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ER Supplemental Information

Chapter 9

Sections 9.3 and 9.4

SNC 2003 to Yokley 2004

Water Allocation for the Alabama-Coosa-Tallapoosa (ACT) River Basin

Alabama and Georgia

Main Report

Lead Agency

U.S. Army Corps of Engineers, Mobile District

Cooperating Agencies

Environmental Protection Agency
Fish and Wildlife Service
Forest Service
Maritime Administration
National Marine Fisheries Service
National Ocean Service
National Park Service
Natural Resources Conservation Service
Southeastern Power Administration
U.S. Geological Survey

September 1998

4.7 Socioeconomic Resources

Socioeconomic resources evaluated in this EIS include human population/demographics and economics. The population evaluation (Section 4.7.1) addresses general population patterns in the ACT basin, as well as environmental justice and children protection issues. The population projections are based on the studies completed for the Comprehensive Study (PMCL, 1996) and correspond with the population data used to develop the water demands included in the HEC-5 model (see Section 4.7.1 and *Appendix G*). The economics section (Section 4.7.3) addresses municipal and industrial water demands, navigation, electric power generation, agricultural water demands, flood control recreation, income, and employment. The economics sections were prepared by the Mobile District Corps' staff and are based on information developed during the Comprehensive Study and on economic modeling completed by the Corps specifically for this EIS. Existing or baseline conditions and potential environmental consequences resulting from the alternatives are presented.

Socioeconomic issues related to three counties in the Mobile Bay area (Baldwin, Mobile, and Washington Counties) were not examined in the Comprehensive Study because impacts from the water allocation formula were expected to be minimal there. However, footnotes are included in the tables in Section 4.7.1.1 to provide the reader with the demographic characteristics of these three counties.

4.7.1 Population/Demographics

The evaluation of population/demographics is based on population estimates developed for the Comprehensive Study to provide consistency between the water demands used in the hydrologic modeling (see Sections 1.3.3.3 and 4.4.1). This section summarizes the existing demographic conditions based on the Comprehensive Study and evaluates the potential environmental consequences of the alternatives.

4.7.1.1 Affected Environment

4.7.1.1.1 Demographics

As part of the Comprehensive Study, DRI/McGraw-Hill developed population projections through 2050 for each of the 42 counties in the Comprehensive Study-designated ACT basin. Forecasts through 2018 for the nation, for Georgia and Alabama, and for metropolitan areas within these states were generated using the DRI/McGraw-Hill August 1993 long-term (TREND-LONG0893) forecast (DRI/McGraw-Hill, 1996). The forecast horizon was extended to 2050 at the national level. Customized subbasin models were created to capture the unique characteristics of each region. Finally, a modeling system was developed to generate population forecasts for specific counties. The methodology used to develop the county-level population projections links population growth to job growth, with no incorporation of changes in commuter patterns. Therefore, counties currently emerging as "bedroom communities" are likely to have population projections that significantly underestimate current and future growth. While county-level population projects are expected to be less accurate, the basinwide figures presented in this section have been approved by the States and are expected to capture the overall growth of fast-developing areas.

The 42-county area in the ACT basin has experienced increases in population from 1975 to 1990, with the trend continuing into the 1990s. From 1975 to 1995, the population increased roughly 22 percent, or an average of 1 percent annually. *Table 4-55* presents the population growth in the ACT basin that has occurred between 1975 and 1995.

Population projections prepared for the Comprehensive Study estimated 2.66 million people to be living in the ACT basin in 1995. Approximately 73.5 percent of the population in the ACT basin resided in Alabama. Georgia claimed 26.5 percent of the basin's residents. *Figure 4-90* illustrates the population distribution in the basin.

TABLE 4-55
Population Growth in the ACT Basin

Area	1975	1980	1985	1990	1995 Estimated
Alabama portion [a]	1,687,000	1,777,000	1,787,000	1,800,000	1,953,000
Georgia portion	495,000	529,000	570,000	647,000	705,000
ACT basin [a]	2,182,000	2,306,000	2,357,000	2,447,000	2,658,000

Source: DRI/McGraw-Hill, 1996

[a] These population estimates do not include the South Alabama area downstream of Claiborne Lock and Dam, which includes the counties of Baldwin, Mobile, and Washington and the Mobile Standard Metropolitan Statistical Area (SMSA). In 1995, the population in these three counties totaled 532,470.

FIGURE 4-90
Population Distribution in the ACT Basin

The 1995 population estimates presented here were used to develop the municipal and industrial water demands presented in Section 4.7.3.1.

4.7.1.1.2 Environmental Justice

On February 11, 1994, President Clinton issued Executive Order (EO) 12898, Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations. The order requires that federal agencies identify and address, as appropriate, disproportionately high and adverse human-health or environmental effects of its programs, policies, and activities on minority and low-income populations. By the memorandum of February 11, 1994, the President directed EPA to ensure that agencies analyze environmental effects on minority and low-income communities, including human-health, social, and economic effects.

The term *minority population* includes persons who identify themselves on the Census as African-American, Asian or Pacific Islander, Native American or Alaskan Native, or Hispanic (CEQ, 1996). A minority population exists if the percentage of minorities in an affected area either exceeds 50 percent or is meaningfully greater than in the general population of the larger surrounding area (EPA, 1996b). A minority community may be either a group of individuals living in geographic proximity to one another, or a geographically dispersed/transient set of individuals (such as migrant workers or Native Americans). Either type of group experiences common conditions of environmental exposure or effect. A selected appropriate unit of geographic analysis may be a governing body's jurisdiction, a neighborhood, a census tract, or another similar unit with no artificial dilution or inflation of the affected minority population. A minority population also exists if there is more than one minority group present and the aggregate minority percentage meets one of the above-stated thresholds.

Analysis of demographic data for the ACT basin shows that the population is almost 75 percent white. African-Americans represent the next largest ethnic group, comprising more than 24 percent of the basin's population. *Table 4-56* shows the demographic characteristics of the basin. For Alabama, the proportion of minority persons living inside the ACT basin (30.7 percent) is higher than for the state as a whole (25.2 percent). However, in Georgia, the proportion of minority persons living within the basin is much smaller than the proportion for the state as a whole. Other minority groups are represented in similar proportions in the basin and in the surrounding states.

TABLE 4-56
Demographics for the ACT Basin, 1990

	White	African-American	American Indian, Eskimo, or Aleut	Asian or Pacific Islander	Other Race	Hispanic
Alabama portion of basin [a]	1,233,296	551,688	4,548	8,098	2,117	8,331
	68.5%	30.7%	0.3%	0.4%	0.1%	0.5%
Georgia portion of basin	595,731	45,402	1,807	1,776	2,956	6,292
	92.0%	7.0%	0.3%	0.3%	0.5%	1.0%
ACT basin [a]	1,829,027	597,090	6,355	9,874	5,073	14,623
	74.7%	24.4%	0.3%	0.4%	0.2%	0.6%
State of Alabama	2,975,247	1,019,743	18,295	21,754	5,548	23,579
	73.6%	25.2%	0.5%	0.5%	0.1%	0.6%
State of Georgia	4,603,396	1,744,882	15,283	73,757	40,898	101,379
	71.1%	26.9%	0.2%	1.1%	0.6%	1.6%
2-state area	7,578,643	2,764,625	33,578	95,511	46,446	124,958
	72.0%	26.3%	0.3%	0.9%	0.4%	1.2%

[a] The statistics presented here do not include the counties of Baldwin, Mobile, and Washington. The combined population in these three counties is 71 percent white; 27.4 percent African-American; 0.9 percent Hispanic; 0.8 percent American Indian, Eskimo, or Aleut; 0.7 percent Asian or Pacific Islander; and 0.1 percent other. Numbers total more than 100 due to rounding.
Source: U.S. Census Bureau, 1998

The existence of low-income persons in the ACT basin was determined from the 1990 U.S. Census statistical poverty threshold, which is based on income and family size. The Bureau of the Census defines a *poverty area* as having 20 percent or more of the residents with incomes below the poverty threshold. Overall, 16.6 percent of the ACT basin's population is below the poverty level (*Table 4-57*). Within the basin, the proportion of persons below the poverty level is much higher in Alabama (18 percent) than in Georgia (11.6 percent). For Alabama, the proportion of low-income residents is almost the same in the basin as in the state as a whole. At a poverty rate of 18 percent, the Alabama portion of the basin (like the state itself) is close to the definition of a poverty area. For Georgia, the percentage of low-income persons is lower in the basin than in the state as a whole and is lower than the nationwide poverty rate of 12.8 percent.

TABLE 4-57
Persons Below the Poverty Level in the ACT Basin, 1990

	Persons for Whom Poverty Status Is Determined	Persons Below the Poverty Level	Percentage of Persons Below the Poverty Level
Alabama portion of basin [a]	2,293,364	413,500	18.0%
Georgia portion of basin	652,685	76,022	11.6%
ACT basin [a]	2,946,049	489,522	16.6%
State of Alabama	4,040,587	723,614	17.9%
State of Georgia	6,478,216	923,085	14.2%
2-state area	10,518,803	1,646,699	15.7%
United States	248,709,873	31,742,864	12.8%

[a] The statistics presented here do not include the counties of Baldwin, Mobile, and Washington. Of the combined population in these three counties, 19.7 percent were identified as "below the poverty level" in the 1990 U.S. Census.

Source: U.S. Census Bureau, 1998

4.7.1.1.3 Protection of Children

On April 21, 1997, the President issued Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks, which recognizes that a growing body of scientific knowledge demonstrates that children may suffer disproportionately from environmental health and safety risks. This EO requires federal agencies, to the extent permitted by law and mission, to identify and assess such environmental health and safety risks.

While EO 13045 does not provide guidance on what age children are to be protected, the Federal Interagency Forum on Child and Family Statistics, which was founded in 1994 and formally established by the EO, focuses on those aged 17 and under (Federal Interagency Forum on Child and Family Statistics, 1997). In the ACT basin, there were 647,836 children 17 and under identified in the 1990 Census. This represents more than 26 percent of the basinwide population. More than 73 percent of the children in the basin were residents of Alabama (475,544). The Georgia portion of the ACT basin had 172,292 children (27 percent).

4.7.1.2 Environmental Consequences

The evaluation of potential environmental consequences on population and demographics was based on the population projections developed during the Comprehensive Study (DRI/McGraw-Hill, 1996). A key assumption of the Comprehensive Study and the EIS has been that population growth will continue as projected, regardless of the availability of water.

4.7.1.2.1 Demographics

Growth in the ACT basin is projected to increase at an average of about 1 percent per year throughout the 55-year study period. *Table 4-58* presents the population projections for the basin through 2050. In 1995, approximately 73.5 percent of the population in the ACT basin resided in Alabama. Georgia claimed 26.5 percent of the population. By 2050, Georgia's share of the population is expected to decrease slightly, with 24.5 percent of the basin's residents expected to be living in that state. The percentage anticipated to be living in Alabama will increase to 75.5 percent.

TABLE 4-58
Projected Population in the ACT Basin

	1995[a]	2020	2050
Alabama portion of basin	1,953,000	2,496,000	3,199,000
Georgia portion of basin	705,000	845,000	1,037,000
ACT basin	2,658,000	3,341,000	4,236,000

[a] Estimated values
Source: Regional Economic Forecast of Population and Employment

Population distribution over the basin will change as an indirect result of the decision made by the Federal Commissioner. Intuitively, populations will increase in areas where water resources become more available and induce growth in some communities, while population declines may occur in other areas. These demographic changes will have additional secondary impacts on land use changes for residential development and support services, will affect water and wastewater treatment demands, and will affect local economics. However, these changes will be localized following water resource changes that are made by the States after the Federal Commissioner has made a decision on the allocation formula. Thus, although there will be impacts from population changes resulting from the selection of an alternative, this programmatic EIS cannot predict specific areas where these changes will take place. Further, because local and regional decisions may be made to implement specific water conservation and water quality measures, the impacts of these changes are also unpredictable until implementation EAs or EISs are completed. Therefore, for the purposes of modeling, it is assumed that there are no differences in population growth between the no action and the action alternative flow scenarios.

4.7.1.2.2 Environmental Justice

Analysis of demographic data indicates a low-income population in the Alabama portion of the ACT basin. The water allocation alternatives are not designed to create either a benefit or an adverse effect for any group or individual, and are not expected to create disproportionately high or adverse human health or environmental impacts on minority or low income populations in the ACT River basin. As indicated in Section 4.7.3.2, no significant impacts to the economy of the basin are expected to arise from the no action or action alternative scenarios addressed in this EIS. Likewise, no human health risks that would disproportionately impact minority or low-income communities have been identified in this EIS. However, the programmatic nature of this EIS precludes identifying specific areas with low income and minority populations of the basin that may experience demographic impacts, as described above.

4.7.1.2.3 Protection of Children

Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks, directs federal agencies to ensure that their policies, programs, activities, and standards address disproportionate risks to children that result from environmental health or safety risks. No human health risks (see Section 4.6.6.2) or safety risks arising from the no action and action alternative flow scenarios that would disproportionately affect children have been identified through this EIS process. Specific impacts arising from changes in stream flows or elevated or lowered lake levels cannot be addressed in a programmatic EIS such as this one, but will be addressed in the EAs that tier off of this document.

4.7.2 Recreation

The following section summarizes the existing recreation conditions in the ACT basin and the potential impacts on recreation associated with implementing the water allocation formula. Recreational opportunities associated with the reservoirs and riverine reaches are addressed separately. The evaluation of recreation within the ACT basin is based on information developed in the Comprehensive Study (Allen et al., 1997) and the evaluation of impacts completed by the Corps economics and planning staff.

4.7.2.1 Affected Environment

Phase I of the Comprehensive Study report (Allen et al., 1997) examined recreation at 25 reservoirs, rivers, and river reaches in the ACT and ACF river basins. The 15 ACT projects included in the study are listed in *Table 4-59.* Five of these study projects are reservoirs operated by the Corps, with the remaining nine reservoirs operated by Alabama Power Company (APCO). The study projects were chosen by the Comprehensive Study Technical Coordination Group (TCG) based on their representation of the entire range of project characteristics in the basins. This analysis focuses on these projects, for which uniform data are available. There are other major recreation areas within the basin that were not analyzed as part of the Comprehensive Study, most notably, National Park Service (NPS) sites and U.S. Forest Service (USFS) sites. Information and use data on those recreation sites are presented to the extent that data were available.

TABLE 4-59
ACT Study Projects Included in Phase I of the Comprehensive Study

River	Official Name	Operated by	Common Name
Coosawatee	Carters Lake and Dam	Corps	Carters Lake
Etowah	Allatoona Lake and Dam	Corps	Lake Allatoona
	Etowah River between Allatoona Dam and confluence with Coosawatee (beginning of Coosa River)		
Coosa	Weiss Dam	APCO	Weiss Lake
	H. Neely Henry Dam	APCO	H. Neely Henry Lake
	Logan Martin Dam	APCO	Logan Martin Lake
	Lay Dam	APCO	Lay Lake
	Mitchell Dam	APCO	Mitchell Lake
	Jordan Dam and Bouldin Dam	APCO	Jordan Lake
Tallapoosa	R.L. Harris Dam	APCO	R.L. Harris Reservoir or Lake Wedowee
	Martin Dam (APC)	APCO	Lake Martin
	Yates Dam and Thurlow Dam APC)	APCO	Yates and Thurlow Dams
Alabama	Alabama River between Claiborne Dam and confluence with Tombigbee River		
	Alabama River Lakes		
	Robert F. Henry Lock and Dam; R.E. "Bob" Woodruff Lake	Corps	Lake Woodruff or Jones Bluff

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TABLE 4-59 (CONTINUED)
ACT Study Projects Included in Phase I of the Comprehensive Study

River	Official Name	Operated by	Common Name
	Wm. "Bill" Dannelly Lock and Dam	Corps	Lake Dannelly or Millers Ferry
	Claiborne Lock and Dam	Corps	Lake Claiborne
Cahaba	River segment		

APCO Alabama Power Company

R.E. "Bob" Woodruff Lake, Wm. "Bill" Dannelly Lake, and Claiborne Lake are collectively referred to as the Alabama River Lakes.

Source: Allen et al., 1997

The reservoirs, rivers, and streams of the ACT basin are used for a variety of recreational purposes. The reservoirs and rivers within the ACT basin provide important recreation opportunities for residents in northern Georgia and a majority of Alabama. Northern Georgia and Alabama contain several national forests, national and state parks, and resort communities that are favorite weekend and vacation destinations. The Georgia portion of the Coosa River basin falls within the heavily used Chattahoochee National Forest. The Cahaba and Coosa rivers run through the Talladega National Forest, south of Birmingham and Anniston, Alabama. South of Auburn-Opelika, Alabama, a tributary to the Tallapoosa River runs through Tuskegee National Forest.

The national forests provide both developed and dispersed recreation opportunities. The developed sites provide a range of primitive or modern facilities. Dispersed activities include hunting, fishing, boating, hiking and off-road vehicle riding (USFS, 1998).

Two popular National Park Service sites are found in the ACT basin. Horseshoe Bend National Military Park is located on a peninsula formed by the horseshoe-shaped bend of the Tallapoosa River. This commemorates the final battle of the Creek War of 1813-14. This 2,040-acre park preserves the site of the battle and includes a visitor center and walking trails, although current visitor use information is not available. Water related recreation facilities are not available at this park, but the flow level of the Tallapoosa River is considered integral to experiencing this historic park. Little River Canyon National Preserve, another popular NPS site located in the ACT basin, is a tributary to the Coosa River draining into Lake Weiss from the north. Sightseeing, picnicking, hiking, wading, advanced white water paddling, canoeing, mountain biking, horseback riding and rock climbing are popular activities at this 816-acre area. Hunting, fishing, and trapping are permitted in designated areas. This preserve is unlikely to be affected by an allocation formula due to its location on a free-flowing tributary of the Coosa River.

Downstream from Claiborne Lock and Dam, the Alabama River joins the Tombigbee River and flows south into Mobile Bay. The Tombigbee, an important commercial waterway, also provides riverine recreation opportunities, including fishing and. The Mobile Bay area also provides recreation opportunities, including deep sea fishing, freshwater fishing in the bays and bayous, and water sports.

Recreation use data were obtained from a survey administered to registered boat owners in the 101 counties located in the ACT and ACF basins. The Phase I survey consisted of a telephone survey that was administered to collect information on boater recreational use at the ACF project sites during the 1995 recreation year. Estimates of number of trips were then adjusted based on the output of the hydrologic modeling (see the Corps recreation report in *Appendix F*). Based on this, the Corps estimates that 2.3 million boating trips were made to the study projects (reservoirs and rivers) in the ACT basin in 1995, representing 9.3 million visitor-days of recreational boating. Summer was the most popular boating season, followed by spring. Together, these seasons account for 78 percent of the recreation use that occurs in the basins. Fall and winter, combined, account for only 22 percent of recreation use (*Table 4-60*).

TABLE 4-60
Annual Boat Recreation Visitation Estimates for ACF Basin

Total Trips (1995)	Total Visitors-Days	Winter (%)	Spring (%)	Summer (%)	Fall (%)
2,307,358	9,293,926	12	34	44	10

Source: The estimates are based on a survey (Allen et al., 1997) that was adjusted based on the output of hydrologic modeling (see Corps recreation report in *Appendix F*).

4.7.2.1.1 Reservoir Recreation

Fifteen reservoirs in the ACT basin provide recreation opportunities and receive varying amounts of usage. Six of the reservoirs are located on the Coosa River, three on the Tallapoosa River, three on the Alabama River, and one each on the Coosawatee and Etowah Rivers. Facilities on the reservoirs provide a range of opportunities for recreation.

Table 4-61 details recreation facilities on each of the reservoirs. Where available, information is provided on the effects of reservoir levels on recreation facilities.

TABLE 4-61
Recreation Facilities on Reservoirs in the ACT Basin

Reservoir/ Surface Area	No. of Parks	Campsites	No. of Picnic Sites	Boat Ramps	Public Docks & Fishing Piers	Comment
Lake Martin/ 40,000 acres	12	981	201	23	4	There are three golf courses on the lake. Wind Creek State Park has 642 camping sites, marina, camp store, fishing pier, hiking trails, playground, and picnic areas. Recreation facilities and access begin to be affected when the reservoir is drawn down 5 feet below normal pool level. At 10 feet below normal pool level, only three to four public boat ramps are available, marina slips are impacted, and boating congestion increases.

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TABLE 4-61 (CONTINUED)
Recreation Facilities on Reservoirs in the ACT Basin

Reservoir/ Surface Area	No. of Parks	Campsites	No. of Picnic Sites	Boat Ramps	Public Docks & Fishing Piers	Comment
Lake Allatoona/ 19,860 acres	45	662	427	21	8	Camping, picnicking, hunting, fishing, boating, tennis courts and swimming facilities are available. Red Top Mountain State Park offers a 33-room lodge, restaurant, and meeting facilities. Facilities and access are impaired when the reservoir is 3 feet below normal pool level; most facilities are unusable when reservoir is drawn down 12 feet below normal pool.
Logan Martin Lake/15,263 acres		79	7	30	28	Pell City is situated on the shores of lake.
Weiss Lake/ 30,200 acres		1,480	384	38	12	World-renowned for Crappie fishing
H. Neely Henry Lake/11,200 acres		108	214	28	11	Gadsden is situated on the shores of the lake.
Jordan Lake/6,807 acres			22	11	1	The lake is located just north of Montgomery.
R.L. Harris Lake/ 10,661 acres	11	105	78	11	9	
Lay Lake/ 12,000 acres		18	22	21	15	
Carters Lake/ 3,220 acres	8	147	94	6	8	Public boat ramps, marina, two barrier-free fishing decks, day-use recreation areas containing picnic shelters are available. Lake is considered one of the best spotted bass fisheries in Georgia and has 12 lodging units.
Mitchell Lake/ 5,850 acres		26	44	11	2	
Yates and Thurlow Dam/ 2,000 acres and 574 acres			10	3	1	
Alabama River Lakes/ 12,510 acres, 18,500 acres, and 5,930 acres		505	387	33	8	There are 35 day-use recreation areas offering tennis courts, playing fields, basketball courts, fishing piers, boat ramps, swimming areas, nature trails, and picnic shelters. At Woodruff and Dannelly, draw-downs of 1.5 feet adversely impact recreation opportunities. Problems are worse in summer due to reduced river flows.

Source: Corps, 1988

Lake Martin is the most visited reservoir in the ACT basin. Lake Martin had approximately 2.4 million visitor-days in 1995, accounting for 27 percent of total visitor-days for all reservoirs. Lake Allatoona, located approximately 30 miles north of Atlanta, also enjoys high visitation with 1.5 million visitor-days. Yates and Thurlow Dam on the Tallapoosa River were the least visited projects in 1995, with approximately 25,000 visitor-days (0.1 percent of total visitor-days for all reservoirs). In general, the most heavily visited reservoirs experienced the largest percentages of use during the summer. At six of the reservoirs (Jordan Lake, Lay Lake, Carters Lake, Mitchell Lake, Yates and Thurlow Dams and the Alabama River Lakes), spring is the most popular recreation season. *Table 4-62* provides detailed information for each reservoir.

TABLE 4-62
Annual Recreation Visitation Estimates for Reservoirs in the ACT Basin, 1995

	Total Trips	Total Visitor-Days	Winter (%)	Spring (%)	Summer (%)	Fall (%)
Lake Martin	402,705	2,368,852	13	27	51	10
Lake Allatoona	378,297	1,454,988	12	35	44	11
Logan Martin Lake	309,041	1,343,657	7	32	50	11
Weiss Lake	293,625	1,276,630	7	41	43	9
H. Neely Henry Lake	170,431	501,268	12	29	53	6
Jordan Lake	160,906	498,663	13	39	36	11
R.L. Harris Lake	96,989	404,121	9	28	50	12
Lay Lake	149,977	453,185	17	43	31	9
Carters Lake	53,598	303,253	20	39	35	6
Mitchell Lake	63,658	164,816	16	39	34	12
Yates and Thurlow Dam	13,533	25,142	19	39	31	11
Alabama River Lakes[a]	131,164	166,030	15	43	33	9
Total	2,223,924	8,960,605				

[a] Alabama River Lakes include Woodruff Lake, Dannelly Lake, and Claiborne Lake.
Source: The estimates are based on a survey (Allen et al., 1997) that was adjusted based on the output of hydrologic modeling (see Corps recreation report in *Appendix F*).

Table 4-63 details activity participation at each reservoir. Overall, boat fishing is the most popular recreation activity on reservoirs in the ACT basin. Pleasure boating, swimming, and picnicking were also important activities.

TABLE 4-63
Activity Participation on Project Reservoirs in the ACT Basin, 1995

Reservoir	Total Trips	Fishing: Shore (%)	Fishing: Boat (%)	Pleasure Boating (%)	Water Skiing (%)	Jet Skiing (%)	Swimming (%)	Camping (%)	Picnicking (%)
Lake Martin	402,705	29	74	60	38	19	50	21	40
Lake Allatoona	378,297	16	73	64	38	9	58	30	49
Logan Martin Lake	309,041	17	82	42	24	12	37	11	30
Weiss Lake	293,625	24	95	41	20	9	35	18	34
H. Neely Henry Lake	170,431	12	82	36	22	7	27	9	22
R.L. Harris Reservoir	96,989	11	96	28	14	4	25	8	19
Jordan Lake	160,906	13	82	42	17	11	31	6	22
Lay Lake	149,997	6	92	26	10	3	21	8	13
Carters Lake	53, 598	15	88	40	22	3	33	22	38

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TABLE 4-63 (CONTINUED)
Activity Participation on Project Reservoirs in the ACT Basin, 1995

Reservoir	Total Trips	Fishing: Shore (%)	Fishing: Boat (%)	Pleasure Boating (%)	Water Skiing (%)	Jet Skiing (%)	Swimming (%)	Camping (%)	Picnicking (%)
Alabama River Lakes [a]	131,164	11	88	40	17	3	29	18	27
Mitchell Lake	63,658	7	86	36	14	6	23	10	17
Yates and Thurlow Dam	13,533	2	95	13	6	2	2	-	4

[a] Alabama River Lakes include Woodruff Lake, Dannelly Lake, and Claiborne Lake.

Activities are not mutually exclusive, therefore, data will sum to more than 100 percent.

Source: The estimates are based on a survey (Allen et al., 1997) that was adjusted based on the output of hydrologic modeling (see Corps recreation report in *Appendix F*).

4.7.2.1.2 Riverine Recreation

The major rivers in the ACT basin include the Alabama, Coosa, Tallapoosa, Etowah, and Cahaba. There are also tributaries to each of these rivers where various recreation activities take place. Because the proposed action would only affect flows in the main stem rivers, the tributaries are not discussed in detail. The Comprehensive Study assessed river recreation on the Etowah, Cahaba, and Alabama Rivers. The Coosa and Tallapoosa Rivers were not included in the study, so secondary data are relied upon for describing recreation opportunities and use on these rivers.

The Alabama River receives the most boating recreation use in the ACT basin. Approximately 55 percent of river recreation, totaling over 186,000 visitor-days in 1995, occurred on the Alabama River. The Cahaba River received half the amount of recreation visitation as the Alabama River, with 91,000 visitor-days in 1995. The Etowah River received just over 55,000 visitor-days during the same period. Boat-based fishing and pleasure boating are the most popular activities on these three rivers. Swimming is also a favorite activity on the Cahaba River, with over 55 percent of visitors reported to have visited the area to swim. Swimming also occurs on the other rivers, but to a lesser degree.

The Corps estimated 1995 annual boating use on the Etowah, Cahaba, and Alabama Rivers to be 83,434 trips, translating to more than 333,000 visitor-days (see *Table 4-64*). Spring is the most popular season for river recreation on the Etowah River, with over 50 percent of recreation use. On the Cahaba and Alabama rivers, summer recreation use is slightly higher than spring use. Recreation use is lowest on all rivers in the winter and fall seasons.

TABLE 4-64
Annual Recreation Visitation Estimates for Rivers in the ACT Basin, 1995

Rivers	Total Trips	Total Visitor-Days	Winter (%)	Spring (%)	Summer (%)	Fall (%)
Etowah River (from Allatona Dam to Rome, GA)	14,410	55,866	12	53	33	2
Cahaba River (from its origin to the confluence with the Alabama River)	24,907	91,033	8	35	37	20
Alabama River (from Claiborne Dam to the confluence with the Tombigbee River)	44,117	186,422	10	31	40	19
Total	**83,434**	**333,321**				

Source: The estimates are based on a survey (Allen et al., 1997) that was adjusted based on the output of hydrologic modeling (see Corps recreation report in *Appendix F*).

Because of its close proximity to the cities of Birmingham, Gadsden, and Anniston, the Coosa River in Alabama hosts a variety of recreational uses, including fishing, canoeing and kayaking. Part of the Coosa River's popularity is due to the consistency of its flows in the dry summer months when the only other dependable summer run for local boaters is 5 or more hours away on the Ocoee River in Tennessee.

Table 4-65 provides activity participation levels for the Etowah, Cahaba, and Alabama rivers. On all three rivers, fishing by boat is the predominant activity, accounting for a majority of recreation use. Pleasure boating is the next highest activity use, but it is far less common than fishing. Scuba diving occurs on the Cahaba River with some frequency, accounting for 10 percent of activity use.

TABLE 4-65
Activity Participation on Project Rivers in the ACT Basin, 1995

Riverine Projects	Total Trips	Fishing: Shore (%)	Fishing: Boat (%)	Pleasure Boating (%)	Water Skiing (%)	Jet Skiing (%)	Scuba Diving (%)	Swimming (%)	Camping (%)	Picnicking (%)
Etowah River (from Allatona Dam to Rome, GA)	14,410	10	85	39	NDA	NDA	NDA	19	11	23
Cahaba River (from its origin to the confluence with the Alabama River)	24,907	13	92	60	2	NDA	10	52	17	31
Alabama River (from Claiborne Dam to the confluence with the Tombigbee River)	44,117	11	86	45	22	2	2	34	25	35

NDA No data available

Activities are not mutually exclusive; therefore, data will sum to more than 100 percent.

Source: The estimates are based on a survey (Allen et al., 1997) that was adjusted based on the output of hydrologic modeling (see Corps recreation report in *Appendix F*).

4.7.2.2 Environmental Consequences

The effect to recreation visitation (specifically to estimated number of boat trips) was evaluated for two alternatives: the no action alternative and the three alternative flow scenarios modeled for the action alternative (low flow, moderate flow, and high flow). The effects of the alternatives were evaluated by overall annual visitation as well as seasonally, recognizing that the spring and summer seasons represent the highest visitation to the reservoirs (accounting for 75 to 80 percent of the boat trips in the ACT basin).

These three scenarios are measured against the no action alternative. However, because of modeling constraints (see Section 4.4.1.2), comparing the action alternative flow scenarios to the no action alternative is difficult because the model excluded flood control, navigation, and hydropower operations with the complexity of the modeling. The effect of the modeling constraints is evident when comparing the range of the action alternative flow scenarios to the no action alternative. In most cases, the modeling predicts that the range of possible flow scenarios produce higher visitation than the no action alternative. This would not necessarily be the case. In some cases, the low, moderate, and high scenarios would experience lower elevations, and lower visitation, than the model predicts.

To compare the effect of alternative operating scenarios on reservoirs, the evaluation relied on the water level/recreation visitation value functions developed as part of the Comprehensive Study. In that study, recreation use data was obtained through a two-phase recreation survey administered to registered boat owners in the 101 counties located in the ACT and ACF basins. The Phase I survey collected information on boater recreational use at each of the ACT and ACF project sites during the 1995 recreation year. The Phase II survey was a contingent use survey that queried respondents on how their recreation use of one of six impact projects would change as the result of low water conditions. From this information, value functions were developed for each recreation project for each season. The water level/trip visitation value functions provided estimates of the number of recreation trips boaters would make at any specific pool level within a range of water levels.

All alternatives were evaluated for 1995, 2020, and 2050 water consumptive demands. Population forecasts that were used to determine the recreation demand for the years were obtained from the Comprehensive Study. The establishment of recreation demand forecasts were based on two assumptions. First, that demand for recreation is directly related to population, so changes in recreation demand correspond to changes in population. Second, that recreation use in each forecast year can be estimated by calculating the percent change in population from the baseline year to a given forecast year and then multiplying the baseline use estimates by the percent population change.

4.7.2.2.1 Reservoir Recreation

Because of modeling constraints (see Section 4.4.1.2), in some individual reservoir cases the modeling predicts that the range of possible flow scenarios produce higher visitation than the no action alternative. This would not necessarily be the case. In some cases, the low, moderate, and high scenarios would experience lower elevations, therefore lower visitation, than the model predicts because the model did not include specific operations for peaking, navigation, or flood control. Nonetheless, this analysis compares the action alternative flow scenarios to the no action alternative.

Examination of the results of the ACT recreation summary analysis *(Table 4-66)* shows that the action alternative flow scenarios all provide higher recreation visitation than the no action alternative. The pattern shows decreasing or equal positive impacts from the low to moderate conditions and increasing positive impacts from the moderate to high flow conditions.

TABLE 4-66
Recreation Trips (ACT Basin)

	No Action Alternative	Action Alternatives		
Year		High Flow Scenario	Moderate Flow Scenario	Low Flow Scenario
1995	2,011,076	2,231,722	2,127,730	2,160,501
2020	2,583,441	2,823,369	2,732,211	2,783,709
2050	3,285,048	3,663,273	3,486,809	3,551,984

These data include the following reservoirs: Carters Lake, Lake Allatoona, Weiss Lake, H. Neely Henry Lake, Logan Martin Lake, Lay Lake, Mitchell Lake, R.L. Harris Reservoir, Lake Martin, Yates and Thurlow Dams, and Alabama River Lakes.

The model predicts that reservoir levels would yield nearly 3.3 million recreation trips for 2050 throughout the ACF basin under the no action alternative. In comparison, the low and moderate flow scenarios would yield 3.6 million trips and 3.5 million trips, respectively (or 200,000 to 300,000 more recreation trips annually). The high flow scenario would yield 3.7 million trips in 2050 (or 400,000 more trips annually than under the no action alternative).

The low flow scenario emphasizes maximum water conservation, thus higher pool levels. Annual visitation with this scenario was slightly higher than the moderate flow scenario (which most closely approximates existing conditions), and was higher than the no action alternative.

Recreation trips under the high flow scenario were about 5 percent lower than under the moderate flow scenario, and 11 percent higher than under the no action alternative. Two factors resulted in visitation being higher under the high flow scenario than the no action alternative. The first factor, which resulted in lower lake levels, was the high downstream minimum flow target. The second factor was not including the seasonal drawdown for flood control in the modeling, which caused average annual lake levels to be higher than would be expected.

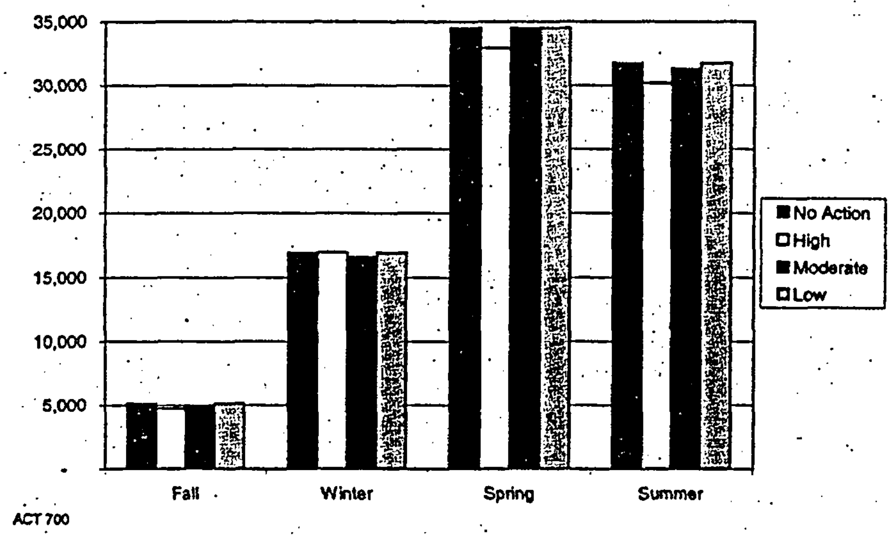
For run-of-the-river and river projects, there was no seasonal drawdown of the reservoirs. Therefore, as the minimum flow release was increased from the low to moderate to high scenarios, there were decreasing positive impacts as lake levels or flow decreased.

The following discussion describes impacts to individual reservoirs in year 2050. Note that Lay Lake, Mitchell Lake, Yates/Thurlow Dams, and the Alabama River Lakes were modeled as run-of-river projects. Therefore, the pool elevation at these projects will remain constant and a water allocation formula applied to the basin will not affect the pool elevation at these reservoirs. As a result, these projects were not included in determining direct impacts to recreation resulting from implementing a water allocation formula. The analysis compares the action flow alternative flow scenarios to the no action alternative. However, because the moderate flow scenario was modeled to be similar to current operations, this scenario was also used as a basis for comparing the different action alternative flow scenarios.

4.7.2.2.1.1 Carters Lake

Carters Lake receives minimal visitation in comparison to the other reservoirs. It is ranked 11th most visited of the 12 projects for which uniform data were available. The model data show that, in the year 2050, the action alternative flow scenarios provide less recreation visitation than the no action alternative in all seasons. *Figure 4-91* details seasonal information for the scenarios.

FIGURE 4-91
Carters Lake Comparison of Recreation Trips, 2050



4.7.2.2.1.2 Lake Allatoona

Lake Allatoona is the most visited reservoir in the ACT basin. Nearly 80 percent of the visitation occurs in the spring and summer seasons. The modeling predicts that the action alternative flow scenarios (low, moderate, and high scenarios) result in significantly higher recreation visitation in spring and summer seasons compared to the no action alternative. However, the modeling did not include specific operations for peaking, navigation, or flood control for the action alternative. Therefore, both reservoir levels and visitation may be overstated. In fall, all alternatives yield similar visitation. In winter, the high flow scenario would lead to higher reservoir elevations, and therefore, higher visitation than the other scenarios. *Figure 4-92* compares seasonal recreation visitation in 2050 for the alternative flow scenarios.

4.7.2.2.1.3 Weiss Lake

Weiss Lake is the fourth visited reservoir in the ACT basin. Like the other reservoirs, most visitation occurs in the spring and summer seasons. Recreation visitation would generally be consistent (within 5 percent) for all alternatives in the spring and summer seasons (see *Figure 4-93*). In the fall season, the modeling indicates that the action alternative flow scenarios would yield the highest number of recreation visits compared to the no action alternative. In winter, the high flow scenario would provide the highest visitation, followed by the no action alternative and the low and moderate flow scenarios.

FIGURE 4-92
Lake Allatoona Comparison of Recreation Trips, 2050

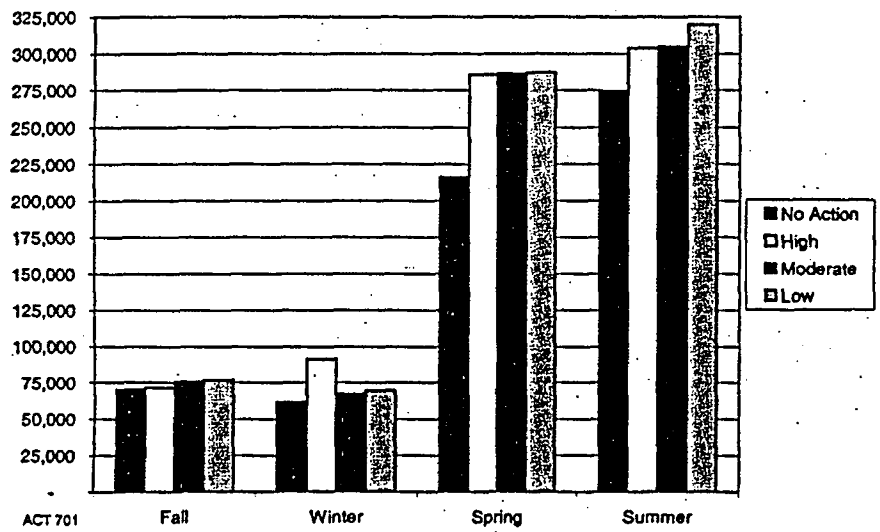
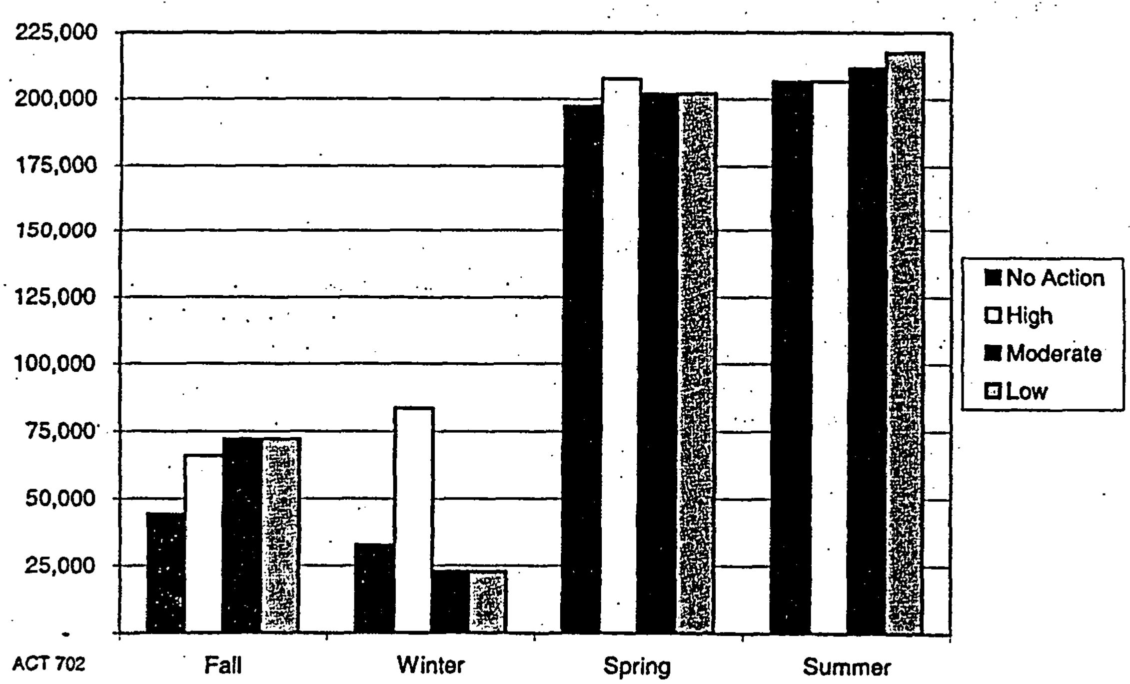


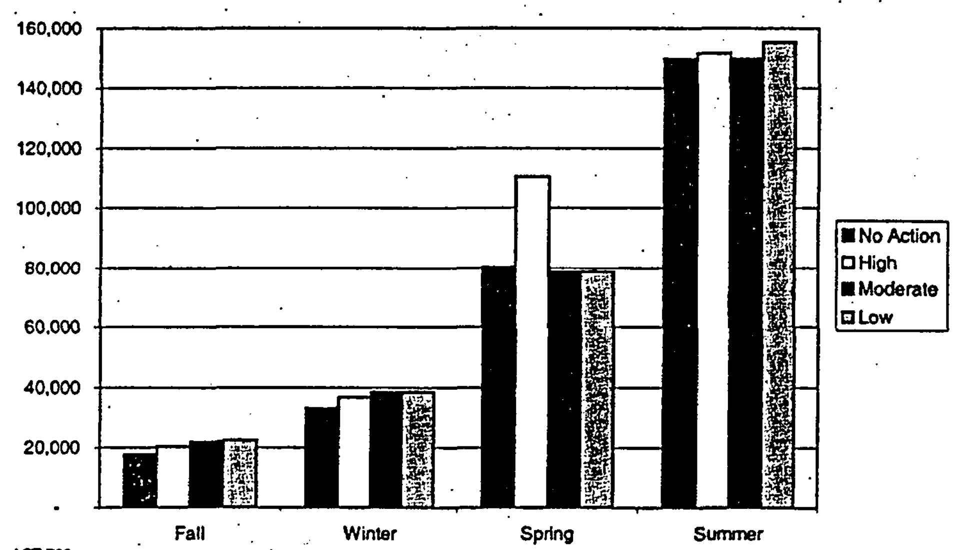
FIGURE 4-93
Weiss Lake Comparison of Recreation Trips, 2050



4.7.2.2.1.4 H. Neely Henry Lake

H. Neely Henry Lake is the fifth visited reservoir in the ACT basin (it receives less than half the annual visitation of Lake Allatoona). Most visitation occurs in the spring and summer seasons. Visitation would be relatively similar for all the alternatives during the summer, fall, and winter seasons. In spring, however, visitation would be similar for all alternatives except the high flow scenario. The high flow scenario would lead to greater reservoir elevations in winter, and therefore, higher visitation potential (see *Figure 4-94*).

FIGURE 4-94
H. Neely Henry Lake Comparison of Recreation Trips, 2050

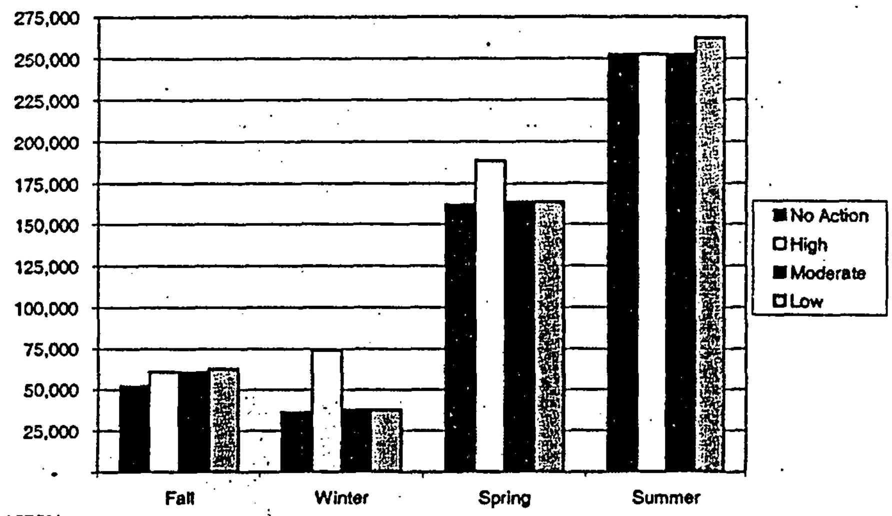


ACT 703

4.7.2.2.1.5 Logan Martin Lake

Logan Martin Lake is the third most visited reservoir in the ACT basin, with spring and summer being the most popular recreation seasons. Comparing the action alternative flow scenarios to the no action alternative in the winter and spring seasons, the low and moderate flow scenarios would produce similar recreation visitation to the no action alternative. The model predicts that the high flow scenario would provide higher reservoir levels, and therefore, higher visitation. For the summer season, the low flow scenario would produce higher visitation, compared to the no action and moderate and high flow scenarios. Visitation would be relatively constant for all alternatives for the fall season. *Figure 4-95* compares seasonal recreation visitation in 2050 for the alternatives.

FIGURE 4-95
Logan Martin Lake Comparison of Recreation Trips, 2050

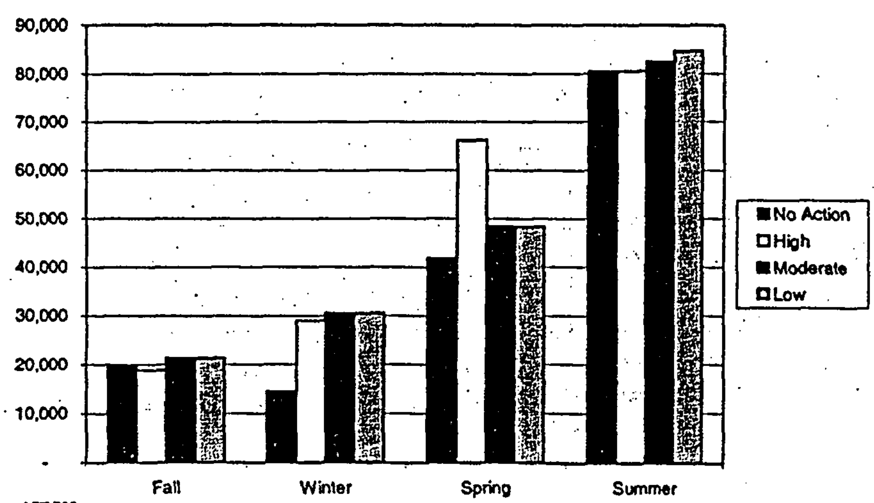


ACT 704

4.7.2.2.1.6 R.L. Harris Lake

R. L. Harris Lake is the eighth most visited of the 12 reservoirs in the ACT basin. Most visitation occurs in the spring and summer seasons. The modeling predicts that, in the winter and spring seasons, the no action alternative flow scenarios would yield more recreation visitation than the no action alternative. In spring, modeling indicates that the high flow scenario would result in 40 to 60 percent more recreation visitation than the other alternative scenarios. In the fall, visitation would be constant for all the alternatives. *Figure 4-96* compares seasonal recreation visitation in 2050 for the alternatives.

FIGURE 4-96
R.L. Harris Lake Comparison of Recreation Trips, 2050

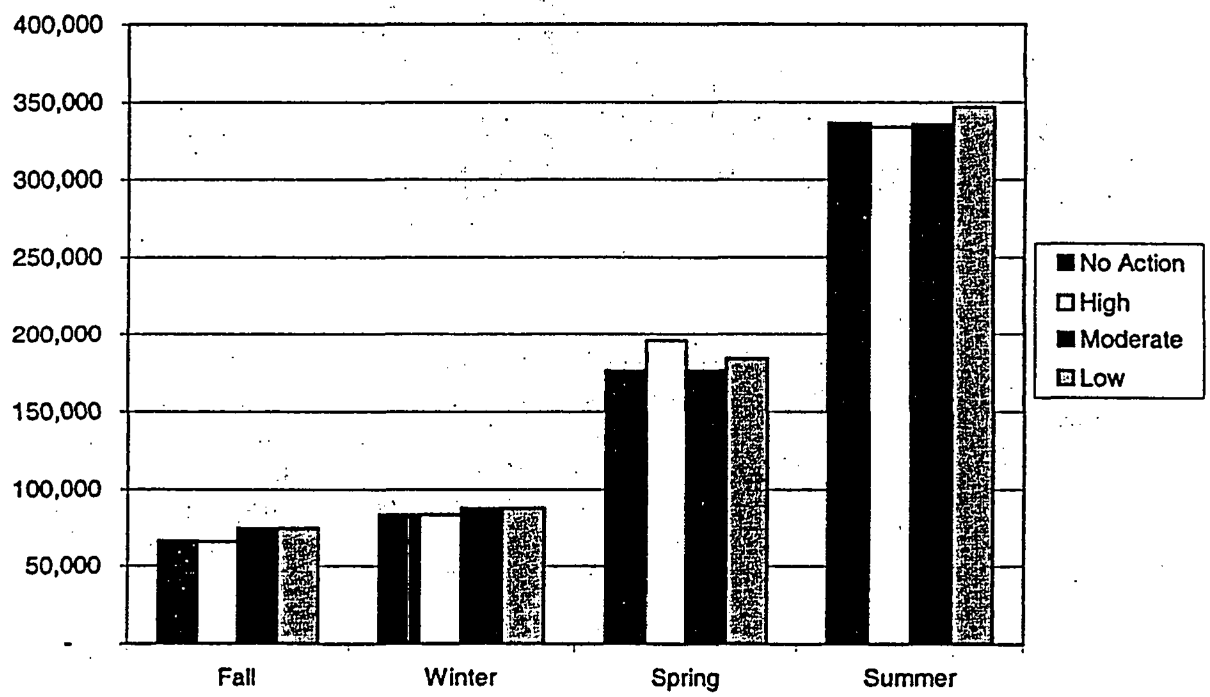


ACT 705

4.7.2.2.1.7 Lake Martin

Lake Martin is the second most visited reservoir in the ACT basin, and receives nearly as much visitation as Lake Allatoona. The model predicts that, for all seasons, there is no appreciable difference between the action alternative flow scenarios and the no action alternative for any of the seasons. *Figure 4-97* compares seasonal recreation visitation in 2050 for the alternatives.

