	401,578	31.23	3,423	43.0%	-91.1	-2,695	29.58	-110	-118	-34.91
11 NG CPSA	4,263.6	152,777	35.83	2,529	19.3%	4.7	181	38.51	7	6	2.34
12 NG CP&L	15,142.8	458,266	30.26	5,817	29.8%	-11.6	-353	30.43	-14	-15	-4.57
13 NG LCRA	44,001.5	1,283,382	29.17	8,395	60.0%	19.1	600	31.41	24	25	7.77
14 NG ST&M	3,822.7	110,040	28.79	816	53.6%	0.5	-4	-8.00	0	1	-0.05
15 NG AUST	2,528.9	88,043	34.81	1,492	19.4%	3.4	114	33.53	5	4	1.48
16 HydroStudy	0.0	0	0.00	0	0.0%	-77.2	0	0.00	0	0	0.00
17 Hydro	511.1	2,556	5.00	427	13.7%	0.0	0	0.00	0	0	0.00
18 Transaction	-1,182.6	0	0.00	-135	100.0%	0.0	0	0.00	0	0	0.00
Totals	401,977.2	10,030,814	24.95	92,152	49.8%	0.0	2,455	31.80	100	46	20.39
Unserved Energy	0.0	0	0.00	--	--	0.0	0	0.00		--	--
Net Total	401,977.2	10,030,814	24.95	--	--	0.0	2,455	31.80		--	--

HYDROPOWER ENERGY VALUE: 31.80 mills/kWh

HYDROPOWER ENERGY BENEFIT: 2,455

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LAKE TEXOMA : GENSUM TABLE
1/12/2004
STUDY YR. JAN 2020

System with Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 NG Reliant	54,925.6	1,815,067	33.05	16,811	37.4%
2 NG TMPP	36,233.0	1,129,056	31.16	12,057	34.4%
3 INTLOAD	0.0	0	0.00	0	0.0%
4 Coal-ERCOT	110,986.5	1,699,573	15.31	15,588	81.5%
5 NG TXU-EAST	109,464.6	3,350,366	30.61	27,783	45.1%
6 Uranium	38,564.9	501,126	12.99	4,752	92.9%
7 FO#2-ERCOT	0.0	157	0.00	0	0.0%
8 Wind	2,382.2	25,588	10.74	273	100.0%
9 NG WETU	12,526.2	479,805	38.30	3,773	38.0%
10 NG TXU-WEST	12,112.7	389,301	32.14	3,432	40.4%
11 NG CPSA	3,842.8	139,104	36.20	2,279	19.3%
12 NG CP&L	14,666.4	457,765	31.21	5,850	28.7%
13 NG LCRA	60,388.6	1,801,049	29.82	11,043	62.6%
14 NG ST&M	3,909.4	114,321	29.24	694	64.5%
15 NG AUST	2,608.4	91,859	35.22	1,493	20.0%
16 HydroStudy	77.2	386	5.00	80	11.0%
17 Hydro	511.3	2,557	5.00	427	13.7%
18 Transaction	-1,185.8	0	0.00	-136	100.0%
Totals	407,088.4	11,997,080	29.47	89,388	52.0%
Unserved Energy	0.0	0	0.00	--	--
Net Total	407,088.4	11,997,080	29.47	--	--