FIGURE 4-97
Lake Martin Comparison of Recreation Trips, 2050



ACT 706

Overall in the ACT basin, the low flow scenario provides the most benefit for recreation. This scenario maintains stable reservoir levels, which enhance recreation in the summer, the most popular season. This, in turn, leads to increased recreation visitation over the no action scenario. In contrast, the high flow scenario provides consistent flows in the rivers, which often leads to reduced reservoir levels (depending on the season). Further, the lack of including several parameters within the modeling effort (e.g., specific operations for peaking, navigation, or flood control) makes it difficult to reconcile some of the data. For instance, at most of the reservoirs, the high flow scenario looks better in the winter months than it would actually be if the additional parameters were factored into the modeling. In some cases, the low, moderate, and high flow scenarios would experience lower elevations, and therefore, lower visitation, than the model predicts.

4.7.2.2.2 *Riverine Recreation*

The primary free flowing segments in the ACT basin are in the headwaters above Weiss Lake and on the Cahaba River. There would be no impacts or changes in the Cahaba because there are no regulated reservoirs on this river. The riverine sections above Weiss Lake could be impacted by changes to discharges at Allatoona and Carters Lakes. Impacts to riverine recreation resources in this area were assessed on the Coosa River at Rome, Georgia. This marks the beginning of the Coosa River, where the Etowah and Oostanaula Rivers join to form the Coosa River. Two hydropower dams and reservoirs are located in this subbasin: Allatoona Dam on the Etowah River, and the Carters Dam and Reregulation Dam on the Coosawattee River.

The low flow scenario would result in reduced riverine flows compared to the moderate flow scenario. Low summer flows would be about 40 percent lower. High summer flows would typically be 20 percent higher under the low flow scenario as compared to the moderate flow scenario. This is because the low flow scenario maintains water levels near the top of the conservation pool, so when rainfall occurs, the reservoirs have no excess storage and have to discharge flows, resulting in higher downstream flows.

The high flow scenario would enhance riverine recreation during low summer flow periods over the moderate flow scenario. Low summer flows would be 40 to 50 percent higher for the high flow scenario as compared to the moderate flow scenario.

4.7.3 Economics

The direct economic impacts of implementing a water allocation formula were evaluated by comparing the alternative flow conditions to the no action alternative. Modeling was completed by the Corps and focuses on the impacts to municipal and industrial water supply, recreation, and employment. Indirect economic impacts were determined using the Economic Impact Forecasting System (EIFS) model developed by the U.S. Army Construction Engineering Research Laboratory (CERL). For its input, the EIFS model uses the direct economic impacts as changes in spending (see Section 1.3.3.7 and *Appendix F* for a description of the economic modeling approach).

4.7.3.1 Affected Environment

This section describes the affected environment, or the baseline conditions, for the economic resources in the ACT basin. Municipal and industrial water demands, navigation, power generation, agriculture, recreation, and flood control are discussed.

4.7.3.1.1 Municipal and Industrial Water Demands

A critical function of the ACT rivers is to supply water. Municipalities draw water from the rivers and reservoir pools for their water supplies. Industrial plants, such as pulp and paper mills and poultry processing operations, use water in their production processes. Recreation-related businesses, such as country clubs, use water to irrigate golf courses. Various state and county parks use water for irrigation and water supply. In many ways, these water uses support local jobs and contribute to the economy. Section 4.4.2 summarizes the municipal and industrial water demands for 1995 developed for the Comprehensive Study.

4.7.3.1.2 Navigation

The Alabama River is an authorized navigation project located in southwest Alabama, stretching 289 miles from its confluence with the Mobile River to the City of Montgomery. There is an existing, authorized 9-foot by 200 foot navigation channel on the Alabama River from its junction with the Mobile River to Montgomery, Alabama, including three sets of locks and dams.

Alabama River traffic is almost entirely related to forest products and pulp (85 percent), and is dominated by just a few large cargo shippers. A more diverse traffic base would occur if the river served the heavy industries located above the present head of navigation at Montgomery, but that can only be realized by constructing the authorized Coosa River navigation improvements. Commercial traffic peaked in the mid 1980s at 4 million tons and then fell to the present level of less than 1 million tons. The decrease in commerce on the river since 1985 is probably attributable to competitive rates offered by other modes and the low reliability of the river during the mid 1980s drought. Although full navigation is not available for a relatively significant proportion of the time, the data reveal that there are few instances of sustained barge light-loading (which occurred during drought years). Virtually all tows are full-loaded to 8.5 or 9 feet. Flat deck sand and gravel barges are loaded to 7 feet (Institute of Water Resources, 1997).

Table 4-67 shows Alabama River waterborne commerce in 1995, as reported by the Waterborne Commerce Statistics Center, U.S. Army Corps of Engineers, New Orleans, Louisiana.

TABLE 4-67
Alabama River Waterborne Commerce

Commodity	1995 Projected Tonnage[a]
Non-metallic minerals	6,000
Forest products and pulp	676,000
Crude petroleum	57,000
Petroleum products	54,000
Total	**793,000**

[a] Rounded to the nearest thousand
Source: Institute of Water Resources, 1997

4.7.3.1.3 Power Generation

The ACT rivers are heavily developed for hydropower generation. The power resources serve residential, commercial, agricultural, and industrial users. Some of the agricultural and industrial users are dependent on economical power sources for continued operations.

The ACT basin's electrical power resource is dominated by thermal (steam) generation. Thermal resources are 77 percent of the basin's total—76 percent steam turbine and 1 percent combustion turbine. Hydropower and pumped storage accounts for the remaining 23 percent. Net annual energy demand for 1995 was estimated to be 32,486,368 megawatt hours (MWh). Alabama Power Company and Georgia Power Company produce 61 percent (1,102 megawatts [MW]) of the MW generated through hydropower and pumped storage; the remaining 39 percent is generated at federal projects. All energy produced by steam and combustion turbines in the ACT basin (6,019 MW) is generated at facilities owned by Alabama Power Company, Georgia Power Company, or Southern Electric Company. *Table 4-68* presents the main stem dams/reservoirs, the owner, and the total power capacity.

TABLE 4-68
Operative Mainstem Dams/Reservoirs in the ACT Basin

River/Project Name	Owner	Total Capacity (MW)[a,b]
Coosawattee River		
Carters Dam and Lake	Corps	575[b]
Etowah River		
Allatoona Dam and Lake	Corps	80[b]
Coosa River		
Weiss Dam and Lake	APCO	98[a]
H. Neely Henry Dam and Lake	APCO	98[a]
Logan Martin Dam and Lake	APCO	143[a]
Lay Dam and Lake	APCO	164[a]
Mitchell Dam and Lake	APCO	156[a]
Jordan Dam and Lake	APCO	116[a]
Bouldin Dam and Lake	APCO	226[a]

(CONTINUED)

TABLE 4-68 (CONTINUED)
Operative Main Stem Dams/Reservoirs in the ACT Basin

River/Project Name	Owner	Total Capacity (MW)[a,b]
Tallapoosa River		
Harris Dam and Lake	APCO	126[a]
Martin Dam and Lake	APCO	150[a]
Yates Dam and Lake	APCO	33[a]
Thurlow Dam and Lake	APCO	54[a]
Alabama River		
Robert F. Henry Lock and Dam/R.E. "Bob" Woodruff Lake	Corps	68[a]
Millers Ferry Lock and Dam/William "Bill" Dannelly Reservoir	Corps	75[a]
Total		2,143.6

[a] Overload capacity
[b] Nameplate capacity

APCO Alabama Power Company
Source: ***Appendix D***

The Southern Subregion of the Southeastern Electrical Reliability Council (SERC) and the larger North American Electric Reliability Council (NERC) consists of three control areas: i.e., areas controlled by the Alabama Electric Cooperative, the South Mississippi Electric Power Association, and the Southern Company. The Southern Company has five operating companies: Alabama Power Company, Georgia Power Company, Gulf Power Company, Mississippi Power Company, and Savannah Electric and Power Company.

SERC collects monthly peak hour demand data and net energy for the Southern Subregion. Each utility's peak hour demand and net energy were aggregated for each month. Then a summer and winter peak hour demand was identified by the month with the highest peak in each season. The net annual energy is the summation of the aggregated monthly net energies. Peak hour demand (MW) and net annual energy (MWh) for the Southern Subregion are presented in *Table 4-69* (Corps, unpublished draft).

TABLE 4-69
Peak Hour Demand (MH) and Net Annual Energy (MWh), Southern Subregion

Year	Gross National Product (1987 Dollars, in Billions)	Peak Hour Demand (MW)	Net Annual Energy (MWh)	Demand Change (Percent)	Energy Change (Percent)	Load Factor
1995	$ 5,354	35,098	180,234	2.58	0.35	0.59

4.7.3.1.4 Agricultural Water Supply

Agriculture is a vital component of the regional economy and, therefore, the availability of adequate water supplies for agricultural purposes is important. According to the U.S. Census, in 1990 approximately 40,500 people in Alabama were employed in the agriculture, forestry, or fisheries industries. Georgia had 73,647 residents employed in these industries in 1990. Potential shortages in meeting agricultural water demands could result in significant economic impacts in portions of the ACT basin. Section 4.4.2 summarizes the 1995 agricultural water demands for the basin.

4.7.3.1.5 Flood Control

Flood control has long been an important focus of the Corps and the reservoirs it operates. Within the ACT basin, Lake Allatoona provides important flood control storage, with spillway sufficient capacities sufficient to discharge floods with return intervals of 500 years. The 500-year floodplain below the dam extends through Bartow and Floyd Counties. The floodplain begins at the Lake Allatoona Dam and concludes on the Coosa River downstream of the Etowah River's confluence with the Oostanaula River. Additional flow control benefits are provided by Carters Lake and the Alabama Power projects during certain stages of plant operations but they are not included in these economic analyses.

The majority of the floodplain structures are located in the cities of Cartersville, Euharlee, and Rome, Georgia. The floodplain below the Lake Allatoona Dam consists of 1,132 residential structures, 9 public structures, and 189 commercial structures. Tax assessor-appraised residential structure values range from a $5,000 trailer to a $450,000 home, with a floodplain total residential structure value of $65.8 million. Residential structure content values are estimated to total $29.1 million. Public structures in the floodplain have a total value of $847,000. The structures range in value from a $35,000 utility building to a $150,000 sewage treatment facility. Public structure inventory and equipment values total $168,000 and $741,000, respectively. The floodplain tax-appraised commercial structure values range from a $10,000 office building to a $119 million industrial plant, with a floodplain total commercial value of $213.6 million. Commercial structure inventory and equipment values total $25 million and $54.3 million, respectively. The total land value in the floodplain is estimated to be $389.6 million.

The Water Management Office (EN-HW) of the Corps has developed an *Annual Damage Reduction Summary* that estimates the flood damages prevented by two projects in the ACT basin: Allatoona Lake and Carters Lake. The cumulative flood damages prevented by Allatoona Lake through 1996 were estimated to be approximately $15.1 million. It was estimated that the Carters Lake project prevented cumulative damages of $265,655 through 1996.

Other lakes in the basin, such as Weiss, H. Neely Henry, Logan Martin, and Harris, also provide flood control value, but this protection has not been calculated.

4.7.3.1.6 Fish and Wildlife Utilization

The total commercial fishery landings in Alabama in 1995 were approximately $49.6 million, or 6 percent of the $724.6 million generated in the Gulf of Mexico (Department of Commerce, 1996a). In 1995, commercial fishery landings at Bayou La Batre were valued at $37.5 million, or 76 percent of the total landings in the state. However, these landings values change substantially from year to year based on climatic conditions, normal changes in the fish and shellfish populations, and numbers and effectiveness of commercial fishermen. For example, the dollar landings value at Bayou La Batre was $24.3 million in 1993 and $37.5 million in 1995, then returned back to $28.6 million in 1996.

The most commercially important species included shrimp, menhaden, blue crab, snapper, grouper, and oysters (Department of Commerce, 1996b). Recreational fishing in the Gulf of

Mexico accounts for 25 percent of the total number of trips in the United States. The most commonly caught nonbait species were spotted seatrout, pinfish, saltwater catfish, and striped bass.

4.7.3.1.7 Recreation Economics

The Phase I survey, completed in conjunction with the Comprehensive Study (Allen et al., 1997) estimated spending at the 12 study projects in the ACT basin. Because the survey was restricted to registered boaters, per-trip spending estimates were probably higher than those for the entire population of recreation users. Other recreation studies have shown that boaters have higher per-trip expenditures and higher levels of discretionary spending than non-boaters.

Information gathered for the Phase I survey indicated that boat owners spent a total of $516.6 million dollars in 1995 during their trips to the projects in the ACT basins, with $240.3 million dollars contributed directly to the projects' local economies. These expenditures included such items as gas, meals, lodging, fees, and groceries, but did not include expenditures for boats. Two types of expenditures were reported: those made inside a 30-mile radius of the project (local) and those made outside a 30-mile radius.

Per-visit National Economic Development (NED) benefits were also developed. These benefits measure consumer surplus, or the difference between the maximum amount someone will pay for a resource and the actual price paid. Travel cost models, based on observed behavior, provided a means of estimating NED benefits. Travel cost analysis can be used to estimate a demand curve, which shows the relationship between price and quantity demanded. Since nearby visitors face a lower cost in travel-related expenses, they are expected to visit more frequently than those who live a greater distance. The relationship between visitation rates and the travel costs from different zones or areas are used to calculate consumer surplus, or NED benefits.

Table 4-70 presents local and total per-trip spending, total annual spending, per-trip NED benefits, and total annual NED benefits for the 12 study reservoirs in the ACT basin.

TABLE 4-70
Local and Total Per-Trip Spending, Total Annual Spending, Per-Trip National Economic Development (NED) Benefits, and Total Annual NED Benefits

Project	Total Trips	Local Spending Per Trip	Total Spending Per Trip	Total Annual Spending	NED Benefits Per Trip	Total Annual NED Benefits
Lake Martin	402,705	$190.80	$248.90	$100,233,275	$36.83	$14,831,625
Lake Allatoona	378,297	$22.50	$92.50	$34,992,473	$41.82	$15,820,381
Logan Martin Lake	309,041	$161.80	$414.40	$128,066,590	$26.03	$8,044,337
Weiss Lake	293,625	$103.90	$239.30	$70,264,463	$35.58	$10,447,178
H. Neely Henry Lake	170,431	$37.00	$168.80	$28,768,753	$31.65	$5,394,141
Jordan Lake	160,906	$63.40	$121.10	$19,485,716	$12.24	$1,969,489
R.L. Harris Reservoir	96,989	$68.60	$156.50	$15,178,779	$37.44	$3,631,268

(CONTINUED)

TABLE 4-70 (CONTINUED)
Local and Total Per-Trip Spending, Total Annual Spending, Per-Trip National Economic Development (NED) Benefits, and Total Annual NED Benefits

Project	Total Trips	Local Spending Per Trip	Total Spending Per Trip	Total Annual Spending	NED Benefits Per Trip	Total Annual NED Benefits
Lay Lake	149,997	$25.50	$58.60	$8,789,824	$35.65	$5,346,680
Carters Lake	53,598	$35.80	$100.80	$5,402,678	$44.44	$2,381,895
Mitchell Lake	63,658	$69.50	$328.60	$20,918,019	$34.28	$2,182,196
Yates and Thurlow Dam	13,533	$11.70	$101.50	$1,373,600	$15.75	$213,145
Alabama River Lakes	131,164	$64.80	$102.80	$13,483,659	$23.88	$2,400,685
Total	**2,223,944**			**$446,957,829**		**$72,663,020**

Alabama River Lakes include Woodruff Lake, Dannelly Lake, and Claiborne Lake.

The accuracy of the per-trip expenditures vary with the number of responses received per recreation area and the ability of the respondent to correctly remember and report expenses for an average trip.

Source: Perr, 1997

Total annual spending within the local economy was highest at Lake Martin ($89.6 million), with Lake Logan Martin having the highest total annual spending ($149.9 million). Average trip expenditures were highest for Lake Logan Martin at $414.40 per trip. The NED benefit per trip was highest at Carters Lake ($16.46); the total annual NED benefit was highest at Lake Allatoona ($6.9 million).

4.7.3.1.8 Income

According to projections prepared for the Comprehensive Study, total personal income in the 42-county ACT basin was nearly $50.7 billion in 1995, almost double the 1985 total personal income of $26.7 billion (*Table 4-71*). Personal income includes both wage (labor) and non-wage income, such as dividends and interest and transfer payments.

TABLE 4-71
Total Personal Income in the ACT Basin

	1985	1995 (estimated)
Alabama portion of basin	$20,254,000,000	$37,902,000,000
Georgia portion of basin	$6,460,000,000	$12,776,000,000
ACT basin	$26,714,000,000	$50,678,000,000

Source: DRI/McGraw-Hill, 1996

Per capita personal income is the total personal income in an area, divided by the number of people living there. A comparison of real per capita income (in 1987 dollars, to adjust for inflation) in the ACT basin shows steady growth, at an average of 2.3 percent annually from 1975 to 1985 and 1.7 percent annually from 1985 to 1995 (*Table 4-72*).

Real per capita income in the Alabama portion of the ACT basin is somewhat higher than in the Georgia portion, which is similar to the State of Alabama as a whole. As in the surrounding State of Georgia, growth in real per capita income in the Georgia portion of the

ACT basin slowed considerably between 1985 and 1995 (1 percent annual average), compared to 3 percent annual growth between 1975 and 1985 (*Table 4-72*).

In current dollars, 1995 per capita income was estimated to be $19,067 in the ACT basin, $19,407 in the Alabama portion of the basin, and $18,122 in the Georgia portion of the basin.

TABLE 4-72
Real Per Capita Income Trends in the ACT Basin[a]

	1975	Annual Average 1975-1985 (%)	1985	Annual Average 1985-1995 (%)	1995[b]
Alabama portion of basin	$10,085	2.1	$12,177	1.9	$14,447
Georgia portion of basin	$9,392	3.0	$12,175	1.1	$13,489
ACT basin	$9,933	2.3	$12,176	1.7	$14,193
Alabama	$9,518	2.3	$11,706	2.0	$13,997
Georgia	$10,428	3.2	$13,717	1.5	$15,730

[a] To adjust for inflation in annual comparisons, all dollar values are adjusted to 1987 equivalents
[b] Estimated
Source: DRI/McGraw-Hill, 1996

4.7.3.1.9 Employment

Employment levels in the ACT basin, which contains or borders on several growing metropolitan areas (including Atlanta, Birmingham, Montgomery, and Mobile), have been slowly but steadily increasing. Between 1985 and 1995, the number of jobs grew at an annual rate of 2.4 percent, comparable to the 2.2 percent annual growth between 1975 and 1985 (*Table 4-73*). The growth rate in both portions is similar to that of the State of Alabama but less than the State of Georgia, which grew nearly 5 percent per year between 1975 and 1985, before slowing to 2.5 percent between 1985 to 1995.

For 1995, total employment in the ACT basin was estimated at 722,695, of which 77 percent was in the Alabama portion of the basin and 23 percent in the Georgia portion.

TABLE 4-73
Employment Trends in the ACT Basin[a]

	Alabama Portion of Basin	Georgia Portion of Basin	ACT Basin	Alabama	Georgia
1975 employment	557,801	164,894	722,695	1,155,445	1,755,674
Annual average growth 1975-1985	2.1%	2.2%	2.2%	2.4%	4.6%
1985 employment	676,749	201,838	878,587	1,427,114	2,569,502
Annual average growth 1985-1995	2.3%	2.6%	2.4%	2.3%	2.5%
1995 employment[a]	835,751	253,428	1,089,179	1,762,052	3,213,460

[a] Total nonfarm employment
Source: DRI/McGraw-Hill, 1996

More than 80 percent of all jobs in the ACT basin are provided by the private sector, i.e., non-farm employers (*Table 4-74*). The primary sources of employment are manufacturing, trade, and services, each of which employed an estimated 22 percent of non-farm workers in 1995. The Georgia portion of the ACT basin is much more dependent on manufacturing (37.4 percent), particularly the textiles industry, than the Alabama portion (about 18 percent), while the Alabama portion relies more on service jobs (24 percent) than the Georgia portion (15.5 percent). The manufacturing sector has been shrinking in the ACT basin, having fallen from 31 percent of non-farm jobs in 1975 to 27 percent in 1985 to 22 percent in 1995.

TABLE 4-74
Estimated Nonfarm Employment by Industry in the ACT Basin in 1995

	Alabama Portion of Basin		Georgia Portion of Basin		ACT Basin	
	Number	Percent	Number	Percent	Number	Percent
Total Nonfarm Employment	835,751	100	253,428	100	1,089,179	100
Mining	3,409	0.4	513	0.2	3,922	0.4
Construction	44,099	5.3	11,333	4.5	55,432	5.1
Manufacturing	148,496	17.8	94,838	37.4	243,334	22.3
Transportation and public utilities	47,381	5.7	9,949	3.9	57,330	5.3
Wholesale and retail trade	192,436	23.0	52,203	20.6	244,639	22.5
Finance, insurance, and real estate	45,825	5.5	7,639	3.0	53,464	4.9
Services	201,197	24.1	39,397	15.5	240,594	22.1
Private Sector Subtotal	682,843	81.7	215,872	85.2	898,715	82.5
Government	152,908	18.3	37,556	14.8	190,464	17.5

Source: DRI/McGraw-Hill, 1996

4.7.3.2 Environmental Consequences

4.7.3.2.1 Municipal and Industrial Water Supply

No significant municipal and industrial economic impacts to water supply were identified. Results of the hydrologic modeling and the risk-based analysis of water supply shortages show that there were only small, seasonal shortages expected to occur for all of the action alternatives.

The low flow scenario has a relatively minor negative impact across the basin, with an Average Annual Equivalent adverse impact of approximately $1.3 million. The moderate flow scenario is expected to result in a $78,000 adverse impact. The high flow scenario is expected to result in a positive impact of approximately $2.35 million. See *Appendix F*, Tables F-11-1 and F-11-2, for additional details.

4.7.3.2.2 Navigation

The evaluation of navigation impacts was completed by the Corps and summarized in a separate report (*Appendix F*). The following section summarizes of this analysis.

Results of the HEC-5 modeling described in Section 4.4 were used to determine the percent of time depth would be available for navigation. Availability of four navigation depths, including 9 feet (full navigation), 8.5 feet, 8.0 feet and 7.5 feet, were determined for the alternative scenarios of high, moderate, and low flow, respectively. These statistics are provided for each month to address the seasonal trends that occur during the yearly wet and dry periods.

The annual commodity forecasts were also determined and seasonally apportioned by month on the basis of past patterns, as extracted from the Lock Performance Monitoring System records (Corps' National Inland Waterways Lock Statistics database). Annual commodity forecasts from the Navigation Element of the Comprehensive Study are summarized in *Table 4-75* for the years 1995, 2020, and 2050. To evaluate cost impacts associated with lack of available river depth, transportation costs for each commodity were developed on the assumption that commodities that could not be shipped by water because of inadequate navigation depths would have to be shipped by other methods (*Appendix F*). These transportation costs were estimated for each year in the HEC-5 period of record (1939 to 1993) and converted to an annual average value. This approach was used to determine average yearly transportation costs for the no action and action alternative scenarios (*Table 4-76*).

TABLE 4-75
Commodity Forecasts, Short Tons

	Farm Products	Non-Metallic	Forest Products	Industrial Chemicals	Petroleum Products	Commodity Total
1995	333	541,667	732,133	3,067	38,267	1,369,267
2020	498	629,726	919,680	5,450	54,820	1,664,905
2050	809	700,512	1,431,470	10,220	88,086	2,290,075

Source: Comprehensive Study, Navigation Element

TABLE 4-76
Average Yearly Transportation Costs

Year	No Action	High Flow	Moderate Flow	Low Flow
1995	$3,122,147	$3,372,879	$3,216,086	$3,214,577
2020	$3,924,926	$4,157,320	$3,976,204	$3,971,967
2050	$5,470,470	$5,938,605	$5,668,781	$5,664,456

The annual direct impacts on navigation were estimated by determining the difference between the no action and action alternative average annual shipping costs (*Table 4-77*). Direct navigation impacts were assessed to be distributed to the States of Alabama and Georgia based on the number of counties serviced by the waterway in each state. This distribution was used in the analysis of impacts on employment and income. Results of this analysis indicate that the economic impacts associated with the alternatives are small compared to the total transportation costs. Impacts ranged from 1.2 percent ($47,041) in transportation costs for the no action alternative under the low flow scenario in 2020 to 8.6 percent ($468,135) in the high flow 2050 flow scenario.

TABLE 4-77
Direct Impacts on Navigation

	High Flow	Moderate Flow	Low Flow
1995	($250,732)	($93,939)	($92,430)
2020	($232,394)	($51,278)	($47,041)
2050	($468,135)	($198,311)	($193,986)
Average annual	($256,916)	($78,840)	($75,669)

4.7.3.2.3 Power Generation

The power values associated with the ACT-ACF hydropower projects were based on the detailed analysis of two separate years. Because the benefit analysis was based on hourly data, it was not practical to run simulations for all 55 years of historic data. The analysis assumes that the water conditions in 1992 represent an "average" year, and energy generation in this year is assumed to represent the average annual condition.

Tables 4-78, 4-79, and *4-80* present the overall direct impacts in the ACT basin for all hydropower projects. Average annual direct impacts were ($6,597,693), ($2,394,817), and ($2,163,940) for the high, moderate, and low flow scenarios, respectively. These impacts are assumed to occur proportionately across the states of Alabama and Georgia with ($3,298,847) for high flow, ($1,197,409) for moderate flow, and ($1,081,970) for low flow impacts. This assumption is supported by the fact that the power goes to the marketing agency that primarily serves preference customers in both states for all the projects, whether in Alabama or Georgia.

TABLE 4-78
ACT Average Annual Hydropower Energy Production (MWh)

	No Action	High Flow	Moderate Flow	Low Flow
1995	5,494,066	5,256,896	5,409,637	5,421,095
2020	5,457,753	5,231,137	5,374,809	5,381,134
2050	5,410,430	5,196,759	5,328,994	5,331,240

TABLE 4-79
ACT Average Annual Hydropower Energy Gain (MWh)

	High Flow	Moderate Flow	Low Flow
1995	-237,169	-84,428	-72,971
2020	-226,616	-82,944	-76,619
2050	-213,672	-81,437	-79,190

TABLE 4-80
ACT Average Annual Hydropower Energy Direct Impacts (1998$)

	High Flow	Moderate Flow	Low Flow
1995	($6,808,922)	($2,423,866)	($2,094,925)
2020	($6,505,951)	($2,381,253)	($2,199,676)
2050	($6,134,329)	($2,337,980)	($2,273,484)
Average annual	($6,597,693)	($2,394,817)	($2,163,940)

In addition to the economic effects that are included in these estimates, additional impacts could be seen in capacity shortage to the Federal Power Program, which markets power from Corps projects to the southeastern states. These shortages, while undefined at this time, have the potential to require the Federal government to buy additional capacity to meet contractual obligations to its customers, primarily public bodies and cooperatives.

The above impacts to energy generated in the basin do not capture all of the potential impacts (e.g., capacity issues) to power generation. For example, a signification portion of the revenue collected by the Federal Government through the Federal Power Program is capacity based. Capacity reductions can occur as a result of lower flows. While flows may be available for thermal generation, a plant's intake may not function because of its elevation during unusually low flow periods. Since steam plants are an integral part of the electrical system in the Southeast, the stability of the electrical system could become an issue if low flows caused any one or more of these plants to shut down. Further, transmission restraints may prevent additional energy from simply being purchased from off-system. *Appendix F*, Section 4, presents additional information on impacts on power generation that are expected to result under the action alternative flow scenarios, along with information on the limitations of the modeling.

4.7.3.2.4 Agricultural Water Supply

The evaluation of potential economic affects on the agricultural water supply was completed by NRCS based on the studies completed by NRSC during the Comprehensive Study and a review of potential water supply shortages developed by the Corps (Section 4.4.2.3). Any water supply shortages identified for agriculture were to be used to estimate potential economic impacts based on crop damage data developed during the Comprehensive Study. The methodology to estimate crop damage was designed to identify the loss of yield and associated income with decreasing availability of irrigation water during key plant growth stages for major crops in the basin. *Appendix F* includes the agricultural impact report prepared by the NRCS and the Municipal and Industrial Water Supply report developed by the Corps, which provides detailed descriptions of the methodology used to assess agricultural water supply impacts.

Under all alternative scenarios (no action and action alternatives), no impacts from water supply shortages were identified for agricultural irrigation needs. The HEC-5 model used to develop the water supply shortage estimates focuses on water withdrawn from the primary rivers in the ACT basin. Because the majority of all agricultural water supply used in the ACT basin is supplied by groundwater, shortages in meeting agricultural water supply needs would not be expected. Consequently, the limited amount of surface water used for agricultural purposes in the ACT basin are met under all the alternatives. No significant impacts on agricultural production or income are expected under any of the alternatives, and, therefore, no economic effects would occur.

4.7.3.2.5 Flood Control

Both the no action and the action alternative flow scenarios hold permanent flood control storage allocations constant. Since the alternatives all preserve the permanent flood control allocations, flood control impacts are zero for the action alternatives, when compared to the no action alternative.

By examining the impacts (damages) that would arise from eliminating this storage, an estimate of the value the existing allocations provide can be calculated. For the ACT basin, the impacts of eliminating permanent flood control storage at Allatoona Lake were examined. The total average annual impact of decreasing the existing storage allocation to zero is estimated to be ($4,833,640) and depends on the extent of flood flows in the period under review. These impacts represent damages that would occur to property located in the floodplain downstream of Allatoona Dam.

Allatoona Lake is currently operated with a seasonal (winter) drawdown. The high flow alternative assumes that this drawdown is eliminated. No evaluation of the impacts associated with this operating approach has been performed.

Additional detail of the Economic Analysis Section's broad-brush analysis of flood control impacts is included in *Appendix* F.

4.7.3.2.6 Fish and Wildlife Utilization

The economic benefits of fisheries and wildlife uses in the basin show wide-ranging fluctuations that follow natural events related to predation, climate, land use changes, and natural resource management in the region. No detailed economic analysis has been completed for the range of species that might be affected under either the no action or action alternative flow scenarios. However, as discussed in the previous Biological Resources sections, action alternative flow scenarios that reduce available habitat area or use for these resources may be expected to include parallel impacts on the economic attributes of these species. Thus, the low flow scenario would afford positive economic benefits to recreational use of reservoir fisheries but would have a negative impact on benefits that might be provided for downstream fisheries, such as trout fishing. Conversely, the high flow scenario would be expected to have a negative economic impact on recreational fishing in reservoirs.

The impacts of these alternatives on the commercial and recreational fish and shellfish uses of Mobile Bay have not been specifically evaluated for this programmatic EIS. Effects on some species may result from changes that reduce nutrients and increase loss from predators, and such effects may have a negative economic effect on these resources.

4.7.3.2.7 Recreation Economics

The following section discusses the development of the direct economic impacts for ACT projects. It should be noted, however, that Lay Lake, Mitchell Lake, Yates/Thurlow Dams, and Lake Claiborne (Alabama River Lakes) were modeled in the HEC-5 program as run-of-river projects. Therefore, the pool elevation at these projects will remain constant and a water allocation formula applied to the basin will not affect the pool elevation at these reservoirs. As a result, these projects were not included in the determination of direct economic impacts to NRCSrecreation resulting from the implementation of a water allocation formula.

Examination of the results of the ACT recreation summary analysis (*Table 4-81*) shows that the action alternative flow scenarios all have higher economic benefits than the no action alternative flow scenario. The pattern shows generally decreasing or equal positive impacts from the low to moderate conditions, and increasing positive impacts from the moderate to high flow conditions.

The low flow scenario emphasizes maximum water conservation, thus higher pool levels. Average annual benefits under this scenario were higher than the no action alternative, and slightly higher than the moderate flow scenario, which most closely approximates existing conditions.

TABLE 4-81
Recreation Economic Impacts, ACT Basin

		Action Alternative		
	No Action Alternative	High Flow Scenario	Moderate Flow Scenario	Low Flow Scenario
Year	Recreation Value ($)	Recreation Value ($)	Recreation Value ($)	Recreation Value ($)
1995	71,820,885	80,255,001	76,670,407	77,889,885
2020	92,495,331	102,140,797	98,692,684	100,649,961
2050	117,892,257	132,280,186	126,168,031	128,660,557

Source: Corps recreation report in ***Appendix F***

Recreation benefits under the high flow scenario were about 5 percent higher than the moderate flow scenario. This occurred for two reasons. The first, which resulted in lower lake levels, was the high downstream minimum flow target, which was included in the modeling. The second factor was not including the seasonal drawdown for flood control in the modeling. This caused winter reservoir levels in reservoirs, and therefore, visitation to be much higher than under the other scenarios or no action alternative. The high flow scenario is artificially high as a result of the modeling assumptions.

For run-of-the-river and river projects, there was no seasonal drawdown of the reservoirs. Therefore, as the minimum flow release was increased from the low to moderate to high scenarios, there were decreasing positive impacts as lake levels or flow decreased.

A summary of the direct economic impacts to the ACT basin by state is displayed in *Table 4-82.*

TABLE 4-82
Impact Summary Annual Average, ACT Basin

State	Low ($)	Moderate($)	High ($)
Alabama	2,774,066	1,764,403	4,468,881
Georgia	4,753,092	4,056,050	5,048,995.
Total	**7,527,158**	**5,820,453**	**9,517,876**

Source: Corps recreation report in ***Appendix F***

4.7.3.2.8 Income

This section presents the future baseline conditions for income in the ACT basin and addresses the anticipated indirect impacts on income associated with the water allocation scenarios. Information presented in this section is summarized from economic reports prepared by the Corps (*Appendix F*).

By 2020, according to projections for the Comprehensive Study, personal income in the ACT basin is expected to total $195,927,000. By 2050, personal income is projected to total $838,949,000.

As *Table 4-83* shows, the Comprehensive Study projects slower growth in real per capita income in the future. Real per capita income is expected to increase by 1.1 percent from 1995 to 2020, and by only 0.7 percent between 2020 and 2050, discounting inflation. The Georgia portion of the basin is expected to experience this slowdown earlier than the Alabama portion. Factors contributing to this expectation of weak economic growth include a loss of manufacturing jobs and an increase in the number of elderly residents, while the share of working age population in the area declines.

TABLE 4-83
Projected Real Per Capita Personal Income in the ACT Basin[a]

	1995[b]	Annual Average 1995-2020	2020	Annual Average 2020-2050	2050
Alabama portion of basin	$14,447	1.2%	$18,757	0.7%	$21,988
Georgia portion of basin	$13,489	0.9%	$16,580	0.6%	$19,100
ACT basin	$14,193	1.1%	$18,206	0.7%	$21,276

[a] To adjust for inflation in annual comparisons, all dollar values are adjusted to 1987 equivalents.
[B] Estimated values
Source: *Regional Economic Forecast of Population and Employment*

To estimate regional economic impacts, direct changes in income are conveyed to a regional economic impact model, called the Economic Impact Forecasting System (EIFS). This model estimates regional economic impacts for the study area, as well as sub-areas within the study area. Four factors are examined as the primary indicators of socioeconomic change: business volume, employment, personal income, and population (population impacts are discussed in Section 4.7.1).

The model also provides rational threshold values (RTVs), which are used to assess the level of significance of regional economic impacts that may be identified. The RTVs provide a basis for comparing the impacts of an action to the historical fluctuations in a particular area. The RTV analysis uses the fluctuations of the four indicator variables from the average growth rates within the affected area, over time, to set boundaries (threshold values) that can be used assess the magnitude of an action's impacts. These boundaries determine the amount of change required to significantly affect an individual area. If the changes predicted by the EIFS forecast models fall outside these boundaries, the changes may affect the economy of the region significantly. Additional information about the EIFS model and the RTV method is provided in *Appendix F*.

The total direct economic impact for the ACT basin when comparing the no action alternative (no impact) to the low flow scenario is an increase of $4,003,000 (annual average). Total direct economic impact when comparing the no action alternative to the moderate flow scenario is an annual increase of $3,269,000 (annual average). Total direct economic impact when comparing the no action alternative to the high flow scenario is an annual increase of $5,017,000 (annual average). The direct economic impact values, by economic use, for the basin and states, are displayed in *Table 4-84*.

TABLE 4-84
Direct Economic Impacts by State and ACT Basin

Economic Use	ACT Basin Total	Alabama Total	Georgia Total
Low Flow Scenario			
Recreation	$7,527,000	$2,774,000	$4,753,000
M & I water supply	($1,284,000)	$1,214,000	($71,000)
Inland navigation	($76,000)	($76,000)	$0
Electric power	($2,164,000)	($1,082,000)	($1,082,000)
Agricultural water supply	$0	$0	$0
Total Direct Impacts	**$4,003,000**	**$402,000**	**$3,600,000**
Moderate Flow Scenario			
Recreation	$5,821,000	$1,764,000	$4,056,000
M & I water supply	($78,000)	($386,000)	$308,000
Inland navigation	($79,000)	($79,000)	$0
Electric power	($2,395,000)	($1,197,000)	($1,197,000)
Agricultural water supply	$0	$0	$0
Total Direct Impacts	**$3,269,000**	**$102,000**	**$3,167,000**
High Flow Scenario			
Recreation	$9,518,000	$4,469,000	$5,049,000
M & I water supply	$2,354,000	$1,325,000	$1,209,000
Inland navigation	($257,000)	($257,000)	$0
Electric power	($6,598,000)	($3,299,000)	($3,299,000)
Agricultural water supply	$0	$0	$0
Total Direct Impacts	**$5,017,000**	**$2,238,000**	**$2,779,000**

All dollar values used in the EIFS model are adjusted to 1987 equivalents; however, values presented in this table are stated at a 1998 price level.
M & I Municipal and industrial

The regional or indirect impacts on personal income and business volume associated with the low, moderate, and high flow scenarios for the ACT basin and individual states are displayed in *Table 4-85.* The RTVs for the basin and states are presented for comparison. Little or no impacts on the regional economies of the affected areas were identified for the scenarios. Also, none of the impacts approached the RTV levels for the ACT basin or the states of Alabama or Georgia.

According to the EIFS model, the low flow scenario, when compared to the no action alternative, would cause personal income to increase by $1.7 million annually within the ACT basin, compared to the total personal income of $50.7 billion in 1995 in the basin. This represents an annual change of only 0.003 percent. The total indirect impact on business volume is $13.3 million or 0.017 percent. The indirect impact on personal income and business volume is slightly higher in Alabama than in Georgia, but none of the state and basin impacts are significant when compared to the RTVs.

TABLE 4-85
Regional Economic Impacts on Personal Income and Business Volume by State and Basin

Category	Annual Change	Percent Change	RTV Required for Significance (%)	Significance of Impact
Low Flow Scenario				
ACT Basin				
Business volume	$13,268,000	0.017	7.497	No
Personal income	$1,738,000	0.003	6.683	No
ACT Basin – State of Alabama				
Business volume	$1,361,000	0.002	6.853	No
Personal income	$183,000	0.000	5.828	No
ACT Basin – State of Georgia				
Business volume	$8,223,000	0.042	10.216	No
Personal income	$940,000	0.007	9.686	No
Moderate Flow Scenario				
ACT Basin				
Business volume	$10,835,000	0.014	7.497	No
Personal income	$1,418,000	0.003	6.683	No
ACT Basin – State of Alabama				
Business volume	$345,000	0.001	6.853	No
Personal income	$47,000	0.000	5.828	No
ACT Basin – State of Georgia				
Business volume	$7,233,000	0.037	10.216	No
Personal income	$826,000	0.006	9.686	No
High Flow Scenario				
ACT Basin				
Business volume	$16,628,000	0.021	7.497	No
Personal income	$2,177,000	0.004	6.683	No
ACT Basin – State of Alabama				
Business volume	$7,555,000	0.013	6.853	No
Personal income	$1,014,000	0.002	5.828	No
ACT Basin – State of Georgia				
Business volume	$6,347,000	0.033	10.216	No
Personal income	$725,000	0.006	9.686	No

The moderate flow scenario, when compared to the no action alternative, would cause personal income to increase by $1.4 million annually within the ACT basin. This represents an annual change of only 0.003 percent for the basin. Business volume in the ACT basin would increase by $10.8 million. At the state level, the impact is distributed evenly between Georgia and Alabama.

The high flow scenario, when compared to the no action alternative, would cause personal income to increase by $2.1 million annually within the ACT basin. This represents an annual change of only 0.004 percent for the basin. This increase in personal income is higher in

Alabama than in Georgia. None of the state and basin impacts are significant when compared to the RTVs.

4.7.3.3 Employment

This section presents the future conditions for employment in the ACF basin and presents the expected indirect impacts to employment associated with the water allocation scenarios. Information presented in this section is summarized from economic reports prepared by the Corps (*Appendix F*).

Dependence on the manufacturing industry, especially textiles, is expected to restrain employment growth in the ACT basin in the future. According to the Comprehensive Study, the migration of local firms abroad and increasing international competition will cause manufacturing employment to decline at an annual rate of 1.6 percent between 1990 and 2050. Manufacturing is forecasted as providing only 6.4 percent of nonfarm employment in the ACT basin by 2050.

As a result, overall job growth in the ACT basin is expected to slow considerably to an annual average of 0.7 percent between 1995 and 2050 (*Table 4-86*). Forecasts show only minimal job growth (0.1 percent annually) in the Georgia portion of the basin, while the Alabama portion would fare better, at 0.8 percent annual growth, but still much slower than the steady 2-percent growth trend of the 1975 to 1995 period.

TABLE 4-86
Projected Nonfarm Employment in the ACT Basin

	Alabama Portion of Basin	Georgia Portion of Basin	ACT Basin
1995 employment[a]	835,751	253,428	1,089,179
2020 employment[b]	1,036,075	260,553	1,296,628
2050 employment[c]	1,222,516	274,138	1,496,654
Annual average growth 1995-2020	**0.8%**	**0.1%**	**0.7%**

[a] Estimated values
[b] Forecasted values
Source: *DRI-McGraw Hill, 1996*

According to the EIFS model, the low flow scenario, when compared to the no action alternative, would cause employment to increase by an annual total of 69 jobs (0.006 percent) in the ACT basin. When compared to a baseline of nearly 1.1 million non-farm jobs in 1995; to the (annual average) employment growth of 0.7 percent projected to occur between 1995 and 2050; and to the calculated RTVs, which represent typical historic fluctuations in employment for the ACT basin, this represents little or no impact on regional employment.

The moderate flow scenario, when compared to the no action alternative, would cause employment to increase only minimally, by an annual total of 56 jobs (0.005 percent) in the ACT basin (*Table 4-87*). This represents little or no impact on regional and state employment.

TABLE 4-87
Regional Economic Impacts: State and Basin Results

Category	Annual Change	Percent Change	RTV Required for Significance (%)	Significance of Impact
Low Flow Scenario				
ACT Basin				
Employment	69	0.006	2.272	No
ACT Basin – State of Alabama				
Employment	7	0.001	1.895	No
ACT Basin – State of Georgia				
Employment	41	0.016	3.911	No
Moderate Flow Scenario				
ACT Basin				
Employment	56	0.014	2.272	No
ACT Basin – State of Alabama				
Employment	2	0.000	1.895	No
ACT Basin – State of Georgia				
Employment	36	0.014	3.911	No
High Flow Scenario				
ACT Basin				
Employment	87	0.008	2.272	No
ACT Basin – State of Alabama				
Employment	40	0.004	1.895	No
ACT Basin – State of Georgia				
Employment	32	0.013	3.911	No

The high flow scenario, when compared to the no action alternative, would cause employment to increase modestly, by an annual total of 87 jobs (0.008 percent) in the ACT basin. The increase is somewhat greater in Alabama than in Georgia, but these changes represent little or no impact on regional and state employment.

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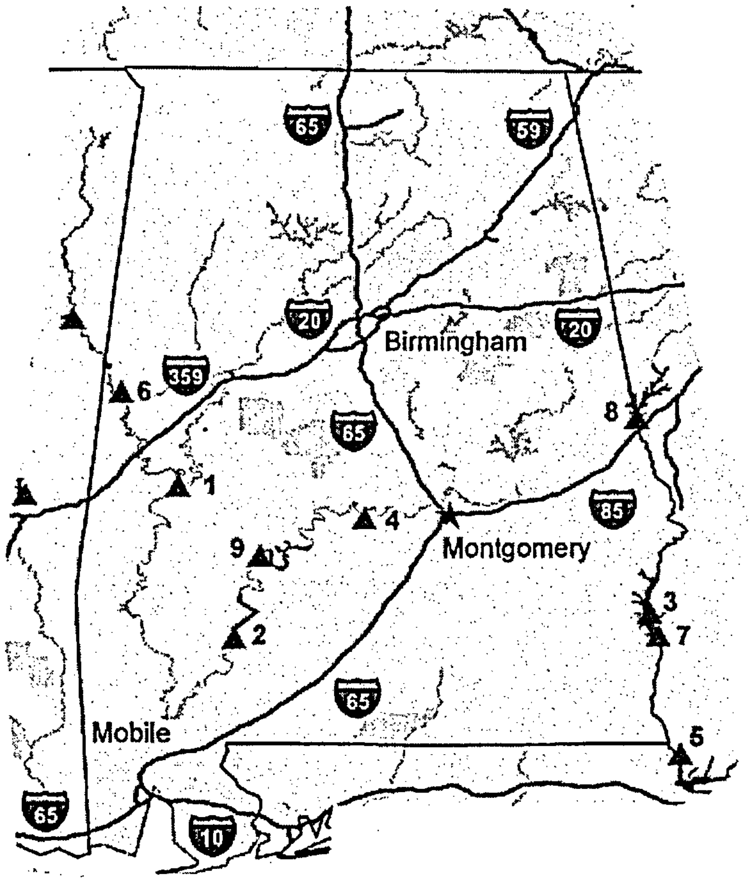
Alabama



- ▲ Campgrounds
- ● Other Visitor Areas
- ★ State Capitals
- • Cities
- Interstate Highways
- Corps Lakes
- Rivers and Streams
- Lakes
- Major Cities

National Parks, Forests, and Monuments

- Forest Service
- National Wildlife Refuge
- National Park Service

Reservations available through ReserveUSA 1-877-444-6777

Recreation Area	Camping	Lodging	Showers	Boat Ramps	Marina	Gas	Picnic Area \ Shelter	Playground	Swimming Area	Fishing Facilities	Trails	Golf Course	Amphitheater	Grocery / Snack Bar
1 - Black Warrior and Tombigbee Lakes	X		X	X	X		X	X	X	X	X		X	
2 - Claiborne Lake				X										
3 - George W. Andrews Lake	X			X			X			X				
4 - R.E. Bob Woodruff Lake	X			X	X		X	X		X	X			
5 - Seminole Lake	X	X	X	X	X		X	X	X	X	X		X	X
6 - Tennessee-Tombigbee Waterway	X	X	X	X	X		X	X	X	X	X		X	
7 - Walter F. George Lake	X	X	X	X	X		X	X	X	X	X	X	X	
8 - West Point Lake	X	X	X	X	X		X	X	X	X	X		X	
9 - William Dannelly Reservoir	X	X	X	X			X	X	X	X		X		X

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USCB 2000a
Sect 9.3

U.S. Census Bureau
American FactFinder

Data Set: Census 2000 Summary File 1 (SF 1) 100-Percent Data

Result contains 4 rows.

	P001001
	Total population: Total
Geneva County, Alabama	25,764
Henry County, Alabama	16,310
Houston County, Alabama	88,787
Dothan city, Alabama	57,737

NOTE: A hyphen (-) indicates that data are not available for this geographic area for the selected data element (column) in your custom table. Please consult the Census 2000 Summary File 1 (SF 1) 100-Percent Data Technical Documentation (PDF 9.1MB) for more information.

V-441

USCB 2000b
Sect 9.3

U.S. Census Bureau
American FactFinder

C-444

FACT SHEET

Houston County, Alabama

View a Fact Sheet for a race, ethnic, or ancestry group

Census 2000 Demographic Profile Highlights:

General Characteristics - show more >>	Number	Percent	U.S.		
Total population	88,787			map	brief
Male	42,170	47.5	49.1%	map	brief
Female	46,617	52.5	50.9%	map	brief
Median age (years)	36.7	(X)	35.3	map	brief
Under 5 years	6,037	6.8	6.8%	map	
18 years and over	65,801	74.1	74.3%		
65 years and over	12,162	13.7	12.4%	map	brief
One race	87,967	99.1	97.6%		
White	64,886	73.1	75.1%	map	brief
Black or African American	21,840	24.6	12.3%	map	brief
American Indian and Alaska Native	329	0.4	0.9%	map	brief
Asian	551	0.6	3.6%	map	brief
Native Hawaiian and Other Pacific Islander	14	0.0	0.1%	map	brief
Some other race	347	0.4	5.5%	map	
Two or more races	820	0.9	2.4%	map	brief
Hispanic or Latino (of any race)	1,122	1.3	12.5%	map	brief
Household population	87,639	98.7	97.2%	map	brief
Group quarters population	1,148	1.3	2.8%	map	
Average household size	2.45	(X)	2.59	map	brief
Average family size	2.95	(X)	3.14	map	
Total housing units	39,571			map	
Occupied housing units	35,834	90.6	91.0%		brief
Owner-occupied housing units	24,904	69.5	66.2%	map	
Renter-occupied housing units	10,930	30.5	33.8%	map	brief
Vacant housing units	3,737	9.4	9.0%	map	

Social Characteristics - show more >>	Number	Percent	U.S.		
Population 25 years and over	58,671				
High school graduate or higher	44,900	76.5	80.4%	map	brief
Bachelor's degree or higher	10,817	18.4	24.4%	map	
Civilian veterans (civilian population 18 years and over)	9,528	14.5	12.7%	map	brief
Disability status (population 5 years and over)	17,911	21.9	19.3%	map	brief
Foreign born	1,418	1.6	11.1%	map	brief
Male, Now married, except separated (population 15 years and over)	20,311	62.3	56.7%		brief
Female, Now married, except separated (population 15 years and over)	20,034	53.8	52.1%		brief
Speak a language other than English at home (population 5 years and over)	2,450	3.0	17.9%	map	brief

Economic Characteristics - show more >>	Number	Percent	U.S.		
In labor force (population 16 years and over)	42,720	62.4	63.9%		brief
Mean travel time to work in minutes (workers 16 years and over)	20.0	(X)	25.5	map	brief
Median household income in 1999 (dollars)	34,431	(X)	41,994	map	
Median family income in 1999 (dollars)	42,437	(X)	50,046	map	
Per capita income in 1999 (dollars)	18,759	(X)	21,587	map	
Families below poverty level	2,981	11.8	9.2%	map	brief
Individuals below poverty level	13,146	15.0	12.4%	map	

Housing Characteristics - show more >>	Number	Percent	U.S.