System without Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh	% C Sav	% E Sav	mills/kWh component
1 NG Reliant	54,952.3	1,815,777	33.04	16,819	37.4%	26.7	710	26.59	27	35	9.18
2 NG TMPP	36,202.2	1,128,588	31.17	12,117	34.2%	-30.8	-468	15.19	-18	-40	0.00
3 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0	0.00	0	0	0.00
4 Coal-ERCOT	110,991.8	1,699,634	15.31	15,589	81.5%	5.3	61	11.51	2	7	0.79
5 NG TXU-EAST	109,686.1	3,357,314	30.61	27,840	45.1%	221.5	6,948	31.37	264	287	89.88
6 Uranium	38,565.9	501,131	12.99	4,752	92.9%	1.0	5	5.00	0	1	0.06
7 FO#2-ERCOT	0.0	157	0.00	0	0.0%	0.0	0	0.00	0	0	0.00
8 Wind	2,382.2	25,588	10.74	273	100.0%	0.0	0	0.00	0	0	0.00
9 NG WETU	12,423.2	476,229	38.33	3,772	37.7%	-103.0	-3,576	34.72	-136	-133	-46.26
10 NG TXU-WEST	12,052.9	387,664	32.16	3,432	40.2%	-59.8	-1,637	27.37	-62	-77	-21.18
11 NG CPSA	3,852.0	139,492	36.21	2,273	19.4%	9.2	388	42.17	15	12	5.02
12 NG CP&L	14,648.9	457,222	31.21	5,843	28.7%	-17.5	-543	31.03	-21	-23	-7.02
13 NG LCRA	60,403.1	1,801,370	29.82	11,045	62.6%	14.5	321	22.14	12	19	4.15
14 NG ST&M	3,909.6	114,307	29.24	693	64.6%	0.2	-14	-70.00	-1	0	-0.18
15 NG AUST	2,618.4	92,293	35.25	1,491	20.1%	10.0	434	43.40	17	13	5.61
16 HydroStudy	0.0	0	0.00	0	0.0%	-77.2	0	0.00	0	0	0.00
17 Hydro	511.3	2,557	5.00	427	13.7%	0.0	0	0.00	0	0	0.00
18 Transaction	-1,185.8	0	0.00	-136	100.0%	0.0	0	0.00	0	0	0.00
Totals	462,014.1	11,999,323	25.97	106,230	49.6%	0.1	2,629	34.05	100	65	30.88
Unserved Energy	0.0	0	0.00	--	--	0.0	0	0.00		--	--
Net Total	462,014.1	11,999,323	25.97	--	--	0.1	2,629	34.05		--	--

HYDROPOWER ENERGY VALUE: 34.05 mills/kWh

HYDROPOWER ENERGY BENEFIT: 2,629

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LAKE TEXOMA : GENSUM TABLE
1/12/2004
STUDY YR. JAN 2025

System with Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF
1 NG Reliant	51,921.6	1,722,627	33.18	14,821	40.1%
2 NG TMPP	43,839.2	1,390,412	31.72	16,453	30.5%
3 INTLOAD	0.0	0	0.00	0	0.0%
4 Coal-ERCOT	112,184.3	1,717,906	15.31	15,547	82.6%
5 NG TXU-EAST	147,831.4	4,544,103	30.74	36,787	46.0%
6 Uranium	37,411.3	484,620	12.95	4,737	90.4%
7 Wind	2,374.9	25,518	10.74	272	100.0%
8 NG WETU	19,261.3	740,786	38.46	5,596	39.4%
9 NG TXU-WEST	10,913.6	350,020	32.07	2,912	42.9%
10 NG CPSA	2,785.8	97,190	34.89	1,405	22.7%
11 NG CP&L	13,092.1	417,940	31.92	5,854	25.6%
12 NG LCRA	84,715.4	2,553,893	30.15	15,271	63.5%
13 NG ST&M	3,656.9	108,661	29.71	692	60.5%
14 NG AUST	2,169.7	80,155	36.94	1,487	16.7%
15 FO#2-ERCOT	0.0	20	0.00	0	0.0%
16 HydroStudy	77.2	386	5.00	80	11.0%
17 Hydro	511.1	2,556	5.00	427	13.7%
18 Transaction	-1,182.6	0	0.00	-135	100.0%
Totals	479,641.6	14,236,793	29.68	107,385	51.0%
Unserved Energy	0.0	0	0.00	--	--
Net Total	479,641.6	14,236,793	29.68	--	--