Single-family owner-occupied homes	19,115				brief
Median value (dollars)	82,000	(X)	119,600	map	brief
Median of selected monthly owner costs	(X)	(X)			brief
With a mortgage (dollars)	717	(X)	1,088	map	
Not mortgaged (dollars)	186	(X)	295		

(X) Not applicable.
Source: U.S. Census Bureau, Summary File 1 (SF 1) and Summary File 3 (SF 3)

U.S. Census Bureau
American FactFinder

FACT SHEET

Henry County, Alabama

View a Fact Sheet for a race, ethnic, or ancestry group

Census 2000 Demographic Profile Highlights:

General Characteristics - show more >>	Number	Percent	U.S.		
Total population	16,310			map	brief
Male	7,754	47.5	49.1%	map	brief
Female	8,556	52.5	50.9%	map	brief
Median age (years)	39.3	(X)	35.3	map	brief
Under 5 years	1,019	6.2	6.8%	map	
18 years and over	12,385	75.9	74.3%		
65 years and over	2,668	16.4	12.4%	map	brief
One race	16,189	99.3	97.6%		
White	10,710	65.7	75.1%	map	brief
Black or African American	5,268	32.3	12.3%	map	brief
American Indian and Alaska Native	34	0.2	0.9%	map	brief
Asian	10	0.1	3.6%	map	brief
Native Hawaiian and Other Pacific Islander	4	0.0	0.1%	map	brief
Some other race	163	1.0	5.5%	map	
Two or more races	121	0.7	2.4%	map	brief
Hispanic or Latino (of any race)	249	1.5	12.5%	map	brief
Household population	16,131	98.9	97.2%	map	brief
Group quarters population	179	1.1	2.8%	map	
Average household size	2.47	(X)	2.59	map	brief
Average family size	2.95	(X)	3.14	map	
Total housing units	8,037			map	
Occupied housing units	6,525	81.2	91.0%		brief
Owner-occupied housing units	5,279	80.9	66.2%	map	
Renter-occupied housing units	1,246	19.1	33.8%	map	brief
Vacant housing units	1,512	18.8	9.0%	map	

Social Characteristics - show more >>	Number	Percent	U.S.		
Population 25 years and over	10,967				
High school graduate or higher	7,313	66.7	80.4%	map	brief
Bachelor's degree or higher	1,545	14.1	24.4%	map	
Civilian veterans (civilian population 18 years and over)	1,849	15.0	12.7%	map	brief
Disability status (population 5 years and over)	4,415	29.3	19.3%	map	brief
Foreign born	184	1.1	11.1%	map	brief
Male, Now married, except separated (population 15 years and over)	3,758	61.0	56.7%		brief
Female, Now married, except separated (population 15 years and over)	3,668	53.0	52.1%		brief
Speak a language other than English at home (population 5 years and over)	434	2.8	17.9%	map	brief

Economic Characteristics - show more >>	Number	Percent	U.S.		
In labor force (population 16 years and over)	7,237	56.5	63.9%		brief
Mean travel time to work in minutes (workers 16 years and over)	25.5	(X)	25.5	map	brief
Median household income in 1999 (dollars)	30,353	(X)	41,994	map	
Median family income in 1999 (dollars)	36,555	(X)	50,046	map	
Per capita income in 1999 (dollars)	15,681	(X)	21,587	map	
Families below poverty level	692	14.5	9.2%	map	brief
Individuals below poverty level	3,070	19.1	12.4%	map	

Housing Characteristics - show more >>	Number	Percent	U.S.

Single-family owner-occupied homes	3,600				brief
Median value (dollars)	69,100	(X)	119,600	map	brief
Median of selected monthly owner costs	(X)	(X)			brief
With a mortgage (dollars)	673	(X)	1,088	map	
Not mortgaged (dollars)	206	(X)	295		

(X) Not applicable.
Source: U.S. Census Bureau, Summary File 1 (SF 1) and Summary File 3 (SF 3)

U.S. Census Bureau
American FactFinder

FACT SHEET

Geneva County, Alabama

View a Fact Sheet for a race, ethnic, or ancestry group

Census 2000 Demographic Profile Highlights:

General Characteristics - show more >>	Number	Percent	U.S.		
Total population	25,764			map	brief
Male	12,529	48.6	49.1%	map	brief
Female	13,235	51.4	50.9%	map	brief
Median age (years)	39.3	(X)	35.3	map	brief
Under 5 years	1,437	5.6	6.8%	map	
18 years and over	19,581	76.0	74.3%		
65 years and over	4,203	16.3	12.4%	map	brief
One race	25,579	99.3	97.6%		
White	22,442	87.1	75.1%	map	brief
Black or African American	2,743	10.6	12.3%	map	brief
American Indian and Alaska Native	197	0.8	0.9%	map	brief
Asian	32	0.1	3.6%	map	brief
Native Hawaiian and Other Pacific Islander	6	0.0	0.1%	map	brief
Some other race	159	0.6	5.5%	map	
Two or more races	185	0.7	2.4%	map	brief
Hispanic or Latino (of any race)	453	1.8	12.5%	map	brief
Household population	25,490	98.9	97.2%	map	brief
Group quarters population	274	1.1	2.8%	map	
Average household size	2.43	(X)	2.59	map	brief
Average family size	2.92	(X)	3.14	map	
Total housing units	12,115			map	
Occupied housing units	10,477	86.5	91.0%		brief
Owner-occupied housing units	8,440	80.6	66.2%	map	
Renter-occupied housing units	2,037	19.4	33.8%	map	brief
Vacant housing units	1,638	13.5	9.0%	map	

Social Characteristics - show more >>	Number	Percent	U.S.		
Population 25 years and over	17,588				
High school graduate or higher	11,542	65.6	80.4%	map	brief
Bachelor's degree or higher	1,526	8.7	24.4%	map	
Civilian veterans (civilian population 18 years and over)	2,796	14.3	12.7%	map	brief
Disability status (population 5 years and over)	6,786	28.2	19.3%	map	brief
Foreign born	197	0.8	11.1%	map	brief
Male, Now married, except separated (population 15 years and over)	6,162	62.2	56.7%		brief
Female, Now married, except separated (population 15 years and over)	6,215	57.4	52.1%		brief
Speak a language other than English at home (population 5 years and over)	503	2.1	17.9%	map	brief

Economic Characteristics - show more >>	Number	Percent	U.S.		
In labor force (population 16 years and over)	11,799	58.0	63.9%		brief
Mean travel time to work in minutes (workers 16 years and over)	27.2	(X)	25.5	map	brief
Median household income in 1999 (dollars)	26,448	(X)	41,994	map	
Median family income in 1999 (dollars)	32,563	(X)	50,046	map	
Per capita income in 1999 (dollars)	14,620	(X)	21,587	map	
Families below poverty level	1,200	15.9	9.2%	map	brief
Individuals below poverty level	5,010	19.6	12.4%	map	

Housing Characteristics - show more >>	Number	Percent	U.S.

Single-family owner-occupied homes	4,975				brief
Median value (dollars)	55,900	(X)	119,600	map	brief
Median of selected monthly owner costs	(X)	(X)			brief
With a mortgage (dollars)	574	(X)	1,088	map	
Not mortgaged (dollars)	186	(X)	295		

(X) Not applicable.
Source: U.S. Census Bureau, Summary File 1 (SF 1) and Summary File 3 (SF 3)

USCB 2000c

V-504

Table DP-1. Profile of General Demographic Characteristics: 2000

Geographic area: Appling County, Georgia

[For information on confidentiality protection, nonsampling error, and definitions, see text]

Subject	Number	Percent
Total population	17,419	100.0
SEX AND AGE		
Male	8,581	49.3
Female	8,838	50.7
Under 5 years	1,273	7.3
5 to 9 years	1,252	7.2
10 to 14 years	1,282	7.4
15 to 19 years	1,422	8.2
20 to 24 years	1,069	6.1
25 to 34 years	2,312	13.3
35 to 44 years	2,657	15.3
45 to 54 years	2,379	13.7
55 to 59 years	949	5.4
60 to 64 years	762	4.4
65 to 74 years	1,149	6.6
75 to 84 years	695	4.0
85 years and over	218	1.3
Median age (years)	35.4	(X)
18 years and over	12,690	72.9
Male	6,125	35.2
Female	6,565	37.7
21 years and over	11,972	68.7
62 years and over	2,527	14.5
65 years and over	2,062	11.8
Male	847	4.9
Female	1,215	7.0
RACE		
One race	17,312	99.4
White	13,376	76.8
Black or African American	3,412	19.6
American Indian and Alaska Native	36	0.2
Asian	52	0.3
Asian Indian	20	0.1
Chinese	1	-
Filipino	16	0.1
Japanese	1	-
Korean	3	-
Vietnamese	10	0.1
Other Asian [1]	1	-
Native Hawaiian and Other Pacific Islander	2	-
Native Hawaiian	-	-
Guamanian or Chamorro	2	-
Samoan	-	-
Other Pacific Islander [2]	-	-
Some other race	434	2.5
Two or more races	107	0.6
Race alone or in combination with one or more other races: [3]		
White	13,472	77.3
Black or African American	3,450	19.8
American Indian and Alaska Native	80	0.5
Asian	65	0.4
Native Hawaiian and Other Pacific Islander	5	-
Some other race	461	2.6

Subject	Number	Percent
HISPANIC OR LATINO AND RACE		
Total population	17,419	100.0
Hispanic or Latino (of any race)	792	4.5
Mexican	693	4.0
Puerto Rican	13	0.1
Cuban	9	0.1
Other Hispanic or Latino	77	0.4
Not Hispanic or Latino	16,627	95.5
White alone	13,053	74.9
RELATIONSHIP		
Total population	17,419	100.0
In households	17,177	98.6
Householder	6,606	37.9
Spouse	3,738	21.5
Child	5,138	29.5
Own child under 18 years	4,002	23.0
Other relatives	1,029	5.9
Under 18 years	499	2.9
Nonrelatives	666	3.8
Unmarried partner	283	1.6
In group quarters	242	1.4
Institutionalized population	237	1.4
Noninstitutionalized population	5	-
HOUSEHOLD BY TYPE		
Total households	6,606	100.0
Family households (families)	4,856	73.5
With own children under 18 years	2,282	34.5
Married-couple family	3,738	56.6
With own children under 18 years	1,658	25.1
Female householder, no husband present	825	12.5
With own children under 18 years	478	7.2
Nonfamily households	1,750	26.5
Householder living alone	1,531	23.2
Householder 65 years and over	650	9.8
Households with individuals under 18 years	2,609	39.5
Households with individuals 65 years and over	1,551	23.5
Average household size	2.60	(X)
Average family size	3.04	(X)
HOUSING OCCUPANCY		
Total housing units	7,854	100.0
Occupied housing units	6,606	84.1
Vacant housing units	1,248	15.9
For seasonal, recreational, or occasional use	229	2.9
Homeowner vacancy rate (percent)	1.7	(X)
Rental vacancy rate (percent)	15.6	(X)
HOUSING TENURE		
Occupied housing units	6,606	100.0
Owner-occupied housing units	5,224	79.1
Renter-occupied housing units	1,382	20.9
Average household size of owner-occupied units	2.58	(X)
Average household size of renter-occupied units	2.67	(X)

- Represents zero or rounds to zero. (X) Not applicable.

[1] Other Asian alone, or two or more Asian categories.

[2] Other Pacific Islander alone, or two or more Native Hawaiian and Other Pacific Islander categories.

[3] In combination with one or more of the other races listed. The six numbers may add to more than the total population and the six percentages may add to more than 100 percent because individuals may report more than one race.

Source: U.S. Census Bureau, Census 2000.

Table DP-1. Profile of General Demographic Characteristics: 2000

Geographic area: Jeff Davis County, Georgia

[For information on confidentiality protection, nonsampling error, and definitions, see text]

Subject	Number	Percent
Total population	12,684	100.0
SEX AND AGE		
Male	6,228	49.1
Female	6,456	50.9
Under 5 years	975	7.7
5 to 9 years	904	7.1
10 to 14 years	982	7.7
15 to 19 years	962	7.6
20 to 24 years	805	6.3
25 to 34 years	1,709	13.5
35 to 44 years	1,872	14.8
45 to 54 years	1,745	13.8
55 to 59 years	638	5.0
60 to 64 years	578	4.6
65 to 74 years	879	6.9
75 to 84 years	479	3.8
85 years and over	156	1.2
Median age (years)	35.0	(X)
18 years and over	9,230	72.8
Male	4,463	35.2
Female	4,767	37.6
21 years and over	8,705	68.6
62 years and over	1,832	14.4
65 years and over	1,514	11.9
Male	622	4.9
Female	892	7.0
RACE		
One race	12,614	99.4
White	10,300	81.2
Black or African American	1,920	15.1
American Indian and Alaska Native	30	0.2
Asian	56	0.4
Asian Indian	24	0.2
Chinese	2	-
Filipino	15	0.1
Japanese	-	-
Korean	4	-
Vietnamese	7	0.1
Other Asian [1]	4	-
Native Hawaiian and Other Pacific Islander	5	-
Native Hawaiian	-	-
Guamanian or Chamorro	-	-
Samoan	-	-
Other Pacific Islander [2]	5	-
Some other race	303	2.4
Two or more races	70	0.6
Race alone or in combination with one or more other races: [3]		
White	10,362	81.7
Black or African American	1,932	15.2
American Indian and Alaska Native	60	0.5
Asian	64	0.5
Native Hawaiian and Other Pacific Islander	17	0.1
Some other race	330	2.6

Subject	Number	Percent
HISPANIC OR LATINO AND RACE		
Total population	12,684	100.0
Hispanic or Latino (of any race)	651	5.1
Mexican	556	4.4
Puerto Rican	6	-
Cuban	8	0.1
Other Hispanic or Latino	81	0.6
Not Hispanic or Latino	12,033	94.9
White alone	9,992	78.8
RELATIONSHIP		
Total population	12,684	100.0
In households	12,588	99.2
Householder	4,828	38.1
Spouse	2,728	21.5
Child	3,851	30.4
Own child under 18 years	3,053	24.1
Other relatives	675	5.3
Under 18 years	330	2.6
Nonrelatives	506	4.0
Unmarried partner	237	1.9
In group quarters	96	0.8
Institutionalized population	96	0.8
Noninstitutionalized population	-	-
HOUSEHOLD BY TYPE		
Total households	4,828	100.0
Family households (families)	3,591	74.4
With own children under 18 years	1,724	35.7
Married-couple family	2,728	56.5
With own children under 18 years	1,239	25.7
Female householder, no husband present	658	13.6
With own children under 18 years	364	7.5
Nonfamily households	1,237	25.6
Householder living alone	1,076	22.3
Householder 65 years and over	440	9.1
Households with individuals under 18 years	1,934	40.1
Households with individuals 65 years and over	1,121	23.2
Average household size	2.61	(X)
Average family size	3.02	(X)
HOUSING OCCUPANCY		
Total housing units	5,581	100.0
Occupied housing units	4,828	86.5
Vacant housing units	753	13.5
For seasonal, recreational, or occasional use	53	0.9
Homeowner vacancy rate (percent)	2.3	(X)
Rental vacancy rate (percent)	17.2	(X)
HOUSING TENURE		
Occupied housing units	4,828	100.0
Owner-occupied housing units	3,737	77.4
Renter-occupied housing units	1,091	22.6
Average household size of owner-occupied units	2.62	(X)
Average household size of renter-occupied units	2.57	(X)

- Represents zero or rounds to zero. (X) Not applicable.

[1] Other Asian alone, or two or more Asian categories.

[2] Other Pacific Islander alone, or two or more Native Hawaiian and Other Pacific Islander categories.

[3] In combination with one or more of the other races listed. The six numbers may add to more than the total population and the six percentages may add to more than 100 percent because individuals may report more than one race.

Source: U.S. Census Bureau, Census 2000.

Table DP-1. Profile of General Demographic Characteristics: 2000

Geographic area: Montgomery County, Georgia

[For information on confidentiality protection, nonsampling error, and definitions, see text]

Subject	Number	Percent
Total population	8,270	100.0
SEX AND AGE		
Male	4,237	51.2
Female	4,033	48.8
Under 5 years	563	6.8
5 to 9 years	581	7.0
10 to 14 years	570	6.9
15 to 19 years	686	8.3
20 to 24 years	728	8.8
25 to 34 years	1,196	14.5
35 to 44 years	1,301	15.7
45 to 54 years	1,015	12.3
55 to 59 years	373	4.5
60 to 64 years	380	4.6
65 to 74 years	501	6.1
75 to 84 years	292	3.5
85 years and over	84	1.0
Median age (years)	33.6	(X)
18 years and over	6,199	75.0
Male	3,182	38.5
Female	3,017	36.5
21 years and over	5,694	68.9
62 years and over	1,096	13.3
65 years and over	877	10.6
Male	365	4.4
Female	512	6.2
RACE		
One race	8,219	99.4
White	5,766	69.7
Black or African American	2,253	27.2
American Indian and Alaska Native	6	0.1
Asian	16	0.2
Asian Indian	4	-
Chinese	2	-
Filipino	4	-
Japanese	2	-
Korean	1	-
Vietnamese	2	-
Other Asian [1]	1	-
Native Hawaiian and Other Pacific Islander	2	-
Native Hawaiian	-	-
Guamanian or Chamorro	-	-
Samoan	1	-
Other Pacific Islander [2]	1	-
Some other race	176	2.1
Two or more races	51	0.6
Race alone or in combination with one or more other races: [3]		
White	5,811	70.3
Black or African American	2,262	27.4
American Indian and Alaska Native	27	0.3
Asian	31	0.4
Native Hawaiian and Other Pacific Islander	5	0.1
Some other race	190	2.3

Subject	Number	Percent
HISPANIC OR LATINO AND RACE		
Total population	8,270	100.0
Hispanic or Latino (of any race)	271	3.3
Mexican	235	2.8
Puerto Rican	-	-
Cuban	2	-
Other Hispanic or Latino	34	0.4
Not Hispanic or Latino	7,999	96.7
White alone	5,684	68.7
RELATIONSHIP		
Total population	8,270	100.0
In households	7,516	90.9
Householder	2,919	35.3
Spouse	1,551	18.8
Child	2,332	28.2
Own child under 18 years	1,831	22.1
Other relatives	413	5.0
Under 18 years	187	2.3
Nonrelatives	301	3.6
Unmarried partner	138	1.7
In group quarters	754	9.1
Institutionalized population	478	5.8
Noninstitutionalized population	276	3.3
HOUSEHOLD BY TYPE		
Total households	2,919	100.0
Family households (families)	2,063	70.7
With own children under 18 years	992	34.0
Married-couple family	1,551	53.1
With own children under 18 years	704	24.1
Female householder, no husband present	395	13.5
With own children under 18 years	225	7.7
Nonfamily households	856	29.3
Householder living alone	746	25.6
Householder 65 years and over	297	10.2
Households with individuals under 18 years	1,118	38.3
Households with individuals 65 years and over	687	23.5
Average household size	2.57	(X)
Average family size	3.08	(X)
HOUSING OCCUPANCY		
Total housing units	3,492	100.0
Occupied housing units	2,919	83.6
Vacant housing units	573	16.4
For seasonal, recreational, or occasional use	130	3.7
Homeowner vacancy rate (percent)	2.5	(X)
Rental vacancy rate (percent)	16.5	(X)
HOUSING TENURE		
Occupied housing units	2,919	100.0
Owner-occupied housing units	2,274	77.9
Renter-occupied housing units	645	22.1
Average household size of owner-occupied units	2.60	(X)
Average household size of renter-occupied units	2.48	(X)

- Represents zero or rounds to zero. (X) Not applicable.

[1] Other Asian alone, or two or more Asian categories.

[2] Other Pacific Islander alone, or two or more Native Hawaiian and Other Pacific Islander categories.

[3] In combination with one or more of the other races listed. The six numbers may add to more than the total population and the six percentages may add to more than 100 percent because individuals may report more than one race.

Source: U.S. Census Bureau, Census 2000.

Table DP-1. Profile of General Demographic Characteristics: 2000

Geographic area: Tattnall County, Georgia

[For information on confidentiality protection, nonsampling error, and definitions, see text]

Subject	Number	Percent
Total population	22,305	100.0
SEX AND AGE		
Male	12,858	57.6
Female	9,447	42.4
Under 5 years	1,354	6.1
5 to 9 years	1,341	6.0
10 to 14 years	1,501	6.7
15 to 19 years	1,499	6.7
20 to 24 years	1,921	8.6
25 to 34 years	3,947	17.7
35 to 44 years	3,773	16.9
45 to 54 years	2,623	11.8
55 to 59 years	1,003	4.5
60 to 64 years	837	3.8
65 to 74 years	1,347	6.0
75 to 84 years	860	3.9
85 years and over	299	1.3
Median age (years)	33.9	(X)
18 years and over	17,197	77.1
Male	10,216	45.8
Female	6,981	31.3
21 years and over	16,238	72.8
62 years and over	2,990	13.4
65 years and over	2,506	11.2
Male	1,003	4.5
Female	1,503	6.7
RACE		
One race	22,100	99.1
White	13,496	60.5
Black or African American	7,010	31.4
American Indian and Alaska Native	31	0.1
Asian	64	0.3
Asian Indian	35	0.2
Chinese	2	-
Filipino	5	-
Japanese	3	-
Korean	18	0.1
Vietnamese	-	-
Other Asian [1]	1	-
Native Hawaiian and Other Pacific Islander	18	0.1
Native Hawaiian	1	-
Guamanian or Chamorro	14	0.1
Samoan	1	-
Other Pacific Islander [2]	2	-
Some other race	1,481	6.6
Two or more races	205	0.9
Race alone or in combination with one or more other races: [3]		
White	13,670	61.3
Black or African American	7,084	31.8
American Indian and Alaska Native	80	0.4
Asian	81	0.4
Native Hawaiian and Other Pacific Islander	29	0.1
Some other race	1,570	7.0

Subject	Number	Percent
HISPANIC OR LATINO AND RACE		
Total population	22,305	100.0
Hispanic or Latino (of any race)	1,883	8.4
Mexican	1,599	7.2
Puerto Rican	48	0.2
Cuban	20	0.1
Other Hispanic or Latino	216	1.0
Not Hispanic or Latino	20,422	91.6
White alone	13,218	59.3
RELATIONSHIP		
Total population	22,305	100.0
In households	18,367	82.3
Householder	7,057	31.6
Spouse	3,608	16.2
Child	5,544	24.9
Own child under 18 years	4,380	19.6
Other relatives	1,158	5.2
Under 18 years	589	2.6
Nonrelatives	1,000	4.5
Unmarried partner	334	1.5
In group quarters	3,938	17.7
Institutionalized population	3,922	17.6
Noninstitutionalized population	16	0.1
HOUSEHOLD BY TYPE		
Total households	7,057	100.0
Family households (families)	4,874	69.1
With own children under 18 years	2,332	33.0
Married-couple family	3,608	51.1
With own children under 18 years	1,599	22.7
Female householder, no husband present	943	13.4
With own children under 18 years	564	8.0
Nonfamily households	2,183	30.9
Householder living alone	1,886	26.7
Householder 65 years and over	843	11.9
Households with individuals under 18 years	2,651	37.6
Households with individuals 65 years and over	1,768	25.1
Average household size	2.60	(X)
Average family size	3.12	(X)
HOUSING OCCUPANCY		
Total housing units	8,578	100.0
Occupied housing units	7,057	82.3
Vacant housing units	1,521	17.7
For seasonal, recreational, or occasional use	232	2.7
Homeowner vacancy rate (percent)	2.7	(X)
Rental vacancy rate (percent)	17.6	(X)
HOUSING TENURE		
Occupied housing units	7,057	100.0
Owner-occupied housing units	4,979	70.6
Renter-occupied housing units	2,078	29.4
Average household size of owner-occupied units	2.57	(X)
Average household size of renter-occupied units	2.69	(X)

- Represents zero or rounds to zero. (X) Not applicable.

[1] Other Asian alone, or two or more Asian categories.

[2] Other Pacific Islander alone, or two or more Native Hawaiian and Other Pacific Islander categories.

[3] In combination with one or more of the other races listed. The six numbers may add to more than the total population and the six percentages may add to more than 100 percent because individuals may report more than one race.

Source: U.S. Census Bureau, Census 2000.

Table DP-1. Profile of General Demographic Characteristics: 2000

Geographic area: Toombs County, Georgia

[For information on confidentiality protection, nonsampling error, and definitions, see text]

Subject	Number	Percent
Total population	26,067	100.0
SEX AND AGE		
Male	12,443	47.7
Female	13,624	52.3
Under 5 years	2,010	7.7
5 to 9 years	1,999	7.7
10 to 14 years	2,142	8.2
15 to 19 years	2,037	7.8
20 to 24 years	1,661	6.4
25 to 34 years	3,440	13.2
35 to 44 years	3,796	14.6
45 to 54 years	3,322	12.7
55 to 59 years	1,336	5.1
60 to 64 years	1,146	4.4
65 to 74 years	1,690	6.5
75 to 84 years	1,040	4.0
85 years and over	448	1.7
Median age (years)	34.2	(X)
18 years and over	18,624	71.4
Male	8,736	33.5
Female	9,888	37.9
21 years and over	17,513	67.2
62 years and over	3,832	14.7
65 years and over	3,178	12.2
Male	1,179	4.5
Female	1,999	7.7
RACE		
One race	25,895	99.3
White	18,029	69.2
Black or African American	6,296	24.2
American Indian and Alaska Native	54	0.2
Asian	122	0.5
Asian Indian	32	0.1
Chinese	23	0.1
Filipino	37	0.1
Japanese	1	-
Korean	12	-
Vietnamese	8	-
Other Asian [1]	9	-
Native Hawaiian and Other Pacific Islander	2	-
Native Hawaiian	-	-
Guamanian or Chamorro	2	-
Samoan	-	-
Other Pacific Islander [2]	-	-
Some other race	1,392	5.3
Two or more races	172	0.7
Race alone or in combination with one or more other races: [3]		
White	18,177	69.7
Black or African American	6,358	24.4
American Indian and Alaska Native	110	0.4
Asian	153	0.6
Native Hawaiian and Other Pacific Islander	10	-
Some other race	1,459	5.6

Subject	Number	Percent
HISPANIC OR LATINO AND RACE		
Total population	26,067	100.0
Hispanic or Latino (of any race)	2,310	8.9
Mexican	1,945	7.5
Puerto Rican	52	0.2
Cuban	18	0.1
Other Hispanic or Latino	295	1.1
Not Hispanic or Latino	23,757	91.1
White alone	17,226	66.1
RELATIONSHIP		
Total population	26,067	100.0
In households	25,593	98.2
Householder	9,877	37.9
Spouse	4,815	18.5
Child	8,006	30.7
Own child under 18 years	6,370	24.4
Other relatives	1,689	6.5
Under 18 years	892	3.4
Nonrelatives	1,206	4.6
Unmarried partner	442	1.7
In group quarters	474	1.8
Institutionalized population	440	1.7
Noninstitutionalized population	34	0.1
HOUSEHOLD BY TYPE		
Total households	9,877	100.0
Family households (families)	6,825	69.1
With own children under 18 years	3,430	34.7
Married-couple family	4,815	48.7
With own children under 18 years	2,237	22.6
Female householder, no husband present	1,536	15.6
With own children under 18 years	956	9.7
Nonfamily households	3,052	30.9
Householder living alone	2,670	27.0
Householder 65 years and over	1,050	10.6
Households with individuals under 18 years	3,916	39.6
Households with individuals 65 years and over	2,277	23.1
Average household size	2.59	(X)
Average family size	3.13	(X)
HOUSING OCCUPANCY		
Total housing units	11,371	100.0
Occupied housing units	9,877	86.9
Vacant housing units	1,494	13.1
For seasonal, recreational, or occasional use	198	1.7
Homeowner vacancy rate (percent)	2.1	(X)
Rental vacancy rate (percent)	13.6	(X)
HOUSING TENURE		
Occupied housing units	9,877	100.0
Owner-occupied housing units	6,467	65.5
Renter-occupied housing units	3,410	34.5
Average household size of owner-occupied units	2.60	(X)
Average household size of renter-occupied units	2.57	(X)

- Represents zero or rounds to zero. (X) Not applicable.

[1] Other Asian alone, or two or more Asian categories.

[2] Other Pacific Islander alone, or two or more Native Hawaiian and Other Pacific Islander categories.

[3] In combination with one or more of the other races listed. The six numbers may add to more than the total population and the six percentages may add to more than 100 percent because individuals may report more than one race.

Source: U.S. Census Bureau, Census 2000.

USCB 2000d

Table DP-3. Profile of Selected Economic Characteristics: 2000

Geographic area: Appling County, Georgia

[Data based on a sample. For information on confidentiality protection, sampling error, nonsampling error, and definitions, see text]

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Subject	Number	Percent
EMPLOYMENT STATUS		
Population 16 years and over	13,261	100.0
In labor force	8,125	61.3
Civilian labor force	8,119	61.2
Employed	7,732	58.3
Unemployed	387	2.9
Percent of civilian labor force	4.8	(X)
Armed Forces	6	-
Not in labor force	5,136	38.7
Females 16 years and over	6,837	100.0
In labor force	3,643	53.3
Civilian labor force	3,643	53.3
Employed	3,426	50.1
Own children under 6 years	1,439	100.0
All parents in family in labor force	889	61.8
COMMUTING TO WORK		
Workers 16 years and over	7,583	100.0
Car, truck, or van - - drove alone	5,783	76.3
Car, truck, or van - - carpooled	1,452	19.1
Public transportation (including taxicab)	24	0.3
Walked	105	1.4
Other means	104	1.4
Worked at home	115	1.5
Mean travel time to work (minutes)[1]	24.1	(X)
Employed civilian population 16 years and over	7,732	100.0
OCCUPATION		
Management, professional, and related occupations	1,628	21.1
Service occupations	844	10.9
Sales and office occupations	1,759	22.7
Farming, fishing, and forestry occupations	305	3.9
Construction, extraction, and maintenance occupations	1,283	16.6
Production, transportation, and material moving occupations	1,913	24.7
INDUSTRY		
Agriculture, forestry, fishing and hunting, and mining	566	7.3
Construction	908	11.7
Manufacturing	1,426	18.4
Wholesale trade	266	3.4
Retail trade	787	10.2
Transportation and warehousing, and utilities	721	9.3
Information	112	1.4
Finance, insurance, real estate, and rental and leasing	234	3.0
Professional, scientific, management, administrative, and waste management services	265	3.4
Educational, health and social services	1,386	17.9
Arts, entertainment, recreation, accommodation and food services	341	4.4
Other services (except public administration)	335	4.3
Public administration	385	5.0
CLASS OF WORKER		
Private wage and salary workers	5,782	74.8
Government workers	1,310	16.9
Self-employed workers in own not incorporated business	581	7.5
Unpaid family workers	59	0.8

Subject	Number	Percent
INCOME IN 1999		
Households	6,594	100.0
Less than $10,000	1,104	16.7
$10,000 to $14,999	525	8.0
$15,000 to $24,999	1,200	18.2
$25,000 to $34,999	899	13.6
$35,000 to $49,999	982	14.9
$50,000 to $74,999	1,080	16.4
$75,000 to $99,999	447	6.8
$100,000 to $149,999	249	3.8
$150,000 to $199,999	59	0.9
$200,000 or more	49	0.7
Median household income (dollars)	30,266	(X)
With earnings	5,074	76.9
Mean earnings (dollars)[1]	42,155	(X)
With Social Security income	1,909	29.0
Mean Social Security income (dollars)[1]	8,241	(X)
With Supplemental Security Income	540	8.2
Mean Supplemental Security Income (dollars)[1]	5,201	(X)
With public assistance income	240	3.6
Mean public assistance income (dollars)[1]	1,287	(X)
With retirement income	933	14.1
Mean retirement income (dollars)[1]	15,923	(X)
Families	4,914	100.0
Less than $10,000	437	8.9
$10,000 to $14,999	400	8.1
$15,000 to $24,999	875	17.8
$25,000 to $34,999	753	15.3
$35,000 to $49,999	814	16.6
$50,000 to $74,999	911	18.5
$75,000 to $99,999	408	8.3
$100,000 to $149,999	224	4.6
$150,000 to $199,999	43	0.9
$200,000 or more	49	1.0
Median family income (dollars)	34,890	(X)
Per capita income (dollars)[1]	15,044	(X)
Median earnings (dollars):		
Male full-time, year-round workers	27,753	(X)
Female full-time, year-round workers	18,148	(X)

Subject	Number below poverty level	Percent below poverty level
POVERTY STATUS IN 1999		
Families	731	14.9
With related children under 18 years	528	21.1
With related children under 5 years	275	27.3
Families with female householder, no husband present	278	36.5
With related children under 18 years	238	46.1
With related children under 5 years	140	62.2
Individuals	3,186	18.6
18 years and over	2,066	16.5
65 years and over	489	24.4
Related children under 18 years	1,094	23.9
Related children 5 to 17 years	731	22.1
Unrelated individuals 15 years and over	810	36.4

-Represents zero or rounds to zero. (X) Not applicable.

[1]If the denominator of a mean value or per capita value is less than 30, then that value is calculated using a rounded aggregate in the numerator. See text.

Source: U.S. Bureau of the Census, Census 2000.

Table DP-3. Profile of Selected Economic Characteristics: 2000

Geographic area: Jeff Davis County, Georgia

[Data based on a sample. For information on confidentiality protection, sampling error, nonsampling error, and definitions, see text]

Subject	Number	Percent
EMPLOYMENT STATUS		
Population 16 years and over	9,603	100.0
In labor force	5,586	58.2
Civilian labor force	5,581	58.1
Employed	5,266	54.8
Unemployed	315	3.3
Percent of civilian labor force	5.6	(X)
Armed Forces	5	0.1
Not in labor force	4,017	41.8
Females 16 years and over	4,908	100.0
In labor force	2,502	51.0
Civilian labor force	2,502	51.0
Employed	2,304	46.9
Own children under 6 years	1,081	100.0
All parents in family in labor force	688	63.6
COMMUTING TO WORK		
Workers 16 years and over	5,132	100.0
Car, truck, or van - - drove alone	4,027	78.5
Car, truck, or van - - carpooled	871	17.0
Public transportation (including taxicab)	-	-
Walked	22	0.4
Other means	101	2.0
Worked at home	111	2.2
Mean travel time to work (minutes)[1]	21.7	(X)
Employed civilian population 16 years and over	5,266	100.0
OCCUPATION		
Management, professional, and related occupations	1,081	20.5
Service occupations	602	11.4
Sales and office occupations	1,102	20.9
Farming, fishing, and forestry occupations	175	3.3
Construction, extraction, and maintenance occupations	767	14.6
Production, transportation, and material moving occupations	1,539	29.2
INDUSTRY		
Agriculture, forestry, fishing and hunting, and mining	308	5.8
Construction	304	5.8
Manufacturing	1,533	29.1
Wholesale trade	139	2.6
Retail trade	699	13.3
Transportation and warehousing, and utilities	451	8.6
Information	58	1.1
Finance, insurance, real estate, and rental and leasing	147	2.8
Professional, scientific, management, administrative, and waste management services	180	3.4
Educational, health and social services	789	15.0
Arts, entertainment, recreation, accommodation and food services	214	4.1
Other services (except public administration)	215	4.1
Public administration	229	4.3
CLASS OF WORKER		
Private wage and salary workers	4,137	78.6
Government workers	803	15.2
Self-employed workers in own not incorporated business	276	5.2
Unpaid family workers	50	0.9

Subject	Number	Percent
INCOME IN 1999		
Households	4,844	100.0
Less than $10,000	836	17.3
$10,000 to $14,999	499	10.3
$15,000 to $24,999	892	18.4
$25,000 to $34,999	774	16.0
$35,000 to $49,999	776	16.0
$50,000 to $74,999	653	13.5
$75,000 to $99,999	176	3.6
$100,000 to $149,999	165	3.4
$150,000 to $199,999	42	0.9
$200,000 or more	31	0.6
Median household income (dollars)	27,310	(X)
With earnings	3,636	75.1
Mean earnings (dollars)[1]	39,761	(X)
With Social Security income	1,503	31.0
Mean Social Security income (dollars)[1]	9,737	(X)
With Supplemental Security Income	327	6.8
Mean Supplemental Security Income (dollars)[1]	6,150	(X)
With public assistance income	194	4.0
Mean public assistance income (dollars)[1]	1,413	(X)
With retirement income	574	11.8
Mean retirement income (dollars)[1]	11,956	(X)
Families	3,693	100.0
Less than $10,000	424	11.5
$10,000 to $14,999	299	8.1
$15,000 to $24,999	681	18.4
$25,000 to $34,999	659	17.8
$35,000 to $49,999	675	18.3
$50,000 to $74,999	586	15.9
$75,000 to $99,999	176	4.8
$100,000 to $149,999	135	3.7
$150,000 to $199,999	42	1.1
$200,000 or more	16	0.4
Median family income (dollars)	30,930	(X)
Per capita income (dollars)[1]	13,780	(X)
Median earnings (dollars):		
Male full-time, year-round workers	26,261	(X)
Female full-time, year-round workers	20,095	(X)

Subject	Number below poverty level	Percent below poverty level
POVERTY STATUS IN 1999		
Families	621	16.8
With related children under 18 years	377	19.2
With related children under 5 years	173	20.4
Families with female householder, no husband present	213	30.8
With related children under 18 years	183	43.6
With related children under 5 years	111	68.5
Individuals	2,434	19.4
18 years and over	1,692	18.5
65 years and over	332	22.1
Related children under 18 years	728	21.7
Related children 5 to 17 years	502	20.9
Unrelated individuals 15 years and over	499	33.9

-Represents zero or rounds to zero. (X) Not applicable.

[1]If the denominator of a mean value or per capita value is less than 30, then that value is calculated using a rounded aggregate in the numerator. See text.

Source: U.S. Bureau of the Census, Census 2000.

Table DP-3. Profile of Selected Economic Characteristics: 2000

Geographic area: Montgomery County, Georgia

[Data based on a sample. For information on confidentiality protection, sampling error, nonsampling error, and definitions, see text]

Subject	Number	Percent
EMPLOYMENT STATUS		
Population 16 years and over	6,415	100.0
In labor force	3,701	57.7
Civilian labor force	3,698	57.6
Employed	3,554	55.4
Unemployed	144	2.2
Percent of civilian labor force	3.9	(X)
Armed Forces	3	-
Not in labor force	2,714	42.3
Females 16 years and over	3,160	100.0
In labor force	1,673	52.9
Civilian labor force	1,670	52.8
Employed	1,576	49.9
Own children under 6 years	579	100.0
All parents in family in labor force	345	59.6
COMMUTING TO WORK		
Workers 16 years and over	3,483	100.0
Car, truck, or van - - drove alone	2,483	71.3
Car, truck, or van - - carpooled	734	21.1
Public transportation (including taxicab)	1	-
Walked	163	4.7
Other means	42	1.2
Worked at home	60	1.7
Mean travel time to work (minutes)[1]	27.0	(X)
Employed civilian population 16 years and over	3,554	100.0
OCCUPATION		
Management, professional, and related occupations	949	26.7
Service occupations	611	17.2
Sales and office occupations	804	22.6
Farming, fishing, and forestry occupations	66	1.9
Construction, extraction, and maintenance occupations	480	13.5
Production, transportation, and material moving occupations	644	18.1
INDUSTRY		
Agriculture, forestry, fishing and hunting, and mining	174	4.9
Construction	364	10.2
Manufacturing	506	14.2
Wholesale trade	103	2.9
Retail trade	379	10.7
Transportation and warehousing, and utilities	263	7.4
Information	32	0.9
Finance, insurance, real estate, and rental and leasing	133	3.7
Professional, scientific, management, administrative, and waste management services	117	3.3
Educational, health and social services	782	22.0
Arts, entertainment, recreation, accommodation and food services	127	3.6
Other services (except public administration)	239	6.7
Public administration	335	9.4
CLASS OF WORKER		
Private wage and salary workers	2,483	69.9
Government workers	823	23.2
Self-employed workers in own not incorporated business	240	6.8
Unpaid family workers	8	0.2

Subject	Number	Percent
INCOME IN 1999		
Households	2,947	100.0
Less than $10,000	505	17.1
$10,000 to $14,999	242	8.2
$15,000 to $24,999	461	15.6
$25,000 to $34,999	420	14.3
$35,000 to $49,999	556	18.9
$50,000 to $74,999	439	14.9
$75,000 to $99,999	152	5.2
$100,000 to $149,999	125	4.2
$150,000 to $199,999	28	1.0
$200,000 or more	19	0.6
Median household income (dollars)	30,240	(X)
With earnings	2,260	76.7
Mean earnings (dollars)[1]	40,300	(X)
With Social Security income	851	28.9
Mean Social Security income (dollars)[1]	9,448	(X)
With Supplemental Security Income	194	6.6
Mean Supplemental Security Income (dollars)[1]	5,441	(X)
With public assistance income	52	1.8
Mean public assistance income (dollars)[1]	2,600	(X)
With retirement income	372	12.6
Mean retirement income (dollars)[1]	14,142	(X)
Families	2,120	100.0
Less than $10,000	215	10.1
$10,000 to $14,999	131	6.2
$15,000 to $24,999	329	15.5
$25,000 to $34,999	268	12.6
$35,000 to $49,999	467	22.0
$50,000 to $74,999	413	19.5
$75,000 to $99,999	154	7.3
$100,000 to $149,999	104	4.9
$150,000 to $199,999	26	1.2
$200,000 or more	13	0.6
Median family income (dollars)	38,418	(X)
Per capita income (dollars)[1]	14,182	(X)
Median earnings (dollars):		
Male full-time, year-round workers	27,572	(X)
Female full-time, year-round workers	21,342	(X)

Subject	Number below poverty level	Percent below poverty level
POVERTY STATUS IN 1999		
Families	335	15.8
With related children under 18 years	218	18.6
With related children under 5 years	94	21.3
Families with female householder, no husband present	135	35.5
With related children under 18 years	106	41.1
With related children under 5 years	36	46.8
Individuals	1,485	19.9
18 years and over	987	18.0
65 years and over	208	23.9
Related children under 18 years	485	24.7
Related children 5 to 17 years	367	25.5
Unrelated individuals 15 years and over	389	35.2

-Represents zero or rounds to zero. (X) Not applicable.

[1]If the denominator of a mean value or per capita value is less than 30, then that value is calculated using a rounded aggregate in the numerator. See text.

Source: U.S. Bureau of the Census, Census 2000.

Table DP-3. Profile of Selected Economic Characteristics: 2000

Geographic area: Tattnall County, Georgia

[Data based on a sample. For information on confidentiality protection, sampling error, nonsampling error, and definitions, see text]

Subject	Number	Percent
EMPLOYMENT STATUS		
Population 16 years and over	17,751	100.0
In labor force	8,650	48.7
Civilian labor force	8,583	48.4
Employed	7,996	45.0
Unemployed	587	3.3
Percent of civilian labor force	6.8	(X)
Armed Forces	67	0.4
Not in labor force	9,101	51.3
Females 16 years and over	7,242	100.0
In labor force	3,706	51.2
Civilian labor force	3,699	51.1
Employed	3,430	47.4
Own children under 6 years	1,503	100.0
All parents in family in labor force	821	54.6
COMMUTING TO WORK		
Workers 16 years and over	7,880	100.0
Car, truck, or van - - drove alone	5,650	71.7
Car, truck, or van - - carpooled	1,469	18.6
Public transportation (including taxicab)	33	0.4
Walked	173	2.2
Other means	345	4.4
Worked at home	210	2.7
Mean travel time to work (minutes)[1]	27.5	(X)
Employed civilian population 16 years and over	7,996	100.0
OCCUPATION		
Management, professional, and related occupations	1,860	23.3
Service occupations	1,306	16.3
Sales and office occupations	1,621	20.3
Farming, fishing, and forestry occupations	760	9.5
Construction, extraction, and maintenance occupations	1,116	14.0
Production, transportation, and material moving occupations	1,333	16.7
INDUSTRY		
Agriculture, forestry, fishing and hunting, and mining	1,154	14.4
Construction	705	8.8
Manufacturing	903	11.3
Wholesale trade	241	3.0
Retail trade	796	10.0
Transportation and warehousing, and utilities	400	5.0
Information	98	1.2
Finance, insurance, real estate, and rental and leasing	233	2.9
Professional, scientific, management, administrative, and waste management services	281	3.5
Educational, health and social services	1,484	18.6
Arts, entertainment, recreation, accommodation and food services	258	3.2
Other services (except public administration)	398	5.0
Public administration	1,045	13.1
CLASS OF WORKER		
Private wage and salary workers	5,397	67.5
Government workers	2,007	25.1
Self-employed workers in own not incorporated business	559	7.0
Unpaid family workers	33	0.4

Subject	Number	Percent
INCOME IN 1999		
Households	7,059	100.0
Less than $10,000	1,313	18.6
$10,000 to $14,999	717	10.2
$15,000 to $24,999	1,112	15.8
$25,000 to $34,999	939	13.3
$35,000 to $49,999	1,147	16.2
$50,000 to $74,999	1,212	17.2
$75,000 to $99,999	308	4.4
$100,000 to $149,999	241	3.4
$150,000 to $199,999	36	0.5
$200,000 or more	34	0.5
Median household income (dollars)	28,664	(X)
With earnings	5,378	76.2
Mean earnings (dollars)[1]	39,768	(X)
With Social Security income	2,040	28.9
Mean Social Security income (dollars)[1]	9,161	(X)
With Supplemental Security Income	460	6.5
Mean Supplemental Security Income (dollars)[1]	5,697	(X)
With public assistance income	367	5.2
Mean public assistance income (dollars)[1]	2,933	(X)
With retirement income	1,210	17.1
Mean retirement income (dollars)[1]	15,283	(X)
Families	4,903	100.0
Less than $10,000	600	12.2
$10,000 to $14,999	379	7.7
$15,000 to $24,999	711	14.5
$25,000 to $34,999	701	14.3
$35,000 to $49,999	959	19.6
$50,000 to $74,999	1,042	21.3
$75,000 to $99,999	247	5.0
$100,000 to $149,999	197	4.0
$150,000 to $199,999	36	0.7
$200,000 or more	31	0.6
Median family income (dollars)	35,951	(X)
Per capita income (dollars)[1]	13,439	(X)
Median earnings (dollars):		
Male full-time, year-round workers	28,994	(X)
Female full-time, year-round workers	19,984	(X)

Subject	Number below poverty level	Percent below poverty level
POVERTY STATUS IN 1999		
Families	910	18.6
With related children under 18 years	687	26.3
With related children under 5 years	308	28.8
Families with female householder, no husband present	431	43.5
With related children under 18 years	372	54.0
With related children under 5 years	121	58.2
Individuals	4,369	23.9
18 years and over	2,662	20.1
65 years and over	438	20.2
Related children under 18 years	1,639	32.9
Related children 5 to 17 years	1,211	32.9
Unrelated individuals 15 years and over	1,089	35.4

-Represents zero or rounds to zero. (X) Not applicable.

[1]If the denominator of a mean value or per capita value is less than 30, then that value is calculated using a rounded aggregate in the numerator. See text.

Source: U.S. Bureau of the Census, Census 2000.

Table DP-3. Profile of Selected Economic Characteristics: 2000

Geographic area: Toombs County, Georgia

[Data based on a sample. For information on confidentiality protection, sampling error, nonsampling error, and definitions, see text]

Subject	Number	Percent
EMPLOYMENT STATUS		
Population 16 years and over	19,419	100.0
In labor force	11,660	60.0
Civilian labor force	11,656	60.0
Employed	10,987	56.6
Unemployed	669	3.4
Percent of civilian labor force	5.7	(X)
Armed Forces	4	-
Not in labor force	7,759	40.0
Females 16 years and over	10,428	100.0
In labor force	5,273	50.6
Civilian labor force	5,273	50.6
Employed	4,945	47.4
Own children under 6 years	2,314	100.0
All parents in family in labor force	1,412	61.0
COMMUTING TO WORK		
Workers 16 years and over	10,823	100.0
Car, truck, or van - - drove alone	8,456	78.1
Car, truck, or van - - carpooled	1,842	17.0
Public transportation (including taxicab)	72	0.7
Walked	229	2.1
Other means	102	0.9
Worked at home	122	1.1
Mean travel time to work (minutes)[1]	21.9	(X)
Employed civilian population 16 years and over	10,987	100.0
OCCUPATION		
Management, professional, and related occupations	2,968	27.0
Service occupations	1,783	16.2
Sales and office occupations	2,380	21.7
Farming, fishing, and forestry occupations	631	5.7
Construction, extraction, and maintenance occupations	1,292	11.8
Production, transportation, and material moving occupations	1,933	17.6
INDUSTRY		
Agriculture, forestry, fishing and hunting, and mining	899	8.2
Construction	883	8.0
Manufacturing	1,634	14.9
Wholesale trade	481	4.4
Retail trade	1,084	9.9
Transportation and warehousing, and utilities	842	7.7
Information	141	1.3
Finance, insurance, real estate, and rental and leasing	352	3.2
Professional, scientific, management, administrative, and waste management services	515	4.7
Educational, health and social services	2,020	18.4
Arts, entertainment, recreation, accommodation and food services	658	6.0
Other services (except public administration)	503	4.6
Public administration	975	8.9
CLASS OF WORKER		
Private wage and salary workers	8,187	74.5
Government workers	2,144	19.5
Self-employed workers in own not incorporated business	641	5.8
Unpaid family workers	15	0.1

Subject	Number	Percent
INCOME IN 1999		
Households	9,870	100.0
Less than $10,000	1,889	19.1
$10,000 to $14,999	1,090	11.0
$15,000 to $24,999	1,575	16.0
$25,000 to $34,999	1,313	13.3
$35,000 to $49,999	1,431	14.5
$50,000 to $74,999	1,467	14.9
$75,000 to $99,999	584	5.9
$100,000 to $149,999	368	3.7
$150,000 to $199,999	83	0.8
$200,000 or more	70	0.7
Median household income (dollars)	26,811	(X)
With earnings	7,494	75.9
Mean earnings (dollars)[1]	38,137	(X)
With Social Security income	2,805	28.4
Mean Social Security income (dollars)[1]	9,391	(X)
With Supplemental Security Income	812	8.2
Mean Supplemental Security Income (dollars)[1]	4,422	(X)
With public assistance income	487	4.9
Mean public assistance income (dollars)[1]	1,513	(X)
With retirement income	1,214	12.3
Mean retirement income (dollars)[1]	15,055	(X)
Families	6,875	100.0
Less than $10,000	784	11.4
$10,000 to $14,999	643	9.4
$15,000 to $24,999	1,096	15.9
$25,000 to $34,999	960	14.0
$35,000 to $49,999	1,141	16.6
$50,000 to $74,999	1,257	18.3
$75,000 to $99,999	507	7.4
$100,000 to $149,999	360	5.2
$150,000 to $199,999	72	1.0
$200,000 or more	55	0.8
Median family income (dollars)	34,478	(X)
Per capita income (dollars)[1]	14,252	(X)
Median earnings (dollars):		
Male full-time, year-round workers	26,988	(X)
Female full-time, year-round workers	18,051	(X)

Subject	Number below poverty level	Percent below poverty level
POVERTY STATUS IN 1999		
Families	1,227	17.8
With related children under 18 years	1,047	26.9
With related children under 5 years	541	34.9
Families with female householder, no husband present	592	38.6
With related children under 18 years	541	45.9
With related children under 5 years	279	59.6
Individuals	6,098	23.9
18 years and over	3,570	19.6
65 years and over	527	18.3
Related children under 18 years	2,473	33.8
Related children 5 to 17 years	1,668	31.7
Unrelated individuals 15 years and over	1,522	37.2

-Represents zero or rounds to zero. (X) Not applicable.

[1]If the denominator of a mean value or per capita value is less than 30, then that value is calculated using a rounded aggregate in the numerator. See text.

Source: U.S. Bureau of the Census, Census 2000.

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Table DP-1. Profile of General Demographic Characteristics: 2000

Geographic area: Autauga County, Alabama

[For information on confidentiality protection, nonsampling error, and definitions, see text]

Subject	Number	Percent
Total population	43,671	100.0
SEX AND AGE		
Male	21,221	48.6
Female	22,450	51.4
Under 5 years	3,023	6.9
5 to 9 years	3,618	8.3
10 to 14 years	3,738	8.6
15 to 19 years	3,262	7.5
20 to 24 years	2,344	5.4
25 to 34 years	5,740	13.1
35 to 44 years	7,669	17.6
45 to 54 years	5,635	12.9
55 to 59 years	2,291	5.2
60 to 64 years	1,900	4.4
65 to 74 years	2,681	6.1
75 to 84 years	1,342	3.1
85 years and over	428	1.0
Median age (years)	35.1	(X)
18 years and over	31,177	71.4
Male	14,820	33.9
Female	16,357	37.5
21 years and over	29,538	67.6
62 years and over	5,537	12.7
65 years and over	4,451	10.2
Male	1,817	4.2
Female	2,634	6.0
RACE		
One race	43,266	99.1
White	35,221	80.7
Black or African American	7,473	17.1
American Indian and Alaska Native	194	0.4
Asian	200	0.5
Asian Indian	19	-
Chinese	24	0.1
Filipino	28	0.1
Japanese	39	0.1
Korean	36	0.1
Vietnamese	22	0.1
Other Asian [1]	32	0.1
Native Hawaiian and Other Pacific Islander	13	-
Native Hawaiian	2	-
Guamanian or Chamorro	5	-
Samoan	2	-
Other Pacific Islander [2]	4	-
Some other race	165	0.4
Two or more races	405	0.9
Race alone or in combination with one or more other races: [3]		
White	35,589	81.5
Black or African American	7,549	17.3
American Indian and Alaska Native	410	0.9
Asian	297	0.7
Native Hawaiian and Other Pacific Islander	25	0.1
Some other race	223	0.5

Subject	Number	Percent
HISPANIC OR LATINO AND RACE		
Total population	43,671	100.0
Hispanic or Latino (of any race)	610	1.4
Mexican	302	0.7
Puerto Rican	123	0.3
Cuban	7	-
Other Hispanic or Latino	178	0.4
Not Hispanic or Latino	43,061	98.6
White alone	34,823	79.7
RELATIONSHIP		
Total population	43,671	100.0
In households	43,411	99.4
Householder	16,003	36.6
Spouse	9,653	22.1
Child	14,238	32.6
Own child under 18 years	11,201	25.6
Other relatives	2,260	5.2
Under 18 years	1,113	2.5
Nonrelatives	1,257	2.9
Unmarried partner	550	1.3
In group quarters	260	0.6
Institutionalized population	181	0.4
Noninstitutionalized population	79	0.2
HOUSEHOLD BY TYPE		
Total households	16,003	100.0
Family households (families)	12,353	77.2
With own children under 18 years	6,258	39.1
Married-couple family	9,653	60.3
With own children under 18 years	4,723	29.5
Female householder, no husband present	2,098	13.1
With own children under 18 years	1,199	7.5
Nonfamily households	3,650	22.8
Householder living alone	3,185	19.9
Householder 65 years and over	1,223	7.6
Households with individuals under 18 years	6,880	43.0
Households with individuals 65 years and over	3,316	20.7
Average household size	2.71	(X)
Average family size	3.12	(X)
HOUSING OCCUPANCY		
Total housing units	17,662	100.0
Occupied housing units	16,003	90.6
Vacant housing units	1,659	9.4
For seasonal, recreational, or occasional use	158	0.9
Homeowner vacancy rate (percent)	1.8	(X)
Rental vacancy rate (percent)	14.6	(X)
HOUSING TENURE		
Occupied housing units	16,003	100.0
Owner-occupied housing units	12,929	80.8
Renter-occupied housing units	3,074	19.2
Average household size of owner-occupied units	2.71	(X)
Average household size of renter-occupied units	2.71	(X)

- Represents zero or rounds to zero. (X) Not applicable.

[1] Other Asian alone, or two or more Asian categories.

[2] Other Pacific Islander alone, or two or more Native Hawaiian and Other Pacific Islander categories.

[3] In combination with one or more of the other races listed. The six numbers may add to more than the total population and the six percentages may add to more than 100 percent because individuals may report more than one race.

Source: U.S. Census Bureau, Census 2000.

Table DP-1. Profile of General Demographic Characteristics: 2000

Geographic area: Chilton County, Alabama

[For information on confidentiality protection, nonsampling error, and definitions, see text]

Subject	Number	Percent
Total population	39,593	100.0
SEX AND AGE		
Male	19,581	49.5
Female	20,012	50.5
Under 5 years	2,734	6.9
5 to 9 years	2,838	7.2
10 to 14 years	2,896	7.3
15 to 19 years	2,710	6.8
20 to 24 years	2,586	6.5
25 to 34 years	5,483	13.8
35 to 44 years	5,999	15.2
45 to 54 years	5,255	13.3
55 to 59 years	2,166	5.5
60 to 64 years	1,829	4.6
65 to 74 years	2,869	7.2
75 to 84 years	1,672	4.2
85 years and over	556	1.4
Median age (years)	35.9	(X)
18 years and over	29,428	74.3
Male	14,254	36.0
Female	15,174	38.3
21 years and over	27,893	70.4
62 years and over	6,169	15.6
65 years and over	5,097	12.9
Male	2,109	5.3
Female	2,988	7.5
RACE		
One race	39,318	99.3
White	34,330	86.7
Black or African American	4,200	10.6
American Indian and Alaska Native	111	0.3
Asian	72	0.2
Asian Indian	1	-
Chinese	14	-
Filipino	25	0.1
Japanese	7	-
Korean	9	-
Vietnamese	5	-
Other Asian [1]	11	-
Native Hawaiian and Other Pacific Islander	6	-
Native Hawaiian	-	-
Guamanian or Chamorro	-	-
Samoan	3	-
Other Pacific Islander [2]	3	-
Some other race	599	1.5
Two or more races	275	0.7
Race alone or in combination with one or more other races: [3]		
White	34,578	87.3
Black or African American	4,259	10.8
American Indian and Alaska Native	269	0.7
Asian	113	0.3
Native Hawaiian and Other Pacific Islander	11	-
Some other race	657	1.7

Subject	Number	Percent
HISPANIC OR LATINO AND RACE		
Total population	39,593	100.0
Hispanic or Latino (of any race)	1,152	2.9
Mexican	910	2.3
Puerto Rican	38	0.1
Cuban	25	0.1
Other Hispanic or Latino	179	0.5
Not Hispanic or Latino	38,441	97.1
White alone	33,897	85.6
RELATIONSHIP		
Total population	39,593	100.0
In households	39,242	99.1
Householder	15,287	38.6
Spouse	9,185	23.2
Child	11,607	29.3
Own child under 18 years	9,062	22.9
Other relatives	1,915	4.8
Under 18 years	855	2.2
Nonrelatives	1,248	3.2
Unmarried partner	486	1.2
In group quarters	351	0.9
Institutionalized population	302	0.8
Noninstitutionalized population	49	0.1
HOUSEHOLD BY TYPE		
Total households	15,287	100.0
Family households (families)	11,339	74.2
With own children under 18 years	5,260	34.4
Married-couple family	9,185	60.1
With own children under 18 years	4,089	26.7
Female householder, no husband present	1,598	10.5
With own children under 18 years	900	5.9
Nonfamily households	3,948	25.8
Householder living alone	3,498	22.9
Householder 65 years and over	1,564	10.2
Households with individuals under 18 years	5,804	38.0
Households with individuals 65 years and over	3,780	24.7
Average household size	2.57	(X)
Average family size	3.00	(X)
HOUSING OCCUPANCY		
Total housing units	17,651	100.0
Occupied housing units	15,287	86.6
Vacant housing units	2,364	13.4
For seasonal, recreational, or occasional use	851	4.8
Homeowner vacancy rate (percent)	1.8	(X)
Rental vacancy rate (percent)	9.9	(X)
HOUSING TENURE		
Occupied housing units	15,287	100.0
Owner-occupied housing units	12,576	82.3
Renter-occupied housing units	2,711	17.7
Average household size of owner-occupied units	2.58	(X)
Average household size of renter-occupied units	2.51	(X)

- Represents zero or rounds to zero. (X) Not applicable.

[1] Other Asian alone, or two or more Asian categories.

[2] Other Pacific Islander alone, or two or more Native Hawaiian and Other Pacific Islander categories.

[3] In combination with one or more of the other races listed. The six numbers may add to more than the total population and the six percentages may add to more than 100 percent because individuals may report more than one race.

Source: U.S. Census Bureau, Census 2000.

Table DP-1. Profile of General Demographic Characteristics: 2000

Geographic area: Coosa County, Alabama

[For information on confidentiality protection, nonsampling error, and definitions, see text]

Subject	Number	Percent
Total population	12,202	100.0
SEX AND AGE		
Male	6,232	51.1
Female	5,970	48.9
Under 5 years	759	6.2
5 to 9 years	797	6.5
10 to 14 years	845	6.9
15 to 19 years	821	6.7
20 to 24 years	716	5.9
25 to 34 years	1,648	13.5
35 to 44 years	1,896	15.5
45 to 54 years	1,689	13.8
55 to 59 years	676	5.5
60 to 64 years	594	4.9
65 to 74 years	1,008	8.3
75 to 84 years	560	4.6
85 years and over	193	1.6
Median age (years)	37.7	(X)
18 years and over	9,311	76.3
Male	4,712	38.6
Female	4,599	37.7
21 years and over	8,816	72.3
62 years and over	2,113	17.3
65 years and over	1,761	14.4
Male	773	6.3
Female	988	8.1
RACE		
One race	12,095	99.1
White	7,802	63.9
Black or African American	4,172	34.2
American Indian and Alaska Native	39	0.3
Asian	5	-
Asian Indian	2	-
Chinese	1	-
Filipino	1	-
Japanese	1	-
Korean	-	-
Vietnamese	-	-
Other Asian [1]	-	-
Native Hawaiian and Other Pacific Islander	1	-
Native Hawaiian	-	-
Guamanian or Chamorro	-	-
Samoan	1	-
Other Pacific Islander [2]	-	-
Some other race	76	0.6
Two or more races	107	0.9
Race alone or in combination with one or more other races: [3]		
White	7,893	64.7
Black or African American	4,197	34.4
American Indian and Alaska Native	100	0.8
Asian	13	0.1
Native Hawaiian and Other Pacific Islander	2	-
Some other race	111	0.9

Subject	Number	Percent
HISPANIC OR LATINO AND RACE		
Total population	12,202	100.0
Hispanic or Latino (of any race)	158	1.3
Mexican	106	0.9
Puerto Rican	3	-
Cuban	6	-
Other Hispanic or Latino	43	0.4
Not Hispanic or Latino	12,044	98.7
White alone	7,742	63.4
RELATIONSHIP		
Total population	12,202	100.0
In households	11,810	96.8
Householder	4,682	38.4
Spouse	2,568	21.0
Child	3,384	27.7
Own child under 18 years	2,441	20.0
Other relatives	806	6.6
Under 18 years	400	3.3
Nonrelatives	370	3.0
Unmarried partner	167	1.4
In group quarters	392	3.2
Institutionalized population	392	3.2
Noninstitutionalized population	-	-
HOUSEHOLD BY TYPE		
Total households	4,682	100.0
Family households (families)	3,407	72.8
With own children under 18 years	1,403	30.0
Married-couple family	2,568	54.8
With own children under 18 years	991	21.2
Female householder, no husband present	633	13.5
With own children under 18 years	321	6.9
Nonfamily households	1,275	27.2
Householder living alone	1,140	24.3
Householder 65 years and over	459	9.8
Households with individuals under 18 years	1,629	34.8
Households with individuals 65 years and over	1,294	27.6
Average household size	2.52	(X)
Average family size	2.98	(X)
HOUSING OCCUPANCY		
Total housing units	6,142	100.0
Occupied housing units	4,682	76.2
Vacant housing units	1,460	23.8
For seasonal, recreational, or occasional use	794	12.9
Homeowner vacancy rate (percent)	2.0	(X)
Rental vacancy rate (percent)	11.1	(X)
HOUSING TENURE		
Occupied housing units	4,682	100.0
Owner-occupied housing units	3,970	84.8
Renter-occupied housing units	712	15.2
Average household size of owner-occupied units	2.55	(X)
Average household size of renter-occupied units	2.39	(X)

- Represents zero or rounds to zero. (X) Not applicable.

[1] Other Asian alone, or two or more Asian categories.

[2] Other Pacific Islander alone, or two or more Native Hawaiian and Other Pacific Islander categories.

[3] In combination with one or more of the other races listed. The six numbers may add to more than the total population and the six percentages may add to more than 100 percent because individuals may report more than one race.

Source: U.S. Census Bureau, Census 2000.

Table DP-1. Profile of General Demographic Characteristics: 2000

Geographic area: Elmore County, Alabama

[For information on confidentiality protection, nonsampling error, and definitions, see text]

Subject	Number	Percent
Total population	65,874	100.0
SEX AND AGE		
Male	33,342	50.6
Female	32,532	49.4
Under 5 years	4,370	6.6
5 to 9 years	4,801	7.3
10 to 14 years	4,882	7.4
15 to 19 years	4,543	6.9
20 to 24 years	4,116	6.2
25 to 34 years	9,916	15.1
35 to 44 years	11,213	17.0
45 to 54 years	9,154	13.9
55 to 59 years	3,148	4.8
60 to 64 years	2,660	4.0
65 to 74 years	3,879	5.9
75 to 84 years	2,343	3.6
85 years and over	849	1.3
Median age (years)	35.3	(X)
18 years and over	48,950	74.3
Male	24,631	37.4
Female	24,319	36.9
21 years and over	46,450	70.5
62 years and over	8,645	13.1
65 years and over	7,071	10.7
Male	2,915	4.4
Female	4,156	6.3
RACE		
One race	65,189	99.0
White	50,737	77.0
Black or African American	13,597	20.6
American Indian and Alaska Native	286	0.4
Asian	238	0.4
Asian Indian	25	-
Chinese	19	-
Filipino	35	0.1
Japanese	23	-
Korean	29	-
Vietnamese	9	-
Other Asian [1]	98	0.1
Native Hawaiian and Other Pacific Islander	18	-
Native Hawaiian	6	-
Guamanian or Chamorro	8	-
Samoan	-	-
Other Pacific Islander [2]	4	-
Some other race	313	0.5
Two or more races	685	1.0
Race alone or in combination with one or more other races: [3]		
White	51,338	77.9
Black or African American	13,814	21.0
American Indian and Alaska Native	663	1.0
Asian	362	0.5
Native Hawaiian and Other Pacific Islander	36	0.1
Some other race	413	0.6

Subject	Number	Percent
HISPANIC OR LATINO AND RACE		
Total population	65,874	100.0
Hispanic or Latino (of any race)	805	1.2
Mexican	416	0.6
Puerto Rican	93	0.1
Cuban	15	-
Other Hispanic or Latino	281	0.4
Not Hispanic or Latino	65,069	98.8
White alone	50,376	76.5
RELATIONSHIP		
Total population	65,874	100.0
In households	60,533	91.9
Householder	22,737	34.5
Spouse	13,952	21.2
Child	19,144	29.1
Own child under 18 years	15,159	23.0
Other relatives	3,130	4.8
Under 18 years	1,518	2.3
Nonrelatives	1,570	2.4
Unmarried partner	750	1.1
In group quarters	5,341	8.1
Institutionalized population	5,333	8.1
Noninstitutionalized population	8	-
HOUSEHOLD BY TYPE		
Total households	22,737	100.0
Family households (families)	17,542	77.2
With own children under 18 years	8,497	37.4
Married-couple family	13,952	61.4
With own children under 18 years	6,431	28.3
Female householder, no husband present	2,734	12.0
With own children under 18 years	1,625	7.1
Nonfamily households	5,195	22.8
Householder living alone	4,551	20.0
Householder 65 years and over	1,743	7.7
Households with individuals under 18 years	9,306	40.9
Households with individuals 65 years and over	4,872	21.4
Average household size	2.66	(X)
Average family size	3.07	(X)
HOUSING OCCUPANCY		
Total housing units	25,733	100.0
Occupied housing units	22,737	88.4
Vacant housing units	2,996	11.6
For seasonal, recreational, or occasional use	945	3.7
Homeowner vacancy rate (percent)	2.2	(X)
Rental vacancy rate (percent)	12.2	(X)
HOUSING TENURE		
Occupied housing units	22,737	100.0
Owner-occupied housing units	18,493	81.3
Renter-occupied housing units	4,244	18.7
Average household size of owner-occupied units	2.70	(X)
Average household size of renter-occupied units	2.51	(X)

- Represents zero or rounds to zero. (X) Not applicable.

[1] Other Asian alone, or two or more Asian categories.

[2] Other Pacific Islander alone, or two or more Native Hawaiian and Other Pacific Islander categories.

[3] In combination with one or more of the other races listed. The six numbers may add to more than the total population and the six percentages may add to more than 100 percent because individuals may report more than one race.

Source: U.S. Census Bureau, Census 2000.

USCS 2000*

Table DP-3. Profile of Selected Economic Characteristics: 2000

Geographic area: Autauga County, Alabama

[Data based on a sample. For information on confidentiality protection, sampling error, nonsampling error, and definitions, see text]

Subject	Number	Percent
EMPLOYMENT STATUS		
Population 16 years and over	32,490	100.0
In labor force	21,167	65.1
Civilian labor force	20,601	63.4
Employed	19,595	60.3
Unemployed	1,006	3.1
Percent of civilian labor force	4.9	(X)
Armed Forces	566	1.7
Not in labor force	11,323	34.9
Females 16 years and over	16,938	100.0
In labor force	9,571	56.5
Civilian labor force	9,510	56.1
Employed	9,012	53.2
Own children under 6 years	3,666	100.0
All parents in family in labor force	2,167	59.1
COMMUTING TO WORK		
Workers 16 years and over	19,808	100.0
Car, truck, or van - - drove alone	16,480	83.2
Car, truck, or van - - carpooled	2,635	13.3
Public transportation (including taxicab)	35	0.2
Walked	134	0.7
Other means	152	0.8
Worked at home	372	1.9
Mean travel time to work (minutes)[1]	26.5	(X)
Employed civilian population 16 years and over	19,595	100.0
OCCUPATION		
Management, professional, and related occupations	5,305	27.1
Service occupations	2,768	14.1
Sales and office occupations	5,625	28.7
Farming, fishing, and forestry occupations	164	0.8
Construction, extraction, and maintenance occupations	2,208	11.3
Production, transportation, and material moving occupations	3,525	18.0
INDUSTRY		
Agriculture, forestry, fishing and hunting, and mining	451	2.3
Construction	1,475	7.5
Manufacturing	3,229	16.5
Wholesale trade	834	4.3
Retail trade	2,517	12.8
Transportation and warehousing, and utilities	941	4.8
Information	373	1.9
Finance, insurance, real estate, and rental and leasing	1,279	6.5
Professional, scientific, management, administrative, and waste management services	1,339	6.8
Educational, health and social services	2,839	14.5
Arts, entertainment, recreation, accommodation and food services	1,315	6.7
Other services (except public administration)	973	5.0
Public administration	2,030	10.4
CLASS OF WORKER		
Private wage and salary workers	14,787	75.5
Government workers	3,652	18.6
Self-employed workers in own not incorporated business	1,106	5.6
Unpaid family workers	50	0.3

Subject	Number	Percent
INCOME IN 1999		
Households	15,972	100.0
Less than $10,000	1,635	10.2
$10,000 to $14,999	945	5.9
$15,000 to $24,999	2,003	12.5
$25,000 to $34,999	1,890	11.8
$35,000 to $49,999	2,934	18.4
$50,000 to $74,999	3,663	22.9
$75,000 to $99,999	1,689	10.6
$100,000 to $149,999	884	5.5
$150,000 to $199,999	144	0.9
$200,000 or more	185	1.2
Median household income (dollars)	42,013	(X)
With earnings	13,298	83.3
Mean earnings (dollars)[1]	49,219	(X)
With Social Security income	3,980	24.9
Mean Social Security income (dollars)[1]	10,179	(X)
With Supplemental Security Income	733	4.6
Mean Supplemental Security Income (dollars)[1]	5,437	(X)
With public assistance income	333	2.1
Mean public assistance income (dollars)[1]	2,024	(X)
With retirement income	3,142	19.7
Mean retirement income (dollars)[1]	19,429	(X)
Families	12,414	100.0
Less than $10,000	700	5.6
$10,000 to $14,999	486	3.9
$15,000 to $24,999	1,307	10.5
$25,000 to $34,999	1,446	11.6
$35,000 to $49,999	2,482	20.0
$50,000 to $74,999	3,268	26.3
$75,000 to $99,999	1,592	12.8
$100,000 to $149,999	832	6.7
$150,000 to $199,999	139	1.1
$200,000 or more	162	1.3
Median family income (dollars)	48,458	(X)
Per capita income (dollars)[1]	18,518	(X)
Median earnings (dollars):		
Male full-time, year-round workers	35,168	(X)
Female full-time, year-round workers	22,859	(X)

Subject	Number below poverty level	Percent below poverty level
POVERTY STATUS IN 1999		
Families	1,022	8.2
With related children under 18 years	730	10.8
With related children under 5 years	292	11.5
Families with female householder, no husband present	530	27.1
With related children under 18 years	459	35.1
With related children under 5 years	170	37.6
Individuals	4,738	10.9
18 years and over	3,042	9.8
65 years and over	626	14.4
Related children under 18 years	1,682	13.6
Related children 5 to 17 years	1,255	13.6
Unrelated individuals 15 years and over	1,185	25.7

-Represents zero or rounds to zero. (X) Not applicable.

[1]If the denominator of a mean value or per capita value is less than 30, then that value is calculated using a rounded aggregate in the numerator. See text.

Source: U.S. Bureau of the Census, Census 2000.

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Table DP-3. Profile of Selected Economic Characteristics: 2000

Geographic area: Chilton County, Alabama

[Data based on a sample. For information on confidentiality protection, sampling error, nonsampling error, and definitions, see text]

Subject	Number	Percent
EMPLOYMENT STATUS		
Population 16 years and over	30,545	100.0
In labor force	18,240	59.7
Civilian labor force	18,221	59.7
Employed	17,437	57.1
Unemployed	784	2.6
Percent of civilian labor force	4.3	(X)
Armed Forces	19	0.1
Not in labor force	12,305	40.3
Females 16 years and over	15,697	100.0
In labor force	7,680	48.9
Civilian labor force	7,680	48.9
Employed	7,309	46.6
Own children under 6 years	3,078	100.0
All parents in family in labor force	1,698	55.2
COMMUTING TO WORK		
Workers 16 years and over	17,151	100.0
Car, truck, or van - - drove alone	13,538	78.9
Car, truck, or van - - carpooled	2,868	16.7
Public transportation (including taxicab)	33	0.2
Walked	176	1.0
Other means	144	0.8
Worked at home	392	2.3
Mean travel time to work (minutes)[1]	33.2	(X)
Employed civilian population 16 years and over	17,437	100.0
OCCUPATION		
Management, professional, and related occupations	3,829	22.0
Service occupations	2,163	12.4
Sales and office occupations	4,456	25.6
Farming, fishing, and forestry occupations	248	1.4
Construction, extraction, and maintenance occupations	3,255	18.7
Production, transportation, and material moving occupations	3,486	20.0
INDUSTRY		
Agriculture, forestry, fishing and hunting, and mining	591	3.4
Construction	2,278	13.1
Manufacturing	2,949	16.9
Wholesale trade	656	3.8
Retail trade	2,248	12.9
Transportation and warehousing, and utilities	1,247	7.2
Information	464	2.7
Finance, insurance, real estate, and rental and leasing	1,136	6.5
Professional, scientific, management, administrative, and waste management services	931	5.3
Educational, health and social services	2,564	14.7
Arts, entertainment, recreation, accommodation and food services	875	5.0
Other services (except public administration)	900	5.2
Public administration	598	3.4
CLASS OF WORKER		
Private wage and salary workers	13,845	79.4
Government workers	2,081	11.9
Self-employed workers in own not incorporated business	1,464	8.4
Unpaid family workers	47	0.3

Subject	Number	Percent
INCOME IN 1999		
Households	15,270	100.0
Less than $10,000	2,137	14.0
$10,000 to $14,999	1,341	8.8
$15,000 to $24,999	2,190	14.3
$25,000 to $34,999	2,433	15.9
$35,000 to $49,999	2,651	17.4
$50,000 to $74,999	2,781	18.2
$75,000 to $99,999	1,132	7.4
$100,000 to $149,999	489	3.2
$150,000 to $199,999	33	0.2
$200,000 or more	83	0.5
Median household income (dollars)	32,588	(X)
With earnings	11,676	76.5
Mean earnings (dollars)[1]	41,260	(X)
With Social Security income	4,750	31.1
Mean Social Security income (dollars)[1]	9,636	(X)
With Supplemental Security Income	1,023	6.7
Mean Supplemental Security Income (dollars)[1]	5,675	(X)
With public assistance income	363	2.4
Mean public assistance income (dollars)[1]	2,235	(X)
With retirement income	2,521	16.5
Mean retirement income (dollars)[1]	13,272	(X)
Families	11,395	100.0
Less than $10,000	877	7.7
$10,000 to $14,999	743	6.5
$15,000 to $24,999	1,454	12.8
$25,000 to $34,999	1,846	16.2
$35,000 to $49,999	2,228	19.6
$50,000 to $74,999	2,573	22.6
$75,000 to $99,999	1,092	9.6
$100,000 to $149,999	481	4.2
$150,000 to $199,999	26	0.2
$200,000 or more	75	0.7
Median family income (dollars)	39,505	(X)
Per capita income (dollars)[1]	15,303	(X)
Median earnings (dollars):		
Male full-time, year-round workers	31,006	(X)
Female full-time, year-round workers	21,275	(X)

Subject	Number below poverty level	Percent below poverty level
POVERTY STATUS IN 1999		
Families	1,438	12.6
With related children under 18 years	948	16.2
With related children under 5 years	394	19.6
Families with female householder, no husband present	552	37.7
With related children under 18 years	502	46.2
With related children under 5 years	212	59.4
Individuals	6,152	15.7
18 years and over	4,151	14.3
65 years and over	891	18.2
Related children under 18 years	1,942	19.4
Related children 5 to 17 years	1,392	18.9
Unrelated individuals 15 years and over	1,580	32.9

-Represents zero or rounds to zero. (X) Not applicable.

[1] If the denominator of a mean value or per capita value is less than 30, then that value is calculated using a rounded aggregate in the numerator. See text.

Source: U.S. Bureau of the Census, Census 2000.

Table DP-3. Profile of Selected Economic Characteristics: 2000

Geographic area: Coosa County, Alabama

[Data based on a sample. For information on confidentiality protection, sampling error, nonsampling error, and definitions, see text]

Subject	Number	Percent
EMPLOYMENT STATUS		
Population 16 years and over	9,609	100.0
In labor force	5,220	54.3
Civilian labor force	5,210	54.2
Employed	4,841	50.4
Unemployed	369	3.8
Percent of civilian labor force	7.1	(X)
Armed Forces	10	0.1
Not in labor force	4,389	45.7
Females 16 years and over	4,772	100.0
In labor force	2,378	49.8
Civilian labor force	2,378	49.8
Employed	2,182	45.7
Own children under 6 years	848	100.0
All parents in family in labor force	488	57.5
COMMUTING TO WORK		
Workers 16 years and over	4,750	100.0
Car, truck, or van - - drove alone	3,946	83.1
Car, truck, or van - - carpooled	652	13.7
Public transportation (including taxicab)	20	0.4
Walked	34	0.7
Other means	32	0.7
Worked at home	66	1.4
Mean travel time to work (minutes)[1]	27.7	(X)
Employed civilian population 16 years and over	4,841	100.0
OCCUPATION		
Management, professional, and related occupations	788	16.3
Service occupations	705	14.6
Sales and office occupations	959	19.8
Farming, fishing, and forestry occupations	34	0.7
Construction, extraction, and maintenance occupations	694	14.3
Production, transportation, and material moving occupations	1,661	34.3
INDUSTRY		
Agriculture, forestry, fishing and hunting, and mining	140	2.9
Construction	372	7.7
Manufacturing	1,796	37.1
Wholesale trade	168	3.5
Retail trade	454	9.4
Transportation and warehousing, and utilities	258	5.3
Information	30	0.6
Finance, insurance, real estate, and rental and leasing	107	2.2
Professional, scientific, management, administrative, and waste management services	193	4.0
Educational, health and social services	710	14.7
Arts, entertainment, recreation, accommodation and food services	204	4.2
Other services (except public administration)	201	4.2
Public administration	208	4.3
CLASS OF WORKER		
Private wage and salary workers	3,980	82.2
Government workers	604	12.5
Self-employed workers in own not incorporated business	257	5.3
Unpaid family workers	-	-

Subject	Number	Percent
INCOME IN 1999		
Households	4,694	100.0
Less than $10,000	711	15.1
$10,000 to $14,999	411	8.8
$15,000 to $24,999	859	18.3
$25,000 to $34,999	699	14.9
$35,000 to $49,999	902	19.2
$50,000 to $74,999	719	15.3
$75,000 to $99,999	229	4.9
$100,000 to $149,999	97	2.1
$150,000 to $199,999	21	0.4
$200,000 or more	46	1.0
Median household income (dollars)	29,873	(X)
With earnings	3,558	75.8
Mean earnings (dollars)[1]	38,608	(X)
With Social Security income	1,513	32.2
Mean Social Security income (dollars)[1]	10,308	(X)
With Supplemental Security Income	367	7.8
Mean Supplemental Security Income (dollars)[1]	4,957	(X)
With public assistance income	111	2.4
Mean public assistance income (dollars)[1]	2,221	(X)
With retirement income	884	18.8
Mean retirement income (dollars)[1]	14,374	(X)
Families	3,460	100.0
Less than $10,000	276	8.0
$10,000 to $14,999	229	6.6
$15,000 to $24,999	632	18.3
$25,000 to $34,999	506	14.6
$35,000 to $49,999	816	23.6
$50,000 to $74,999	620	17.9
$75,000 to $99,999	229	6.6
$100,000 to $149,999	85	2.5
$150,000 to $199,999	21	0.6
$200,000 or more	46	1.3
Median family income (dollars)	36,082	(X)
Per capita income (dollars)[1]	14,875	(X)
Median earnings (dollars):		
Male full-time, year-round workers	25,390	(X)
Female full-time, year-round workers	18,171	(X)

Subject	Number below poverty level	Percent below poverty level
POVERTY STATUS IN 1999		
Families	410	11.8
With related children under 18 years	277	16.6
With related children under 5 years	108	17.9
Families with female householder, no husband present	201	34.6
With related children under 18 years	177	47.7
With related children under 5 years	91	58.7
Individuals	1,760	14.9
18 years and over	1,198	13.4
65 years and over	227	13.4
Related children under 18 years	562	19.5
Related children 5 to 17 years	432	20.1
Unrelated individuals 15 years and over	450	31.3

-Represents zero or rounds to zero. (X) Not applicable.

[1]If the denominator of a mean value or per capita value is less than 30, then that value is calculated using a rounded aggregate in the numerator. See text.

Source: U.S. Bureau of the Census, Census 2000.

Table DP-3. Profile of Selected Economic Characteristics: 2000

Geographic area: Elmore County, Alabama

[Data based on a sample. For information on confidentiality protection, sampling error, nonsampling error, and definitions, see text]

Subject	Number	Percent
EMPLOYMENT STATUS		
Population 16 years and over	50,934	100.0
In labor force	30,056	59.0
Civilian labor force	29,434	57.8
Employed	27,970	54.9
Unemployed	1,464	2.9
Percent of civilian labor force	5.0	(X)
Armed Forces	622	1.2
Not in labor force	20,878	41.0
Females 16 years and over	25,271	100.0
In labor force	13,978	55.3
Civilian labor force	13,858	54.8
Employed	13,103	51.8
Own children under 6 years	4,866	100.0
All parents in family in labor force	3,002	61.7
COMMUTING TO WORK		
Workers 16 years and over	28,143	100.0
Car, truck, or van - - drove alone	23,754	84.4
Car, truck, or van - - carpooled	3,395	12.1
Public transportation (including taxicab)	47	0.2
Walked	197	0.7
Other means	122	0.4
Worked at home	628	2.2
Mean travel time to work (minutes)[1]	28.7	(X)
Employed civilian population 16 years and over	27,970	100.0
OCCUPATION		
Management, professional, and related occupations	8,141	29.1
Service occupations	3,505	12.5
Sales and office occupations	7,734	27.7
Farming, fishing, and forestry occupations	188	0.7
Construction, extraction, and maintenance occupations	3,758	13.4
Production, transportation, and material moving occupations	4,644	16.6
INDUSTRY		
Agriculture, forestry, fishing and hunting, and mining	389	1.4
Construction	2,772	9.9
Manufacturing	4,066	14.5
Wholesale trade	1,072	3.8
Retail trade	3,349	12.0
Transportation and warehousing, and utilities	1,449	5.2
Information	449	1.6
Finance, insurance, real estate, and rental and leasing	1,850	6.6
Professional, scientific, management, administrative, and waste management services	2,028	7.3
Educational, health and social services	4,707	16.8
Arts, entertainment, recreation, accommodation and food services	1,632	5.8
Other services (except public administration)	1,531	5.5
Public administration	2,676	9.6
CLASS OF WORKER		
Private wage and salary workers	20,717	74.1
Government workers	5,417	19.4
Self-employed workers in own not incorporated business	1,785	6.4
Unpaid family workers	51	0.2

Subject	Number	Percent
INCOME IN 1999		
Households	22,692	100.0
Less than $10,000	2,104	9.3
$10,000 to $14,999	1,265	5.6
$15,000 to $24,999	2,825	12.4
$25,000 to $34,999	3,225	14.2
$35,000 to $49,999	4,278	18.9
$50,000 to $74,999	4,942	21.8
$75,000 to $99,999	2,195	9.7
$100,000 to $149,999	1,300	5.7
$150,000 to $199,999	270	1.2
$200,000 or more	288	1.3
Median household income (dollars)	41,243	(X)
With earnings	18,610	82.0
Mean earnings (dollars)[1]	49,330	(X)
With Social Security income	5,886	25.9
Mean Social Security income (dollars)[1]	10,531	(X)
With Supplemental Security Income	930	4.1
Mean Supplemental Security Income (dollars)[1]	5,610	(X)
With public assistance income	284	1.3
Mean public assistance income (dollars)[1]	1,959	(X)
With retirement income	4,645	20.5
Mean retirement income (dollars)[1]	16,145	(X)
Families	17,583	100.0
Less than $10,000	827	4.7
$10,000 to $14,999	669	3.8
$15,000 to $24,999	1,851	10.5
$25,000 to $34,999	2,453	14.0
$35,000 to $49,999	3,573	20.3
$50,000 to $74,999	4,434	25.2
$75,000 to $99,999	2,066	11.7
$100,000 to $149,999	1,173	6.7
$150,000 to $199,999	267	1.5
$200,000 or more	270	1.5
Median family income (dollars)	47,155	(X)
Per capita income (dollars)[1]	17,650	(X)
Median earnings (dollars):		
Male full-time, year-round workers	32,643	(X)
Female full-time, year-round workers	24,062	(X)

Subject	Number below poverty level	Percent below poverty level
POVERTY STATUS IN 1999		
Families	1,298	7.4
With related children under 18 years	1,028	11.2
With related children under 5 years	462	13.9
Families with female householder, no husband present	730	27.8
With related children under 18 years	654	35.9
With related children under 5 years	321	50.6
Individuals	6,187	10.2
18 years and over	3,796	8.7
65 years and over	753	11.3
Related children under 18 years	2,356	14.2
Related children 5 to 17 years	1,739	13.9
Unrelated individuals 15 years and over	1,550	24.2

-Represents zero or rounds to zero. (X) Not applicable.

[1]If the denominator of a mean value or per capita value is less than 30, then that value is calculated using a rounded aggregate in the numerator. See text.

Source: U.S. Bureau of the Census, Census 2000.

V-440

USCB 2006a

METROPOLITAN STATISTICAL AREAS AND COMPONENTS, December 2005, WITH CODES

(Metropolitan statistical areas and metropolitan divisions defined by the Office of

Source: Population Division, U.S. Census Bureau
Internet Release Date: 1/19/2006
Last Revised: 1/19/2006

CBSA Code	Div Code	FIPS State/ County	Metropolitan Statistical Area and Division Titles and Compon
10180			Abilene, TX Metropolitan Statistical Area
10180		48059	Callahan County, TX
10180		48253	Jones County, TX
10180		48441	Taylor County, TX
10380			Aguadilla-Isabela-San Sebastián, PR Metropolitan Statistical
10380		72003	Aguada Municipio, PR
10380		72005	Aguadilla Municipio, PR
10380		72011	Añasco Municipio, PR
10380		72071	Isabela Municipio, PR
10380		72081	Lares Municipio, PR
10380		72099	Moca Municipio, PR
10380		72117	Rincón Municipio, PR
10380		72131	San Sebastián Municipio, PR
10420			Akron, OH Metropolitan Statistical Area
10420		39133	Portage County, OH
10420		39153	Summit County, OH
10500			Albany, GA Metropolitan Statistical Area
10500		13007	Baker County, GA
10500		13095	Dougherty County, GA
10500		13177	Lee County, GA
10500		13273	Terrell County, GA
10500		13321	Worth County, GA
10580			Albany-Schenectady-Troy, NY Metropolitan Statistical Area
10580		36001	Albany County, NY
10580		36083	Rensselaer County, NY
10580		36091	Saratoga County, NY
10580		36093	Schenectady County, NY
10580		36095	Schoharie County, NY
10740			Albuquerque, NM Metropolitan Statistical Area
10740		35001	Bernalillo County, NM
10740		35043	Sandoval County, NM
10740		35057	Torrance County, NM
10740		35061	Valencia County, NM
10780			Alexandria, LA Metropolitan Statistical Area
10780		22043	Grant Parish, LA
10780		22079	Rapides Parish, LA
10900			Allentown-Bethlehem-Easton, PA-NJ Metropolitan Statistical A
10900		34041	Warren County, NJ
10900		42025	Carbon County, PA
10900		42077	Lehigh County, PA
10900		42095	Northampton County, PA

11020		Altoona, PA Metropolitan Statistical Area
11020	42013	Blair County, PA
11100		Amarillo, TX Metropolitan Statistical Area
11100	48011	Armstrong County, TX
11100	48065	Carson County, TX
11100	48375	Potter County, TX
11100	48381	Randall County, TX
11180		Ames, IA Metropolitan Statistical Area
11180	19169	Story County, IA
11260		Anchorage, AK Metropolitan Statistical Area
11260	02020	Anchorage Municipality, AK
11260	02170	Matanuska-Susitna Borough, AK
11300		Anderson, IN Metropolitan Statistical Area
11300	18095	Madison County, IN
11340		Anderson, SC Metropolitan Statistical Area
11340	45007	Anderson County, SC
11460		Ann Arbor, MI Metropolitan Statistical Area
11460	26161	Washtenaw County, MI
11500		Anniston-Oxford, AL Metropolitan Statistical Area
11500	01015	Calhoun County, AL
11540		Appleton, WI Metropolitan Statistical Area
11540	55015	Calumet County, WI
11540	55087	Outagamie County, WI
11700		Asheville, NC Metropolitan Statistical Area
11700	37021	Buncombe County, NC
11700	37087	Haywood County, NC
11700	37089	Henderson County, NC
11700	37115	Madison County, NC
12020		Athens-Clarke County, GA Metropolitan Statistical Area
12020	13059	Clarke County, GA
12020	13195	Madison County, GA
12020	13219	Oconee County, GA
12020	13221	Oglethorpe County, GA
12060		Atlanta-Sandy Springs-Marietta, GA Metropolitan Statistical
12060	13013	Barrow County, GA
12060	13015	Bartow County, GA
12060	13035	Butts County, GA
12060	13045	Carroll County, GA
12060	13057	Cherokee County, GA
12060	13063	Clayton County, GA
12060	13067	Cobb County, GA
12060	13077	Coweta County, GA
12060	13085	Dawson County, GA
12060	13089	DeKalb County, GA
12060	13097	Douglas County, GA
12060	13113	Fayette County, GA
12060	13117	Forsyth County, GA
12060	13121	Fulton County, GA
12060	13135	Gwinnett County, GA

12060	13143	Haralson County, GA
12060	13149	Heard County, GA
12060	13151	Henry County, GA
12060	13159	Jasper County, GA
12060	13171	Lamar County, GA
12060	13199	Meriwether County, GA
12060	13217	Newton County, GA
12060	13223	Paulding County, GA
12060	13227	Pickens County, GA
12060	13231	Pike County, GA
12060	13247	Rockdale County, GA
12060	13255	Spalding County, GA
12060	13297	Walton County, GA
12100		Atlantic City, NJ Metropolitan Statistical Area
12100	34001	Atlantic County, NJ
12220		Auburn-Opelika, AL Metropolitan Statistical Area
12220	01081	Lee County, AL
12260		Augusta-Richmond County, GA-SC Metropolitan Statistical Area
12260	13033	Burke County, GA
12260	13073	Columbia County, GA
12260	13189	McDuffie County, GA
12260	13245	Richmond County, GA
12260	45003	Aiken County, SC
12260	45037	Edgefield County, SC
12420		Austin-Round Rock, TX Metropolitan Statistical Area
12420	48021	Bastrop County, TX
12420	48055	Caldwell County, TX
12420	48209	Hays County, TX
12420	48453	Travis County, TX
12420	48491	Williamson County, TX
12540		Bakersfield, CA Metropolitan Statistical Area
12540	06029	Kern County, CA
12580		Baltimore-Towson, MD Metropolitan Statistical Area
12580	24003	Anne Arundel County, MD
12580	24005	Baltimore County, MD
12580	24013	Carroll County, MD
12580	24025	Harford County, MD
12580	24027	Howard County, MD
12580	24035	Queen Anne's County, MD
12580	24510	Baltimore city, MD
12620		Bangor, ME Metropolitan Statistical Area
12620	23019	Penobscot County, ME
12700		Barnstable Town, MA Metropolitan Statistical Area
12700	25001	Barnstable County, MA
12940		Baton Rouge, LA Metropolitan Statistical Area
12940	22005	Ascension Parish, LA
12940	22033	East Baton Rouge Parish, LA
12940	22037	East Feliciana Parish, LA
12940	22047	Iberville Parish, LA
12940	22063	Livingston Parish, LA
12940	22077	Pointe Coupee Parish, LA

12940	22091	St. Helena Parish, LA
12940	22121	West Baton Rouge Parish, LA
12940	22125	West Feliciana Parish, LA
12980		Battle Creek, MI Metropolitan Statistical Area
12980	26025	Calhoun County, MI
13020		Bay City, MI Metropolitan Statistical Area
13020	26017	Bay County, MI
13140		Beaumont-Port Arthur, TX Metropolitan Statistical Area
13140	48199	Hardin County, TX
13140	48245	Jefferson County, TX
13140	48361	Orange County, TX
13380		Bellingham, WA Metropolitan Statistical Area
13380	53073	Whatcom County, WA
13460		Bend, OR Metropolitan Statistical Area
13460	41017	Deschutes County, OR
13740		Billings, MT Metropolitan Statistical Area
13740	30009	Carbon County, MT
13740	30111	Yellowstone County, MT
13780		Binghamton, NY Metropolitan Statistical Area
13780	36007	Broome County, NY
13780	36107	Tioga County, NY
13820		Birmingham-Hoover, AL Metropolitan Statistical Area
13820	01007	Bibb County, AL
13820	01009	Blount County, AL
13820	01021	Chilton County, AL
13820	01073	Jefferson County, AL
13820	01115	St. Clair County, AL
13820	01117	Shelby County, AL
13820	01127	Walker County, AL
13900		Bismarck, ND Metropolitan Statistical Area
13900	38015	Burleigh County, ND
13900	38059	Morton County, ND
13980		Blacksburg-Christiansburg-Radford, VA Metropolitan Statistic
13980	51071	Giles County, VA
13980	51121	Montgomery County, VA
13980	51155	Pulaski County, VA
13980	51750	Radford city, VA
14020		Bloomington, IN Metropolitan Statistical Area
14020	18055	Greene County, IN
14020	18105	Monroe County, IN
14020	18119	Owen County, IN
14060		Bloomington-Normal, IL Metropolitan Statistical Area
14060	17113	McLean County, IL
14260		Boise City-Nampa, ID Metropolitan Statistical Area
14260	16001	Ada County, ID
14260	16015	Boise County, ID
14260	16027	Canyon County, ID

14260		16045	Gem County, ID
14260		16073	Owyhee County, ID
14460			Boston-Cambridge-Quincy, MA-NH Metropolitan Statistical Area
14460	14484		Boston-Quincy, MA Metropolitan Division
14460	14484	25021	Norfolk County, MA
14460	14484	25023	Plymouth County, MA
14460	14484	25025	Suffolk County, MA
14460	15764		Cambridge-Newton-Framingham, MA Metropolitan Division
14460	15764	25017	Middlesex County, MA
14460	21604		Essex County, MA Metropolitan Division
14460	21604	25009	Essex County, MA
14460	40484		Rockingham County-Strafford County, NH Metropolitan Divis
14460	40484	33015	Rockingham County, NH
14460	40484	33017	Strafford County, NH
14500			Boulder, CO Metropolitan Statistical Area
14500		08013	Boulder County, CO
14540			Bowling Green, KY Metropolitan Statistical Area
14540		21061	Edmonson County, KY
14540		21227	Warren County, KY
14740			Bremerton-Silverdale, WA Metropolitan Statistical Area
14740		53035	Kitsap County, WA
14860			Bridgeport-Stamford-Norwalk, CT Metropolitan Statistical Are
14860		09001	Fairfield County, CT
15180			Brownsville-Harlingen, TX Metropolitan Statistical Area
15180		48061	Cameron County, TX
15260			Brunswick, GA Metropolitan Statistical Area
15260		13025	Brantley County, GA
15260		13127	Glynn County, GA
15260		13191	McIntosh County, GA
15380			Buffalo-Niagara Falls, NY Metropolitan Statistical Area
15380		36029	Erie County, NY
15380		36063	Niagara County, NY
15500			Burlington, NC Metropolitan Statistical Area
15500		37001	Alamance County, NC
15540			Burlington-South Burlington, VT Metropolitan Statistical Are
15540		50007	Chittenden County, VT
15540		50011	Franklin County, VT
15540		50013	Grand Isle County, VT
15940			Canton-Massillon, OH Metropolitan Statistical Area
15940		39019	Carroll County, OH
15940		39151	Stark County, OH
15980			Cape Coral-Fort Myers, FL Metropolitan Statistical Area
15980		12071	Lee County, FL
16180			Carson City, NV Metropolitan Statistical Area
16180		32510	Carson City, NV
16220			Casper, WY Metropolitan Statistical Area

16220		56025	Natrona County, WY
16300			Cedar Rapids, IA Metropolitan Statistical Area
16300		19011	Benton County, IA
16300		19105	Jones County, IA
16300		19113	Linn County, IA
16580			Champaign-Urbana, IL Metropolitan Statistical Area
16580		17019	Champaign County, IL
16580		17053	Ford County, IL
16580		17147	Piatt County, IL
16620			Charleston, WV Metropolitan Statistical Area
16620		54005	Boone County, WV
16620		54015	Clay County, WV
16620		54039	Kanawha County, WV
16620		54043	Lincoln County, WV
16620		54079	Putnam County, WV
16700			Charleston-North Charleston, SC Metropolitan Statistical Are
16700		45015	Berkeley County, SC
16700		45019	Charleston County, SC
16700		45035	Dorchester County, SC
16740			Charlotte-Gastonia-Concord, NC-SC Metropolitan Statistical A
16740		37007	Anson County, NC
16740		37025	Cabarrus County, NC
16740		37071	Gaston County, NC
16740		37119	Mecklenburg County, NC
16740		37179	Union County, NC
16740		45091	York County, SC
16820			Charlottesville, VA Metropolitan Statistical Area
16820		51003	Albemarle County, VA
16820		51065	Fluvanna County, VA
16820		51079	Greene County, VA
16820		51125	Nelson County, VA
16820		51540	Charlottesville city, VA
16860			Chattanooga, TN-GA Metropolitan Statistical Area
16860		13047	Catoosa County, GA
16860		13083	Dade County, GA
16860		13295	Walker County, GA
16860		47065	Hamilton County, TN
16860		47115	Marion County, TN
16860		47153	Sequatchie County, TN
16940			Cheyenne, WY Metropolitan Statistical Area
16940		56021	Laramie County, WY
16980			Chicago-Naperville-Joliet, IL-IN-WI Metropolitan Statistical
16980	16974		Chicago-Naperville-Joliet, IL Metropolitan Division
16980	16974	17031	Cook County, IL
16980	16974	17037	DeKalb County, IL
16980	16974	17043	DuPage County, IL
16980	16974	17063	Grundy County, IL
16980	16974	17089	Kane County, IL
16980	16974	17093	Kendall County, IL
16980	16974	17111	McHenry County, IL
16980	16974	17197	Will County, IL

16980	23844		Gary, IN Metropolitan Division
16980	23844	18073	Jasper County, IN
16980	23844	18089	Lake County, IN
16980	23844	18111	Newton County, IN
16980	23844	18127	Porter County, IN
16980	29404		Lake County-Kenosha County, IL-WI Metropolitan Division
16980	29404	17097	Lake County, IL
16980	29404	55059	Kenosha County, WI
17020			Chico, CA Metropolitan Statistical Area
17020		06007	Butte County, CA
17140			Cincinnati-Middletown, OH-KY-IN Metropolitan Statistical Are
17140		18029	Dearborn County, IN
17140		18047	Franklin County, IN
17140		18115	Ohio County, IN
17140		21015	Boone County, KY
17140		21023	Bracken County, KY
17140		21037	Campbell County, KY
17140		21077	Gallatin County, KY
17140		21081	Grant County, KY
17140		21117	Kenton County, KY
17140		21191	Pendleton County, KY
17140		39015	Brown County, OH
17140		39017	Butler County, OH
17140		39025	Clermont County, OH
17140		39061	Hamilton County, OH
17140		39165	Warren County, OH
17300			Clarksville, TN-KY Metropolitan Statistical Area
17300		21047	Christian County, KY
17300		21221	Trigg County, KY
17300		47125	Montgomery County, TN
17300		47161	Stewart County, TN
17420			Cleveland, TN Metropolitan Statistical Area
17420		47011	Bradley County, TN
17420		47139	Polk County, TN
17460			Cleveland-Elyria-Mentor, OH Metropolitan Statistical Area
17460		39035	Cuyahoga County, OH
17460		39055	Geauga County, OH
17460		39085	Lake County, OH
17460		39093	Lorain County, OH
17460		39103	Medina County, OH
17660			Coeur d'Alene, ID Metropolitan Statistical Area
17660		16055	Kootenai County, ID
17780			College Station-Bryan, TX Metropolitan Statistical Area
17780		48041	Brazos County, TX
17780		48051	Burleson County, TX
17780		48395	Robertson County, TX
17820			Colorado Springs, CO Metropolitan Statistical Area
17820		08041	El Paso County, CO
17820		08119	Teller County, CO
17860			Columbia, MO Metropolitan Statistical Area
17860		29019	Boone County, MO