System without Lake Texoma Hydro

Type of Plant	Energy (GWh)	Cost ($1000)	mills/kwh	Capacity	PF	Ch Enrgy	Ch Cost	mills/kWh	% C Sav	% E Sav	mills/kWh component
1 NG Reliant	51,900.5	1,722,120	33.18	14,815	40.1%	-21.1	-507	24.03	-18	-27	0.00
2 NG TMPP	43,894.1	1,392,568	31.73	16,528	30.4%	54.9	2,156	39.27	78	71	27.89
3 INTLOAD	0.0	0	0.00	0	0.0%	0.0	0	0.00	0	0	0.00
4 Coal-ERCOT	112,172.1	1,717,778	15.31	15,545	82.6%	-12.2	-128	10.49	-5	-16	-1.66
5 NG TXU-EAST	148,074.8	4,551,438	30.74	36,768	46.1%	243.4	7,335	30.14	266	315	94.89
6 Uranium	37,408.7	484,606	12.95	4,737	90.4%	-2.6	-14	5.38	-1	-3	-0.18
7 Wind	2,374.9	25,518	10.74	272	100.0%	0.0	0	0.00	0	0	0.00
8 NG WETU	19,097.1	734,946	38.48	5,591	39.1%	-164.2	-5,840	-58,400.00	-212	-212	124052.78
9 NG TXU-WEST	10,871.5	348,904	32.09	2,914	42.7%	-42.1	-1,116	26.51	-40	-54	-14.44
10 NG CPSA	2,770.2	96,578	34.86	1,403	22.6%	-15.6	-612	39.23	-22	-20	-7.92
11 NG CP&L	13,066.0	417,192	31.93	5,842	25.6%	-26.1	-748	28.66	-27	-34	-9.68
12 NG LCRA	84,779.2	2,556,172	30.15	15,283	63.5%	63.8	2,279	35.72	83	83	29.48
13 NG ST&M	3,659.7	108,734	29.71	691	60.6%	2.8	73	26.07	3	4	0.94
14 NG AUST	2,166.0	80,038	36.95	1,485	16.7%	-3.7	-117	31.62	-4	-5	-1.51
15 FO#2-ERCOT	0.0	20	0.00	0	0.0%	0.0	0	0.00	0	0	0.00
16 HydroStudy	0.0	0	0.00	0	0.0%	-77.2	0	0.00	0	0	0.00
17 Hydro	511.1	2,556	5.00	427	13.7%	0.0	0	0.00	0	0	0.00
18 Transaction	-1,182.6	0	0.00	-135	100.0%	0.0	0	0.00	0	0	0.00
Totals	531,563.3	14,239,168	26.79	122,166	49.7%	0.1	2,761	35.76	100	127	124170.61
Unserved Energy	0.0	0	0.00	--	--	0.0	0	0.00		--	--
Net Total	531,563.3	14,239,168	26.79	--	--	0.1	2,761	35.76		--	--

HYDROPOWER ENERGY VALUE: 35.76 mills/kWh

HYDROPOWER ENERGY BENEFIT: 2,761

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Appendix 11.6 Denison Dam & Powerhouse, Lake Texoma, Red River, Oklahoma & Texas-Water Supply Storage Reallocation Power Benefits Foregone Study, Prepared by Hydropower Analysis Center, U.S. Army Corps of Engineers Dated April 2005, and Appendix A dated August 2005.

08/23/2005

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Denison - Lake Texoma
Hydropower Impacts from Water Storage Reallocation

Revenues Foregone	300,000 acre-feet Alternative Corps	300,000 acre-feet Alternative SWPA	450,000 acre-feet Alternative Corps	450,000 acre-feet Alternative SWPA
Annual Energy Losses (MWh)	11,995	11,995	23,792	23,792
Additional water usage adjustment (MWh)	-	15,069	-	30,131
Total Annual Energy Losses (MWh)	11,995	27,064	23,792	53,923
Energy value ($/MWh)	8.25	8.20	8.25	8.20
Annual energy revenue foregone	**$98,959**	**$221,926**	**$196,284**	**$442,165**
Capacity Losses (kW)	12,730	11,483	28,263	23,685
Capacity value ($/kW)	23.52	36.36	23.52	36.36
Annual capacity revenue foregone	**$299,410**	**$417,522**	**$664,746**	**$861,187**
Total Annual Revenues Foregone	**$398,368**	**$639,448**	**$861,030**	**$1,303,352**

Benefits Foregone	300,000 acre-feet Alternative Corps	300,000 acre-feet Alternative SWPA	450,000 acre-feet Alternative Corps	450,000 acre-feet Alternative SWPA
Annual Energy Losses (MWh)	11,995	11,995	23,792	23,792
Additional water usage adjustment (MWh)	-	15,069	-	30,131
Total Annual Energy Losses (MWh)	11,995	27,064	23,792	53,923
Energy value ($/MWh)	31.81	59.73	31.81	59.73
Annual energy benefit foregone	**$381,561**	**$1,616,543**	**$756,824**	**$3,220,796**
Capacity Losses (kW)	2,310	11,483	5,472	23,685
Capacity value ($/kW)	111.80	63.00	111.80	63.00
Annual capacity benefit foregone	**$258,258**	**$723,429**	**$611,770**	**$1,492,155**
Total Annual Benefits Foregone	**$639,819**	**$2,339,972**	**$1,368,593**	**$4,712,951**

07/18/2005

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Southwestern Power Administration
Water Storage Reallocation
Hydropower Impacts
Executive Summary

The purpose of the paper is to document the Southwestern Power Administration's (Southwestern) concerns with the procedures used by the US Army Corps of Engineers (Corps) in determining and compensating the hydropower purpose for impacts resulting from water storage reallocations at Corps projects.

1. Capacity Loss Calculations. The Corps uses average year capacity losses instead of the critical year capacity losses used by Southwestern to market the capacity. While the Corps' method may be applicable in determining the feasibility of new hydropower, Southwestern does not believe it is applicable to existing hydropower that is already meeting market energy and capacity needs. As such, a loss of Southwestern's marketable capacity is a loss in the National electrical energy market.

2. Energy Loss Calculations. Both agencies generally use the same procedure to calculate energy losses. Southwestern is concerned that the "water storage yield" amount used in the simulations as withdrawal for the water represents the minimum amount that can be withdrawn. Southwestern encourages development of a method that represents a maximum, or at least an average, withdrawal rate.

3. Capacity Cost Calculations. Southwestern generally agrees with the Corps use of the Federal Energy Regulatory Commission's (FERC) procedure to develop the cost of alternative sources of generation. Southwestern believes the alternative generation source should be selected based on the replacement of capacity as used in the power sales contract and not based on the project's average annual generation.

4. Energy Cost Calculations. Because Southwestern occasionally purchases energy in the market, it is familiar with the energy costs. Southwestern cannot typically purchase replacement energy at the unit costs assumed in the Corps' study. The energy market has changed significantly in the past several years and the procedures used to estimate the price of energy must therefore also change. Southwestern suggests the use of properly selected FERC calculated energy values as appropriate in determining the energy replacement costs. Care should also be taken in the studies in handling on-peak and off-peak energy.

5. Compensation Issues. The Corps agrees to provide compensation for benefits foregone through the life of the current power sales contracts. Southwestern believes that its 1980 Final Power Allocations assures the Federal customers continuation of their contracted capacity and energy. It would therefore

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follow that the hydropower purpose should be credited for the benefits foregone through the life of the project (much as the water supply users are guaranteed the water storage through the life of the project). Southwestern also believes that a procedure to provide the hydropower purpose the financial credit should be developed and included in the Corps' water storage reallocation reports.

07/18/2005

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Southwestern Power Administration
Water Storage Reallocations
Hydropower Impacts

Purpose: To provide Southwestern Power Administration's (Southwestern) general observations and concerns with the US Army Corps of Engineers (Corps) methods of determining the hydropower purpose impacts resulting from water storage reallocations at Corps projects along with any associated compensation.