17860		29089	Howard County, MO
17900			Columbia, SC Metropolitan Statistical Area
17900		45017	Calhoun County, SC
17900		45039	Fairfield County, SC
17900		45055	Kershaw County, SC
17900		45063	Lexington County, SC
17900		45079	Richland County, SC
17900		45081	Saluda County, SC
17980			Columbus, GA-AL Metropolitan Statistical Area
17980		01113	Russell County, AL
17980		13053	Chattahoochee County, GA
17980		13145	Harris County, GA
17980		13197	Marion County, GA
17980		13215	Muscogee County, GA
18020			Columbus, IN Metropolitan Statistical Area
18020		18005	Bartholomew County, IN
18140			Columbus, OH Metropolitan Statistical Area
18140		39041	Delaware County, OH
18140		39045	Fairfield County, OH
18140		39049	Franklin County, OH
18140		39089	Licking County, OH
18140		39097	Madison County, OH
18140		39117	Morrow County, OH
18140		39129	Pickaway County, OH
18140		39159	Union County, OH
18580			Corpus Christi, TX Metropolitan Statistical Area
18580		48007	Aransas County, TX
18580		48355	Nueces County, TX
18580		48409	San Patricio County, TX
18700			Corvallis, OR Metropolitan Statistical Area
18700		41003	Benton County, OR
19060			Cumberland, MD-WV Metropolitan Statistical Area
19060		24001	Allegany County, MD
19060		54057	Mineral County, WV
19100			Dallas-Fort Worth-Arlington, TX Metropolitan Statistical Are
19100	19124		Dallas-Plano-Irving, TX Metropolitan Division
19100	19124	48085	Collin County, TX
19100	19124	48113	Dallas County, TX
19100	19124	48119	Delta County, TX
19100	19124	48121	Denton County, TX
19100	19124	48139	Ellis County, TX
19100	19124	48231	Hunt County, TX
19100	19124	48257	Kaufman County, TX
19100	19124	48397	Rockwall County, TX
19100	23104		Fort Worth-Arlington, TX Metropolitan Division
19100	23104	48251	Johnson County, TX
19100	23104	48367	Parker County, TX
19100	23104	48439	Tarrant County, TX
19100	23104	48497	Wise County, TX
19140			Dalton, GA Metropolitan Statistical Area
19140		13213	Murray County, GA

19140		13313	Whitfield County, GA
19180			Danville, IL Metropolitan Statistical Area
19180		17183	Vermilion County, IL
19260			Danville, VA Metropolitan Statistical Area
19260		51143	Pittsylvania County, VA
19260		51590	Danville city, VA
19340			Davenport-Moline-Rock Island, IA-IL Metropolitan Statistical
19340		17073	Henry County, IL
19340		17131	Mercer County, IL
19340		17161	Rock Island County, IL
19340		19163	Scott County, IA
19380			Dayton, OH Metropolitan Statistical Area
19380		39057	Greene County, OH
19380		39109	Miami County, OH
19380		39113	Montgomery County, OH
19380		39135	Preble County, OH
19460			Decatur, AL Metropolitan Statistical Area
19460		01079	Lawrence County, AL
19460		01103	Morgan County, AL
19500			Decatur, IL Metropolitan Statistical Area
19500		17115	Macon County, IL
19660			Deltona-Daytona Beach-Ormond Beach, FL Metropolitan Statisti
19660		12127	Volusia County, FL
19740			Denver-Aurora, CO Metropolitan Statistical Area
19740		08001	Adams County, CO
19740		08005	Arapahoe County, CO
19740		08014	Broomfield County, CO
19740		08019	Clear Creek County, CO
19740		08031	Denver County, CO
19740		08035	Douglas County, CO
19740		08039	Elbert County, CO
19740		08047	Gilpin County, CO
19740		08059	Jefferson County, CO
19740		08093	Park County, CO
19780			Des Moines-West Des Moines, IA Metropolitan Statistical Area
19780		19049	Dallas County, IA
19780		19077	Guthrie County, IA
19780		19121	Madison County, IA
19780		19153	Polk County, IA
19780		19181	Warren County, IA
19820			Detroit-Warren-Livonia, MI Metropolitan Statistical Area
19820	19804		Detroit-Livonia-Dearborn, MI Metropolitan Division
19820	19804	26163	Wayne County, MI
19820	47644		Warren-Troy-Farmington Hills, MI Metropolitan Division
19820	47644	26087	Lapeer County, MI
19820	47644	26093	Livingston County, MI
19820	47644	26099	Macomb County, MI
19820	47644	26125	Oakland County, MI
19820	47644	26147	St. Clair County, MI

20020		Dothan, AL Metropolitan Statistical Area
20020	01061	Geneva County, AL
20020	01067	Henry County, AL
20020	01069	Houston County, AL
20100		Dover, DE Metropolitan Statistical Area
20100	10001	Kent County, DE
20220		Dubuque, IA Metropolitan Statistical Area
20220	19061	Dubuque County, IA
20260		Duluth, MN-WI Metropolitan Statistical Area
20260	27017	Carlton County, MN
20260	27137	St. Louis County, MN
20260	55031	Douglas County, WI
20500		Durham, NC Metropolitan Statistical Area
20500	37037	Chatham County, NC
20500	37063	Durham County, NC
20500	37135	Orange County, NC
20500	37145	Person County, NC
20740		Eau Claire, WI Metropolitan Statistical Area
20740	55017	Chippewa County, WI
20740	55035	Eau Claire County, WI
20940		El Centro, CA Metropolitan Statistical Area
20940	06025	Imperial County, CA
21060		Elizabethtown, KY Metropolitan Statistical Area
21060	21093	Hardin County, KY
21060	21123	Larue County, KY
21140		Elkhart-Goshen, IN Metropolitan Statistical Area
21140	18039	Elkhart County, IN
21300		Elmira, NY Metropolitan Statistical Area
21300	36015	Chemung County, NY
21340		El Paso, TX Metropolitan Statistical Area
21340	48141	El Paso County, TX
21500		Erie, PA Metropolitan Statistical Area
21500	42049	Erie County, PA
21660		Eugene-Springfield, OR Metropolitan Statistical Area
21660	41039	Lane County, OR
21780		Evansville, IN-KY Metropolitan Statistical Area
21780	18051	Gibson County, IN
21780	18129	Posey County, IN
21780	18163	Vanderburgh County, IN
21780	18173	Warrick County, IN
21780	21101	Henderson County, KY
21780	21233	Webster County, KY
21820		Fairbanks, AK Metropolitan Statistical Area
21820	02090	Fairbanks North Star Borough, AK
21940		Fajardo, PR Metropolitan Statistical Area

21940	72037	Ceiba Municipio, PR
21940	72053	Fajardo Municipio, PR
21940	72089	Luquillo Municipio, PR
22020		Fargo, ND-MN Metropolitan Statistical Area
22020	27027	Clay County, MN
22020	38017	Cass County, ND
22140		Farmington, NM Metropolitan Statistical Area
22140	35045	San Juan County, NM
22180		Fayetteville, NC Metropolitan Statistical Area
22180	37051	Cumberland County, NC
22180	37093	Hoke County, NC
22220		Fayetteville-Springdale-Rogers, AR-MO Metropolitan Statistic
22220	05007	Benton County, AR
22220	05087	Madison County, AR
22220	05143	Washington County, AR
22220	29119	McDonald County, MO
22380		Flagstaff, AZ Metropolitan Statistical Area
22380	04005	Coconino County, AZ
22420		Flint, MI Metropolitan Statistical Area
22420	26049	Genesee County, MI
22500		Florence, SC Metropolitan Statistical Area
22500	45031	Darlington County, SC
22500	45041	Florence County, SC
22520		Florence-Muscle Shoals, AL Metropolitan Statistical Area
22520	01033	Colbert County, AL
22520	01077	Lauderdale County, AL
22540		Fond du Lac, WI Metropolitan Statistical Area
22540	55039	Fond du Lac County, WI
22660		Fort Collins-Loveland, CO Metropolitan Statistical Area
22660	08069	Larimer County, CO
22900		Fort Smith, AR-OK Metropolitan Statistical Area
22900	05033	Crawford County, AR
22900	05047	Franklin County, AR
22900	05131	Sebastian County, AR
22900	40079	Le Flore County, OK
22900	40135	Sequoyah County, OK
23020		Fort Walton Beach-Crestview-Destin, FL Metropolitan Statisti
23020	12091	Okaloosa County, FL
23060		Fort Wayne, IN Metropolitan Statistical Area
23060	18003	Allen County, IN
23060	18179	Wells County, IN
23060	18183	Whitley County, IN
23420		Fresno, CA Metropolitan Statistical Area
23420	06019	Fresno County, CA
23460		Gadsden, AL Metropolitan Statistical Area

23460	01055	Etowah County, AL
23540		Gainesville, FL Metropolitan Statistical Area
23540	12001	Alachua County, FL
23540	12041	Gilchrist County, FL
23580		Gainesville, GA Metropolitan Statistical Area
23580	13139	Hall County, GA
24020		Glens Falls, NY Metropolitan Statistical Area
24020	36113	Warren County, NY
24020	36115	Washington County, NY
24140		Goldsboro, NC Metropolitan Statistical Area
24140	37191	Wayne County, NC
24220		Grand Forks, ND-MN Metropolitan Statistical Area
24220	27119	Polk County, MN
24220	38035	Grand Forks County, ND
24300		Grand Junction, CO Metropolitan Statistical Area
24300	08077	Mesa County, CO
24340		Grand Rapids-Wyoming, MI Metropolitan Statistical Area
24340	26015	Barry County, MI
24340	26067	Ionia County, MI
24340	26081	Kent County, MI
24340	26123	Newaygo County, MI
24500		Great Falls, MT Metropolitan Statistical Area
24500	30013	Cascade County, MT
24540		Greeley, CO Metropolitan Statistical Area
24540	08123	Weld County, CO
24580		Green Bay, WI Metropolitan Statistical Area
24580	55009	Brown County, WI
24580	55061	Kewaunee County, WI
24580	55083	Oconto County, WI
24660		Greensboro-High Point, NC Metropolitan Statistical Area
24660	37081	Guilford County, NC
24660	37151	Randolph County, NC
24660	37157	Rockingham County, NC
24780		Greenville, NC Metropolitan Statistical Area
24780	37079	Greene County, NC
24780	37147	Pitt County, NC
24860		Greenville, SC Metropolitan Statistical Area
24860	45045	Greenville County, SC
24860	45059	Laurens County, SC
24860	45077	Pickens County, SC
25020		Guayama, PR Metropolitan Statistical Area
25020	72015	Arroyo Municipio, PR
25020	72057	Guayama Municipio, PR
25020	72109	Patillas Municipio, PR
25060		Gulfport-Biloxi, MS Metropolitan Statistical Area

25060	28045	Hancock County, MS
25060	28047	Harrison County, MS
25060	28131	Stone County, MS
25180		Hagerstown-Martinsburg, MD-WV Metropolitan Statistical Area
25180	24043	Washington County, MD
25180	54003	Berkeley County, WV
25180	54065	Morgan County, WV
25260		Hanford-Corcoran, CA Metropolitan Statistical Area
25260	06031	Kings County, CA
25420		Harrisburg-Carlisle, PA Metropolitan Statistical Area
25420	42041	Cumberland County, PA
25420	42043	Dauphin County, PA
25420	42099	Perry County, PA
25500		Harrisonburg, VA Metropolitan Statistical Area
25500	51165	Rockingham County, VA
25500	51660	Harrisonburg city, VA
25540		Hartford-West Hartford-East Hartford, CT Metropolitan Statis
25540	09003	Hartford County, CT
25540	09007	Middlesex County, CT
25540	09013	Tolland County, CT
25620		Hattiesburg, MS Metropolitan Statistical Area
25620	28035	Forrest County, MS
25620	28073	Lamar County, MS
25620	28111	Perry County, MS
25860		Hickory-Lenoir-Morganton, NC Metropolitan Statistical Area
25860	37003	Alexander County, NC
25860	37023	Burke County, NC
25860	37027	Caldwell County, NC
25860	37035	Catawba County, NC
25980		Hinesville-Fort Stewart, GA Metropolitan Statistical Area
25980	13179	Liberty County, GA
25980	13183	Long County, GA
26100		Holland-Grand Haven, MI Metropolitan Statistical Area
26100	26139	Ottawa County, MI
26180		Honolulu, HI Metropolitan Statistical Area
26180	15003	Honolulu County, HI
26300		Hot Springs, AR Metropolitan Statistical Area
26300	05051	Garland County, AR
26380		Houma-Bayou Cane-Thibodaux, LA Metropolitan Statistical Area
26380	22057	Lafourche Parish, LA
26380	22109	Terrebonne Parish, LA
26420		Houston-Sugar Land-Baytown, TX Metropolitan Statistical Area
26420	48015	Austin County, TX
26420	48039	Brazoria County, TX
26420	48071	Chambers County, TX
26420	48157	Fort Bend County, TX
26420	48167	Galveston County, TX

26420	48201	Harris County, TX
26420	48291	Liberty County, TX
26420	48339	Montgomery County, TX
26420	48407	San Jacinto County, TX
26420	48473	Waller County, TX
26580		Huntington-Ashland, WV-KY-OH Metropolitan Statistical Area
26580	21019	Boyd County, KY
26580	21089	Greenup County, KY
26580	39087	Lawrence County, OH
26580	54011	Cabell County, WV
26580	54099	Wayne County, WV
26620		Huntsville, AL Metropolitan Statistical Area
26620	01083	Limestone County, AL
26620	01089	Madison County, AL
26820		Idaho Falls, ID Metropolitan Statistical Area
26820	16019	Bonneville County, ID
26820	16051	Jefferson County, ID
26900		Indianapolis-Carmel, IN Metropolitan Statistical Area
26900	18011	Boone County, IN
26900	18013	Brown County, IN
26900	18057	Hamilton County, IN
26900	18059	Hancock County, IN
26900	18063	Hendricks County, IN
26900	18081	Johnson County, IN
26900	18097	Marion County, IN
26900	18109	Morgan County, IN
26900	18133	Putnam County, IN
26900	18145	Shelby County, IN
26980		Iowa City, IA Metropolitan Statistical Area
26980	19103	Johnson County, IA
26980	19183	Washington County, IA
27060		Ithaca, NY Metropolitan Statistical Area
27060	36109	Tompkins County, NY
27100		Jackson, MI Metropolitan Statistical Area
27100	26075	Jackson County, MI
27140		Jackson, MS Metropolitan Statistical Area
27140	28029	Copiah County, MS
27140	28049	Hinds County, MS
27140	28089	Madison County, MS
27140	28121	Rankin County, MS
27140	28127	Simpson County, MS
27180		Jackson, TN Metropolitan Statistical Area
27180	47023	Chester County, TN
27180	47113	Madison County, TN
27260		Jacksonville, FL Metropolitan Statistical Area
27260	12003	Baker County, FL
27260	12019	Clay County, FL
27260	12031	Duval County, FL
27260	12089	Nassau County, FL
27260	12109	St. Johns County, FL

27340		Jacksonville, NC Metropolitan Statistical Area
27340	37133	Onslow County, NC
27500		Janesville, WI Metropolitan Statistical Area
27500	55105	Rock County, WI
27620		Jefferson City, MO Metropolitan Statistical Area
27620	29027	Callaway County, MO
27620	29051	Cole County, MO
27620	29135	Moniteau County, MO
27620	29151	Osage County, MO
27740		Johnson City, TN Metropolitan Statistical Area
27740	47019	Carter County, TN
27740	47171	Unicoi County, TN
27740	47179	Washington County, TN
27780		Johnstown, PA Metropolitan Statistical Area
27780	42021	Cambria County, PA
27860		Jonesboro, AR Metropolitan Statistical Area
27860	05031	Craighead County, AR
27860	05111	Poinsett County, AR
27900		Joplin, MO Metropolitan Statistical Area
27900	29097	Jasper County, MO
27900	29145	Newton County, MO
28020		Kalamazoo-Portage, MI Metropolitan Statistical Area
28020	26077	Kalamazoo County, MI
28020	26159	Van Buren County, MI
28100		Kankakee-Bradley, IL Metropolitan Statistical Area
28100	17091	Kankakee County, IL
28140		Kansas City, MO-KS Metropolitan Statistical Area
28140	20059	Franklin County, KS
28140	20091	Johnson County, KS
28140	20103	Leavenworth County, KS
28140	20107	Linn County, KS
28140	20121	Miami County, KS
28140	20209	Wyandotte County, KS
28140	29013	Bates County, MO
28140	29025	Caldwell County, MO
28140	29037	Cass County, MO
28140	29047	Clay County, MO
28140	29049	Clinton County, MO
28140	29095	Jackson County, MO
28140	29107	Lafayette County, MO
28140	29165	Platte County, MO
28140	29177	Ray County, MO
28420		Kennewick-Richland-Pasco, WA Metropolitan Statistical Area
28420	53005	Benton County, WA
28420	53021	Franklin County, WA
28660		Killeen-Temple-Fort Hood, TX Metropolitan Statistical Area
28660	48027	Bell County, TX
28660	48099	Coryell County, TX

28660	48281	Lampasas County, TX
28700		Kingsport-Bristol-Bristol, TN-VA Metropolitan Statistical Ar
28700	47073	Hawkins County, TN
28700	47163	Sullivan County, TN
28700	51169	Scott County, VA
28700	51191	Washington County, VA
28700	51520	Bristol city, VA
28740		Kingston, NY Metropolitan Statistical Area
28740	36111	Ulster County, NY
28940		Knoxville, TN Metropolitan Statistical Area
28940	47001	Anderson County, TN
28940	47009	Blount County, TN
28940	47093	Knox County, TN
28940	47105	Loudon County, TN
28940	47173	Union County, TN
29020		Kokomo, IN Metropolitan Statistical Area
29020	18067	Howard County, IN
29020	18159	Tipton County, IN
29100		La Crosse, WI-MN Metropolitan Statistical Area
29100	27055	Houston County, MN
29100	55063	La Crosse County, WI
29140		Lafayette, IN Metropolitan Statistical Area
29140	18007	Benton County, IN
29140	18015	Carroll County, IN
29140	18157	Tippecanoe County, IN
29180		Lafayette, LA Metropolitan Statistical Area
29180	22055	Lafayette Parish, LA
29180	22099	St. Martin Parish, LA
29340		Lake Charles, LA Metropolitan Statistical Area
29340	22019	Calcasieu Parish, LA
29340	22023	Cameron Parish, LA
29460		Lakeland, FL Metropolitan Statistical Area
29460	12105	Polk County, FL
29540		Lancaster, PA Metropolitan Statistical Area
29540	42071	Lancaster County, PA
29620		Lansing-East Lansing, MI Metropolitan Statistical Area
29620	26037	Clinton County, MI
29620	26045	Eaton County, MI
29620	26065	Ingham County, MI
29700		Laredo, TX Metropolitan Statistical Area
29700	48479	Webb County, TX
29740		Las Cruces, NM Metropolitan Statistical Area
29740	35013	Dona Ana County, NM
29820		Las Vegas-Paradise, NV Metropolitan Statistical Area
29820	32003	Clark County, NV

29940			Lawrence, KS Metropolitan Statistical Area
29940		20045	Douglas County, KS
30020			Lawton, OK Metropolitan Statistical Area
30020		40031	Comanche County, OK
30140			Lebanon, PA Metropolitan Statistical Area
30140		42075	Lebanon County, PA
30300			Lewiston, ID-WA Metropolitan Statistical Area
30300		16069	Nez Perce County, ID
30300		53003	Asotin County, WA
30340			Lewiston-Auburn, ME Metropolitan Statistical Area
30340		23001	Androscoggin County, ME
30460			Lexington-Fayette, KY Metropolitan Statistical Area
30460		21017	Bourbon County, KY
30460		21049	Clark County, KY
30460		21067	Fayette County, KY
30460		21113	Jessamine County, KY
30460		21209	Scott County, KY
30460		21239	Woodford County, KY
30620			Lima, OH Metropolitan Statistical Area
30620		39003	Allen County, OH
30700			Lincoln, NE Metropolitan Statistical Area
30700		31109	Lancaster County, NE
30700		31159	Seward County, NE
30780			Little Rock-North Little Rock, AR Metropolitan Statistical A
30780		05045	Faulkner County, AR
30780		05053	Grant County, AR
30780		05085	Lonoke County, AR
30780		05105	Perry County, AR
30780		05119	Pulaski County, AR
30780		05125	Saline County, AR
30860			Logan, UT-ID Metropolitan Statistical Area
30860		16041	Franklin County, ID
30860		49005	Cache County, UT
30980			Longview, TX Metropolitan Statistical Area
30980		48183	Gregg County, TX
30980		48401	Rusk County, TX
30980		48459	Upshur County, TX
31020			Longview, WA Metropolitan Statistical Area
31020		53015	Cowlitz County, WA
31100			Los Angeles-Long Beach-Santa Ana, CA Metropolitan Statistica
31100	31084		Los Angeles-Long Beach-Glendale, CA Metropolitan Division
31100	31084	06037	Los Angeles County, CA
31100	42044		Santa Ana-Anaheim-Irvine, CA Metropolitan Division
31100	42044	06059	Orange County, CA
31140			Louisville-Jefferson County, KY-IN Metropolitan Statistical
31140		18019	Clark County, IN
31140		18043	Floyd County, IN

31140	18061	Harrison County, IN
31140	18175	Washington County, IN
31140	21029	Bullitt County, KY
31140	21103	Henry County, KY
31140	21111	Jefferson County, KY
31140	21163	Meade County, KY
31140	21179	Nelson County, KY
31140	21185	Oldham County, KY
31140	21211	Shelby County, KY
31140	21215	Spencer County, KY
31140	21223	Trimble County, KY
31180		Lubbock, TX Metropolitan Statistical Area
31180	48107	Crosby County, TX
31180	48303	Lubbock County, TX
31340		Lynchburg, VA Metropolitan Statistical Area
31340	51009	Amherst County, VA
31340	51011	Appomattox County, VA
31340	51019	Bedford County, VA
31340	51031	Campbell County, VA
31340	51515	Bedford city, VA
31340	51680	Lynchburg city, VA
31420		Macon, GA Metropolitan Statistical Area
31420	13021	Bibb County, GA
31420	13079	Crawford County, GA
31420	13169	Jones County, GA
31420	13207	Monroe County, GA
31420	13289	Twiggs County, GA
31460		Madera, CA Metropolitan Statistical Area
31460	06039	Madera County, CA
31540		Madison, WI Metropolitan Statistical Area
31540	55021	Columbia County, WI
31540	55025	Dane County, WI
31540	55049	Iowa County, WI
31700		Manchester-Nashua, NH Metropolitan Statistical Area
31700	33011	Hillsborough County, NH
31900		Mansfield, OH Metropolitan Statistical Area
31900	39139	Richland County, OH
32420		Mayagüez, PR Metropolitan Statistical Area
32420	72067	Hormigueros Municipio, PR
32420	72097	Mayagüez Municipio, PR
32580		McAllen-Edinburg-Mission, TX Metropolitan Statistical Area
32580	48215	Hidalgo County, TX
32780		Medford, OR Metropolitan Statistical Area
32780	41029	Jackson County, OR
32820		Memphis, TN-MS-AR Metropolitan Statistical Area
32820	05035	Crittenden County, AR
32820	28033	DeSoto County, MS
32820	28093	Marshall County, MS
32820	28137	Tate County, MS

32820		28143	Tunica County, MS
32820		47047	Fayette County, TN
32820		47157	Shelby County, TN
32820		47167	Tipton County, TN
32900			Merced, CA Metropolitan Statistical Area
32900		06047	Merced County, CA
33100			Miami-Fort Lauderdale-Miami Beach, FL Metropolitan Statistic
33100	22744		Fort Lauderdale-Pompano Beach-Deerfield Beach, FL Metropo
33100	22744	12011	Broward County, FL
33100	33124		Miami-Miami Beach-Kendall, FL Metropolitan Division
33100	33124	12086	Miami-Dade County, FL
33100	48424		West Palm Beach-Boca Raton-Boynton Beach, FL Metropolitan
33100	48424	12099	Palm Beach County, FL
33140			Michigan City-La Porte, IN Metropolitan Statistical Area
33140		18091	LaPorte County, IN
33260			Midland, TX Metropolitan Statistical Area
33260		48329	Midland County, TX
33340			Milwaukee-Waukesha-West Allis, WI Metropolitan Statistical A
33340		55079	Milwaukee County, WI
33340		55089	Ozaukee County, WI
33340		55131	Washington County, WI
33340		55133	Waukesha County, WI
33460			Minneapolis-St. Paul-Bloomington, MN-WI Metropolitan Statist
33460		27003	Anoka County, MN
33460		27019	Carver County, MN
33460		27025	Chisago County, MN
33460		27037	Dakota County, MN
33460		27053	Hennepin County, MN
33460		27059	Isanti County, MN
33460		27123	Ramsey County, MN
33460		27139	Scott County, MN
33460		27141	Sherburne County, MN
33460		27163	Washington County, MN
33460		27171	Wright County, MN
33460		55093	Pierce County, WI
33460		55109	St. Croix County, WI
33540			Missoula, MT Metropolitan Statistical Area
33540		30063	Missoula County, MT
33660			Mobile, AL Metropolitan Statistical Area
33660		01097	Mobile County, AL
33700			Modesto, CA Metropolitan Statistical Area
33700		06099	Stanislaus County, CA
33740			Monroe, LA Metropolitan Statistical Area
33740		22073	Ouachita Parish, LA
33740		22111	Union Parish, LA
33780			Monroe, MI Metropolitan Statistical Area
33780		26115	Monroe County, MI
33860			Montgomery, AL Metropolitan Statistical Area

33860	01001	Autauga County, AL
33860	01051	Elmore County, AL
33860	01085	Lowndes County, AL
33860	01101	Montgomery County, AL
34060		Morgantown, WV Metropolitan Statistical Area
34060	54061	Monongalia County, WV
34060	54077	Preston County, WV
34100		Morristown, TN Metropolitan Statistical Area
34100	47057	Grainger County, TN
34100	47063	Hamblen County, TN
34100	47089	Jefferson County, TN
34580		Mount Vernon-Anacortes, WA Metropolitan Statistical Area
34580	53057	Skagit County, WA
34620		Muncie, IN Metropolitan Statistical Area
34620	18035	Delaware County, IN
34740		Muskegon-Norton Shores, MI Metropolitan Statistical Area
34740	26121	Muskegon County, MI
34820		Myrtle Beach-Conway-North Myrtle Beach, SC Metropolitan Stat
34820	45051	Horry County, SC
34900		Napa, CA Metropolitan Statistical Area
34900	06055	Napa County, CA
34940		Naples-Marco Island, FL Metropolitan Statistical Area
34940	12021	Collier County, FL
34980		Nashville-Davidson--Murfreesboro, TN Metropolitan Statistica
34980	47015	Cannon County, TN
34980	47021	Cheatham County, TN
34980	47037	Davidson County, TN
34980	47043	Dickson County, TN
34980	47081	Hickman County, TN
34980	47111	Macon County, TN
34980	47147	Robertson County, TN
34980	47149	Rutherford County, TN
34980	47159	Smith County, TN
34980	47165	Sumner County, TN
34980	47169	Trousdale County, TN
34980	47187	Williamson County, TN
34980	47189	Wilson County, TN
35300		New Haven-Milford, CT Metropolitan Statistical Area
35300	09009	New Haven County, CT
35380		New Orleans-Metairie-Kenner, LA Metropolitan Statistical Are
35380	22051	Jefferson Parish, LA
35380	22071	Orleans Parish, LA
35380	22075	Plaquemines Parish, LA
35380	22087	St. Bernard Parish, LA
35380	22089	St. Charles Parish, LA
35380	22095	St. John the Baptist Parish, LA
35380	22103	St. Tammany Parish, LA
35620		New York-Northern New Jersey-Long Island, NY-NJ-PA Metropoli

35620	20764		Edison, NJ Metropolitan Division
35620	20764	34023	Middlesex County, NJ
35620	20764	34025	Monmouth County, NJ
35620	20764	34029	Ocean County, NJ
35620	20764	34035	Somerset County, NJ
35620	35004		Nassau-Suffolk, NY Metropolitan Division
35620	35004	36059	Nassau County, NY
35620	35004	36103	Suffolk County, NY
35620	35644		New York-White Plains-Wayne, NY-NJ Metropolitan Division
35620	35644	34003	Bergen County, NJ
35620	35644	34017	Hudson County, NJ
35620	35644	34031	Passaic County, NJ
35620	35644	36005	Bronx County, NY
35620	35644	36047	Kings County, NY
35620	35644	36061	New York County, NY
35620	35644	36079	Putnam County, NY
35620	35644	36081	Queens County, NY
35620	35644	36085	Richmond County, NY
35620	35644	36087	Rockland County, NY
35620	35644	36119	Westchester County, NY
35620	35084		Newark-Union, NJ-PA Metropolitan Division
35620	35084	34013	Essex County, NJ
35620	35084	34019	Hunterdon County, NJ
35620	35084	34027	Morris County, NJ
35620	35084	34037	Sussex County, NJ
35620	35084	34039	Union County, NJ
35620	35084	42103	Pike County, PA
35660			Niles-Benton Harbor, MI Metropolitan Statistical Area
35660		26021	Berrien County, MI
35980			Norwich-New London, CT Metropolitan Statistical Area
35980		09011	New London County, CT
36100			Ocala, FL Metropolitan Statistical Area
36100		12083	Marion County, FL
36140			Ocean City, NJ Metropolitan Statistical Area
36140		34009	Cape May County, NJ
36220			Odessa, TX Metropolitan Statistical Area
36220		48135	Ector County, TX
36260			Ogden-Clearfield, UT Metropolitan Statistical Area
36260		49011	Davis County, UT
36260		49029	Morgan County, UT
36260		49057	Weber County, UT
36420			Oklahoma City, OK Metropolitan Statistical Area
36420		40017	Canadian County, OK
36420		40027	Cleveland County, OK
36420		40051	Grady County, OK
36420		40081	Lincoln County, OK
36420		40083	Logan County, OK
36420		40087	McClain County, OK
36420		40109	Oklahoma County, OK
36500			Olympia, WA Metropolitan Statistical Area
36500		53067	Thurston County, WA

36540			Omaha-Council Bluffs, NE-IA Metropolitan Statistical Area
36540		19085	Harrison County, IA
36540		19129	Mills County, IA
36540		19155	Pottawattamie County, IA
36540		31025	Cass County, NE
36540		31055	Douglas County, NE
36540		31153	Sarpy County, NE
36540		31155	Saunders County, NE
36540		31177	Washington County, NE
36740			Orlando-Kissimmee, FL Metropolitan Statistical Area
36740		12069	Lake County, FL
36740		12095	Orange County, FL
36740		12097	Osceola County, FL
36740		12117	Seminole County, FL
36780			Oshkosh-Neenah, WI Metropolitan Statistical Area
36780		55139	Winnebago County, WI
36980			Owensboro, KY Metropolitan Statistical Area
36980		21059	Daviess County, KY
36980		21091	Hancock County, KY
36980		21149	McLean County, KY
37100			Oxnard-Thousand Oaks-Ventura, CA Metropolitan Statistical Ar
37100		06111	Ventura County, CA
37340			Palm Bay-Melbourne-Titusville, FL Metropolitan Statistical A
37340		12009	Brevard County, FL
37460			Panama City-Lynn Haven, FL Metropolitan Statistical Area
37460		12005	Bay County, FL
37620			Parkersburg-Marietta-Vienna, WV-OH Metropolitan Statistical
37620		39167	Washington County, OH
37620		54073	Pleasants County, WV
37620		54105	Wirt County, WV
37620		54107	Wood County, WV
37700			Pascagoula, MS Metropolitan Statistical Area
37700		28039	George County, MS
37700		28059	Jackson County, MS
37860			Pensacola-Ferry Pass-Brent, FL Metropolitan Statistical Area
37860		12033	Escambia County, FL
37860		12113	Santa Rosa County, FL
37900			Peoria, IL Metropolitan Statistical Area
37900		17123	Marshall County, IL
37900		17143	Peoria County, IL
37900		17175	Stark County, IL
37900		17179	Tazewell County, IL
37900		17203	Woodford County, IL
37980			Philadelphia-Camden-Wilmington, PA-NJ-DE-MD Metropolitan Sta
37980	15804		Camden, NJ Metropolitan Division
37980	15804	34005	Burlington County, NJ
37980	15804	34007	Camden County, NJ
37980	15804	34015	Gloucester County, NJ
37980	37964		Philadelphia, PA Metropolitan Division

37980	37964	42017	Bucks County, PA
37980	37964	42029	Chester County, PA
37980	37964	42045	Delaware County, PA
37980	37964	42091	Montgomery County, PA
37980	37964	42101	Philadelphia County, PA
37980	48864		Wilmington, DE-MD-NJ Metropolitan Division
37980	48864	10003	New Castle County, DE
37980	48864	24015	Cecil County, MD
37980	48864	34033	Salem County, NJ
38060			Phoenix-Mesa-Scottsdale, AZ Metropolitan Statistical Area
38060		04013	Maricopa County, AZ
38060		04021	Pinal County, AZ
38220			Pine Bluff, AR Metropolitan Statistical Area
38220		05025	Cleveland County, AR
38220		05069	Jefferson County, AR
38220		05079	Lincoln County, AR
38300			Pittsburgh, PA Metropolitan Statistical Area
38300		42003	Allegheny County, PA
38300		42005	Armstrong County, PA
38300		42007	Beaver County, PA
38300		42019	Butler County, PA
38300		42051	Fayette County, PA
38300		42125	Washington County, PA
38300		42129	Westmoreland County, PA
38340			Pittsfield, MA Metropolitan Statistical Area
38340		25003	Berkshire County, MA
38540			Pocatello, ID Metropolitan Statistical Area
38540		16005	Bannock County, ID
38540		16077	Power County, ID
38660			Ponce, PR Metropolitan Statistical Area
38660		72075	Juana Díaz Municipio, PR
38660		72113	Ponce Municipio, PR
38660		72149	Villalba Municipio, PR
38860			Portland-South Portland-Biddeford, ME Metropolitan Statistic
38860		23005	Cumberland County, ME
38860		23023	Sagadahoc County, ME
38860		23031	York County, ME
38900			Portland-Vancouver-Beaverton, OR-WA Metropolitan Statistical
38900		41005	Clackamas County, OR
38900		41009	Columbia County, OR
38900		41051	Multnomah County, OR
38900		41067	Washington County, OR
38900		41071	Yamhill County, OR
38900		53011	Clark County, WA
38900		53059	Skamania County, WA
38940			Port St. Lucie-Fort Pierce, FL Metropolitan Statistical Area
38940		12085	Martin County, FL
38940		12111	St. Lucie County, FL
39100			Poughkeepsie-Newburgh-Middletown, NY Metropolitan Statistica
39100		36027	Dutchess County, NY

39100	36071	Orange County, NY
39140		Prescott, AZ Metropolitan Statistical Area
39140	04025	Yavapai County, AZ
39300		Providence-New Bedford-Fall River, RI-MA Metropolitan Statis
39300	25005	Bristol County, MA
39300	44001	Bristol County, RI
39300	44003	Kent County, RI
39300	44005	Newport County, RI
39300	44007	Providence County, RI
39300	44009	Washington County, RI
39340		Provo-Orem, UT Metropolitan Statistical Area
39340	49023	Juab County, UT
39340	49049	Utah County, UT
39380		Pueblo, CO Metropolitan Statistical Area
39380	08101	Pueblo County, CO
39460		Punta Gorda, FL Metropolitan Statistical Area
39460	12015	Charlotte County, FL
39540		Racine, WI Metropolitan Statistical Area
39540	55101	Racine County, WI
39580		Raleigh-Cary, NC Metropolitan Statistical Area
39580	37069	Franklin County, NC
39580	37101	Johnston County, NC
39580	37183	Wake County, NC
39660		Rapid City, SD Metropolitan Statistical Area
39660	46093	Meade County, SD
39660	46103	Pennington County, SD
39740		Reading, PA Metropolitan Statistical Area
39740	42011	Berks County, PA
39820		Redding, CA Metropolitan Statistical Area
39820	06089	Shasta County, CA
39900		Reno-Sparks, NV Metropolitan Statistical Area
39900	32029	Storey County, NV
39900	32031	Washoe County, NV
40060		Richmond, VA Metropolitan Statistical Area
40060	51007	Amelia County, VA
40060	51033	Caroline County, VA
40060	51036	Charles City County, VA
40060	51041	Chesterfield County, VA
40060	51049	Cumberland County, VA
40060	51053	Dinwiddie County, VA
40060	51075	Goochland County, VA
40060	51085	Hanover County, VA
40060	51087	Henrico County, VA
40060	51097	King and Queen County, VA
40060	51101	King William County, VA
40060	51109	Louisa County, VA
40060	51127	New Kent County, VA
40060	51145	Powhatan County, VA

40060	51149	Prince George County, VA
40060	51183	Sussex County, VA
40060	51570	Colonial Heights city, VA
40060	51670	Hopewell city, VA
40060	51730	Petersburg city, VA
40060	51760	Richmond city, VA
40140		Riverside-San Bernardino-Ontario, CA Metropolitan Statistica
40140	06065	Riverside County, CA
40140	06071	San Bernardino County, CA
40220		Roanoke, VA Metropolitan Statistical Area
40220	51023	Botetourt County, VA
40220	51045	Craig County, VA
40220	51067	Franklin County, VA
40220	51161	Roanoke County, VA
40220	51770	Roanoke city, VA
40220	51775	Salem city, VA
40340		Rochester, MN Metropolitan Statistical Area
40340	27039	Dodge County, MN
40340	27109	Olmsted County, MN
40340	27157	Wabasha County, MN
40380		Rochester, NY Metropolitan Statistical Area
40380	36051	Livingston County, NY
40380	36055	Monroe County, NY
40380	36069	Ontario County, NY
40380	36073	Orleans County, NY
40380	36117	Wayne County, NY
40420		Rockford, IL Metropolitan Statistical Area
40420	17007	Boone County, IL
40420	17201	Winnebago County, IL
40580		Rocky Mount, NC Metropolitan Statistical Area
40580	37065	Edgecombe County, NC
40580	37127	Nash County, NC
40660		Rome, GA Metropolitan Statistical Area
40660	13115	Floyd County, GA
40900		Sacramento--Arden-Arcade--Roseville, CA Metropolitan Statist
40900	06017	El Dorado County, CA
40900	06061	Placer County, CA
40900	06067	Sacramento County, CA
40900	06113	Yolo County, CA
40980		Saginaw-Saginaw Township North, MI Metropolitan Statistical
40980	26145	Saginaw County, MI
41060		St. Cloud, MN Metropolitan Statistical Area
41060	27009	Benton County, MN
41060	27145	Stearns County, MN
41100		St. George, UT Metropolitan Statistical Area
41100	49053	Washington County, UT
41140		St. Joseph, MO-KS Metropolitan Statistical Area
41140	20043	Doniphan County, KS

41140	29003	Andrew County, MO
41140	29021	Buchanan County, MO
41140	29063	DeKalb County, MO
41180		St. Louis, MO-IL Metropolitan Statistical Area
41180	17005	Bond County, IL
41180	17013	Calhoun County, IL
41180	17027	Clinton County, IL
41180	17083	Jersey County, IL
41180	17117	Macoupin County, IL
41180	17119	Madison County, IL
41180	17133	Monroe County, IL
41180	17163	St. Clair County, IL
41180	29055	Crawford County, MO (pt.)*
41180	29071	Franklin County, MO
41180	29099	Jefferson County, MO
41180	29113	Lincoln County, MO
41180	29183	St. Charles County, MO
41180	29189	St. Louis County, MO
41180	29219	Warren County, MO
41180	29221	Washington County, MO
41180	29510	St. Louis city, MO
41420		Salem, OR Metropolitan Statistical Area
41420	41047	Marion County, OR
41420	41053	Polk County, OR
41500		Salinas, CA Metropolitan Statistical Area
41500	06053	Monterey County, CA
41540		Salisbury, MD Metropolitan Statistical Area
41540	24039	Somerset County, MD
41540	24045	Wicomico County, MD
41620		Salt Lake City, UT Metropolitan Statistical Area
41620	49035	Salt Lake County, UT
41620	49043	Summit County, UT
41620	49045	Tooele County, UT
41660		San Angelo, TX Metropolitan Statistical Area
41660	48235	Irion County, TX
41660	48451	Tom Green County, TX
41700		San Antonio, TX Metropolitan Statistical Area
41700	48013	Atascosa County, TX
41700	48019	Bandera County, TX
41700	48029	Bexar County, TX
41700	48091	Comal County, TX
41700	48187	Guadalupe County, TX
41700	48259	Kendall County, TX
41700	48325	Medina County, TX
41700	48493	Wilson County, TX
41740		San Diego-Carlsbad-San Marcos, CA Metropolitan Statistical A
41740	06073	San Diego County, CA
41780		Sandusky, OH Metropolitan Statistical Area
41780	39043	Erie County, OH
41860		San Francisco-Oakland-Fremont, CA Metropolitan Statistical A

41860	36084		Oakland-Fremont-Hayward, CA Metropolitan Division
41860	36084	06001	Alameda County, CA
41860	36084	06013	Contra Costa County, CA
41860	41884		San Francisco-San Mateo-Redwood City, CA Metropolitan Div
41860	41884	06041	Marin County, CA
41860	41884	06075	San Francisco County, CA
41860	41884	06081	San Mateo County, CA
41900			San Germán-Cabo Rojo, PR Metropolitan Statistical Area
41900		72023	Cabo Rojo Municipio, PR
41900		72079	Lajas Municipio, PR
41900		72121	Sabana Grande Municipio, PR
41900		72125	San Germán Municipio, PR
41940			San Jose-Sunnyvale-Santa Clara, CA Metropolitan Statistical
41940		06069	San Benito County, CA
41940		06085	Santa Clara County, CA
41980			San Juan-Caguas-Guaynabo, PR Metropolitan Statistical Area
41980		72007	Aguas Buenas Municipio, PR
41980		72009	Aibonito Municipio, PR
41980		72013	Arecibo Municipio, PR
41980		72017	Barceloneta Municipio, PR
41980		72019	Barranquitas Municipio, PR
41980		72021	Bayamón Municipio, PR
41980		72025	Caguas Municipio, PR
41980		72027	Camuy Municipio, PR
41980		72029	Canóvanas Municipio, PR
41980		72031	Carolina Municipio, PR
41980		72033	Cataño Municipio, PR
41980		72035	Cayey Municipio, PR
41980		72039	Ciales Municipio, PR
41980		72041	Cidra Municipio, PR
41980		72045	Comerío Municipio, PR
41980		72047	Corozal Municipio, PR
41980		72051	Dorado Municipio, PR
41980		72054	Florida Municipio, PR
41980		72061	Guaynabo Municipio, PR
41980		72063	Gurabo Municipio, PR
41980		72065	Hatillo Municipio, PR
41980		72069	Humacao Municipio, PR
41980		72077	Juncos Municipio, PR
41980		72085	Las Piedras Municipio, PR
41980		72087	Loíza Municipio, PR
41980		72091	Manatí Municipio, PR
41980		72095	Maunabo Municipio, PR
41980		72101	Morovis Municipio, PR
41980		72103	Naguabo Municipio, PR
41980		72105	Naranjito Municipio, PR
41980		72107	Orocovis Municipio, PR
41980		72115	Quebradillas Municipio, PR
41980		72119	Río Grande Municipio, PR
41980		72127	San Juan Municipio, PR
41980		72129	San Lorenzo Municipio, PR
41980		72135	Toa Alta Municipio, PR
41980		72137	Toa Baja Municipio, PR
41980		72139	Trujillo Alto Municipio, PR
41980		72143	Vega Alta Municipio, PR
41980		72145	Vega Baja Municipio, PR
41980		72151	Yabucoa Municipio, PR

42020			San Luis Obispo-Paso Robles, CA Metropolitan Statistical Are
42020		06079	San Luis Obispo County, CA
42060			Santa Barbara-Santa Maria, CA Metropolitan Statistical Area
42060		06083	Santa Barbara County, CA
42100			Santa Cruz-Watsonville, CA Metropolitan Statistical Area
42100		06087	Santa Cruz County, CA
42140			Santa Fe, NM Metropolitan Statistical Area
42140		35049	Santa Fe County, NM
42220			Santa Rosa-Petaluma, CA Metropolitan Statistical Area
42220		06097	Sonoma County, CA
42260			Sarasota-Bradenton-Venice, FL Metropolitan Statistical Area
42260		12081	Manatee County, FL
42260		12115	Sarasota County, FL
42340			Savannah, GA Metropolitan Statistical Area
42340		13029	Bryan County, GA
42340		13051	Chatham County, GA
42340		13103	Effingham County, GA
42540			Scranton--Wilkes-Barre, PA Metropolitan Statistical Area
42540		42069	Lackawanna County, PA
42540		42079	Luzerne County, PA
42540		42131	Wyoming County, PA
42660			Seattle-Tacoma-Bellevue, WA Metropolitan Statistical Area
42660	42644		Seattle-Bellevue-Everett, WA Metropolitan Division
42660	42644	53033	King County, WA
42660	42644	53061	Snohomish County, WA
42660	45104		Tacoma, WA Metropolitan Division
42660	45104	53053	Pierce County, WA
42680			Sebastian-Vero Beach, FL Metropolitan Statistical Area
42680		12061	Indian River County, FL
43100			Sheboygan, WI Metropolitan Statistical Area
43100		55117	Sheboygan County, WI
43300			Sherman-Denison, TX Metropolitan Statistical Area
43300		48181	Grayson County, TX
43340			Shreveport-Bossier City, LA Metropolitan Statistical Area
43340		22015	Bossier Parish, LA
43340		22017	Caddo Parish, LA
43340		22031	De Soto Parish, LA
43580			Sioux City, IA-NE-SD Metropolitan Statistical Area
43580		19193	Woodbury County, IA
43580		31043	Dakota County, NE
43580		31051	Dixon County, NE
43580		46127	Union County, SD
43620			Sioux Falls, SD Metropolitan Statistical Area
43620		46083	Lincoln County, SD
43620		46087	McCook County, SD

43620	46099	Minnehaha County, SD
43620	46125	Turner County, SD
43780		South Bend-Mishawaka, IN-MI Metropolitan Statistical Area
43780	18141	St. Joseph County, IN
43780	26027	Cass County, MI
43900		Spartanburg, SC Metropolitan Statistical Area
43900	45083	Spartanburg County, SC
44060		Spokane, WA Metropolitan Statistical Area
44060	53063	Spokane County, WA
44100		Springfield, IL Metropolitan Statistical Area
44100	17129	Menard County, IL
44100	17167	Sangamon County, IL
44140		Springfield, MA Metropolitan Statistical Area
44140	25011	Franklin County, MA
44140	25013	Hampden County, MA
44140	25015	Hampshire County, MA
44180		Springfield, MO Metropolitan Statistical Area
44180	29043	Christian County, MO
44180	29059	Dallas County, MO
44180	29077	Greene County, MO
44180	29167	Polk County, MO
44180	29225	Webster County, MO
44220		Springfield, OH Metropolitan Statistical Area
44220	39023	Clark County, OH
44300		State College, PA Metropolitan Statistical Area
44300	42027	Centre County, PA
44700		Stockton, CA Metropolitan Statistical Area
44700	06077	San Joaquin County, CA
44940		Sumter, SC Metropolitan Statistical Area
44940	45085	Sumter County, SC
45060		Syracuse, NY Metropolitan Statistical Area
45060	36053	Madison County, NY
45060	36067	Onondaga County, NY
45060	36075	Oswego County, NY
45220		Tallahassee, FL Metropolitan Statistical Area
45220	12039	Gadsden County, FL
45220	12065	Jefferson County, FL
45220	12073	Leon County, FL
45220	12129	Wakulla County, FL
45300		Tampa-St. Petersburg-Clearwater, FL Metropolitan Statistical
45300	12053	Hernando County, FL
45300	12057	Hillsborough County, FL
45300	12101	Pasco County, FL
45300	12103	Pinellas County, FL
45460		Terre Haute, IN Metropolitan Statistical Area
45460	18021	Clay County, IN

45460	18153	Sullivan County, IN
45460	18165	Vermillion County, IN
45460	18167	Vigo County, IN
45500		Texarkana, TX-Texarkana, AR Metropolitan Statistical Area
45500	05091	Miller County, AR
45500	48037	Bowie County, TX
45780		Toledo, OH Metropolitan Statistical Area
45780	39051	Fulton County, OH
45780	39095	Lucas County, OH
45780	39123	Ottawa County, OH
45780	39173	Wood County, OH
45820		Topeka, KS Metropolitan Statistical Area
45820	20085	Jackson County, KS
45820	20087	Jefferson County, KS
45820	20139	Osage County, KS
45820	20177	Shawnee County, KS
45820	20197	Wabaunsee County, KS
45940		Trenton-Ewing, NJ Metropolitan Statistical Area
45940	34021	Mercer County, NJ
46060		Tucson, AZ Metropolitan Statistical Area
46060	04019	Pima County, AZ
46140		Tulsa, OK Metropolitan Statistical Area
46140	40037	Creek County, OK
46140	40111	Okmulgee County, OK
46140	40113	Osage County, OK
46140	40117	Pawnee County, OK
46140	40131	Rogers County, OK
46140	40143	Tulsa County, OK
46140	40145	Wagoner County, OK
46220		Tuscaloosa, AL Metropolitan Statistical Area
46220	01063	Greene County, AL
46220	01065	Hale County, AL
46220	01125	Tuscaloosa County, AL
46340		Tyler, TX Metropolitan Statistical Area
46340	48423	Smith County, TX
46540		Utica-Rome, NY Metropolitan Statistical Area
46540	36043	Herkimer County, NY
46540	36065	Oneida County, NY
46660		Valdosta, GA Metropolitan Statistical Area
46660	13027	Brooks County, GA
46660	13101	Echols County, GA
46660	13173	Lanier County, GA
46660	13185	Lowndes County, GA
46700		Vallejo-Fairfield, CA Metropolitan Statistical Area
46700	06095	Solano County, CA
47020		Victoria, TX Metropolitan Statistical Area
47020	48057	Calhoun County, TX
47020	48175	Goliad County, TX

47020		48469	Victoria County, TX
47220			Vineland-Millville-Bridgeton, NJ Metropolitan Statistical Ar
47220		34011	Cumberland County, NJ
47260			Virginia Beach-Norfolk-Newport News, VA-NC Metropolitan Stat
47260		37053	Currituck County, NC
47260		51073	Gloucester County, VA
47260		51093	Isle of Wight County, VA
47260		51095	James City County, VA
47260		51115	Mathews County, VA
47260		51181	Surry County, VA
47260		51199	York County, VA
47260		51550	Chesapeake city, VA
47260		51650	Hampton city, VA
47260		51700	Newport News city, VA
47260		51710	Norfolk city, VA
47260		51735	Poquoson city, VA
47260		51740	Portsmouth city, VA
47260		51800	Suffolk city, VA
47260		51810	Virginia Beach city, VA
47260		51830	Williamsburg city, VA
47300			Visalia-Porterville, CA Metropolitan Statistical Area
47300		06107	Tulare County, CA
47380			Waco, TX Metropolitan Statistical Area
47380		48309	McLennan County, TX
47580			Warner Robins, GA Metropolitan Statistical Area
47580		13153	Houston County, GA
47900			Washington-Arlington-Alexandria, DC-VA-MD-WV Metropolitan St
47900	13644		Bethesda-Gaithersburg-Frederick, MD Metropolitan Division
47900	13644	24021	Frederick County, MD
47900	13644	24031	Montgomery County, MD
47900	47894		Washington-Arlington-Alexandria, DC-VA-MD-WV Metropolitan
47900	47894	11001	District of Columbia, DC
47900	47894	24009	Calvert County, MD
47900	47894	24017	Charles County, MD
47900	47894	24033	Prince George's County, MD
47900	47894	51013	Arlington County, VA
47900	47894	51043	Clarke County, VA
47900	47894	51059	Fairfax County, VA
47900	47894	51061	Fauquier County, VA
47900	47894	51107	Loudoun County, VA
47900	47894	51153	Prince William County, VA
47900	47894	51177	Spotsylvania County, VA
47900	47894	51179	Stafford County, VA
47900	47894	51187	Warren County, VA
47900	47894	51510	Alexandria city, VA
47900	47894	51600	Fairfax city, VA
47900	47894	51610	Falls Church city, VA
47900	47894	51630	Fredericksburg city, VA
47900	47894	51683	Manassas city, VA
47900	47894	51685	Manassas Park city, VA
47900	47894	54037	Jefferson County, WV
47940			Waterloo-Cedar Falls, IA Metropolitan Statistical Area
47940		19013	Black Hawk County, IA

47940	19017	Bremer County, IA
47940	19075	Grundy County, IA
48140		Wausau, WI Metropolitan Statistical Area
48140	55073	Marathon County, WI
48260		Weirton-Steubenville, WV-OH Metropolitan Statistical Area
48260	39081	Jefferson County, OH
48260	54009	Brooke County, WV
48260	54029	Hancock County, WV
48300		Wenatchee, WA Metropolitan Statistical Area
48300	53007	Chelan County, WA
48300	53017	Douglas County, WA
48540		Wheeling, WV-OH Metropolitan Statistical Area
48540	39013	Belmont County, OH
48540	54051	Marshall County, WV
48540	54069	Ohio County, WV
48620		Wichita, KS Metropolitan Statistical Area
48620	20015	Butler County, KS
48620	20079	Harvey County, KS
48620	20173	Sedgwick County, KS
48620	20191	Sumner County, KS
48660		Wichita Falls, TX Metropolitan Statistical Area
48660	48009	Archer County, TX
48660	48077	Clay County, TX
48660	48485	Wichita County, TX
48700		Williamsport, PA Metropolitan Statistical Area
48700	42081	Lycoming County, PA
48900		Wilmington, NC Metropolitan Statistical Area
48900	37019	Brunswick County, NC
48900	37129	New Hanover County, NC
48900	37141	Pender County, NC
49020		Winchester, VA-WV Metropolitan Statistical Area
49020	51069	Frederick County, VA
49020	51840	Winchester city, VA
49020	54027	Hampshire County, WV
49180		Winston-Salem, NC Metropolitan Statistical Area
49180	37059	Davie County, NC
49180	37067	Forsyth County, NC
49180	37169	Stokes County, NC
49180	37197	Yadkin County, NC
49340		Worcester, MA Metropolitan Statistical Area
49340	25027	Worcester County, MA
49420		Yakima, WA Metropolitan Statistical Area
49420	53077	Yakima County, WA
49500		Yauco, PR Metropolitan Statistical Area
49500	72055	Guánica Municipio, PR
49500	72059	Guayanilla Municipio, PR
49500	72111	Peñuelas Municipio, PR

49500	72153	Yauco Municipio, PR
49620		York-Hanover, PA Metropolitan Statistical Area
49620	42133	York County, PA
49660		Youngstown-Warren-Boardman, OH-PA Metropolitan Statistical A
49660	39099	Mahoning County, OH
49660	39155	Trumbull County, OH
49660	42085	Mercer County, PA
49700		Yuba City, CA Metropolitan Statistical Area
49700	06101	Sutter County, CA
49700	06115	Yuba County, CA
49740		Yuma, AZ Metropolitan Statistical Area
49740	04027	Yuma County, AZ

File Layout:

Character	Length	Field
1-5	5	Core Based Statistical Area code (December 2005 definition)
6-8	3	Blank
9-13	5	CBSA division code (blank for CBSAs without divisions)
14-16	3	Blank
17-18	2	FIPS state code (blank at CBSA and division level)
19-21	3	FIPS county code (blank at CBSA and division level)
22-24	3	Blank
25-99	75	CBSA Title
28-99	72	CBSA Division Title
31-99	69	County

* The portion of Sullivan city in Crawford County, Missouri, is legally part of the St. Louis, MO-IL MSA. Census 2000 tabulations and intercensal estimates for the St. Louis, MO-IL Metropolitan Statistical Areas do not include this area.