Background: The Corps occasionally reallocates water storage from one purpose to another at their multipurpose lake projects (most often, but not always, for municipal and industrial water supply usage). Whenever a reallocation occurs at a project that includes hydropower as a project purpose, there is typically a negative impact to the hydropower purpose. During the study phase, the Corps requests their Hydropower Analysis Center (HAC) to determine the impact of the proposed water storage reallocation to the hydropower purpose. Determination of the hydropower impacts by HAC is generally composed of four parts: 1) amount of capacity lost, 2) amount of energy lost, 3) value of capacity lost, and 4) value of energy lost. As a result of reviewing numerous such studies, Southwestern has several areas of concern with the methodologies being used to determine those amounts and values. Additionally, Southwestern also has concern with how the Corps compensates the hydropower purpose once those impacts are determined. The following is a discussion of the current methods and proposed changes.

Capacity Loss: The determination of the amount of dependable capacity lost as the result of a water storage reallocation at a Corps project is of critical importance to Southwestern. Reliable capacity with associated energy is the major resource Southwestern has to market in order to repay the nation's hydropower investment in the project. In benefit calculations, the "...dependable capacity of a project is used to represent the amount of thermal capacity that would be displaced by the hydro plant. More specifically, it is intended to identify how much thermal capacity would be required to carry the same amount of system peak load as would be carried by the hydro plant..." [Section 6-7b(1) of the Corps' EM 1110-2-1701, Hydropower, dated 31 December 1985]. HAC and Southwestern differ in the method used to compute the dependable capacity loss in the case of storage reallocations.

a) <u>HAC's Method</u>: In Southwestern's marketing area, HAC typically uses the average availability method as described in Section 6-7g of the Corps' EM 1110-2-1701. HAC's justification for such usage is that hydropower in Southwestern's area represents only a small portion of the region's generating resources and as such, random hydrologic variations can be considered equivalent to random thermal generating plant forced outages.

DRAFT

In general, the average availability method computes the dependable capacity for a critical load demand period for each year of a given period-of-record based on energy produced and peaking demand hours (never allowing it to be more than machine capability). The dependable capacity for each year is then averaged over the period-of-record to determine the project's dependable capacity. To determine the impacts of a reallocation, the average dependable capacity is determined for both a base case and an alternative case modified to represent the proposed reallocation. The difference in the two cases is the capacity loss due to the proposed reallocation.

More specifically, in the average availability method, a period-of-record simulation is made for the base and modified conditions. The annual peak demand period is determined in consultation with Southwestern (typically June through August in Southwestern's area) and the project's average weekly energy output is computed for that peak demand period for each year of the simulation. Southwestern provides HAC with the critical flow year as used in its studies. In order to calculate the number of peaking hours required from the project each week, the average weekly energy for the peak demand period of the critical year of the base case is divided by the amount of capacity that Southwestern markets from the project. The average weekly energy for the peak demand period for each year of the entire period-of-record is then divided by the number of hours required by week as computed above to determine the potential supportable capacity. That value for each year is compared with machine capability (reduced for loss of head based on headwater and tailwater conditions) and the lower value chosen for the actual supportable capacity. The actual supportable capacity computed for each year of the period-of-record is averaged and used as the dependable capacity of the project. Using the required number of hours per week from the base case, the actual supportable capacity is computed for the alternative's modified conditions. The alternative average capacity is subtracted from the base average capacity to determine the loss of dependable capacity that is used in the study to determine revenues and benefits lost due to the proposed reallocation.

b) Southwestern's Method: Southwestern's method used to determine the lost capacity reflects how the capacity is marketed and used in the region. The capacity available from the Corps' hydropower projects is the only capacity available to Southwestern to meet the obligations of Federal long-term power sales contracts in its area. The revenues collected from those power sales contracts are used to repay the Federal investment in the projects, with interest. Southwestern has entered into those power sales contracts after determining the amount of capacity available for marketing based on the ability of the hydropower projects to reliably provide capacity and firm energy throughout the worst drought of record. The Federal customers receiving the electricity request long-term power sales contracts in order to provide them sufficient time to make arrangements for replacement generation sources if the hydropower is no longer available. Based on Section 5 of the Flood Control Act of 1944, as amended, and on discussions with the Office of Management and Budget, Southwestern believes that it only has the authority to market the capacity dependably available at the projects. If the capacity is not available because of a drought period, Southwestern cannot purchase replacement capacity, even if it was available, and therefore, Southwestern cannot market

DRAFT

that capacity through the Federal power sales contracts. (Special allowance is made for forced outages that are expected to return to service). If Southwestern cannot market the capacity on a long-term basis, then it is not available to the region as a generating resource and must be replaced in the long-term with the construction of thermal plant capacity. Therefore, benefits from the hydropower capacity that was marketed and now lost are no longer a benefit to the Nation.

Southwestern, from time to time, purchases energy on the shoulders of the peak during drought conditions to conserve water in storage to preserve the marketed project capacity. Southwestern must maintain the ability to meet the peak capacity demands solely with its hydropower resources. In system projects, an attempt is made to maintain a balance of the projects' storage to equitably address the needs of all the water users.

As mentioned, Southwestern determines the capacity loss of a water storage reallocation based on a critical drought period (instead of average conditions). A period-of-record simulation is made for both the base case (existing conditions) and an alternative case (modified to represent the proposed water storage reallocation yield). The peaking loads used in the alternative case are reduced by the amount of the reallocated water storage yield in order to maintain the minimum pool elevation achieved in the base case in the high load month of August during the critical drought period. From the two runs, the energy produced during the critical drought period (from the time the water surface receded into the power storage until the minimum August pool is reached) is computed. The critical drought period will often exceed one year. The number of peaking hours needed for the critical drought period is based on Southwestern's power sales contracts (1,200 hours per year) and a critical loading pattern based on the requirements of those contracts. The lost capacity is then computed by taking the amount of energy lost during the critical drought period between the base and alternative cases and dividing it by the number of peaking hours needed during the drought period.

c) Comparison: Southwestern's method uses procedures (energy loss divided by peaking hours required) similar to those used by HAC in determining the capacity lost. Southwestern uses a longer critical period (similar to the critical period used in a water yield analysis) than HAC (uses two to four months during the peak demand period). Most importantly, Southwestern is compelled, for reasons stated above, to use the critical drought capacity instead of the average available capacity. In addition, the critical drought conditions have a greater impact than random hydrologic variations and in Southwestern's area, critical drought conditions occur in several of the major river basins concurrently. Southwestern believes that the HAC method can be properly used in planning studies to determine whether new hydropower projects should be constructed. However, once a project is constructed and marketed into the electrical system, it has been established as a generating resource meeting specific electrical loads. Without the ability to provide capacity throughout the critical drought period, Southwestern cannot make the capacity available for long-term marketing. If that generating resource were no longer available for long-term marketing, it would have to be replaced by equivalent thermal plant capacity at the associated cost. Therefore, the capacity lost to the electrical system would be the amount of capacity lost during the critical drought period.

DRAFT

d) Flood control reallocation: When the proposed water storage reallocation is taken from the flood control storage, the impacts on the hydropower purpose will vary. If the reallocation provides for hydropower yield protection operation (HYPO) for the hydropower purpose, similar to the dependable yield mitigation storage for the water supply purpose, the hydropower storage capabilities remain whole, and there is no impact on the marketable capacity. If HYPO is not provided to protect the yield of the storage for hydropower, then the impact of the yield reduction of the hydropower storage must be determined and the associated capacity loss determined.

Energy Loss: Both HAC and Southwestern use the same method to compute the amount of energy lost from a proposed water storage reallocation. A period-of-record simulation is made for both the base case (existing conditions) and an alternative case (modified to represent the proposed water storage reallocation yield). The average annual energy produced is computed in both simulations. The average annual energy produced by the alternative case is subtracted from the base case value and the result is the average annual energy loss associated with the proposed water storage reallocation.