USCB 2006b

V-508

State & County QuickFacts

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Georgia

People QuickFacts	Georgia	USA
Population, 2004 estimate	8,829,383	293,655,404
Population, percent change, April 1, 2000 to July 1, 2004	7.8%	4.3%
Population, 2000	8,186,453	281,421,906
Population, percent change, 1990 to 2000	26.4%	13.1%
Persons under 5 years old, percent, 2000	7.3%	6.8%
Persons under 18 years old, percent, 2000	26.5%	25.7%
Persons 65 years old and over, percent, 2000	9.6%	12.4%
Female persons, percent, 2000	50.8%	50.9%
White persons, percent, 2000 (a)	65.1%	75.1%
Black or African American persons, percent, 2000 (a)	28.7%	12.3%
American Indian and Alaska Native persons, percent, 2000 (a)	0.3%	0.9%
Asian persons, percent, 2000 (a)	2.1%	3.6%
Native Hawaiian and Other Pacific Islander, percent, 2000 (a)	0.1%	0.1%
Persons reporting some other race, percent, 2000 (a)	2.4%	5.5%
Persons reporting two or more races, percent, 2000	1.4%	2.4%
White persons, not of Hispanic/Latino origin, percent, 2000	62.6%	69.1%
Persons of Hispanic or Latino origin, percent, 2000 (b)	5.3%	12.5%
Living in same house in 1995 and 2000', pct age 5+, 2000	49.2%	54.1%
Foreign born persons, percent, 2000	7.1%	11.1%
Language other than English spoken at home, pct age 5+, 2000	9.9%	17.9%
High school graduates, percent of persons age 25+, 2000	78.6%	80.4%
Bachelor's degree or higher, pct of persons age 25+, 2000	24.3%	24.4%
Persons with a disability, age 5+, 2000	1,456,812	49,746,248
Mean travel time to work (minutes), workers age 16+, 2000	27.7	25.5
Housing units, 2002	3,487,088	119,302,132
Homeownership rate, 2000	67.5%	66.2%
Housing units in multi-unit structures, percent, 2000	20.8%	26.4%
Median value of owner-occupied housing units, 2000	$111,200	$119,600
Households, 2000	3,006,369	105,480,101
Persons per household, 2000	2.65	2.59

Median household income, 1999	$42,433	$41,994
Per capita money income, 1999	$21,154	$21,587
Persons below poverty, percent, 1999	13.0%	12.4%
Business QuickFacts	**Georgia**	**USA**
Private nonfarm establishments with paid employees, 2001	202,505	7,095,302
Private nonfarm employment, 2001	3,498,583	115,061,184
Private nonfarm employment, percent change 2000-2001	0.4%	0.9%
Nonemployer establishments, 2000	468,430	16,529,955
Manufacturers shipments, 1997 ($1000)	124,526,834	3,842,061,405
Retail sales, 1997 ($1000)	72,212,484	2,460,886,012
Retail sales per capita, 1997	$9,646	$9,190
Minority-owned firms, percent of total, 1997	15.6%	14.6%
Women-owned firms, percent of total, 1997	25.6%	26.0%
Housing units authorized by building permits, 2002	97,523	1,747,678
Federal funds and grants, 2002 ($1000)	51,335,502	1,901,247,889
Geography QuickFacts	**Georgia**	**USA**
Land area, 2000 (square miles)	57,906	3,537,438
Persons per square mile, 2000	141.4	79.6
FIPS Code	13	

(a) Includes persons reporting only one race.
(b) Hispanics may be of any race, so also are included in applicable race categories.

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Z: Value greater than zero but less than half unit of measure shown
F: Fewer than 100 firms

Source U.S. Census Bureau: State and County QuickFacts. Data derived from Population Estimates, 2000 Census of Population and Housing, 1990 Census of Population and Housing, Small Area Income and Poverty Estimates, County Business Patterns, 1997 Economic Census, Minority- and Women-Owned Business, Building Permits, Consolidated Federal Funds Report, 1997 Census of Governments

Last Revised: Thursday, 12-Jan-2006 13:32:48 EST

Census Bureau Links: • • • • • • • • •

State & County QuickFacts

Savannah (city), Georgia

People QuickFacts	Savannah	Georgia
Population, 2003 estimate	127,573	8,684,715
Population, percent change, April 1, 2000 to July 1, 2003	-3.2%	6.1%
Population, 2000	131,510	8,186,453
Population, percent change, 1990 to 2000	-4.4%	26.4%
Persons under 5 years old, percent, 2000	7.0%	7.3%
Persons under 18 years old, percent, 2000	25.6%	26.5%
Persons 65 years old and over, percent, 2000	13.3%	9.6%
Female persons, percent, 2000	52.8%	50.8%
White persons, percent, 2000 (a)	38.9%	65.1%
Black or African American persons, percent, 2000 (a)	57.1%	28.7%
American Indian and Alaska Native persons, percent, 2000 (a)	0.2%	0.3%
Asian persons, percent, 2000 (a)	1.5%	2.1%
Native Hawaiian and Other Pacific Islander, percent, 2000 (a)	0.1%	0.1%
Persons reporting some other race, percent, 2000 (a)	0.9%	2.4%
Persons reporting two or more races, percent, 2000	1.3%	1.4%
Persons of Hispanic or Latino origin, percent, 2000 (b)	2.2%	5.3%
Living in same house in 1995 and 2000', pct age 5+, 2000	50.8%	49.2%
Foreign born persons, percent, 2000	3.8%	7.1%
Language other than English spoken at home, pct age 5+, 2000	6.7%	9.9%
High school graduates, percent of persons age 25+, 2000	76.1%	78.6%
Bachelor's degree or higher, pct of persons age 25+, 2000	20.2%	24.3%
Mean travel time to work (minutes), workers age 16+, 2000	21.4	27.7
Housing units, 2000	57,437	3,281,737
Homeownership rate, 2000	50.3%	67.5%
Median value of owner-occupied housing units, 2000	$78,500	$111,200
Households, 2000	51,375	3,006,369
Persons per household, 2000	2.45	2.65
Median household income, 1999	$29,038	$42,433
Per capita money income, 1999	$16,921	$21,154
Persons below poverty, percent, 1999	21.8%	13.0%

Business QuickFacts	Savannah	Georgia
Manufacturers shipments, 1997 ($1000)	1,279,731	11,100,008
Wholesale trade sales, 1997 ($1000)	1,487,206	163,782,649
Retail sales, 1997 ($1000)	1,894,348	72,212,484
Retail sales per capita, 1997	$14,212	$9,646
Accomodation and foodservices sales, 1997 ($1000)	334,571	9,689,927
Total number of firms, 1997	9,107	568,552
Minority-owned firms, percent of total, 1997	21.8%	15.6%
Women-owned firms, percent of total, 1997	25.4%	25.6%
Geography QuickFacts	**Savannah**	**Georgia**
Land area, 2000 (square miles)	75	57,906
Persons per square mile, 2000	1,759.5	141.4
FIPS Code	69000	13
Counties		

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Census Bureau Links: • • • • • • • • •

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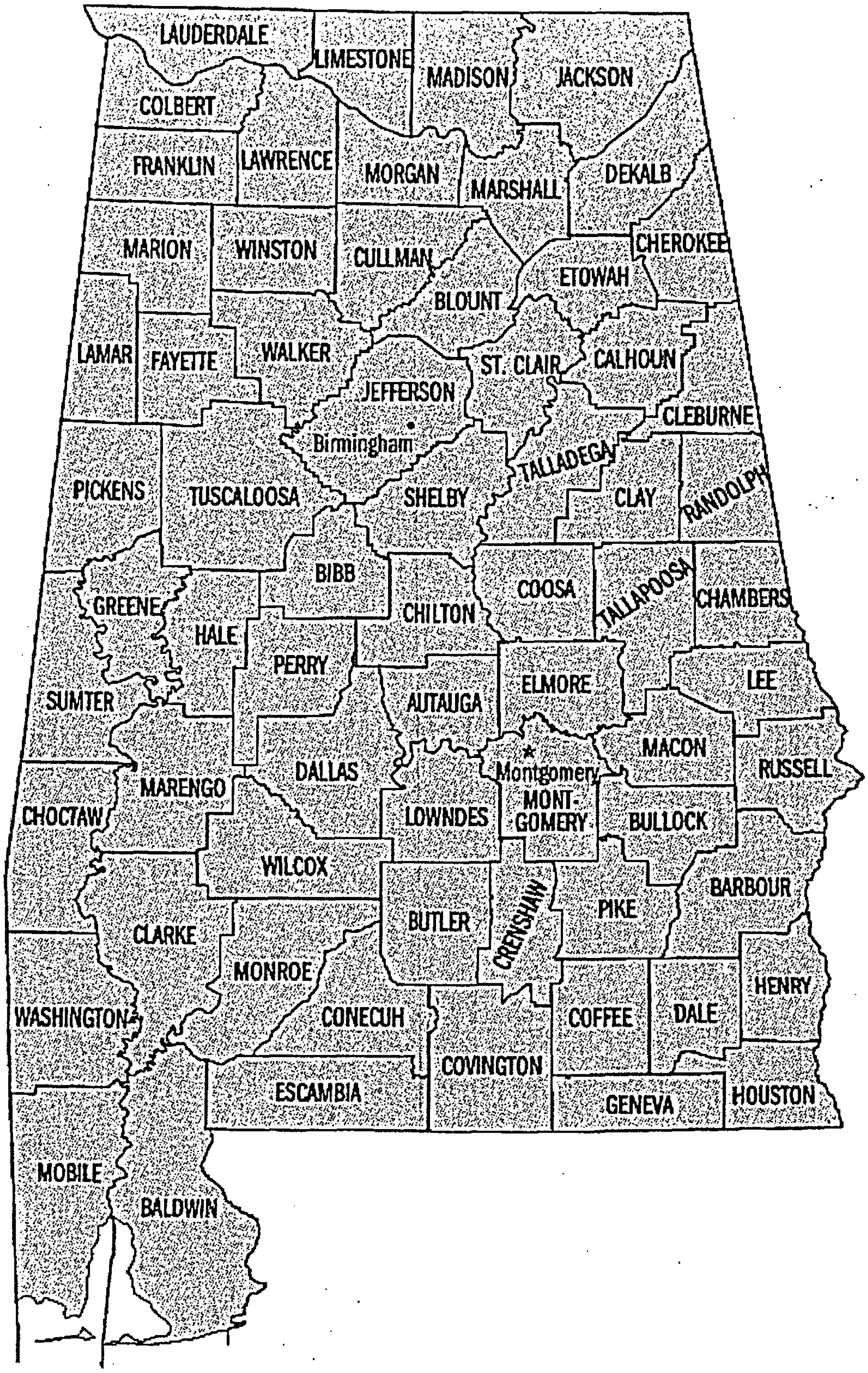

State & County QuickFacts

Alabama

People QuickFacts	Alabama	USA
Population, 2004 estimate	4,530,182	293,655,404
Population, percent change, April 1, 2000 to July 1, 2004	1.9%	4.3%
Population, 2000	4,447,100	281,421,906
Population, percent change, 1990 to 2000	10.1%	13.1%
Persons under 5 years old, percent, 2000	6.7%	6.8%
Persons under 18 years old, percent, 2000	25.3%	25.7%
Persons 65 years old and over, percent, 2000	13.0%	12.4%
Female persons, percent, 2000	51.7%	50.9%
White persons, percent, 2000 (a)	71.1%	75.1%
Black or African American persons, percent, 2000 (a)	26.0%	12.3%
American Indian and Alaska Native persons, percent, 2000 (a)	0.5%	0.9%
Asian persons, percent, 2000 (a)	0.7%	3.6%
Native Hawaiian and Other Pacific Islander, percent, 2000 (a)	Z	0.1%
Persons reporting some other race, percent, 2000 (a)	0.7%	5.5%
Persons reporting two or more races, percent, 2000	1.0%	2.4%
White persons, not of Hispanic/Latino origin, percent, 2000	70.3%	69.1%
Persons of Hispanic or Latino origin, percent, 2000 (b)	1.7%	12.5%
Living in same house in 1995 and 2000', pct age 5+, 2000	57.4%	54.1%
Foreign born persons, percent, 2000	2.0%	11.1%
Language other than English spoken at home, pct age 5+, 2000	3.9%	17.9%
High school graduates, percent of persons age 25+, 2000	75.3%	80.4%
Bachelor's degree or higher, pct of persons age 25+, 2000	19.0%	24.4%
Persons with a disability, age 5+, 2000	945,705	49,746,248
Mean travel time to work (minutes), workers age 16+, 2000	24.8	25.5
Housing units, 2002	2,014,536	119,302,132
Homeownership rate, 2000	72.5%	66.2%
Housing units in multi-unit structures, percent, 2000	15.3%	26.4%
Median value of owner-occupied housing units, 2000	$85,100	$119,600
Households, 2000	1,737,080	105,480,101
Persons per household, 2000	2.49	2.59

Median household income, 1999	$34,135	$41,994
Per capita money income, 1999	$18,189	$21,587
Persons below poverty, percent, 1999	16.1%	12.4%
Business QuickFacts	**Alabama**	**USA**
Private nonfarm establishments with paid employees, 2001	99,261	7,095,302
Private nonfarm employment, 2001	1,620,952	115,061,184
Private nonfarm employment, percent change 2000-2001	-1.9%	0.9%
Nonemployer establishments, 2000	223,103	16,529,955
Manufacturers shipments, 1997 ($1000)	67,970,076	3,842,061,405
Retail sales, 1997 ($1000)	36,623,327	2,460,886,012
Retail sales per capita, 1997	$8,477	$9,190
Minority-owned firms, percent of total, 1997	9.9%	14.6%
Women-owned firms, percent of total, 1997	24.4%	26.0%
Housing units authorized by building permits, 2002	18,403	1,747,678
Federal funds and grants, 2002 ($1000)	34,291,352	1,901,247,889
Geography QuickFacts	**Alabama**	**USA**
Land area, 2000 (square miles)	50,744	3,537,438
Persons per square mile, 2000	87.6	79.6
FIPS Code	01	

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Census Bureau Links:

State & County QuickFacts

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Birmingham (city), Alabama

People QuickFacts	Birmingham	Alabama
Population, 2003 estimate	236,620	4,500,752
Population, percent change, April 1, 2000 to July 1, 2003	-2.5%	1.2%
Population, 2000	242,820	4,447,100
Population, percent change, 1990 to 2000	-8.7%	10.1%
Persons under 5 years old, percent, 2000	6.8%	6.7%
Persons under 18 years old, percent, 2000	25.0%	25.3%
Persons 65 years old and over, percent, 2000	13.5%	13.0%
Female persons, percent, 2000	53.9%	51.7%
White persons, percent, 2000 (a)	24.1%	71.1%
Black or African American persons, percent, 2000 (a)	73.5%	26.0%
American Indian and Alaska Native persons, percent, 2000 (a)	0.2%	0.5%
Asian persons, percent, 2000 (a)	0.8%	0.7%
Native Hawaiian and Other Pacific Islander, percent, 2000 (a)	Z	Z
Persons reporting some other race, percent, 2000 (a)	0.6%	0.7%
Persons reporting two or more races, percent, 2000	0.8%	1.0%
Persons of Hispanic or Latino origin, percent, 2000 (b)	1.6%	1.7%
Living in same house in 1995 and 2000', pct age 5+, 2000	54.7%	57.4%
Foreign born persons, percent, 2000	2.1%	2.0%
Language other than English spoken at home, pct age 5+, 2000	4.7%	3.9%
High school graduates, percent of persons age 25+, 2000	75.5%	75.3%
Bachelor's degree or higher, pct of persons age 25+, 2000	18.5%	19.0%
Mean travel time to work (minutes), workers age 16+, 2000	23.5	24.8
Housing units, 2000	111,927	1,963,711
Homeownership rate, 2000	53.7%	72.5%
Median value of owner-occupied housing units, 2000	$62,100	$85,100
Households, 2000	98,782	1,737,080
Persons per household, 2000	2.37	2.49
Median household income, 1999	$26,735	$34,135
Per capita money income, 1999	$15,663	$18,189
Persons below poverty, percent, 1999	24.7%	16.1%

Business QuickFacts	Birmingham	Alabama
Manufacturers shipments, 1997 ($1000)	3,179,467	67,970,076
Wholesale trade sales, 1997 ($1000)	6,744,435	40,986,328
Retail sales, 1997 ($1000)	3,085,494	36,623,327
Retail sales per capita, 1997	$12,219	$8,477
Accomodation and foodservices sales, 1997 ($1000)	346,844	3,881,782
Total number of firms, 1997	15,265	285,206
Minority-owned firms, percent of total, 1997	24.8%	9.9%
Women-owned firms, percent of total, 1997	24.3%	24.4%
Geography QuickFacts	**Birmingham**	**Alabama**
Land area, 2000 (square miles)	150	50,744
Persons per square mile, 2000	1,619.7	87.6
FIPS Code	07000	01
Counties		

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UGA 2006

DEMOGRAPHIC PROFILE

	APPLING CO.	GEORGIA TOTAL	Avg. Co. in GA
AGRICULTURE			
Total Farm Gate Value of production, 2004	$92,637,111	$10,283,536,190	$64,676,328
Total Farm Gate Value per farm	$166,314	$208,544	$204,529
Total Farm Gate value per acre of farm land	$780	$957	$1,181
Poultry/eggs value	$28,231,107	$4,750,925,309	$29,880,033
Row/forage crops value	$22,927,325	$1,539,792,437	$9,684,229
Livestock/aquaculture value	$17,779,336	$1,305,226,550	$8,208,972
Forestry & products value	$8,878,917	$607,909,852	$3,823,332
Vegetables value	$816,630	$725,281,592	$4,561,519
Ornamental horticulture value	$2,059,000	$656,868,481	$4,131,248
Fruits & nuts value	$7,349,850	$227,406,888	$1,430,232
Other income value	$4,594,947	$470,125,080	$2,956,762
Farm production expenses, 2003	$34,840,000	$4,003,400,000	$25,178,616
Net farm proprieter's income, 2003	$21,273,000	$1,957,619,000	$12,312,465
Number of farms, 2002	557	49,311	310
% change in number of farms, 1997-2002	-10.2	-0.1	0.9
Land in farms, acres, 2002	118,720	10,744,239	67,574
% of farmers working 200+ days off farm, 2002	40.4	39.8	40.3
Average farm size in acres, 2002	213	218	244
Harvested cropland, acres, 2002	53,566	3,245,784	20,414
Acres of irrigated farm land, 2004	7,110	1,546,756	9,728
CRIME			
Index crimes reported, 2004	300	360,425	2,267
Index crime rate per 100,000	1,669.8	4,082.1	2,691.7
Arrests for index crimes, 2004	30	59,079	372
% juvenile arrests	23.3	23.2	17.5
Index crime arrest rate per 100,000, 2004	167.0	669.1	533.2
Juvenile commitment rate per 1,000 (age 10-16), FY2005	3.34	3.02	2.32
State prison inmates' home county, 2005	84	47,495	264
% incarcerated for violent/sex crimes	57.1	60.5	59.9
Probationers county of conviction, 2005	280	124,634	769
ECONOMICS			
Deposits in financial institutions, 2004	$195,978,000	$142,650,207,000	$897,171,113
Personal bankruptcies filed per 1,000 population, 2004	9.8	8.9	9.1
Gross tax digest 40% value of assessed property, 2004	$587,083,476	$289,418,742,651	$1,820,243,664
Taxes levied, 2004	$14,699,427	$8,455,894,148	$53,181,724
Millage rate, county-wide, 2003	25.20	–	26.46
Total lottery sales, FY2005	$6,647,767	$2,919,844,265	$18,363,800
Per capita lottery sales	$370	$331	$377
Median household income, 2002 estimate	$29,541	$42,359	$34,153
Persons below poverty level, 2002 estimate	3,007	1,107,209	6,964
% of all persons	17.1	13.0	16.5
% of children 0-17	23.8	17.8	22.1
Families living below poverty level, % in 1999	14.9	9.9	13.5
Per capita income, 2003	$19,747	$29,000	$22,879
Total personal income, 2003	$352,603,000	$251,620,610,000	$1,582,519,560
Transfer receipts, 2003	$85,823,000	$32,640,313,000	$205,284,987
Transfer receipts as a % of total personal income	24.3	13.0	20.8
Per capita transfer receipts	$4,806	$3,762	$4,560
Total retail sales, 2004	$149,905,000	$115,210,992,000	$724,597,434
Pull factor (1 = average)	0.90	1.00	0.82
EDUCATION--Public School Systems, (County/City combined) 2003-04			
Total enrollment	3,166	1,486,125	9,346
% Black	25.9	37.9	37.2
% White	67.0	50.6	56.5
% Hispanic	5.8	6.9	4.1
% economically disadvantaged (qualify for free/red. lunch)	60.8	46.4	56.8
General Fund Expenditures per pupil	$6,832	$6,712	$6,478
Number of high school dropouts (grades 9-12)	58	23,680	149
High school dropout rate per 100 enrolled	6.1	5.1	5.6
Total graduates	137	66,716	420
% of grads with college prep. diploma	56.9	73.4	60.2
Class of 2004 percent completion	57.6	65.4	61.4
Number of teachers	238	104,545	657
% with advanced degrees	50.8	51.8	52.8
Total recipients of HOPE Scholarships, FY2005	643	222,541	1,396
HOPE $ awards	$947,822	$427,364,658	$2,675,368

V-473

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	APPLING CO.	GEORGIA TOTAL	Avg. Co. In GA
EDUCATION--Highest Level Completed (Age 25+) 2000			
% NOT completing high school	32.7	21.4	29.3
% high school graduate (includes GED)	37.2	28.7	34.9
% some college and/or associate degree	21.7	25.6	21.8
% Bachelor's degree	5.3	16.0	8.9
% Graduate or professional degree	3.1	8.3	5.1
GOVERNMENT			
Date of county creation	Dec. 15, 1818	--	--
Total direct Federal government expenditures, FY2003	$100,030,768	$51,910,195,521	$304,578,997
% Defense spending	5.3	17.3	7.9
Total registered voters as of 2004 General Election	9,585	4,248,837	26,722
2004 % of registered voters voting for President	66.4	77.6	74.4
2004 % of voting-age population voting for President	48.0	50.8	49.1
HEALTH			
Disability, % age 21-64, 2000	21.8	19.9	23.8
Disability, % age 65+, 2000	60.3	47.5	50.7
Licensed child day care facilities, 2005	4	2,981	19
General hospitals, 2004	1	150	1
General nursing homes, SFY04	2	362	2
Medicare payments, 2003	$18,009,000	$6,260,652,000	$39,375,170
Total practicing physicians, 2002	22	16,483	104
Persons per physician ratio	124.6	192.6	107.5
HOUSING / HOUSEHOLDS			
Private residential units authorized for construction, 2004	7	108,356	681
Value of construction	$991,667	$12,884,207,336	$81,032,751
Total housing units, 2004 estimate	8,018	3,672,677	23,098.6
% change 2000-04	2.1	11.9	8.2
Housing unit density per sq. mi. of land area	15.8	63.4	72.8
% mobile homes of total housing units, 2000	36.7	12.0	25.5
% owner-occupied of total housing units, 2000	79.1	67.5	73.9
Median value of owner-occupied units, 2000	$63,700	$111,200	$81,599
Total families, 2000	4,856	2,111,647	13,281
% with own children <18	47.0	49.8	47.3
% married couples	77.0	73.3	73.4
% female householder, no husband present	17.0	20.6	20.7
% female h/holder, no husband, w/children <18	9.8	12.2	11.9
Total households, 2000	6,606	3,006,369	18,908
# persons per household	2.60	2.65	2.64
LABOR			
Civilian labor force, 2004	8,241	4,390,395	27,613
Average annual unemployment rate, 2004	6.1	4.6	4.9
Average # of business establishments, 2004	423	246,245	1,431
Average monthly employment, 2004	5,937	3,834,456	23,665
Average weekly wage, all industries, 2004	$648	$728	$526
Residents' mean travel time to work in minutes, 2000	24.1	27.7	26.4
% of residents working outside of county, 2000	28.3	41.5	45.5
% or residents who drove alone to work, 2000	76.3	77.5	77.1
% change in residents who drove alone, 1990-2000	22.2	24.8	26.0
% of workforce coming into county from elsewhere, 2000	25.6	41.8	33.1
NATURAL RESOURCES			
Total area in square miles, 2000 Census	512.1	59,424.8	373.7
Rank of size, 1=highest (1-159)	26	--	--
Acres of forestland, 2004	223,860	24,726,400	155,512
% of all land in forests	68.8	66.7	65.4
Volume of live trees, all species, cubic ft., 2004	341,821,000	36,727,216,000	230,988,774
Water withdrawals (gallons per day), 2000	63,550,000	6,486,580,000	40,798,491
Public use per capita in gallons per day	162.4	185.1	189.8
Water use for irrigation (millions of gal/day)	3.70	1,092.16	7
Hazardous waste sites, 2005	4	436	3
Toxic chemical releases (pounds per year), 2003	5,368	126,197,045	795,081
POPULATION			
Metropolitan county in 2006?	NO	--	--
Total, 2004 estimate	17,966	8,829,383	55,531
Rank of population size, 1=highest (1-159)	91	--	--
% change in total, 2000-04	3.2	7.8	6.0
Rank of % change in total, 2000-04	87	--	--
Growth rate by natural increase, 2000-04	4.3	8.3	4.8
Growth rate by net migration, 2000-04	3.1	9.5	8.2
% change in total population, 1930-2004	34.9	203.6	190.5
Rank of % change, 1=highest (1-159)	96	--	--

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	APPLING CO.	GEORGIA TOTAL	Avg. Co. in GA
Persons per square mile, 2004 estimate	35.3	152.5	176.2
Rank of population density, 1=highest (1-159)	113	–	–
% urban, 2000	29.9	71.7	36.4
% rural, 2000	70.1	28.3	63.6
Total, 2010 Trend (Center for Agribusiness)	18,905	9,822,289	61,775
Total, 2010 projection (GA Office of Planning & Budget)	18,724	9,864,970	62,044
Total, 2015 projection (GA Office of Planning & Budget)	19,394	10,813,573	68,010
% Black alone, 2004 estimate	19.6	29.6	28.2
% White alone, 2004 estimate	79.4	66.4	70.0
% Other races alone, 2004 estimate	0.66	2.99	1.2
% Hispanic/Latino, 2004 estimate	5.6	6.8	4.3
% Age 65 and over, 2004 estimate	12.0	9.6	12.0
Median age, Total, 2004 estimate	35.3	33.8	35.1
Religion--churches/synagogues/mosques/temples, 2000	55	8,962	56
Adherents as % of population	78.6	44.8	43.9
Total civilian veterans, 2005 estimate	1,305	758,963	4,773
PUBLIC ASSISTANCE			
Child abuse cases investigated, 2004	299	85,562	538
% of child abuse cases substantiated	46.8	36.2	36.1
Substantiated child maltreatment victims, 2004	222	51,717	325
Maltreatment rate per 1,000 children <18	47.1	22.5	31.1
Child Welfare, adoptions, FY2004	3	1210	8
Food stamp average # of recipients, FY2004	2,137	847,886	5,333
Food stamp recipients % of population	11.9	9.6	13.0
Medicaid average # of recipients, FY2004	7,340	2,056,826	12,935
Medicaid recipients % of population	40.9	23.3	28.7
TANF average # of recipients, FY2004	192	135,515	852
TANF recipients % of population	1.1	1.5	1.8
OASDI (Social Security) recipients % of pop., 12/2004	18.1	13.5	17.4
SSI (Supplemental Security Income) % of pop., 12/2004	4.1	2.3	3.3
TRANSPORTATION			
Total traffic crashes, 2003	614	331,612	2,086
Crash rate per 10,000 licensed drivers	454.1	478.1	320.2
Total fatalities	3	1,610	10
Deer-related crashes	180	10,343	65.1
Licensed drivers, 2003	13,522	6,936,026	43,623
Drivers involved in alcohol/drug related crashes	27	10,694	67
Daily vehicle miles traveled, as of 12/31/2004	793,736	306,695,953	1,928,905
Total road mileage, as of 12/31/2004	1,088.40	115,408.62	725.84
% unpaved	59.7	25.4	28.8
Total motor vehicle registrations, as of 7/2005	19,579	7,781,049	48,934
Housing units with no vehicles available, 2000	476	248,546	1,563
VITAL STATISTICS, 2003 (Rate not shown when number of events is >0 and <5)			
Live births, total	271	135,831	854
Live birth rate (per 1,000 population)	15.2	15.6	14.0
Live births to unwed mothers, total	96	51,804	326
% Unwed births of total live births	35.4	38.1	42.2
% Unwed births to teen mothers of all births	11.1	9.6	12.1
Low weight births, total (< 2500 grams)	31	12,205	77
% Low weight of total live births	11.4	9.0	9.6
Induced terminations, total	11	30,396	191
Induced termination rate (per 1,000 fem. age 15-44)	3.0	15.5	–
Teen Pregnancies, total	57	21,557	136
Teen pregnancy rate (per 1,000 fem. age 10-19)	44.0	35.1	36.1
Deaths, total	165	66,337	417
Death rate (per 100,000 population)	927.1	763.8	974.3
Infant deaths, total	4	1,153	7
VITAL STATISTICS, 10-Yr. CUMULATIVE RATES, 1994-2003			
Live birth rate (per 1,000 population)	15.1	15.6	14.4
Live births to unwed mothers rate (per 100 live births)	35.3	36.5	40.6
Low birth weight rate (per 1,000 live births)	8.7	8.8	9.2
Induced termination rate (per 1,000 females age 15-44)	2.0	16.8	9.1
Death rate (per 100,000 population)	1020.1	789.6	977.1
Infant death rate (per 1,000 live births)	13.9	8.8	9.7
Suicide rate (per 100,000 population)	8.8	11.0	–
Homicide rate (per 100,000 population)	5.8	8.7	–

– Data not available or data tabulation not appropriate.

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	JEFF DAVIS CO.	GEORGIA TOTAL	Avg. Co. in GA
AGRICULTURE			
Total Farm Gate Value of production, 2004	$56,344,904	$10,283,536,190	$64,676,328
Total Farm Gate Value per farm	$221,830	$208,544	$204,529
Total Farm Gate value per acre of farm land	$1,003	$957	$1,181
Poultry/eggs value	$13,707,704	$4,750,925,309	$29,880,033
Row/forage crops value	$21,057,400	$1,539,792,437	$9,684,229
Livestock/aquaculture value	$7,557,080	$1,305,226,550	$8,208,972
Forestry & products value	$6,406,768	$607,909,852	$3,823,332
Vegetables value	$122,675	$725,281,592	$4,561,519
Ornamental horticulture value	$2,967,245	$656,868,481	$4,131,248
Fruits & nuts value	$1,526,860	$227,406,888	$1,430,232
Other income value	$2,999,172	$470,125,080	$2,956,762
Farm production expenses, 2003	$19,839,000	$4,003,400,000	$25,178,616
Net farm proprieter's income, 2003	$10,848,000	$1,957,619,000	$12,312,465
Number of farms, 2002	254	49,311	310
% change in number of farms, 1997-2002	-4.9	-0.1	0.9
Land in farms, acres, 2002	56,198	10,744,239	67,574
% of farmers working 200+ days off farm, 2002	48.4	39.8	40.3
Average farm size in acres, 2002	221	218	244
Harvested cropland, acres, 2002	22,836	3,245,784	20,414
Acres of irrigated farm land, 2004	13,193	1,546,756	9,728
CRIME			
Index crimes reported, 2004	550	360,425	2,267
Index crime rate per 100,000	4,290.2	4,082.1	2,691.7
Arrests for index crimes, 2004	82	59,079	372
% juvenile arrests	20.7	23.2	17.5
Index crime arrest rate per 100,000, 2004	639.6	669.1	533.2
Juvenile commitment rate per 1,000 (age 10-16), FY2005	2.93	3.02	2.32
State prison inmates' home county, 2005	69	47,495	264
% incarcerated for violent/sex crimes	53.6	60.5	59.9
Probationers county of conviction, 2005	235	124,634	769
ECONOMICS			
Deposits in financial institutions, 2004	$154,028,000	$142,650,207,000	$897,171,113
Personal bankruptcies filed per 1,000 population, 2004	13.2	8.9	9.1
Gross tax digest 40% value of assessed property, 2004	$267,072,912	$289,418,742,651	$1,820,243,664
Taxes levied, 2004	$6,109,889	$8,455,894,148	$53,181,724
Millage rate, county-wide, 2003	20.89	--	26.46
Total lottery sales, FY2005	$3,784,795	$2,919,844,265	$18,363,800
Per capita lottery sales	$295	$331	$377
Median household income, 2002 estimate	$27,599	$42,359	$34,153
Persons below poverty level, 2002 estimate	2,261	1,107,209	6,964
% of all persons	17.6	13.0	16.5
% of children 0-17	25.1	17.8	22.1
Families living below poverty level, % in 1999	16.8	9.9	13.5
Per capita income, 2003	$21,088	$29,000	$22,879
Total personal income, 2003	$270,499,000	$251,620,610,000	$1,582,519,560
Transfer receipts, 2003	$65,629,000	$32,640,313,000	$205,284,987
Transfer receipts as a % of total personal income	24.3	13.0	20.8
Per capita transfer receipts	$5,116	$3,762	$4,560
Total retail sales, 2004	$234,538,000	$115,210,992,000	$724,597,434
Pull factor (1 = average)	2.12	1.00	0.82
EDUCATION--Public School Systems, (County/City combined) 2003-04			
Total enrollment	2,502	1,486,125	9,346
% Black	15.7	37.9	37.2
% White	75.1	50.6	56.5
% Hispanic	7.9	6.9	4.1
% economically disadvantaged (qualify for free/red. lunch)	58.4	46.4	56.8
General Fund Expenditures per pupil	$6,319	$6,712	$6,478
Number of high school dropouts (grades 9-12)	33	23,680	149
High school dropout rate per 100 enrolled	4.5	5.1	5.6
Total graduates	108	66,716	420
% of grads with college prep. diploma	47.2	73.4	60.2
Class of 2004 percent completion	65.5	65.4	61.4
Number of teachers	182	104,545	657
% with advanced degrees	64.3	51.8	52.8
Total recipients of HOPE Scholarships, FY2005	485	222,541	1,396
HOPE $ awards	$674,206	$427,364,658	$2,675,368

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	JEFF DAVIS CO.	GEORGIA TOTAL	Avg. Co. in GA
EDUCATION--Highest Level Completed (Age 25+) 2000			
% NOT completing high school	36.7	21.4	29.3
% high school graduate (includes GED)	35.4	28.7	34.9
% some college and/or associate degree	18.5	25.6	21.8
% Bachelor's degree	6.0	16.0	8.9
% Graduate or professional degree	3.3	8.3	5.1
GOVERNMENT			
Date of county creation	Aug. 18, 1905	--	--
Total direct Federal government expenditures, FY2003	$75,471,170	$51,910,195,521	$304,578,997
% Defense spending	1.4	17.3	7.9
Total registered voters as of 2004 General Election	7,016	4,248,837	26,722
2004 % of registered voters voting for President	69.0	77.6	74.4
2004 % of voting-age population voting for President	52.1	50.8	49.1
HEALTH			
Disability, % age 21-64, 2000	26.5	19.9	23.8
Disability, % age 65+, 2000	58.7	47.5	50.7
Licensed child day care facilities, 2005	2	2,981	19
General hospitals, 2004	1	150	1
General nursing homes, SFY04	1	362	2
Medicare payments, 2003	$13,017,000	$6,260,652,000	$39,375,170
Total practicing physicians, 2002	14	16,483	104
Persons per physician ratio	108.4	192.6	107.5
HOUSING / HOUSEHOLDS			
Private residential units authorized for construction, 2004	4	108,356	681
Value of construction	$229,500	$12,884,207,336	$81,032,751
Total housing units, 2004 estimate	5,683	3,672,677	23,098.6
% change 2000-04	1.8	11.9	8.2
Housing unit density per sq. mi. of land area	17.0	63.4	72.8
% mobile homes of total housing units, 2000	34.8	12.0	25.5
% owner-occupied of total housing units, 2000	77.4	67.5	73.9
Median value of owner-occupied units, 2000	$61,000	$111,200	$81,599
Total families, 2000	3,591	2,111,647	13,281
% with own children <18	48.0	49.8	47.3
% married couples	76.0	73.3	73.4
% female householder, no husband present	18.3	20.6	20.7
% female h/holder, no husband, w/children <18	10.1	12.2	11.9
Total households, 2000	4,828	3,006,369	18,908
# persons per household	2.61	2.65	2.64
LABOR			
Civilian labor force, 2004	5,478	4,390,395	27,613
Average annual unemployment rate, 2004	6.8	4.6	4.9
Average # of business establishments, 2004	324	246,245	1,431
Average monthly employment, 2004	4,637	3,834,456	23,665
Average weekly wage, all industries, 2004	$491	$728	$526
Residents' mean travel time to work in minutes, 2000	21.7	27.7	26.4
% of residents working outside of county, 2000	28.4	41.5	45.5
% or residents who drove alone to work, 2000	78.5	77.5	77.1
% change in residents who drove alone, 1990-2000	-3.4	24.8	26.0
% of workforce coming into county from elsewhere, 2000	27.9	41.8	33.1
NATURAL RESOURCES			
Total area in square miles, 2000 Census	335.4	59,424.8	373.7
Rank of size, 1=highest (1-159)	86	--	--
Acres of forestland, 2004	158,120	24,726,400	155,512
% of all land in forests	74.1	66.7	65.4
Volume of live trees, all species, cubic ft., 2004	176,752,000	36,727,216,000	230,988,774
Water withdrawals (gallons per day), 2000	6,440,000	6,486,580,000	40,798,491
Public use per capita in gallons per day	130.9	185.1	189.8
Water use for irrigation (millions of gal/day)	4.73	1,092.16	7
Hazardous waste sites, 2005	1	436	3
Toxic chemical releases (pounds per year), 2003	0	126,197,045	795,081
POPULATION			
Metropolitan county in 2006?	NO	--	--
Total, 2004 estimate	12,820	8,829,383	55,531
Rank of population size, 1=highest (1-159)	113	--	--
% change in total, 2000-04	1.1	7.8	6.0
Rank of % change in total, 2000-04	117	--	--
Growth rate by natural increase, 2000-04	4.4	8.3	4.8
Growth rate by net migration, 2000-04	-1.8	9.5	8.2
% change in total population, 1930-2004	57.9	203.6	190.5
Rank of % change, 1=highest (1-159)	81	--	--

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	JEFF DAVIS CO.	GEORGIA TOTAL	Avg. Co. in GA
Persons per square mile, 2004 estimate	38.5	152.5	176.2
Rank of population density, 1=highest (1-159)	108	--	--
% urban, 2000	31.0	71.7	36.4
% rural, 2000	69.0	28.3	63.6
Total, 2010 Trend (Center for Agribusiness)	13,156	9,822,289	61,775
Total, 2010 projection (GA Office of Planning & Budget)	13,574	9,864,970	62,044
Total, 2015 projection (GA Office of Planning & Budget)	14,035	10,813,573	68,010
% Black alone, 2004 estimate	14.9	29.6	28.2
% White alone, 2004 estimate	84.0	66.4	70.0
% Other races alone, 2004 estimate	1.01	2.99	1.2
% Hispanic/Latino, 2004 estimate	6.9	6.8	4.3
% Age 65 and over, 2004 estimate	11.7	9.6	12.0
Median age, Total, 2004 estimate	34.8	33.8	35.1
Religion--churches/synagogues/mosques/temples, 2000	35	8,962	56
Adherents as % of population	71.6	44.8	43.9
Total civilian veterans, 2005 estimate	844	758,963	4,773
PUBLIC ASSISTANCE			
Child abuse cases investigated, 2004	227	85,562	538
% of child abuse cases substantiated	20.3	36.2	36.1
Substantiated child maltreatment victims, 2004	71	51,717	325
Maltreatment rate per 1,000 children <18	20.2	22.5	31.1
Child Welfare, adoptions, FY2004	3	1210	8
Food stamp average # of recipients, FY2004	1,911	847,886	5,333
Food stamp recipients % of population	14.9	9.6	13.0
Medicaid average # of recipients, FY2004	4,961	2,056,826	12,935
Medicaid recipients % of population	38.7	23.3	28.7
TANF average # of recipients, FY2004	117	135,515	852
TANF recipients % of population	0.9	1.5	1.8
OASDI (Social Security) recipients % of pop., 12/2004	20.5	13.5	17.4
SSI (Supplemental Security Income) % of pop., 12/2004	3.7	2.3	3.3
TRANSPORTATION			
Total traffic crashes, 2003	333	331,612	2,086
Crash rate per 10,000 licensed drivers	303.4	478.1	320.2
Total fatalities	3	1,610	10
Deer-related crashes	4	10,343	65.1
Licensed drivers, 2003	10,974	6,936,026	43,623
Drivers involved in alcohol/drug related crashes	14	10,694	67
Daily vehicle miles traveled, as of 12/31/2004	431,034	306,695,953	1,928,905
Total road mileage, as of 12/31/2004	648.52	115,408.62	725.84
% unpaved	52.2	25.4	28.8
Total motor vehicle registrations, as of 7/2005	14,147	7,781,049	48,934
Housing units with no vehicles available, 2000	362	248,546	1,563
VITAL STATISTICS, 2003 (Rate not shown when number of events is >0 and <5)			
Live births, total	211	135,831	854
Live birth rate (per 1,000 population)	16.4	15.6	14.0
Live births to unwed mothers, total	85	51,804	326
% Unwed births of total live births	40.3	38.1	42.2
% Unwed births to teen mothers of all births	16.1	9.6	12.1
Low weight births, total (< 2500 grams)	14	12,205	77
% Low weight of total live births	6.6	9.0	9.6
Induced terminations, total	6	30,396	191
Induced termination rate (per 1,000 fem. age 15-44)	2.3	15.5	--
Teen Pregnancies, total	47	21,557	136
Teen pregnancy rate (per 1,000 fem. age 10-19)	51.4	35.1	36.1
Deaths, total	147	66,337	417
Death rate (per 100,000 population)	1140.6	763.8	974.3
Infant deaths, total	1	1,153	7
VITAL STATISTICS, 10-Yr. CUMULATIVE RATES, 1994-2003			
Live birth rate (per 1,000 population)	16.4	15.6	14.4
Live births to unwed mothers rate (per 100 live births)	37.2	36.5	40.6
Low birth weight rate (per 1,000 live births)	8.7	8.8	9.2
Induced termination rate (per 1,000 females age 15-44)	2.4	16.8	9.1
Death rate (per 100,000 population)	1054.0	789.6	977.1
Infant death rate (per 1,000 live births)	11.6	8.8	9.7
Suicide rate (per 100,000 population)	13.5	11.0	--
Homicide rate (per 100,000 population)	6.3	8.7	--

-- Data not available or data tabulation not appropriate.