Southwestern's concern in the process is typically limited to efforts to assure that the proposed reallocation is properly modeled in the simulation runs. Southwestern believes that use of the water storage yield as the normal withdrawal in the simulation underestimates the amount of water that can normally be withdrawn from the storage. The yield represents the amount of water that can be withdrawn in the critical drought period. During the rest of the period-of-record, withdrawals exceeding the yield can be made from the water storage. Since there are normally no restrictions in the Corps' water storage contracts to limit the withdrawal amount and in order to properly model the impacts, the maximum withdrawal rate for each period must be assumed. When the potential withdrawal (average withdrawal instead of critical drought withdrawal) is properly modeled in the simulation, the energy losses associated with the reallocation would increase. With that exception, Southwestern generally agrees with the energy loss values computed by HAC. However, in a few studies, a distinction should be made to differentiate between the loss and gain of on-peak and off-peak energy in order for proper cost values to be assigned to each. Southwestern is willing to work with the Corps in developing a process to better model the potential average water withdrawal available from proposed storage reallocations.

Capacity Cost: Once the amount of capacity loss is established, the cost or value of the capacity lost must be determined. Both capacity revenues and benefits foregone are computed by HAC. The revenues are straightforward and are based on the capacity loss multiplied by the current rates Southwestern is charging for the capacity in the power sales contracts. The capacity cost used by HAC to calculate benefits foregone represents the unit cost of constructing an increment of the most likely thermal generating alternative to replace the lost hydropower capacity. HAC computes the capacity unit values for coal-fired steam, gas-fired combined cycle, and combustion turbine plants using procedures developed by the Federal Energy Regulatory Commission (FERC). The

DRAFT

capacity values are computed for the applicable region based on the current interest rate with the construction costs adjusted to the current price level. Southwestern agrees with the use of the FERC model in determination of the capacity values. However, it appears that the construction costs, although brought to the current price level, are based on older data and should be updated based on new construction cost information.

HAC uses the FERC thermal alternative cost information to develop a thermal screening curve of annual costs versus the operating plant factors. A project hourly generation duration curve is also developed from a typical generation year. From those two curves, HAC selects a least-cost thermal mix that represents the least-cost thermal alternative for generation of the typical annual generation from the project. Weighting factors are calculated to represent that mix and applied to the previously calculated FERC unit capacity values for each thermal alternative. A composite unit capacity value is calculated and multiplied by the previously calculated capacity loss to determine the capacity benefit loss from the proposed reallocation.

Southwestern believes that, while the HAC approach provides a reasonable thermal mix for the modified project's average annual generation, it does not represent the most likely thermal alternative for the capacity and energy that is being lost because of the reallocation. Southwestern believes that the thermal generating alternative selected to replace the lost hydropower capacity should be based on replacement of capacity as used in the power sales contracts to meet the firm peaking energy requirements. The hydropower storage at a project provides the dependability that makes the capacity marketable. It is used to meet the 1,200 hours per year of energy guaranteed in the power sales contracts (not the average annual generation). The loss of the use of a portion of that storage reduces the amount of marketable capacity at the project available to meet the 1,200 hours. The thermal generating alternative used to replace the product Southwestern markets from those projects would be used to provide 1,200 hours per year, or a plant factor of 13.7 percent. Therefore, Southwestern believes that the most likely thermal generating alternative for most of the water storage reallocations proposed in its area should be a gas-fired combustion turbine.

Energy Cost: After the amount of energy loss is estimated, the cost or value of the lost energy must be determined. Both energy revenues and benefits foregone are computed by HAC. The energy portion of the revenue foregone is computed by multiplying the energy loss by Southwestern's current energy rate. Both on-peak and off-peak rates are available in Southwestern's current rate structure.

a) <u>On-peak energy</u>: Because the hydropower storage at a project is used to produce peaking energy, the impact in Southwestern's area of reducing the hydropower storage is the loss of peaking energy. HAC and Southwestern differ in the method used to compute the value of the energy loss in the case of storage reallocations.

1) <u>HAC's Method</u>: HAC uses the computer model PROSYM, which is developed and maintained by Henwood Energy Services, to develop the

DRAFT

area power system cost of producing an equivalent amount of thermal replacement energy to offset that hydropower energy lost due to the reallocation. It appears that the model tries to absorb the lost energy into the existing resources, assuming that there is sufficient energy in reserve to meet the loss, and to replace the loss with the existing thermal generating alternative that has the lowest production cost.