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DEMOGRAPHIC PROFILE

	MONTGOMERY CO.	GEORGIA TOTAL	Avg. Co. In GA
AGRICULTURE			
Total Farm Gate Value of production, 2004	$21,179,169	$10,283,536,190	$64,676,328
Total Farm Gate Value per farm	$84,044	$208,544	$204,529
Total Farm Gate value per acre of farm land	$286	$957	$1,181
Poultry/eggs value	$1,298,160	$4,750,925,309	$29,880,033
Row/forage crops value	$4,560,708	$1,539,792,437	$9,684,229
Livestock/aquaculture value	$7,369,306	$1,305,226,550	$8,208,972
Forestry & products value	$2,976,115	$607,909,852	$3,823,332
Vegetables value	$2,221,483	$725,281,592	$4,561,519
Ornamental horticulture value	$415,875	$656,868,481	$4,131,248
Fruits & nuts value	$795,069	$227,406,888	$1,430,232
Other income value	$1,542,454	$470,125,080	$2,956,762
Farm production expenses, 2003	$10,417,000	$4,003,400,000	$25,178,616
Net farm proprieter's income, 2003	$4,284,000	$1,957,619,000	$12,312,465
Number of farms, 2002	252	49,311	310
% change in number of farms, 1997-2002	-14.0	-0.1	0.9
Land in farms, acres, 2002	74,057	10,744,239	67,574
% of farmers working 200+ days off farm, 2002	39.7	39.8	40.3
Average farm size in acres, 2002	294	218	244
Harvested cropland, acres, 2002	9,710	3,245,784	20,414
Acres of irrigated farm land, 2004	3,706	1,546,756	9,728
CRIME			
Index crimes reported, 2004	0	360,425	2,267
Index crime rate per 100,000	0.0	4,082.1	2,691.7
Arrests for Index crimes, 2004	0	59,079	372
% juvenile arrests	--	23.2	17.5
Index crime arrest rate per 100,000, 2004	0.0	669.1	533.2
Juvenile commitment rate per 1,000 (age 10-16), FY2005	2.55	3.02	2.32
State prison inmates' home county, 2005	34	47,495	264
% incarcerated for violent/sex crimes	58.8	60.5	59.9
Probationers county of conviction, 2005	143	124,634	769
ECONOMICS			
Deposits in financial institutions, 2004	$107,543,000	$142,650,207,000	$897,171,113
Personal bankruptcies filed per 1,000 population, 2004	7.0	8.9	9.1
Gross tax digest 40% value of assessed property, 2004	$160,731,566	$289,418,742,651	$1,820,243,664
Taxes levied, 2004	$3,652,828	$8,455,894,148	$53,181,724
Millage rate, county-wide, 2003	24.08	--	26.46
Total lottery sales, FY2005	$2,446,672	$2,919,844,265	$18,363,800
Per capita lottery sales	$273	$331	$377
Median household income, 2002 estimate	$28,418	$42,359	$34,153
Persons below poverty level, 2002 estimate	1,625	1,107,209	6,964
% of all persons	20.5	13.0	16.5
% of children 0-17	25.8	17.8	22.1
Families living below poverty level, % in 1999	15.8	9.9	13.5
Per capita income, 2003	$19,457	$29,000	$22,879
Total personal income, 2003	$171,163,000	$251,620,610,000	$1,582,519,560
Transfer receipts, 2003	$40,935,000	$32,640,313,000	$205,284,987
Transfer receipts as a % of total personal income	23.9	13.0	20.8
Per capita transfer receipts	$4,653	$3,762	$4,560
Total retail sales, 2004	$38,884,000	$115,210,992,000	$724,597,434
Pull factor (1 = average)	0.46	1.00	0.82
EDUCATION--Public School Systems, (County/City combined) 2003-04			
Total enrollment	1,228	1,486,125	9,346
% Black	34.8	37.9	37.2
% White	57.7	50.6	56.5
% Hispanic	6.4	6.9	4.1
% economically disadvantaged (qualify for free/red. lunch)	65.3	46.4	56.8
General Fund Expenditures per pupil	$6,411	$6,712	$6,478
Number of high school dropouts (grades 9-12)	10	23,680	149
High school dropout rate per 100 enrolled	2.8	5.1	5.6
Total graduates	58	66,716	420
% of grads with college prep. diploma	36.2	73.4	60.2
Class of 2004 percent completion	62.4	65.4	61.4
Number of teachers	91	104,545	657
% with advanced degrees	46.2	51.8	52.8
Total recipients of HOPE Scholarships, FY2005	285	222,541	1,396
HOPE $ awards	$407,528	$427,364,658	$2,675,368

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	MONTGOMERY CO.	GEORGIA TOTAL	Avg. Co. in GA
EDUCATION--Highest Level Completed (Age 25+) 2000			
% NOT completing high school	28.6	21.4	29.3
% high school graduate (includes GED)	39.4	28.7	34.9
% some college and/or associate degree	18.6	25.6	21.8
% Bachelor's degree	8.9	16.0	8.9
% Graduate or professional degree	4.6	8.3	5.1
GOVERNMENT			
Date of county creation	Dec. 19, 1793	--	--
Total direct Federal government expenditures, FY2003	$50,725,074	$51,910,195,521	$304,578,997
% Defense spending	1.4	17.3	7.9
Total registered voters as of 2004 General Election	4,128	4,248,837	26,722
2004 % of registered voters voting for President	76.7	77.6	74.4
2004 % of voting-age population voting for President	46.2	50.8	49.1
HEALTH			
Disability, % age 21-64, 2000	23.0	19.9	23.8
Disability, % age 65+, 2000	53.8	47.5	50.7
Licensed child day care facilities, 2005	2	2,981	19
General hospitals, 2004	0	150	1
General nursing homes, SFY04	0	362	2
Medicare payments, 2003	$8,449,000	$6,260,652,000	$39,375,170
Total practicing physicians, 2002	5	16,483	104
Persons per physician ratio	59.5	192.6	107.5
HOUSING / HOUSEHOLDS			
Private residential units authorized for construction, 2004	66	108,356	681
Value of construction	$6,270,000	$12,884,207,336	$81,032,751
Total housing units, 2004 estimate	3,696	3,672,677	23,098.6
% change 2000-04	5.8	11.9	8.2
Housing unit density per sq. mi. of land area	15.1	63.4	72.8
% mobile homes of total housing units, 2000	33.6	12.0	25.5
% owner-occupied of total housing units, 2000	77.9	67.5	73.9
Median value of owner-occupied units, 2000	$68,300	$111,200	$81,599
Total families, 2000	2,063	2,111,647	13,281
% with own children <18	48.1	49.8	47.3
% married couples	75.2	73.3	73.4
% female householder, no husband present	19.1	20.6	20.7
% female h/holder, no husband, w/children <18	10.9	12.2	11.9
Total households, 2000	2,919	3,006,369	18,908
# persons per household	2.57	2.65	2.64
LABOR			
Civilian labor force, 2004	3,951	4,390,395	27,613
Average annual unemployment rate, 2004	5.5	4.6	4.9
Average # of business establishments, 2004	143	246,245	1,431
Average monthly employment, 2004	1,790	3,834,456	23,665
Average weekly wage, all industries, 2004	$470	$728	$526
Residents' mean travel time to work in minutes, 2000	27.0	27.7	26.4
% of residents working outside of county, 2000	68.2	41.5	45.5
% or residents who drove alone to work, 2000	71.3	77.5	77.1
% change in residents who drove alone, 1990-2000	15.0	24.8	26.0
% of workforce coming into county from elsewhere, 2000	33.4	41.8	33.1
NATURAL RESOURCES			
Total area in square miles, 2000 Census	247.3	59,424.8	373.7
Rank of size, 1=highest (1-159)	127	--	--
Acres of forestland, 2004	122,240	24,726,400	155,512
% of all land in forests	77.8	66.7	65.4
Volume of live trees, all species, cubic ft., 2004	129,492,000	36,727,216,000	230,988,774
Water withdrawals (gallons per day), 2000	2,360,000	6,486,580,000	40,798,491
Public use per capita in gallons per day	85.0	185.1	189.8
Water use for irrigation (millions of gal/day)	1.62	1,092.16	7
Hazardous waste sites, 2005	0	436	3
Toxic chemical releases (pounds per year), 2003	0	126,197,045	795,081
POPULATION			
Metropolitan county in 2006?	NO	--	--
Total, 2004 estimate	8,970	8,829,383	55,531
Rank of population size, 1=highest (1-159)	136	--	--
% change in total, 2000-04	8.5	7.8	6.0
Rank of % change in total, 2000-04	48	--	--
Growth rate by natural increase, 2000-04	4.2	8.3	4.8
Growth rate by net migration, 2000-04	15.0	9.5	8.2
% change in total population, 1930-2004	-10.5	203.6	190.5
Rank of % change, 1=highest (1-159)	127	--	--

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	MONTGOMERY CO.	GEORGIA TOTAL	Avg. Co. in GA
Persons per square mile, 2004 estimate	36.6	152.5	176.2
Rank of population density, 1=highest (1-159)	111	--	--
% urban, 2000	1.7	71.7	36.4
% rural, 2000	98.3	28.3	63.6
Total, 2010 Trend (Center for Agribusiness)	9,642	9,822,289	61,775
Total, 2010 projection (GA Office of Planning & Budget)	10,159	9,864,970	62,044
Total, 2015 projection (GA Office of Planning & Budget)	10,986	10,813,573	68,010
% Black alone, 2004 estimate	26.5	29.6	28.2
% White alone, 2004 estimate	73.0	66.4	70.0
% Other races alone, 2004 estimate	0.37	2.99	1.2
% Hispanic/Latino, 2004 estimate	4.2	6.8	4.3
% Age 65 and over, 2004 estimate	10.8	9.6	12.0
Median age, Total, 2004 estimate	33.0	33.8	35.1
Religion--churches/synagogues/mosques/temples, 2000	27	8,962	56
Adherents as % of population	41.7	44.8	43.9
Total civilian veterans, 2005 estimate	641	758,963	4,773
PUBLIC ASSISTANCE			
Child abuse cases investigated, 2004	117	85,562	538
% of child abuse cases substantiated	47.0	36.2	36.1
Substantiated child maltreatment victims, 2004	97	51,717	325
Maltreatment rate per 1,000 children <18	46.0	22.5	31.1
Child Welfare, adoptions, FY2004	0	1210	8
Food stamp average # of recipients, FY2004	1,203	847,886	5,333
Food stamp recipients % of population	13.4	9.6	13.0
Medicaid average # of recipients, FY2004	2,792	2,056,826	12,935
Medicaid recipients % of population	31.1	23.3	28.7
TANF average # of recipients, FY2004	148	135,515	852
TANF recipients % of population	1.6	1.5	1.8
OASDI (Social Security) recipients % of pop., 12/2004	16.8	13.5	17.4
SSI (Supplemental Security Income) % of pop., 12/2004	4.0	2.3	3.3
TRANSPORTATION			
Total traffic crashes, 2003	100	331,612	2,086
Crash rate per 10,000 licensed drivers	154.1	478.1	320.2
Total fatalities	5	1,610	10
Deer-related crashes	6	10,343	65.1
Licensed drivers, 2003	6,489	6,936,026	43,623
Drivers involved in alcohol/drug related crashes	15	10,694	67
Daily vehicle miles traveled, as of 12/31/2004	294,821	306,695,953	1,928,905
Total road mileage, as of 12/31/2004	461.45	115,408.62	725.84
% unpaved	46.1	25.4	28.8
Total motor vehicle registrations, as of 7/2005	8,153	7,781,049	48,934
Housing units with no vehicles available, 2000	235	248,546	1,563
VITAL STATISTICS, 2003 (Rate not shown when number of events is >0 and <5)			
Live births, total	126	135,831	854
Live birth rate (per 1,000 population)	14.5	15.6	14.0
Live births to unwed mothers, total	45	51,804	326
% Unwed births of total live births	35.7	38.1	42.2
% Unwed births to teen mothers of all births	15.1	9.6	12.1
Low weight births, total (< 2500 grams)	11	12,205	77
% Low weight of total live births	8.7	9.0	9.6
Induced terminations, total	10	30,396	191
Induced termination rate (per 1,000 fem. age 15-44)	5.1	15.5	--
Teen Pregnancies, total	26	21,557	136
Teen pregnancy rate (per 1,000 fem. age 10-19)	37.9	35.1	36.1
Deaths, total	81	66,337	417
Death rate (per 100,000 population)	932.0	763.8	974.3
Infant deaths, total	3	1,153	7
VITAL STATISTICS, 10-Yr. CUMULATIVE RATES, 1994-2003			
Live birth rate (per 1,000 population)	13.4	15.6	14.4
Live births to unwed mothers rate (per 100 live births)	39.2	36.5	40.6
Low birth weight rate (per 1,000 live births)	7.9	8.8	9.2
Induced termination rate (per 1,000 females age 15-44)	6.5	16.8	9.1
Death rate (per 100,000 population)	915.3	789.6	977.1
Infant death rate (per 1,000 live births)	8.2	8.8	9.7
Suicide rate (per 100,000 population)	9.8	11.0	--
Homicide rate (per 100,000 population)	6.1	8.7	--

-- Data not available or data tabulation not appropriate.

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	TATTNALL CO.	GEORGIA TOTAL	Avg. Co. in GA
AGRICULTURE			
Total Farm Gate Value of production, 2004	$250,615,853	$10,283,536,190	$64,676,328
Total Farm Gate Value per farm	$389,155	$208,544	$204,529
Total Farm Gate value per acre of farm land	$1,748	$957	$1,181
Poultry/eggs value	$152,489,633	$4,750,925,309	$29,880,033
Row/forage crops value	$16,121,679	$1,539,792,437	$9,684,229
Livestock/aquaculture value	$13,913,381	$1,305,226,550	$8,208,972
Forestry & products value	$5,173,404	$607,909,852	$3,823,332
Vegetables value	$53,013,959	$725,281,592	$4,561,519
Ornamental horticulture value	$235,800	$656,868,481	$4,131,248
Fruits & nuts value	$4,107,200	$227,406,888	$1,430,232
Other income value	$5,560,798	$470,125,080	$2,956,762
Farm production expenses, 2003	$104,651,000	$4,003,400,000	$25,178,616
Net farm proprieter's income, 2003	$73,333,000	$1,957,619,000	$12,312,465
Number of farms, 2002	644	49,311	310
% change in number of farms, 1997-2002	-5.0	-0.1	0.9
Land in farms, acres, 2002	143,358	10,744,239	67,574
% of farmers working 200+ days off farm, 2002	41.6	39.8	40.3
Average farm size in acres, 2002	223	218	244
Harvested cropland, acres, 2002	41,133	3,245,784	20,414
Acres of irrigated farm land, 2004	25,563	1,546,756	9,728
CRIME			
Index crimes reported, 2004	605	360,425	2,267
Index crime rate per 100,000	2,631.1	4,082.1	2,691.7
Arrests for index crimes, 2004	154	59,079	372
% juvenile arrests	14.9	23.2	17.5
Index crime arrest rate per 100,000, 2004	669.7	669.1	533.2
Juvenile commitment rate per 1,000 (age 10-16), FY2005	1.94	3.02	2.32
State prison inmates' home county, 2005	125	47,495	264
% incarcerated for violent/sex crimes	49.6	60.5	59.9
Probationers county of conviction, 2005	202	124,634	769
ECONOMICS			
Deposits in financial institutions, 2004	$228,994,000	$142,650,207,000	$897,171,113
Personal bankruptcies filed per 1,000 population, 2004	6.9	8.9	9.1
Gross tax digest 40% value of assessed property, 2004	$332,348,511	$289,418,742,651	$1,820,243,664
Taxes levied, 2004	$9,524,126	$8,455,894,148	$53,181,724
Millage rate, county-wide, 2003	25.75	–	26.46
Total lottery sales, FY2005	$5,625,173	$2,919,844,265	$18,363,800
Per capita lottery sales	$245	$331	$377
Median household income, 2002 estimate	$26,722	$42,359	$34,153
Persons below poverty level, 2002 estimate	4,710	1,107,209	6,964
% of all persons	25.2	13.0	16.5
% of children 0-17	27.6	17.8	22.1
Families living below poverty level, % in 1999	18.6	9.9	13.5
Per capita income, 2003	$20,099	$29,000	$22,879
Total personal income, 2003	$452,500,000	$251,620,610,000	$1,582,519,560
Transfer receipts, 2003	$96,199,000	$32,640,313,000	$205,284,987
Transfer receipts as a % of total personal income	21.3	13.0	20.8
Per capita transfer receipts	$4,273	$3,762	$4,560
Total retail sales, 2004	$126,896,000	$115,210,992,000	$724,597,434
Pull factor (1 = average)	0.63	1.00	0.82
EDUCATION--Public School Systems, (County/City combined) 2003-04			
Total enrollment	3,109	1,486,125	9,346
% Black	30.9	37.9	37.2
% White	53.3	50.6	56.5
% Hispanic	13.3	6.9	4.1
% economically disadvantaged (qualify for free/red. lunch)	68.9	46.4	56.8
General Fund Expenditures per pupil	$5,974	$6,712	$6,478
Number of high school dropouts (grades 9-12)	36	23,680	149
High school dropout rate per 100 enrolled	3.7	5.1	5.6
Total graduates	105	66,716	420
% of grads with college prep. diploma	24.8	73.4	60.2
Class of 2004 percent completion	52.5	65.4	61.4
Number of teachers	239	104,545	657
% with advanced degrees	51.5	51.8	52.8
Total recipients of HOPE Scholarships, FY2005	614	222,541	1,396
HOPE $ awards	$918,168	$427,364,658	$2,675,368

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	TATTNALL CO.	GEORGIA TOTAL	Avg. Co. in GA
EDUCATION–Highest Level Completed (Age 25+) 2000			
% NOT completing high school	33.7	21.4	29.3
% high school graduate (includes GED)	39.2	28.7	34.9
% some college and/or associate degree	19.2	25.6	21.8
% Bachelor's degree	5.5	16.0	8.9
% Graduate or professional degree	2.3	8.3	5.1
GOVERNMENT			
Date of county creation	Dec. 5, 1801	–	–
Total direct Federal government expenditures, FY2003	$121,408,809	$51,910,195,521	$304,578,997
% Defense spending	4.5	17.3	7.9
Total registered voters as of 2004 General Election	9,543	4,248,837	26,722
2004 % of registered voters voting for President	67.7	77.6	74.4
2004 % of voting-age population voting for President	36.5	50.8	49.1
HEALTH			
Disability, % age 21-64, 2000	22.7	19.9	23.8
Disability, % age 65+, 2000	49.9	47.5	50.7
Licensed child day care facilities, 2005	4	2,981	19
General hospitals, 2004	1	150	1
General nursing homes, SFY04	2	362	2
Medicare payments, 2003	$19,263,000	$6,260,652,000	$39,375,170
Total practicing physicians, 2002	13	16,483	104
Persons per physician ratio	57.6	192.6	107.5
HOUSING / HOUSEHOLDS			
Private residential units authorized for construction, 2004	62	108,356	681
Value of construction	$4,716,000	$12,884,207,336	$81,032,751
Total housing units, 2004 estimate	8,700	3,672,677	23,098.6
% change 2000-04	1.4	11.9	8.2
Housing unit density per sq. mi. of land area	18.0	63.4	72.8
% mobile homes of total housing units, 2000	35.0	12.0	25.5
% owner-occupied of total housing units, 2000	70.6	67.5	73.9
Median value of owner-occupied units, 2000	$67,300	$111,200	$81,599
Total families, 2000	4,874	2,111,647	13,281
% with own children <18	47.8	49.8	47.3
% married couples	74.0	73.3	73.4
% female householder, no husband present	19.3	20.6	20.7
% female h/holder, no husband, w/children <18	11.6	12.2	11.9
Total households, 2000	7,057	3,006,369	18,908
# persons per household	2.60	2.65	2.64
LABOR			
Civilian labor force, 2004	8,459	4,390,395	27,613
Average annual unemployment rate, 2004	5.3	4.6	4.9
Average # of business establishments, 2004	356	246,245	1,431
Average monthly employment, 2004	5,768	3,834,456	23,665
Average weekly wage, all industries, 2004	$433	$728	$526
Residents' mean travel time to work in minutes, 2000	27.5	27.7	26.4
% of residents working outside of county, 2000	40.4	41.5	45.5
% or residents who drove alone to work, 2000	71.7	77.5	77.1
% change in residents who drove alone, 1990-2000	21.3	24.8	26.0
% of workforce coming into county from elsewhere, 2000	32.3	41.8	33.1
NATURAL RESOURCES			
Total area in square miles, 2000 Census	488.2	59,424.8	373.7
Rank of size, 1=highest (1-159)	33	–	–
Acres of forestland, 2004	197,010	24,726,400	155,512
% of all land in forests	63.6	66.7	65.4
Volume of live trees, all species, cubic ft., 2004	230,094,000	36,727,216,000	230,988,774
Water withdrawals (gallons per day), 2000	9,510,000	6,486,580,000	40,798,491
Public use per capita in gallons per day	125.9	185.1	189.8
Water use for irrigation (millions of gal/day)	5.91	1,092.16	7
Hazardous waste sites, 2005	0	436	3
Toxic chemical releases (pounds per year), 2003	0	126,197,045	795,081
POPULATION			
Metropolitan county in 2006?	NO	–	–
Total, 2004 estimate	22,994	8,829,383	55,531
Rank of population size, 1=highest (1-159)	76	–	–
% change in total, 2000-04	3.1	7.8	6.0
Rank of % change in total, 2000-04	89	–	–
Growth rate by natural increase, 2000-04	5.5	8.3	4.8
Growth rate by net migration, 2000-04	1.8	9.5	8.2
% change in total population, 1930-2004	49.2	203.6	190.5
Rank of % change, 1=highest (1-159)	87	–	–

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	TATTNALL CO.	GEORGIA TOTAL	Avg. Co. in GA
Persons per square mile, 2004 estimate	47.5	152.5	176.2
Rank of population density, 1=highest (1-159)	93	–	–
% urban, 2000	21.7	71.7	36.4
% rural, 2000	78.3	28.3	63.6
Total, 2010 Trend (Center for Agribusiness)	25,217	9,822,289	61,775
Total, 2010 projection (GA Office of Planning & Budget)	23,094	9,864,970	62,044
Total, 2015 projection (GA Office of Planning & Budget)	23,549	10,813,573	68,010
% Black alone, 2004 estimate	30.4	29.6	28.2
% White alone, 2004 estimate	68.6	66.4	70.0
% Other races alone, 2004 estimate	0.80	2.99	1.2
% Hispanic/Latino, 2004 estimate	11.3	6.8	4.3
% Age 65 and over, 2004 estimate	11.0	9.6	12.0
Median age, Total, 2004 estimate	33.3	33.8	35.1
Religion–churches/synagogues/mosques/temples, 2000	52	8,962	56
Adherents as % of population	39.5	44.8	43.9
Total civilian veterans, 2005 estimate	2,227	758,963	4,773
PUBLIC ASSISTANCE			
Child abuse cases investigated, 2004	288	85,562	538
% of child abuse cases substantiated	50.0	36.2	36.1
Substantiated child maltreatment victims, 2004	279	51,717	325
Maltreatment rate per 1,000 children <18	54.1	22.5	31.1
Child Welfare, adoptions, FY2004	2	1210	8
Food stamp average # of recipients, FY2004	2,719	847,886	5,333
Food stamp recipients % of population	11.8	9.6	13.0
Medicaid average # of recipients, FY2004	6,367	2,056,826	12,935
Medicaid recipients % of population	27.7	23.3	28.7
TANF average # of recipients, FY2004	388	135,515	852
TANF recipients % of population	1.7	1.5	1.8
OASDI (Social Security) recipients % of pop., 12/2004	16.1	13.5	17.4
SSI (Supplemental Security Income) % of pop., 12/2004	4.1	2.3	3.3
TRANSPORTATION			
Total traffic crashes, 2003	343	331,612	2,086
Crash rate per 10,000 licensed drivers	230.8	478.1	320.2
Total fatalities	3	1,610	10
Deer-related crashes	26	10,343	65.1
Licensed drivers, 2003	14,863	6,936,026	43,623
Drivers involved in alcohol/drug related crashes	34	10,694	67
Daily vehicle miles traveled, as of 12/31/2004	619,274	306,695,953	1,928,905
Total road mileage, as of 12/31/2004	951.45	115,408.62	725.84
% unpaved	51.6	25.4	28.8
Total motor vehicle registrations, as of 7/2005	17,824	7,781,049	48,934
Housing units with no vehicles available, 2000	746	248,546	1,563
VITAL STATISTICS, 2003 (Rate not shown when number of events is >0 and <5)			
Live births, total	342	135,831	854
Live birth rate (per 1,000 population)	15.3	15.6	14.0
Live births to unwed mothers, total	151	51,804	326
% Unwed births of total live births	44.2	38.1	42.2
% Unwed births to teen mothers of all births	14.6	9.6	12.1
Low weight births, total (< 2500 grams)	42	12,205	77
% Low weight of total live births	12.3	9.0	9.6
Induced terminations, total	21	30,396	191
Induced termination rate (per 1,000 fem. age 15-44)	5.5	15.5	–
Teen Pregnancies, total	78	21,557	136
Teen pregnancy rate (per 1,000 fem. age 10-19)	56.8	35.1	36.1
Deaths, total	251	66,337	417
Death rate (per 100,000 population)	1121.3	763.8	974.3
Infant deaths, total	3	1,153	7
VITAL STATISTICS, 10-Yr. CUMULATIVE RATES, 1994-2003			
Live birth rate (per 1,000 population)	15.0	15.6	14.4
Live births to unwed mothers rate (per 100 live births)	43.2	36.5	40.6
Low birth weight rate (per 1,000 live births)	8.7	8.8	9.2
Induced termination rate (per 1,000 females age 15-44)	6.6	16.8	9.1
Death rate (per 100,000 population)	1060.5	789.6	977.1
Infant death rate (per 1,000 live births)	8.1	8.8	9.7
Suicide rate (per 100,000 population)	18.2	11.0	–
Homicide rate (per 100,000 population)	7.5	8.7	–

– Data not available or data tabulation not appropriate.

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DEMOGRAPHIC PROFILE

	TOOMBS CO.	GEORGIA TOTAL	Avg. Co. in GA
AGRICULTURE			
Total Farm Gate Value of production, 2004	$74,810,997	$10,283,536,190	$64,676,328
Total Farm Gate Value per farm	$195,840	$208,544	$204,529
Total Farm Gate value per acre of farm land	$805	$957	$1,181
Poultry/eggs value	$4,626,502	$4,750,925,309	$29,880,033
Row/forage crops value	$9,070,639	$1,539,792,437	$9,684,229
Livestock/aquaculture value	$6,650,239	$1,305,226,550	$8,208,972
Forestry & products value	$4,055,860	$607,909,852	$3,823,332
Vegetables value	$41,222,165	$725,281,592	$4,561,519
Ornamental horticulture value	$4,993,770	$656,868,481	$4,131,248
Fruits & nuts value	$329,420	$227,406,888	$1,430,232
Other income value	$3,862,402	$470,125,080	$2,956,762
Farm production expenses, 2003	$27,392,000	$4,003,400,000	$25,178,616
Net farm proprieter's income, 2003	$17,413,000	$1,957,619,000	$12,312,465
Number of farms, 2002	382	49,311	310
% change in number of farms, 1997-2002	-22.0	-0.1	0.9
Land in farms, acres, 2002	92,934	10,744,239	67,574
% of farmers working 200+ days off farm, 2002	42.9	39.8	40.3
Average farm size in acres, 2002	243	218	244
Harvested cropland, acres, 2002	25,362	3,245,784	20,414
Acres of irrigated farm land, 2004	16,734	1,546,756	9,728
CRIME			
Index crimes reported, 2004	758	360,425	2,267
Index crime rate per 100,000	2,831.0	4,082.1	2,691.7
Arrests for index crimes, 2004	110	59,079	372
% juvenile arrests	17.3	23.2	17.5
Index crime arrest rate per 100,000, 2004	410.8	669.1	533.2
Juvenile commitment rate per 1,000 (age 10-16), FY2005	1.70	3.02	2.32
State prison inmates' home county, 2005	243	47,495	264
% incarcerated for violent/sex crimes	49.4	60.5	59.9
Probationers county of conviction, 2005	348	124,634	769
ECONOMICS			
Deposits in financial institutions, 2004	$739,932,000	$142,650,207,000	$897,171,113
Personal bankruptcies filed per 1,000 population, 2004	7.1	8.9	9.1
Gross tax digest 40% value of assessed property, 2004	$482,543,299	$289,418,742,651	$1,820,243,664
Taxes levied, 2004	$11,405,193	$8,455,894,148	$53,181,724
Millage rate, county-wide, 2003	19.56	–	26.46
Total lottery sales, FY2005	$10,619,846	$2,919,844,265	$18,363,800
Per capita lottery sales	$397	$331	$377
Median household income, 2002 estimate	$26,160	$42,359	$34,153
Persons below poverty level, 2002 estimate	5,780	1,107,209	6,964
% of all persons	22.1	13.0	16.5
% of children 0-17	30.3	17.8	22.1
Families living below poverty level, % in 1999	17.8	9.9	13.5
Per capita income, 2003	$21,984	$29,000	$22,879
Total personal income, 2003	$582,332,000	$251,620,610,000	$1,582,519,560
Transfer receipts, 2003	$151,267,000	$32,640,313,000	$205,284,987
Transfer receipts as a % of total personal income	26.0	13.0	20.8
Per capita transfer receipts	$5,711	$3,762	$4,560
Total retail sales, 2004	$266,965,000	$115,210,992,000	$724,597,434
Pull factor (1 = average)	1.18	1.00	0.82
EDUCATION–Public School Systems, (County/City combined) 2003-04			
Total enrollment	5,004	1,486,125	9,346
% Black	34.1	37.9	37.2
% White	53.7	50.6	56.5
% Hispanic	10.2	6.9	4.1
% economically disadvantaged (qualify for free/red. lunch)	64.2	46.4	56.8
General Fund Expenditures per pupil	$5,751	$6,712	$6,478
Number of high school dropouts (grades 9-12)	59	23,680	149
High school dropout rate per 100 enrolled	3.8	5.1	5.6
Total graduates	229	66,716	420
% of grads with college prep. diploma	50.2	73.4	60.2
Class of 2004 percent completion	61.1	65.4	61.4
Number of teachers	360	104,545	657
% with advanced degrees	41.9	51.8	52.8
Total recipients of HOPE Scholarships, FY2005	1,073	222,541	1,396
HOPE $ awards	$1,727,415	$427,364,658	$2,675,368

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	TOOMBS CO.	GEORGIA TOTAL	Avg. Co. in GA
EDUCATION--Highest Level Completed (Age 25+) 2000			
% NOT completing high school	32.7	21.4	29.3
% high school graduate (includes GED)	35.0	28.7	34.9
% some college and/or associate degree	19.7	25.6	21.8
% Bachelor's degree	8.4	16.0	8.9
% Graduate or professional degree	4.2	8.3	5.1
GOVERNMENT			
Date of county creation	Aug. 18, 1905	--	--
Total direct Federal government expenditures, FY2003	$147,639,615	$51,910,195,521	$304,578,997
% Defense spending	2.1	17.3	7.9
Total registered voters as of 2004 General Election	11,814	4,248,837	26,722
2004 % of registered voters voting for President	74.6	77.6	74.4
2004 % of voting-age population voting for President	45.7	50.8	49.1
HEALTH			
Disability, % age 21-64, 2000	25.5	19.9	23.8
Disability, % age 65+, 2000	49.4	47.5	50.7
Licensed child day care facilities, 2005	18	2,981	19
General hospitals, 2004	1	150	1
General nursing homes, SFY04	3	362	2
Medicare payments, 2003	$25,251,000	$6,260,652,000	$39,375,170
Total practicing physicians, 2002	45	16,483	104
Persons per physician ratio	170.5	192.6	107.5
HOUSING / HOUSEHOLDS			
Private residential units authorized for construction, 2004	93	108,356	681
Value of construction	$9,790,525	$12,884,207,336	$81,032,751
Total housing units, 2004 estimate	11,682	3,672,677	23,098.6
% change 2000-04	2.7	11.9	8.2
Housing unit density per sq. mi. of land area	31.9	63.4	72.8
% mobile homes of total housing units, 2000	26.2	12.0	25.5
% owner-occupied of total housing units, 2000	65.5	67.5	73.9
Median value of owner-occupied units, 2000	$66,400	$111,200	$81,599
Total families, 2000	6,825	2,111,647	13,281
% with own children <18	50.3	49.8	47.3
% married couples	70.5	73.3	73.4
% female householder, no husband present	22.5	20.6	20.7
% female h/holder, no husband, w/children <18	14.0	12.2	11.9
Total households, 2000	9,877	3,006,369	18,908
# persons per household	2.59	2.65	2.64
LABOR			
Civilian labor force, 2004	11,860	4,390,395	27,613
Average annual unemployment rate, 2004	6.0	4.6	4.9
Average # of business establishments, 2004	753	246,245	1,431
Average monthly employment, 2004	11,004	3,834,456	23,665
Average weekly wage, all industries, 2004	$453	$728	$526
Residents' mean travel time to work in minutes, 2000	21.9	27.7	26.4
% of residents working outside of county, 2000	25.3	41.5	45.5
% or residents who drove alone to work, 2000	78.1	77.5	77.1
% change in residents who drove alone, 1990-2000	13.8	24.8	26.0
% of workforce coming into county from elsewhere, 2000	30.5	41.8	33.1
NATURAL RESOURCES			
Total area in square miles, 2000 Census	368.6	59,424.8	373.7
Rank of size, 1=highest (1-159)	70	--	--
Acres of forestland, 2004	142,410	24,726,400	155,512
% of all land in forests	60.7	66.7	65.4
Volume of live trees, all species, cubic ft., 2004	158,438,000	36,727,216,000	230,988,774
Water withdrawals (gallons per day), 2000	14,050,000	6,486,580,000	40,798,491
Public use per capita in gallons per day	129.9	185.1	189.8
Water use for irrigation (millions of gal/day)	10.84	1,092.16	7
Hazardous waste sites, 2005	1	436	3
Toxic chemical releases (pounds per year), 2003	665	126,197,045	795,081
POPULATION			
Metropolitan county in 2006?	NO	--	--
Total, 2004 estimate	26,775	8,829,383	55,531
Rank of population size, 1=highest (1-159)	63	--	--
% change in total, 2000-04	2.7	7.8	6.0
Rank of % change in total, 2000-04	97	--	--
Growth rate by natural increase, 2000-04	5.5	8.3	4.8
Growth rate by net migration, 2000-04	0.9	9.5	8.2
% change in total population, 1930-2004	56.0	203.6	190.5
Rank of % change, 1=highest (1-159)	82	--	--

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	TOOMBS CO.	GEORGIA TOTAL	Avg. Co. in GA
Persons per square mile, 2004 estimate	73.0	152.5	176.2
Rank of population density, 1=highest (1-159)	67	–	–
% urban, 2000	49.0	71.7	36.4
% rural, 2000	51.0	28.3	63.6
Total, 2010 Trend (Center for Agribusiness)	27,912	9,822,289	61,775
Total, 2010 projection (GA Office of Planning & Budget)	27,489	9,864,970	62,044
Total, 2015 projection (GA Office of Planning & Budget)	28,219	10,813,573	68,010
% Black alone, 2004 estimate	25.2	29.6	28.2
% White alone, 2004 estimate	73.7	66.4	70.0
% Other races alone, 2004 estimate	0.84	2.99	1.2
% Hispanic/Latino, 2004 estimate	10.4	6.8	4.3
% Age 65 and over, 2004 estimate	12.4	9.6	12.0
Median age, Total, 2004 estimate	34.3	33.8	35.1
Religion–churches/synagogues/mosques/temples, 2000	56	8,962	56
Adherents as % of population	53.5	44.8	43.9
Total civilian veterans, 2005 estimate	1,947	758,963	4,773
PUBLIC ASSISTANCE			
Child abuse cases investigated, 2004	536	85,562	538
% of child abuse cases substantiated	29.7	36.2	36.1
Substantiated child maltreatment victims, 2004	263	51,717	325
Maltreatment rate per 1,000 children <18	35.2	22.5	31.1
Child Welfare, adoptions, FY2004	3	1210	8
Food stamp average # of recipients, FY2004	5,013	847,886	5,333
Food stamp recipients % of population	18.7	9.6	13.0
Medicaid average # of recipients, FY2004	10,662	2,056,826	12,935
Medicaid recipients % of population	39.8	23.3	28.7
TANF average # of recipients, FY2004	727	135,515	852
TANF recipients % of population	2.7	1.5	1.8
OASDI (Social Security) recipients % of pop., 12/2004	19.6	13.5	17.4
SSI (Supplemental Security Income) % of pop., 12/2004	5.3	2.3	3.3
TRANSPORTATION			
Total traffic crashes, 2003	790	331,612	2,086
Crash rate per 10,000 licensed drivers	382.1	478.1	320.2
Total fatalities	4	1,610	10
Deer-related crashes	131	10,343	65.1
Licensed drivers, 2003	20,674	6,936,026	43,623
Drivers involved in alcohol/drug related crashes	38	10,694	67
Daily vehicle miles traveled, as of 12/31/2004	848,548	306,695,953	1,928,905
Total road mileage, as of 12/31/2004	794.07	115,408.62	725.84
% unpaved	43.6	25.4	28.8
Total motor vehicle registrations, as of 7/2005	26,924	7,781,049	48,934
Housing units with no vehicles available, 2000	1,021	248,546	1,563
VITAL STATISTICS, 2003 (Rate not shown when number of events is >0 and <5)			
Live births, total	428	135,831	854
Live birth rate (per 1,000 population)	16.2	15.6	14.0
Live births to unwed mothers, total	222	51,804	326
% Unwed births of total live births	51.9	38.1	42.2
% Unwed births to teen mothers of all births	14.5	9.6	12.1
Low weight births, total (< 2500 grams)	45	12,205	77
% Low weight of total live births	10.5	9.0	9.6
Induced terminations, total	43	30,396	191
Induced termination rate (per 1,000 fem. age 15-44)	7.8	15.5	–
Teen Pregnancies, total	93	21,557	136
Teen pregnancy rate (per 1,000 fem. age 10-19)	45.0	35.1	36.1
Deaths, total	290	66,337	417
Death rate (per 100,000 population)	1095.6	763.8	974.3
Infant deaths, total	0	1,153	7
VITAL STATISTICS, 10-Yr. CUMULATIVE RATES, 1994-2003			
Live birth rate (per 1,000 population)	16.4	15.6	14.4
Live births to unwed mothers rate (per 100 live births)	47.2	36.5	40.6
Low birth weight rate (per 1,000 live births)	8.8	8.8	9.2
Induced termination rate (per 1,000 females age 15-44)	7.5	16.8	9.1
Death rate (per 100,000 population)	1070.6	789.6	977.1
Infant death rate (per 1,000 live births)	8.5	8.8	9.7
Suicide rate (per 100,000 population)	11.6	11.0	–
Homicide rate (per 100,000 population)	18.6	8.7	–

– Data not available or data tabulation not appropriate.

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

DEMOGRAPHIC PROFILE

	WAYNE CO.	GEORGIA TOTAL	Avg. Co. in GA
AGRICULTURE			
Total Farm Gate Value of production, 2004	$68,211,781	$10,283,536,190	$64,676,328
Total Farm Gate Value per farm	$200,035	$208,544	$204,529
Total Farm Gate value per acre of farm land	$1,058	$957	$1,181
Poultry/eggs value	$12,183,603	$4,750,925,309	$29,880,033
Row/forage crops value	$11,976,405	$1,539,792,437	$9,684,229
Livestock/aquaculture value	$5,359,966	$1,305,226,550	$8,208,972
Forestry & products value	$20,760,000	$607,909,852	$3,823,332
Vegetables value	$9,916,710	$725,281,592	$4,561,519
Ornamental horticulture value	$560,302	$656,868,481	$4,131,248
Fruits & nuts value	$2,135,300	$227,406,888	$1,430,232
Other income value	$5,319,495	$470,125,080	$2,956,762
Farm production expenses, 2003	$16,315,000	$4,003,400,000	$25,178,616
Net farm proprieter's income, 2003	$3,914,000	$1,957,619,000	$12,312,465
Number of farms, 2002	341	49,311	310
% change in number of farms, 1997-2002	0.9	-0.1	0.9
Land in farms, acres, 2002	64,490	10,744,239	67,574
% of farmers working 200+ days off farm, 2002	40.8	39.8	40.3
Average farm size in acres, 2002	189	218	244
Harvested cropland, acres, 2002	19,933	3,245,784	20,414
Acres of irrigated farm land, 2004	7,430	1,546,756	9,728
CRIME			
Index crimes reported, 2004	86	360,425	2,267
Index crime rate per 100,000	305.0	4,082.1	2,691.7
Arrests for index crimes, 2004	1	59,079	372
% juvenile arrests	0.0	23.2	17.5
Index crime arrest rate per 100,000, 2004	3.5	669.1	533.2
Juvenile commitment rate per 1,000 (age 10-16), FY2005	1.81	3.02	2.32
State prison inmates' home county, 2005	152	47,495	264
% incarcerated for violent/sex crimes	49.3	60.5	59.9
Probationers county of conviction, 2005	558	124,634	769
ECONOMICS			
Deposits in financial institutions, 2004	$235,868,000	$142,650,207,000	$897,171,113
Personal bankruptcies filed per 1,000 population, 2004	11.4	8.9	9.1
Gross tax digest 40% value of assessed property, 2004	$672,838,017	$289,418,742,651	$1,820,243,664
Taxes levied, 2004	$19,819,374	$8,455,894,148	$53,181,724
Millage rate, county-wide, 2003	30.84	--	26.46
Total lottery sales, FY2005	$8,084,060	$2,919,844,265	$18,363,800
Per capita lottery sales	$287	$331	$377
Median household income, 2002 estimate	$31,986	$42,359	$34,153
Persons below poverty level, 2002 estimate	4,989	1,107,209	6,964
% of all persons	19.6	13.0	16.5
% of children 0-17	26.1	17.8	22.1
Families living below poverty level, % in 1999	13.4	9.9	13.5
Per capita income, 2003	$21,013	$29,000	$22,879
Total personal income, 2003	$581,628,000	$251,620,610,000	$1,582,519,560
Transfer receipts, 2003	$136,896,000	$32,640,313,000	$205,284,987
Transfer receipts as a % of total personal income	23.5	13.0	20.8
Per capita transfer receipts	$4,946	$3,762	$4,560
Total retail sales, 2004	$297,509,000	$115,210,992,000	$724,597,434
Pull factor (1 = average)	1.07	1.00	0.82
EDUCATION--Public School Systems, (County/City combined) 2003-04			
Total enrollment	5,031	1,486,125	9,346
% Black	23.8	37.9	37.2
% White	71.2	50.6	56.5
% Hispanic	3.1	6.9	4.1
% economically disadvantaged (qualify for free/red. lunch)	53.3	46.4	56.8
General Fund Expenditures per pupil	$6,088	$6,712	$6,478
Number of high school dropouts (grades 9-12)	114	23,680	149
High school dropout rate per 100 enrolled	6.8	5.1	5.6
Total graduates	214	66,716	420
% of grads with college prep. diploma	65.0	73.4	60.2
Class of 2004 percent completion	52.1	65.4	61.4
Number of teachers	344	104,545	657
% with advanced degrees	43.0	51.8	52.8
Total recipients of HOPE Scholarships, FY2005	894	222,541	1,396
HOPE $ awards	$1,348,421	$427,364,658	$2,675,368

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 [illegible]

DEMOGRAPHIC PROFILE

	WAYNE CO.	GEORGIA TOTAL	Avg. Co. in GA
EDUCATION--Highest Level Completed (Age 25+) 2000			
% NOT completing high school	29.9	21.4	29.3
% high school graduate (includes GED)	37.1	28.7	34.9
% some college and/or associate degree	21.5	25.6	21.8
% Bachelor's degree	7.6	16.0	8.9
% Graduate or professional degree	4.0	8.3	5.1
GOVERNMENT			
Date of county creation	May 11, 1803	--	--
Total direct Federal government expenditures, FY2003	$164,591,778	$51,910,195,521	$304,578,997
% Defense spending	2.6	17.3	7.9
Total registered voters as of 2004 General Election	12,516	4,248,837	26,722
2004 % of registered voters voting for President	76.2	77.6	74.4
2004 % of voting-age population voting for President	45.2	50.8	49.1
HEALTH			
Disability, % age 21-64, 2000	22.7	19.9	23.8
Disability, % age 65+, 2000	49.5	47.5	50.7
Licensed child day care facilities, 2005	4	2,981	19
General hospitals, 2004	1	150	1
General nursing homes, SFY04	3	362	2
Medicare payments, 2003	$31,800,000	$6,260,652,000	$39,375,170
Total practicing physicians, 2002	39	16,483	104
Persons per physician ratio	144.1	192.6	107.5
HOUSING / HOUSEHOLDS			
Private residential units authorized for construction, 2004	19	108,356	681
Value of construction	$1,511,110	$12,884,207,336	$81,032,751
Total housing units, 2004 estimate	11,061	3,672,677	23,098.6
% change 2000-04	2.2	11.9	8.2
Housing unit density per sq. mi. of land area	17.2	63.4	72.8
% mobile homes of total housing units, 2000	32.5	12.0	25.5
% owner-occupied of total housing units, 2000	76.5	67.5	73.9
Median value of owner-occupied units, 2000	$71,200	$111,200	$81,599
Total families, 2000	6,937	2,111,647	13,281
% with own children <18	48.2	49.8	47.3
% married couples	76.0	73.3	73.4
% female householder, no husband present	18.9	20.6	20.7
% female h/holder, no husband, w/children <18	11.4	12.2	11.9
Total households, 2000	9,324	3,006,369	18,908
# persons per household	2.62	2.65	2.64
LABOR			
Civilian labor force, 2004	11,609	4,390,395	27,613
Average annual unemployment rate, 2004	5.4	4.6	4.9
Average # of business establishments, 2004	549	246,245	1,431
Average monthly employment, 2004	8,887	3,834,456	23,665
Average weekly wage, all industries, 2004	$568	$728	$526
Residents' mean travel time to work in minutes, 2000	26.2	27.7	26.4
% of residents working outside of county, 2000	25.1	41.5	45.5
% or residents who drove alone to work, 2000	80.5	77.5	77.1
% change in residents who drove alone, 1990-2000	16.0	24.8	26.0
% of workforce coming into county from elsewhere, 2000	18.4	41.8	33.1
NATURAL RESOURCES			
Total area in square miles, 2000 Census	648.8	59,424.8	373.7
Rank of size, 1=highest (1-159)	11	--	--
Acres of forestland, 2004	338,590	24,726,400	155,512
% of all land in forests	82.1	66.7	65.4
Volume of live trees, all species, cubic ft., 2004	336,128,000	36,727,216,000	230,988,774
Water withdrawals (gallons per day), 2000	64,400,000	6,486,580,000	40,798,491
Public use per capita in gallons per day	158.1	185.1	189.8
Water use for irrigation (millions of gal/day)	1.81	1,092.16	7
Hazardous waste sites, 2005	0	436	3
Toxic chemical releases (pounds per year), 2003	3,332,849	126,197,045	795,081
POPULATION			
Metropolitan county in 2006?	NO	--	--
Total, 2004 estimate	28,198	8,829,383	55,531
Rank of population size, 1=highest (1-159)	56	--	--
% change in total, 2000-04	6.1	7.8	6.0
Rank of % change in total, 2000-04	62	--	--
Growth rate by natural increase, 2000-04	4.9	8.3	4.8
Growth rate by net migration, 2000-04	9.2	9.5	8.2
% change in total population, 1930-2004	123.0	203.6	190.5
Rank of % change, 1=highest (1-159)	63	--	--

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or [illegible]

DEMOGRAPHIC PROFILE

	WAYNE CO.	GEORGIA TOTAL	Avg. Co. in GA
Persons per square mile, 2004 estimate	43.7	152.5	176.2
Rank of population density, 1=highest (1-159)	96	--	--
% urban, 2000	48.2	71.7	36.4
% rural, 2000	51.8	28.3	63.6
Total, 2010 Trend (Center for Agribusiness)	30,656	9,822,289	61,775
Total, 2010 projection (GA Office of Planning & Budget)	29,960	9,864,970	62,044
Total, 2015 projection (GA Office of Planning & Budget)	31,724	10,813,573	68,010
% Black alone, 2004 estimate	20.5	29.6	28.2
% White alone, 2004 estimate	78.1	66.4	70.0
% Other races alone, 2004 estimate	0.81	2.99	1.2
% Hispanic/Latino, 2004 estimate	4.3	6.8	4.3
% Age 65 and over, 2004 estimate	11.5	9.6	12.0
Median age, Total, 2004 estimate	35.1	33.8	35.1
Religion--churches/synagogues/mosques/temples, 2000	61	8,962	56
Adherents as % of population	63.2	44.8	43.9
Total civilian veterans, 2005 estimate	2,791	758,963	4,773
PUBLIC ASSISTANCE			
Child abuse cases investigated, 2004	358	85,562	538
% of child abuse cases substantiated	35.8	36.2	36.1
Substantiated child maltreatment victims, 2004	241	51,717	325
Maltreatment rate per 1,000 children <18	34.6	22.5	31.1
Child Welfare, adoptions, FY2004	9	1210	8
Food stamp average # of recipients, FY2004	4,070	847,886	5,333
Food stamp recipients % of population	14.4	9.6	13.0
Medicaid average # of recipients, FY2004	8,477	2,056,826	12,935
Medicaid recipients % of population	30.1	23.3	28.7
TANF average # of recipients, FY2004	414	135,515	852
TANF recipients % of population	1.5	1.5	1.8
OASDI (Social Security) recipients % of pop., 12/2004	18.0	13.5	17.4
SSI (Supplemental Security Income) % of pop., 12/2004	3.4	2.3	3.3
TRANSPORTATION			
Total traffic crashes, 2003	557	331,612	2,086
Crash rate per 10,000 licensed drivers	269.6	478.1	320.2
Total fatalities	4	1,610	10
Deer-related crashes	89	10,343	65.1
Licensed drivers, 2003	20,662	6,936,026	43,623
Drivers involved in alcohol/drug related crashes	23	10,694	67
Daily vehicle miles traveled, as of 12/31/2004	949,327	306,695,953	1,928,905
Total road mileage, as of 12/31/2004	987.79	115,408.62	725.84
% unpaved	53.5	25.4	28.8
Total motor vehicle registrations, as of 7/2005	27,075	7,781,049	48,934
Housing units with no vehicles available, 2000	731	248,546	1,563
VITAL STATISTICS, 2003 (Rate not shown when number of events is >0 and <5)			
Live births, total	421	135,831	854
Live birth rate (per 1,000 population)	15.3	15.6	14.0
Live births to unwed mothers, total	188	51,804	326
% Unwed births of total live births	44.7	38.1	42.2
% Unwed births to teen mothers of all births	15.0	9.6	12.1
Low weight births, total (< 2500 grams)	26	12,205	77
% Low weight of total live births	6.2	9.0	9.6
Induced terminations, total	12	30,396	191
Induced termination rate (per 1,000 fem. age 15-44)	2.1	15.5	--
Teen Pregnancies, total	84	21,557	136
Teen pregnancy rate (per 1,000 fem. age 10-19)	42.5	35.1	36.1
Deaths, total	299	66,337	417
Death rate (per 100,000 population)	1086.9	763.8	974.3
Infant deaths, total	3	1,153	7
VITAL STATISTICS, 10-Yr. CUMULATIVE RATES, 1994-2003			
Live birth rate (per 1,000 population)	13.8	15.6	14.4
Live births to unwed mothers rate (per 100 live births)	39.0	36.5	40.6
Low birth weight rate (per 1,000 live births)	7.9	8.8	9.2
Induced termination rate (per 1,000 females age 15-44)	2.9	16.8	9.1
Death rate (per 100,000 population)	999.7	789.6	977.1
Infant death rate (per 1,000 live births)	9.5	8.8	9.7
Suicide rate (per 100,000 population)	14.6	11.0	--
Homicide rate (per 100,000 population)	4.2	8.7	--

-- Data not available or data tabulation not appropriate.