2) Southwestern's Method: While Southwestern believes that the model and procedure used by HAC had merit in previous planning studies in determining the feasibility of constructing new hydropower facilities, it believes the value used by HAC in the studies for the replacement cost of the peaking energy loss is not valid. In the existing open, de-regulated energy market, the replacement of the lost hydropower energy will be made through either the purchase of peaking energy at market-based rates or through the construction of a new thermal generating plant. The price of energy in the new market-driven industry is no longer based on production costs, but rather on supply and demand. Southwestern has responsibility for the purchase of peaking energy from time to time to preserve water storage in the reservoirs. Therefore, it has practical experience in the energy market. The unit cost of peaking energy purchased by Southwestern is considerably more than the energy unit cost used by HAC in the studies. The unit cost of energy used by HAC in the studies is not reasonable or representative of the actual energy market. Until a market cost forecast model is developed, Southwestern believes that the peaking energy replacement costs can adequately be represented by use of the FERC energy values computed for the gas-fired combustion turbine.

b) Off-peak energy: In studies where the proposed water storage reallocation is from the flood control pool and HYPO is provided to protect the hydropower yield, the capability of the hydropower storage is not impacted. Energy loss in that case should be considered off-peak energy and its cost or value should reflect the lower costs. Additionally, in a recent study, the reallocation energy loss was offset by energy generated through new, larger station service units that generated when the main units were not used. In the study, all the energy was treated as having the same value. Since the main units are typically run to produce energy when needed to meet the firm peaking energy requirements of the power sales contracts, the energy from the new station service units should be considered as off-peak energy (not used to meet the peaking energy requirements). In the energy market, such off-peak energy has a much lower value. Southwestern recommends that when similar conditions are evaluated, the off-peak energy should be valued at the FERC energy value for the coal-fired steam as the most likely thermal alternative to replace the off-peak energy in the benefits calculations.

Compensation: Southwestern has concerns with two issues involving compensation to the hydropower purpose for any proposed water storage reallocation. The first issue

DRAFT

involves the amount of compensation and the second involves the procedure for compensation.

a) Amount: Appendix E of the Corps' ER 1105-2-100, Planning Guidance Notebook, dated 22 Apr 2000, allows for hydropower to receive a financial credit of revenues foregone when hydropower is adversely impacted by water storage reallocations. Additionally, where existing Federal power delivery contracts require market purchases of power as a result of storage reallocations and withdrawal, the additional credit for funds expended for purchases is provided. In essence, the latter provision gives the hydropower purpose a financial credit for the replacement costs or benefits foregone for the duration of the power sales contracts.

Under the same Appendix E, the permanent right to storage is discussed for water supply users that continue to make payments pursuant to their agreement with the government. Southwestern believes that the Federal power customers have a similar guarantee of continued benefits under Southwestern's Final Power Allocations published in the Federal Register on March 24, 1980. It states, "SWPA will not withdraw any capacity now under contract to a preference customer in order to sell the capacity to another preference customer. As contracts expire, SWPA will offer to enter into peaking contracts for the sale of a like amount of capacity with 1200 kWh/kW/yr of associated energy." It further states that "Capacity that becomes available with the expiration of a preference customer contract is to be used for continued service to that preference customer and is, therefore, not available for allocation to others." The 1980 Final Power Allocations provides the permanent right to the capacity and associated energy to the existing preference customers provided that the "power allottee will accept the amounts allocated with its attendant terms" and "transmission facilities will be available to move this power to load centers." As such, Southwestern believes that, while compensation for the loss of hydropower capacity and energy associated with the reallocation of water storage should continue to be based on the replacement costs or benefits foregone for the term of the contract, the contract should be considered permanent, or without end.

b) Procedure: In order to assure that the proposed hydropower compensation is accomplished, Southwestern believes that the water storage reallocation reports should have clearly delineated procedures that outline the process for providing a financial credit to the hydropower purpose. It is imperative that the hydropower purpose actually receives the credit on the financial books in order that Southwestern's electrical rates can reflect the proposed compensation. Southwestern is willing to work with the Corps in the development of a standard financial credit procedure for hydropower compensation.