Source: The Georgia County Guide, 2005-2006, Center for Agribusiness and Economic Development, UGA, Athens, GA. 706-542-8938 or 706-542-0760 www.georgiastats.uga.edu and www.caed.uga.edu

USGS 2005

V-484

2004 Water Year

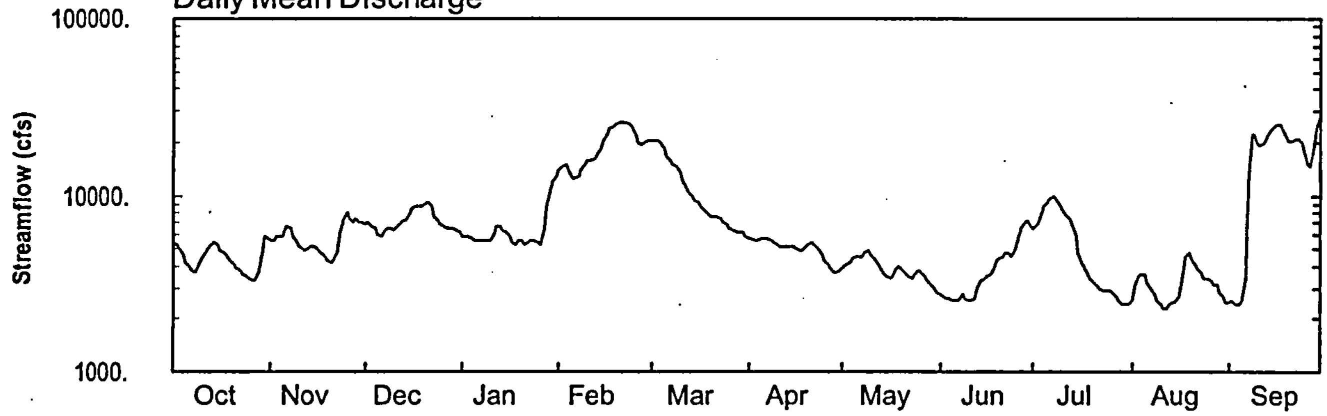
ALTAMAHA RIVER BASIN

02225000 ALTAMAHA RIVER NEAR BAXLEY, GA

Latitude: 31°56'20" Longitude: 082°21'13" Hydrologic Unit Code: 03070106

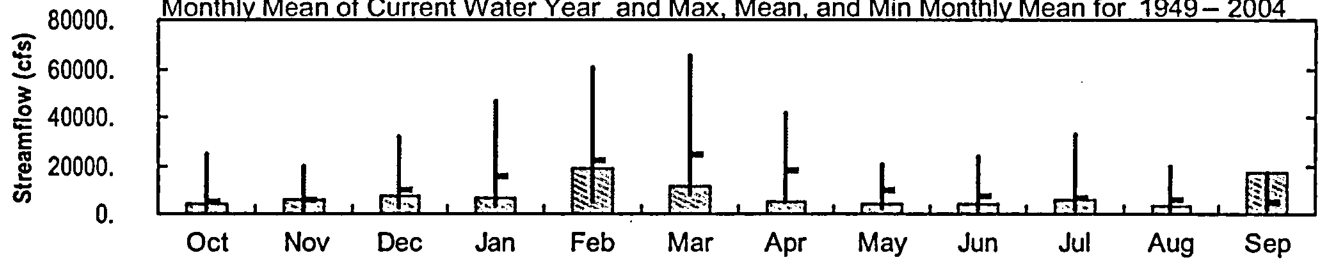
Appling County Datum: 61.51 feet Drainage Area: 11600 mi²

Daily Mean Discharge

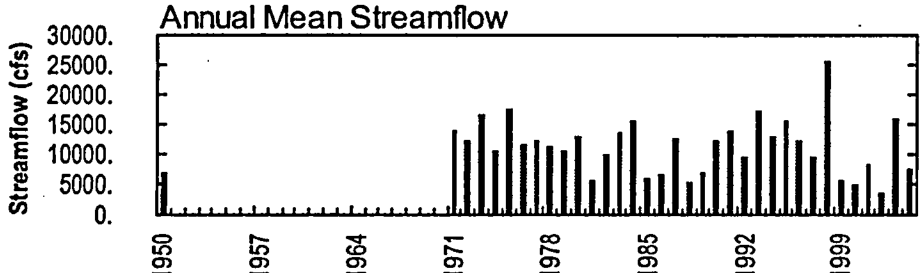


Monthly Statistics

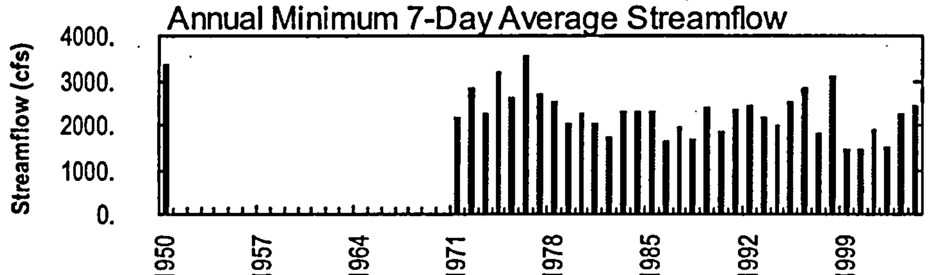
Monthly Mean of Current Water Year and Max, Mean, and Min Monthly Mean for 1949 – 2004



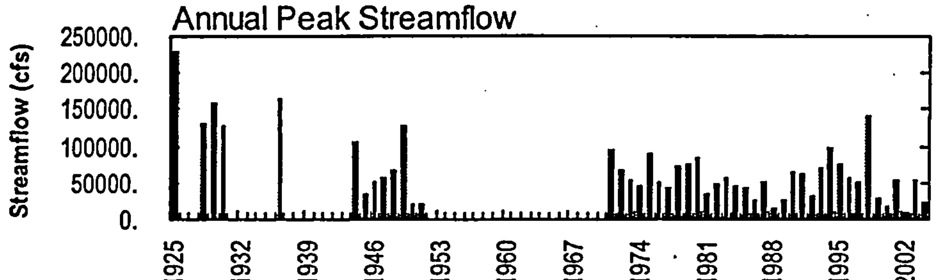
Annual Mean Streamflow



Annual Minimum 7-Day Average Streamflow



Annual Peak Streamflow



USGS science for a changing world

NO PHOTOS AVAILABLE FOR THIS SITE

ALTAMAHA RIVER BASIN
2004 Water Year

02225000 ALTAMAHA RIVER NEAR BAXLEY, GA

LOCATION.—Lat 31°56'20", long 82°21'13" referenced to North American Datum (NAD) of 1927, Appling-Toombs County line, Hydrologic Unit 03070106, on right bank 400 feet downstream from bridge on U.S. 1, 2.2 miles upstream from Bay Creek, 8.0 miles downstream from Bullards Creek, and 12.0 miles north of Baxley.

DRAINAGE AREA.—11,600 square miles, approximately.

COOPERATION.—Georgia Power Corporation.

WATER-DISCHARGE RECORDS

PERIOD OF RECORD.—August 1949 to June 1951, October 1970 to current year.

GAGE.—Satellite transmitter with a water-stage recorder. Datum of gage is 61.51 feet above National Geodetic Vertical Datum (NGVD) of 1929. From August 13, 1949, to June 30, 1951, a non-recording gage was located at site 400.00 feet upstream at same datum.

REMARKS.—Records good, except from August 1-30, and periods of estimated discharge, which are fair. Maximum recorded discharge for 2004 water year occurred on September 30, 2004 as part of a storm event that peaked on October 7, 2004 and is not considered the peak discharge of the 2004 water year.

EXTREMES OUTSIDE PERIOD OF RECORD.—Flood of December 10, 1948, reached a stage of 25.1 feet, from flood marks, discharge, 130,000 cfs. Flood of January 1925 reached a stage of 30.0 feet, from information furnished by Georgia Department of Transportation.

PEAK DISCHARGES FOR CURRENT YEAR.—Peak discharges greater than base discharge of 25,000 cfs and maximum (*):

DATE	TIME	DISCHARGE (cfs)	GAGE-HEIGHT (feet)
02/21	1330	26,000*	13.88*
09/16	0030	26,000	13.87

02225000 ALTAMAHA RIVER NEAR BAXLEY, GA—continued.

WATER-STAGE RECORDS

PERIOD OF RECORD.—August 1949 to June 1951, October 1970 to current year.

GAGE.—Satellite transmitter with a water-stage recorder. Datum of gage is 61.51 feet above National Geodetic Vertical Datum (NGVD) of 1929. From August 13, 1949, to June 30, 1951, a non-recording gage was located at site 400.00 feet upstream at same datum.

REMARKS.—Records good, except from August 1-30, which is fair. Maximum recorded stage for 2004 water year occurred on September 30, 2004 as part of a storm event that peaked on October 7, 2004 and is not considered the peak stage of the 2004 water year.

EXTREMES FOR CURRENT YEAR.—Maximum gage-height recorded, 13.88 feet, February 21; minimum gage-height recorded, 1.53 feet, August 12.

PRECIPITATION RECORDS

PERIOD OF RECORD.—September 6, 2000 to current year.

GAGE.—Tipping-bucket raingage.

REMARKS.—Records good.

U.S. DEPARTMENT OF THE INTERIOR - U.S. GEOLOGICAL SURVEY - WATER RESOURCES

STATION NUMBER 02225000 ALTAMAHA RIVER NEAR BAXLEY, GA STREAM SOURCE AGENCY USGS STATE 13 COUNTY 001
LATITUDE 315620 LONGITUDE 0822113 NAD27 DRAINAGE AREA 11600 CONTRIBUTING DRAINAGE AREA 11600* DATUM 61.51 NGVD29

Discharge, cubic feet per second
WATER YEAR OCTOBER 2003 TO SEPTEMBER 2004
DAILY MEAN VALUES

DAY	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1	5460	5500	6940	5930	13900	20300	5680	3840	2790	6510	2580	2480
2	5260	5520	6980	5880	14700	20300	5650	4040	2720	6840	3060	2530
3	4970	5800	6710	5790	15000	20300	5630	4230	2650	7790	3470	2450
4	4600	5890	6440	5720	13800	19800	5630	4350	2610	8590	3540	2400
5	4220	5870	6030	5580	12400	18200	5700	4480	2530	9060	e3590	2530
6	3970	6690	5940	5530	12300	16700	5760	4550	2520	9510	3210	3410
7	3810	6490	6110	5540	13000	15800	5720	4580	2580	9890	2960	11500
8	3700	5850	e6460	5540	13900	15100	5620	4740	2760	9670	2770	21900
9	3970	5370	6450	5600	15000	14500	5460	4870	2610	8880	2580	22100
10	4380	5090	6370	5570	15600	13600	5290	4690	2550	8340	2450	19600
11	4700	4970	6520	6030	15900	12300	5190	4410	2550	7910	2300	19500
12	5050	4840	6870	6630	16300	11000	5110	4110	2640	7430	2290	20200
13	5240	4960	7160	6630	17200	10400	5090	3850	3010	6890	2410	22100
14	5480	5160	7310	6410	18500	9880	5130	3610	3350	5980	2480	23600
15	5290	5130	7850	6180	20200	9400	5100	3460	3280	4790	2460	24600
16	4920	4950	8440	5920	22200	9030	4970	3370	3510	4230	2670	25100
17	4800	4730	8730	5410	23700	8590	4900	3470	3580	3920	3580	25200
18	4590	4490	8610	5270	24600	8160	4940	3860	3800	3610	4540	23900
19	4290	4280	8730	5590	25200	7830	5100	3940	4310	3380	4720	21400
20	4060	4200	8960	5500	25700	7600	5270	3730	4360	3230	4370	20400
21	3900	4320	9030	5330	25900	7540	5370	3600	4470	3070	4050	20600
22	3760	4710	8570	5380	25800	7590	5300	3500	4810	2970	3880	21200
23	3620	6000	7690	5560	25400	7370	4990	3430	4810	2890	3630	21100
24	3480	7220	7150	5620	24500	7050	4620	3590	4570	2880	3440	20100
25	3370	7980	6850	5420	22000	6830	4290	3750	4900	2880	3410	18100
26	3290	7430	6770	5290	20000	6590	4040	3670	5950	2820	3270	15100
27	3280	7070	6580	6270	19500	6360	3860	3470	6450	e2660	3140	14500
28	3650	7340	6450	8590	19900	6200	3660	3290	7070	e2530	3140	18900
29	4810	7080	6460	10800	20300	6240	3660	3160	7150	e2420	2860	23700
30	5810	e6980	6390	12000	---	6100	3750	3010	6750	2430	2660	28600
31	5780	---	6120	13000	---	5810	---	2860	---	2440	2500	---
TOTAL	137510	171910	221670	199510	552400	342470	150480	119510	117640	166440	98010	518800
MEAN	4436	5730	7151	6436	19050	11050	5016	3855	3921	5369	3162	17290
MAX	5810	7980	9030	13000	25900	20300	5760	4870	7150	9890	4720	28600
MIN	3280	4200	5940	5270	12300	5810	3660	2860	2520	2420	2290	2400
CFSM	0.38	0.49	0.62	0.55	1.64	0.95	0.43	0.33	0.34	0.46	0.27	1.49
IN.	0.44	0.55	0.71	0.64	1.77	1.10	0.48	0.38	0.38	0.53	0.31	1.66

STATISTICS OF MONTHLY MEAN DATA FOR WATER YEARS 1949 - 2004, BY WATER YEAR (WY)

	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
MEAN	5279	5890	9878	15430	21760	24670	18340	9558	7115	6410	6013	5049
MAX	24560	19540	31920	46750	60420	65210	41730	20630	23340	32470	19600	17290
(WY)	1995	1998	1998	1998	1998	1998	1975	1975	2003	1994	1994	2004
MIN	1864	1871	2424	3395	4803	7978	5016	2576	1877	1667	1627	1643
(WY)	1982	2002	2002	1981	1989	2002	2004	1986	2000	2000	2002	1999

SUMMARY STATISTICS	FOR 2003 CALENDAR YEAR		FOR 2004 WATER YEAR		WATER YEARS 1949 - 2004	
ANNUAL TOTAL	5673380		2796350			
ANNUAL MEAN	15540		7640		11320	
HIGHEST ANNUAL MEAN					25530	1998
LOWEST ANNUAL MEAN					3762	2002
HIGHEST DAILY MEAN	55700	Mar 29	28600	Sep 30	142000	Mar 16 1998
LOWEST DAILY MEAN	3280	Oct 27	2290	Aug 12	1450	Aug 29 2000
ANNUAL SEVEN-DAY MINIMUM	3490	Oct 22	2420	Aug 9	1460	Aug 25 2000
MAXIMUM PEAK FLOW			30900	Sep 30	144000	Mar 16 1998
MAXIMUM PEAK STAGE			14.85	Sep 30	24.15	Mar 16 1998
INSTANTANEOUS LOW FLOW			2230	Aug 12	1440	Aug 27 2000
ANNUAL RUNOFF (CFSM)	1.34		0.659		0.976	
ANNUAL RUNOFF (INCHES)	18.19		8.97		13.26	
10 PERCENT EXCEEDS	30000		19500		25700	
50 PERCENT EXCEEDS	12400		5510		6710	
90 PERCENT EXCEEDS	4710		2860		2550	

e Estimated

U.S. DEPARTMENT OF THE INTERIOR - U.S. GEOLOGICAL SURVEY - WATER RESOURCES

STATION NUMBER 02225000 ALTAMAHA RIVER NEAR BAXLEY, GA STREAM SOURCE AGENCY USGS STATE 13 COUNTY 001
LATITUDE 315620 LONGITUDE 0822113 NAD27 DRAINAGE AREA 11600 CONTRIBUTING DRAINAGE AREA 11600* DATUM 61.51 NGVD29

Gage height, feet
WATER YEAR OCTOBER 2003 TO SEPTEMBER 2004
DAILY MEAN VALUES

DAY	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1	4.78	4.81	5.58	4.89	9.55	12.25	4.71	3.20	2.16	5.29	1.92	1.81
2	4.61	4.83	5.61	4.85	9.93	12.23	4.68	3.38	2.08	5.52	2.45	1.87
3	4.37	5.06	5.43	4.79	10.09	12.23	4.67	3.55	2.01	6.12	2.85	1.77
4	4.06	5.12	5.25	4.73	9.49	12.04	4.67	3.65	1.96	6.61	2.92	1.72
5	3.72	5.11	4.96	4.63	8.80	11.46	4.72	3.76	1.87	6.88	---	1.87
6	3.50	5.73	4.89	4.60	8.75	10.87	4.76	3.82	1.86	7.15	2.60	2.76
7	3.34	5.59	5.02	4.60	9.07	10.44	4.74	3.85	1.92	7.38	2.34	8.12
8	3.24	5.09	---	4.60	9.57	10.12	4.66	3.98	2.13	7.25	2.14	12.76
9	3.49	4.71	5.25	4.64	10.06	9.83	4.54	4.08	1.96	6.78	1.93	12.84
10	3.87	4.47	5.20	4.62	10.36	9.38	4.41	3.94	1.89	6.47	1.77	12.00
11	4.15	4.38	5.30	4.95	10.50	8.72	4.34	3.70	1.89	6.20	1.60	11.93
12	4.45	4.27	5.54	5.38	10.70	8.04	4.27	3.44	1.99	5.90	1.58	12.19
13	4.60	4.37	5.73	5.37	11.07	7.68	4.26	3.21	2.39	5.55	1.73	12.83
14	4.80	4.53	5.82	5.22	11.56	7.37	4.29	2.98	2.73	4.92	1.81	13.27
15	4.64	4.51	6.16	5.07	12.20	7.09	4.26	2.85	2.67	4.02	1.78	13.53
16	4.33	4.36	6.52	4.88	12.90	6.87	4.16	2.76	2.90	3.55	2.02	13.66
17	4.23	4.18	6.70	4.50	13.31	6.61	4.11	2.86	2.96	3.27	2.95	13.69
18	4.05	3.97	6.62	4.39	13.54	6.35	4.14	3.22	3.16	2.99	3.81	13.37
19	3.79	3.78	6.69	4.64	13.69	6.15	4.26	3.29	3.62	2.76	3.96	12.64
20	3.57	3.71	6.83	4.57	13.80	6.01	4.40	3.10	3.66	2.61	3.67	12.27
21	3.42	3.78	6.87	4.45	13.86	5.97	4.48	2.98	3.75	2.45	3.39	12.36
22	3.29	4.08	6.60	4.48	13.83	6.00	4.42	2.88	4.03	2.35	3.24	12.54
23	3.16	5.05	6.07	4.62	13.74	5.86	4.18	2.82	4.03	2.26	3.01	12.52
24	3.02	5.83	5.72	4.66	13.52	5.66	3.88	2.96	3.83	2.26	2.82	12.15
25	2.91	6.26	5.53	4.51	12.81	5.51	3.60	3.12	4.10	2.26	2.80	11.42
26	2.83	5.90	5.47	4.41	12.13	5.35	3.38	3.05	4.90	2.19	2.66	10.12
27	2.81	5.67	5.34	5.12	11.95	5.19	3.22	2.86	5.25	---	2.53	9.82
28	3.18	5.84	5.26	6.60	12.09	5.08	3.04	2.68	5.67	---	2.52	11.70
29	4.23	5.68	5.26	7.88	12.22	5.11	3.03	2.55	5.72	---	2.23	13.29
30	5.07	---	5.21	8.56	---	5.01	3.12	2.39	5.46	1.75	2.02	14.41
31	5.04	---	5.02	9.07	---	4.80	---	2.23	---	1.76	1.84	---
MEAN	3.89	---	---	5.17	11.55	7.78	4.18	3.20	3.15	---	---	10.24
MAX	5.07	---	---	9.07	13.86	12.25	4.76	4.08	5.72	---	---	14.41
MIN	2.81	---	---	4.39	8.75	4.80	3.03	2.23	1.86	---	---	1.72

U.S. DEPARTMENT OF THE INTERIOR - U.S. GEOLOGICAL SURVEY - WATER RESOURCES

STATION NUMBER 02225000 ALTAMAHA RIVER NEAR BAXLEY, GA STREAM SOURCE AGENCY USGS STATE 13 COUNTY 001
LATITUDE 315620 LONGITUDE 0822113 NAD27 DRAINAGE AREA 11600 CONTRIBUTING DRAINAGE AREA 11600* DATUM 61.51 NGVD29

Precipitation, total, inches
WATER YEAR OCTOBER 2003 TO SEPTEMBER 2004
DAILY SUM VALUES

DAY	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP
1	0.00	0.00	0.00	0.00	0.09	0.00	0.00	0.07	0.71	0.02	0.00	2.12
2	0.00	0.00	0.00	0.00	0.15	0.00	0.00	0.47	0.00	0.21	0.96	0.68
3	0.00	0.02	0.00	0.00	0.01	0.00	0.00	0.20	0.00	0.01	0.01	0.00
4	0.00	0.06	0.16	0.00	0.00	0.00	0.00	0.00	0.05	0.00	0.35	0.21
5	0.00	0.18	0.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02
6	0.01	0.00	0.00	0.00	1.12	0.00	0.00	0.00	0.00	0.00	0.00	5.48
7	0.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.33	0.06	0.00	1.77
8	0.00	0.03	0.00	0.08	0.00	0.00	0.45	0.00	0.07	0.00	0.00	0.01
9	0.00	0.00	0.00	0.25	0.00	0.09	0.00	0.00	0.01	0.00	0.00	0.00
10	0.00	0.00	0.40	0.00	0.00	0.01	0.00	0.00	0.12	0.22	0.18	0.31
11	0.02	0.00	0.00	0.00	0.19	0.00	0.00	0.00	0.00	0.59	0.26	0.01
12	0.00	0.00	0.00	0.00	0.81	0.00	0.00	0.40	0.04	0.00	0.40	0.02
13	0.23	0.00	0.01	0.00	0.03	0.00	0.25	0.00	0.79	0.00	0.29	1.59
14	0.02	0.00	0.76	0.00	1.27	0.00	0.00	0.00	0.16	0.00	0.29	0.11
15	0.00	0.00	0.00	0.00	0.04	0.00	0.00	0.00	1.13	0.01	0.00	0.01
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00
17	0.00	0.00	0.03	0.00	0.01	0.00	0.00	0.00	0.00	0.00	2.21	0.52
18	0.00	0.00	0.00	0.10	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
19	0.00	0.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.59	0.00	0.76	0.00
22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.22	0.00	0.00	0.00
23	0.00	0.00	0.00	0.00	0.06	0.00	0.00	0.00	0.26	0.04	1.35	0.00
24	0.00	0.11	0.03	0.00	0.02	0.00	0.00	0.00	0.02	0.00	0.00	0.00
25	0.00	0.00	0.00	0.12	0.33	0.00	0.00	0.00	0.55	0.07	0.00	0.00
26	0.13	0.00	0.00	2.77	0.43	0.00	0.69	0.00	0.09	0.00	0.00	0.23
27	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.62	0.00	1.94
28	3.74	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.42	0.00	0.00
29	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.33	0.00	0.00
30	0.00	0.00	0.15	0.00	---	0.06	0.17	0.00	0.26	0.00	0.26	0.00
31	0.00	---	0.00	0.00	---	0.00	---	0.09	---	0.00	0.00	---
TOTAL	4.94	1.11	1.54	3.52	4.56	0.16	1.56	1.24	6.47	2.61	7.32	15.03

USGS U.S. Geological Survey

Programs in Alabama

The USGS provides maps, reports, and information to help others meet their needs to manage, develop, and protect America's water, energy, mineral, and land resources. We help find natural resources needed to build tomorrow, and supply scientific understanding needed to help minimize or mitigate the effects of natural hazards and environmental damage caused by human activities. The results of our efforts touch the daily lives of almost every American.

Index of Subjects:

- National Coal Resources Data System State Cooperatives
- Effects of Federal Rulemaking on Coal Markets
- Competing Demands for Water
- Alabama-Coosa-Tallapoosa River Basin
- Baldwin County Area
- Hydrologic Hazards
- Collection of Hydrologic Data
- Potential Contamination
- Evolution and History of Incised Valleys
- National Mapping Program
- Earth Observation Data
- Landslide Hazards in Alabama
- Cooperative Programs

The U.S. Geological Survey (USGS) has offices in every State, thus providing a local presence and facilitating relations with the public and private sectors, academia, State and local agencies, and Federal agencies. This widely distributed network of scientific personnel provides a long-term earth science information base that makes the USGS a valued national resource. This Fact Sheet describes several of the USGS activities in Alabama.

National Coal Resource Data System State Cooperatives

Federal, State, and regional planners, as well as scientists, industry, and other government agencies, require current, credible, understandable, and standardized information on the location, quantity, and quality of the coal resources of the United States to provide the basis for optimum energy development and utilization policies. A joint venture between the USGS and State Geological Surveys was initiated in 1975 to develop the National Coal Resources Data System (NCRDS), with the USGS providing the central hardware, software, and analytical capabilities, and with the USGS and the States building and using the data bases. Currently (1995), cooperative projects are ongoing with 22 States which represents 98 percent of current U.S. coal production.

A cooperative project between the USGS and Alabama was initiated in 1978 to collect, evaluate, and correlate drill-hole, mine, and outcrop data; to encode and enter geologic and geochemical data into the NCRDS; and to access NCRDS data bases and software to generate new maps, reports, and resource assessments. The continued data collection and support of the NCRDS data bases provide baseline information that can be accessed for annual State resource updates and used to meet many foreseen and even unforeseen needs as they arise.

Effects of Federal Rulemaking on Coal Markets

The Office of Surface Mining (OSM) is establishing a Federal rule for Valid Existing Rights that could affect access to coal in environmentally sensitive areas and is determining whether underground mining should be prohibited in environmentally sensitive areas. To complete a valid rule-making action, the OSM is preparing an environmental impact statement in accordance with the National Environmental Policy Act and an economic analysis in accordance with Executive Order No. 12866. The USGS is providing coal-resource assessment and economic analysis to the OSM to support the preparation of the environmental impact statement and economic analysis. The USGS performs the following assessments:

- Coal resources in environmentally sensitive areas. The rulemaking could change access to surface-minable coal resources in environmentally sensitive areas. These are privately owned coal resources in National Parks, Wilderness Areas, Wild and Scenic Rivers, Wildlife Refuges, National Trail System, National Recreation Areas, National Forests, State and local parks, and National Historic Sites in Alabama.
- Deep coal resources in areas where OSM rulemaking could limit longwall mining. The USGS and the Geological Survey of Alabama are working together to gather data that can be used to illustrate the effect of such a rule. Economic costs for longwall mining and next best mining will be compared to determine costs of rulemaking.

Competing Demands for Water

Historically, Alabama has had an abundant supply of freshwater in most areas of the State. However, population growth and economic development have led to competing demands in areas where water resources are limited. Water use during 1990, excluding use for thermoelectric power generation, was 1,770 million gallons per day (fig. 1).

Figure 1. Water use in Alabama, by county, for 1990.

Competition for water has increased as increased use of water has reduced flow in rivers and lowered ground-water levels in some areas of the State and caused saltwater intrusion into aquifers in coastal areas. To resolve these conflicts, State and Federal agencies are evaluating water resources in some areas. The USGS provides needed information on water quality and quantity and water use so that planners and other officials can make informed decisions on water-resources issues.

The Alabama-Coosa-Tallapoosa River Basin

The Alabama-Coosa-Tallapoosa River Basin is an area where competing demands for water have caused concern among planners and developers. The headwaters of the Basin are in northern Georgia where expanding urban areas are placing increased demands on the water resources that, in turn, reduce available water resources downstream in Alabama. Between 1970 and 1990, water used for public supply in the portion of the Alabama-Coosa-Tallapoosa Basin in Alabama increased 44 percent to almost 185 million gallons per day. During that period, withdrawals for self-supplied commercial/industrial users decreased by about 5 percent. Explanations for this decrease are increased supplies by public-water-supply systems and more efficient use of water by industries. Total water use in the Alabama portion of the Alabama-Coosa-Tallapoosa Basin increased about 7 percent. The USGS, in cooperation with the Alabama Department of Economic and Community Affairs and the U.S. Army Corps of Engineers, is working on a series of reports to describe the ground-water resources for the Basin. The reports provide a scientific data base to be used for water-resource-management decisions that concern allocation of water resources within the Basin. The primary focus of the reports is assessment of low-flow conditions to develop a conceptual model of the ground-water-flow system, to estimate the volume of water entering and exiting subareas within the basin, to describe ground-water availability, and to identify areas where ground-water resources are overutilized or underutilized.

Baldwin County Area

Baldwin County is one of the fastest growing areas in Alabama. Presently, it is totally dependent on ground water for public-water supply and most agricultural, commercial, and industrial supply. In 1990, total ground-water withdrawals in the County were more than 30 million gallons per day.

Potential problems facing the area include saltwater intrusion near the coast, water shortages caused by overpumping, vulnerability of a single-source water supply to contamination, and competition among managers and planners. The USGS is answering questions about the amount of ground water that is available for use, recharge rates compared with withdrawal rates, the potential for saltwater intrusion, and what risks contaminants pose to water supplies.

Hydrologic Hazards

Floods and droughts are very damaging natural hazards in Alabama. In July 1994, rainfall from Tropical Storm Alberto caused flooding in several areas. In Alabama, damage was most serious along the Choctawhatchee and the Pea Rivers. This was one of the most damaging floods in history along these streams. Torrential rains from Alberto also produced extensive flash flooding in southeastern Alabama; many highways, bridges, and storm drainage systems were damaged. In all, 10 counties in Alabama had some type of flood damage. Damage from such a severe flood cannot be averted completely, but with sound hydrologic information, reliable estimates of peak river stages and discharge can be made, and communities can be warned of impending danger. Data collected during and after the flood by the USGS can help local, State, and Federal agencies to develop mitigation strategies in response to similar emergencies in the future.

With accurate estimates of flood magnitude and frequency, planners and managers can better design highway bridges and culverts, determine locations for water- and wastewater-treatment facilities, prepare zoning ordinances, and establish flood-insurance rates. Methods of estimating peak discharges for recurrence intervals of 2, 5, 10, 25, 50, 100, 200, and 500 years have been developed for rural streams in Alabama not affected by regulation or urbanization. Flood-frequency characteristics are defined for 200 streamflow gaging stations having 10 or more years of record through September 1991.

Each year, the USGS annually publishes streamflow and stage data and prepares reports that describe hydrologically significant floods. All data collected are stored in a computer data base and are available to the public.

The network of USGS surface-water data-collection stations also is used to document drought conditions and to prepare reports on low flows during droughts. In Alabama, the decade of the 1980's generally was characterized by below-normal-flow conditions, and the State experienced at least three significant periods of low-flow conditions 1981, 1986, and 1988. The USGS respon-ded to the drought conditions by making several nonroutine measurements of low-flow conditions. These data were published in the annual water data report.

Collection of Hydrologic Data

Alabama has 10 major rivers-the Tennessee, the Mobile, the Tombigbee, the Black Warrior, the Alabama, the Cahaba, the Coosa, the Tallapoosa, the Conecuh, and the Chattahoochee. The USGS, in cooperation with numerous local, State, and Federal agencies, has collected streamflow, ground-water, and water-quality data at sites throughout the State (fig.Ê2). Recent water-quality studies involve monitoring programs on water-supply reservoirs for Tuscaloosa, Birmingham, and Mobile, Alabama, a monitoring program on Locust Fork and some of its tributaries, and a countywide stream-monitoring program in Baldwin County. The data are needed for surveillance, planning, design, hazard warning, operation, and management in water-related fields such as water supply, hydroelectric-power generation, flood control, irrigation, bridge and culvert design, wildlife management, pollution abatement, flood-plain management, and water-resources development.

Figure 2. Water-quality data-collection sites in Alabama.

Potential Contamination

Where soil or ground water has been contaminated by human activities, the potential exists for contaminants to spread to other areas that could affect water supplies or cause direct health hazards for people living in those areas. The USGS, in cooperation with the U.S. Department of Defense, is conducting studies at selected military bases in Alabama where underground storage tanks and waste-disposal sites are potential sources of contaminants that could infiltrate to the ground water. The USGS is determining whether contaminants have been released and in which direction they are moving away from the site.

Evolution and History of Incised Valleys-*Benefits to Shoreline Erosion Mitigation*

Incised valleys along the Gulf Coast commonly result from rivers eroding the stream channel and valley wall materials rapidly in response to an increase in the velocity of streamflow caused by a fall in sea level. As sea level rises, sediments fill incised valleys and form near-shore elongated sand bodies, such as barrier islands (fig. 3). These sand bodies can be potential sites for hard-mineral accumulations and are modern analogues to buried sands in the ancient rock record with high potential for being oil and gas reservoirs. Processes that formed residual sediment accumulations also may help the State of Alabama predict the outcome of erosion mitigation strategies and wetland-nourishment efforts. Today, the geologic imprint of incised valleys across the continental shelf provides evidence of sea-level change over the past 18,000 years.

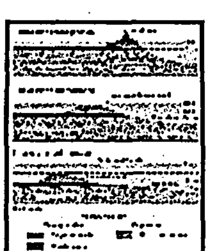


Figure 3. A schematic cross section showing shoal formation, developed by using seismic and core data collected from a submerged portion of the St. Bernard Delta (a lobe of the Mississippi River Delta). As sea level (SL 1 and 2) rose during the transgression, a barrier island arc was formed. In response to rising sea level, the barrier island migrated shoreward over lagoonal muds. Rising sea level (SL 3) drowned the barrier island and continuing sea level rise (SL 4) reworked the drowned barrier to form the St. Bernard Shoals.

National Mapping Program

Among the most popular and versatile products of the USGS are its 1:24,000-scale topographic maps (1 inch on the map represents 2,000 feet on the ground). These maps depict basic natural and cultural features of the landscape, such as lakes and streams, highways and railroads, boundaries, and geographic names. Contour lines are used to depict the elevation and shape of terrain. Alabama is covered by 912 maps at this scale, which is useful for civil engineering, land-use planning, natural-resource monitoring, and other technical applications. These maps have long been favorites with the general public for outdoor uses, including hiking, camping, exploring, and back-country fishing expeditions.

Earth Observation Data

Through its Earth Resource Observation Systems Data Center near Sioux Falls, South Dakota, the USGS distributes a variety of aerial photographs and satellite image data products that cover the entire State. Mapping photographs of some sites go back about 40 years. Satellite images dating from 1972 can be used to study changes in regional landscapes.

Landslide Hazards in Alabama

Although prehistoric landslides in Alabama include rock masses more than one-half of a mile across and fast-moving debris flows more than one-quarter of a mile long, most recent landslides appear limited to movements of less than about 100 yards across. These landslides, as well as smaller and faster slides and rockfalls, occur mostly where slopes have been steepened during construction of roads, but some homes on steep terrains have also been endangered. To better understand potential problems posed by landsliding in the State, the USGS has assisted the Geological Survey of Alabama in compiling an inventory of landslides, by using such sources as the Alabama Highway Department, county highway departments, the U.S. Forest Service, and scientific literature. Analysis of the compiled data shows that landsliding is most abundant in the northern part of the State, where it tends to be concentrated in particular mapped geologic units. This information helps in anticipating the distribution and cost effects of landsliding, and thereby helps developers, businesses, highway departments, and local agencies to improve the cost-effectiveness of engineered structures.

Cooperative Programs

Much of the USGS work in Alabama is pursued in partnership with many State and local agencies. Cooperative programs in 1994 included the following agencies: the Alabama Department of Environmental Management; the cities of Birmingham, Huntsville, Anniston, Greenville, Mobile, Tuscaloosa, and

Prattville; Coffee, Sumter, Jefferson, and Baldwin Counties; the Alabama Department of Economic and Community Affairs; the Alabama Emergency Management; the towns of Blountsville and Parrish; the Geological Survey of Alabama; the Alabama Department of Transportation; and Auburn University.

from U.S. Department of the Interior, U.S. Geological Survey, Fact Sheet FS-002-95

For more information contact any of the following:

- *Water Resources of Alabama*
- *Mapping Applications Center (MAC), Reston, Virginia*
- *Assistant Chief Geologist, 953 National Center, Reston, Virginia 20192*
  (703) 648-6660
- *National Landslide Information Center, Denver Federal Center, Mail Stop 966, Denver, Colorado 80225*
  1-800-654-4966
- *USGS Node of National Geospatial Data Clearinghouse*
- *USGS home page*
- *For more information on all USGS reports and products (including maps, images, and computerized data), call1-800-USA-MAPS*

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ENVIRONMENTAL ASSESSMENTS

YOKLEY ENVIRONMENTAL CONSULTING SERVICE

3698 Chisholm Road
Florence, Alabama 35630

Fax (256) 764-3780

Phone (256) 764-3780

E-Mail: pyj@hiwaay.net

October 16, 2004

SUBJECT: SUBCONTRACT No. CC-040901(RB)

SUBCONTRACT ADMINISTRATOR: Ms. Rue Bowen
Tetra Tech NUS, Inc.
20251 Century Boulevard, Suite 200
Germantown, MD 29874-7114

Dear Ms. Bowen,

Threatened and endangered freshwater mussel survey has been performed at the Farley Nuclear Plant discharge plume located near Dothan, Alabama.

Enclosed are the results in a report of the survey made recently for freshwater mussels in the discharge plume at Farley Nuclear Plant in the Chattahoochee River, Houston County, Alabama. Any questions related to the report should be directed to me at (256) 764-3780. A copy has also been sent to the Project Manager: Ms. Nicole Hill and a copy to Mr. Bruce Porter, U. S. Fish & Wildlife Service, Daphne, Alabama.

Sincerely,

Paul Yokley, Jr.

Paul Yokley, Jr. Ph.D
Malacologist

V-511

Expedite

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ENVIRONMENTAL ASSESSMENTS

YOKLEY ENVIRONMENTAL CONSULTING SERVICE

3698 Chisholm Road
Florence, Alabama 35630

Fax (256) 764-3780 Phone (256) 764-3780

E-Mail: pyi@hiwaay.net

October 16, 2004

SUBJECT: SUBCONTRACT No. CC-040901(RB)

Freshwater Mussel Survey of Chattahoochee River below the Farley Nuclear Waste Water Outflow, Houston County, Alabama

On October 8, 9, 10, 2004, a freshwater mussel survey was made below the waste water outflow into the Chattahoochee River from the Farley Nuclear Plant. The survey included all of the mixing zone of the warm waste water with the river water. A search area was measured by placing buoy markers at the upper and lower width and length of the search area. The search area was 150 feet wide and 500 feet in length producing an area of 75,000 square feet. This area was then searched by two divers stretching a line from the west shore across the river to the buoy marker 150 feet from shore. A diver on each side of the line searched an eight feet width. Thus a total of 16 feet of river bottom was searched with each crossing. A total of 32 feet thus would be searched in a single round trip. Sixteen round trips were made in the search area back and forth across the river. We looked at the river bottom almost completely and the substrate was mostly loose sand with no macrobenthic organisms seen including insect larvae and small crustaceans. The sand was riffle-like in the area and appeared somewhat like desert sand may appear. No fish were seen feeding by the divers in the loose sand area with no food to attract fish. Shad minnows were near the surface at the outflow origin and predaceous fish were attracted to the site to feed on the shad minnows. The prerequisite for freshwater mussels in an area is a substrate with nutrients attractive to fish species that serve as hosts for mussels.

The loose sandy substrate provided no anchoring point for native mussels and in the total search only a few old shells of mussels were found. These shells most likely were washed into the area from upstream tributaries that support the mussels. The shells of four species were identifiable and found in the search. None of these originated from the site where found. The species represented in the search area are not presently considered to be threatened and/or endangered. A special concern note has however been made for the delicate spike, *Elliptio arctata*. This mussel is most commonly found in small creeks. The yellow sandshell is a second one found. Five old shells were found representing the yellow sandshell, *Lampsilis teres*. The yellow sandshell is widely distributed in the southeast and considered to be currently stable. The small mussel with the common name little spectaclecase, *Villosa lienosa* is most often found in small creeks and in gulf coast rivers. It

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EPA 2001

United States Environmental Protection Agency

Office of Water (4303)

EPA-821-R-01-036
November 2001

EPA

Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities

Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities

U.S. Environmental Protection Agency
Office of Science and Technology
Engineering and Analysis Division

Washington, DC 20460
November 9, 2001

This document was prepared by Office of Water staff. The following contractors (in alphabetical order) provided assistance and support in performing the underlying analysis supporting the conclusions detailed in this report.

Abt Associates Inc.,
Science Applications International Corporation,
Stratus Consulting Inc., and
Tetra Tech.

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Chapter 1: Baseline Projections of New Facilities

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Facilities regulated under the final § 316(b) New Facility Rule are new greenfield and stand alone electric generators and manufacturing facilities that operate a new cooling water intake structure (CWIS) (or a CWIS whose design capacity is increased), require a National Pollutant Discharge Elimination System (NPDES) permit, have a design intake flow of equal to or greater than two million gallons per day (MGD), and use at least 25 percent of their intake water for cooling purposes. The overall costs and economic impacts of the final rule depend on the number of new facilities subject to the rule and on the planned characteristics (i.e., construction, design, location, and capacity) of their CWISs. The projection of the number and characteristics of new facilities represents baseline conditions in the absence of the rule and identifies the facilities that will be subject to the final § 316(b) New Facility Rule.

EPA did not consider the oil and gas industry in the Phase I 316(b) rulemaking for new facilities. The Phase I proposal and its record included no analysis of issues associated with offshore and coastal oil and gas extraction facilities that could significantly increase the costs and economic impacts and affect the technical feasibility of complying with the proposed requirements for land-based industrial operations. Additionally, EPA believes it is not appropriate to include these facilities in the Phase II regulations scheduled for proposal in February 2002; the Phase II regulations are intended to address the largest existing facilities in the steam-electric generating industry. During Phase III, EPA will address cooling water intake structures at existing facilities in a variety of industry sectors. Therefore, EPA believes it is most appropriate to defer rulemaking for offshore and coastal [oil and gas] extraction facilities to Phase III. For further discussion, see Chapter 5: Industry Profile - Oil and Gas Extraction Industry.

This chapter provides a summary EPA's forecasts for the number of new electric generators and manufacturing facilities subject to the final § 316(b) New Facility Rule that will begin operating between 2001 and 2020. The chapter consists of four sections. The first three sections address the forecasts of new facilities and the final section presents a profile of the electricity generation industry. Section 1.1 presents the estimates for the number and characteristics of new electric generating facilities. Section 1.2 presents the estimates for the number of new manufacturing facilities. Section 1.3 summarizes the results of the new baseline projections of facilities. For detailed discussion of the methodology behind the forecasts consult *Chapter 5 of the Economic Analysis.*

1.1 NEW ELECTRIC GENERATORS

EPA estimates that 83 new electric generators subject to the final § 316(b) New Facility Rule will begin operation between 2001 and 2020. Of these, 69 are new combined-cycle facilities and 14 are new coal facilities.[1] This projection is based on a combination of national forecasts of new steam electric capacity additions and information on the characteristics of specific facilities that are planned for construction in the near future or that have been constructed in the recent past. Using these two types of information, EPA developed model facilities that provide the basis for estimating costs and economic impacts for electric generators throughout the remainder of this document. For more detailed information regarding new electric generators, see *Economic Analysis of the Final Regulations Addressing Cooling Water Intake Structures for New Facilities.*

1.1.1 Methodology

EPA used four main data sources to project the number and characteristics of new steam electric generators subject to the final rule: (1) the Energy Information Administration's (EIA) *Annual Energy Outlook 2001* (AEO2001); (2) Resource Data International's (RDI) *NEWGen Database*, (3) EPA's § 316(b) industry survey of existing facilities; and (4) EIA's Form EIA-860A and 860B databases. The following sections provide detail on each data source used in this analysis. The final subsection 5.1.1.e summarizes how EPA combined the information from the different data sources to calculate the number of new combined-cycle and coal facilities.

Annual Energy Outlook 2001

The Annual Energy Outlook (AEO) is published annually by the U.S. Department of Energy's Energy Information Administration (EIA) and presents forecasts of energy supply, demand, and prices. These forecasts are based on results generated from EIA's National Energy Modeling System (NEMS). The NEMS system generates projections based on known levels of technological capabilities, technological and demographic trends, and current laws and regulations. Other key assumptions are made regarding the pricing and availability of fossil fuels, levels of economic growth, and trends in energy consumption. The AEO projections are used by Federal, State, and local governments, trade associations, and other planners and decision makers in both the public and private sectors. EPA used the most recent forecast of capacity additions between 2001 and 2020 (presented in the AEO2001) to estimate the number of new combined-cycle and coal-fired steam electric plants.

The AEO2001 presents forecasts of both planned and unplanned capacity additions between 2001 and 2020 for eight facility types (coal steam, other fossil steam, combined-cycle, combustion turbine/diesel, nuclear, pumped storage/other, fuel cells and renewables). EPA has determined that only facilities that employ a steam electric cycle require significant quantities of cooling water and are thus potentially affected by the final § 316(b) New Facility Rule. As a result, this analysis considers capacity additions associated with coal steam, other fossil steam, combined-cycle, and nuclear facilities only. In its Reference Case, the AEO2001 forecasts total capacity additions of 370 GW

[1]Combined-cycle facilities use an electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine to produce electricity. This process increases the efficiency of the electric generating unit.

from all facility types between 2001 and 2020.[2] Coal steam facilities account for 22 GW, or 6 percent of the total forecast, and combined-cycle facilities account for 204 GW, or 55 percent. The remaining capacity additions, 39 percent of the total, come from non-steam facility types. Based on all available data in the rulemaking record, EPA projects no new additions for nuclear and other fossil steam capacity.

NEWGen Database

The NEWGen database is created and regularly updated by Resource Data International's (RDI) Energy Industry Consulting Practice. The database provides detailed facility-level data on electric generation projects, including new (greenfield and stand alone) facilities and additions and modifications to existing facilities, proposed over the next several years. Information in the NEWGen database includes: generating technology, fuel type, generation capacity, owner and holding company, electric interconnection, project status, on-line dates, and other operational details. The majority of the information contained in this database is obtained from trade journals, developers, local authorities, siting boards, and state environmental agencies.

EPA used the February 2001 version of the NEWGen database to develop model facilities for the economic analysis of electric generators. Specifically, the database was used to:

- calculate the percentage of total combined-cycle capacity additions derived from new (greenfield and stand alone) facilities;
- calculate the percentage of total coal capacity additions derived from new (greenfield and stand alone) facilities;
- estimate the in-scope percentage of new combined-cycle facilities; and
- determine the technical, operational, and ownership characteristics of new in-scope combined-cycle facilities.

§ 316(b) Industry Survey of Existing Facilities

Because the NEWGen database discussed in the previous section contained information on only 16 new (greenfield and stand alone) coal facilities, EPA believes that information from EPA's § 316(b) industry survey of existing facilities (*Industry Screener Questionnaire: Phase I Cooling Water Intake Structures*, *Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures*, and *Industry Short Technical Questionnaire: Phase II Cooling Water Intake Structures*) was more reliable for estimating characteristics of new coal facilities projected over the 2001-2020 analysis period because it included far more plants over a longer time period.

All three survey instruments requested technical information, including the facility's in scope status, cooling system type, intake flow, and source water body. In addition, the screener questionnaire and the detailed questionnaire also requested economic and financial information. For more information on the three survey instruments, see ICR No. 1973.02.

[2] Among other model parameters, the AEO2001 Reference Case assumes economic growth of 3 percent and electricity demand growth of 1.8 percent.

EPA used the following survey data on coal plants constructed during the past 20 years to project the number and characteristics of new (greenfield and stand alone) coal facilities: in-scope status, waterbody type, and cooling system type.[3]

In developing model coal facilities, EPA only considered those existing survey plants that have a once-through system, a recirculating system, or a recirculating system with a cooling lake or pond.

EIA Databases

In addition to the § 316(b) industry survey of existing facilities, EPA used two of EIA's electricity databases (Form EIA-860A, Annual Electric Generator Report – Utility; and Form EIA-860B, Annual Electric Generator Report – Nonutility; both 1998) in the analysis of projected new coal plants. EPA used these databases for three purposes:

- **Identify which of the surveyed electric generators are "coal" plants:** EPA used the prime mover and the primary energy source, reported in the EIA databases, to determine if a surveyed facility is a coal plant. Only plants that only have coal units were considered in this analysis.
- **Identify coal plants constructed during the past 20 years:** Both EIA databases request the in-service date of each unit. Of the surveyed facilities, 111 coal-fired plants began commercial operation between 1980 and 1999.
- **Determine the average size of new coal plants:** The 111 identified coal plants have an average nameplate rating of 475 MW.[4]

Summary of the Number of New Facilities

EPA estimated the number of projected new combined-cycle and coal plants using information from the four data sources described in subsections 5.1.1.a to 5.1.1.d above. EPA used the U.S. Department of Energy's estimate of new capacity additions (combined-cycle: 204 GW, coal: 22 GW) and multiplied it by the percentage of capacity additions that will be built at new facilities (combined-cycle: 88%, coal: 76%) to determine the new capacity that will be constructed at new facilities (combined-cycle: 179 GW, coal: 17 GW). EPA then divided this value by the average facility size (combined-cycle: 741 MW, coal: 475 MW) to determine the total number of potential new facilities (combined-cycle: 241, coal: 35; both in scope and out of scope of today's final rule). Finally, based on EPA's estimate of the percentage of facilities that meet the two MGD flow threshold (combined-cycle: 28.6%, coal: 40.5%), EPA estimates there will be 69 new in-scope combined-cycle facilities and 14 new coal facilities over the 2001–2020 period.

Development of Model Facilities

The final step in the baseline projection of new electric generators was the development of model facilities for the costing and economic impact analyses. This step required translating characteristics of the analyzed combined-cycle and coal facilities into characteristics of the 83 projected new facilities. The characteristics of interest are: (1) the type of water body from which the intake structure withdraws (freshwater or marine water); (2) the facility's type of

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[3]Coal plants constructed during the past 20 years were identified from Forms EIA-860A and EIA-860B. See discussion in subsection 1.1.1.d below.

[4]The average capacity for in-scope coal facilities is 763 MW, while the average for out of scope coal facilities is 278 MW.

cooling system (once-through or recirculating system); and (3) the facility's steam electric generating capacity. The following two subsections discuss how EPA developed model facilities for combined-cycle and coal facilities, respectively.

1.1.2 Projected Number of New Electric Generation Facilities

Combined-Cycle Facilities

EPA's analysis projected 69 new in-scope combined-cycle facilities. Cooling water and economic characteristics of these 69 facilities were determined based on the characteristics of the 57 in-scope NEWGen facilities.[5] EPA developed six model facility types based on the 57 facilities' combinations of source water body and type of cooling system. Within each source water body/cooling system group, EPA created between one and three model facilities, depending on the number of facilities within that group and the range of their steam electric capacities.

Based on the distribution of the 57 NEWGen facilities by source water body group, cooling system type, and size group, EPA determined how many of the 69 projected new facilities are represented by each of the six model facility types. Table 1-1 below presents the six model facility types, their estimated steam electric capacity, the number of NEWGen facilities upon which each model facility type was based, and the number of projected new facilities that belong to each type.

Table 1-1: Combined-Cycle Model Facilities

Model Facility Type	Cooling System Type	Source Water Body	Steam Electric Capacity (MW)	Number of NEWGen Facilities	Number of Projected New Facilities
CC OT/M-1	Once Through	Marine	1,031	4	5
CC R/M-1	Recirculating	Marine	489	4	5
CC R/M-2	Recirculating	Marine	1,030	1	1
CC R/FW-1	Recirculating	Freshwater	439	15	18
CC R/FW-2	Recirculating	Freshwater	699	17	21
CC R/FW-3	Recirculating	Freshwater	1,061	16	19
Total				57	69

Source: EPA Analysis, 2001.

Generally, NEWGen facilities were not always consistent in how they reported their intake flows. Some NEWGen facilities reported design flows, some reported maximum flows and some reported average flows. It was therefore necessary to estimate design flows for those facilities that had reported either maximum or average flows. To do

[5]EPA could determine the water body type for all 57 in-scope facilities but did not have information on the cooling system type for 18 facilities. Since all freshwater facilities with a known cooling system type propose to build a recirculating system, EPA assumed that the 15 freshwater facilities with an unknown cooling system type will also build a recirculating system. For marine facilities, EPA assumed that two of the three facilities with an unknown system type would build a recirculating system in the baseline while one would build a once-through system.

so, EPA assumed estimated design flows to be equivalent to maximum flows, or to three times average flows, based on the results of previous analysis of DQ combined cycle power plants. As was done for the coal-fired plants, EPA normalized estimated design flows for the NEWGen facilities by dividing by MW capacities.

Many NEWGen facilities did not report any intake flow information. EPA developed model facility flow estimates based only on those NEWGen facilities for which flows had been reported. The NEWGen facilities that did not report flows were assumed to follow the same distribution as those which had reported flow information.

EPA grouped the NEWGen facilities according to CWS type (once-through vs. recirculating) and water body type (freshwater vs. marine) to yield several baseline scenarios. The baseline scenarios for combined cycle power plants are listed in Table 1-2 below.

Table 1-2: Baseline Combined Cycle Power Plant Scenarios

Industry Category	Industry Description	Baseline Cooling Technology	Water Body Type
Combined Cycle Power Plants	Includes both Utility and Non-utility facilities	Once-through	Marine
Combined Cycle Power Plants	Includes both Utility and Non-utility facilities	Recirculating with Wet Towers	Marine
Combined Cycle Power Plants	Includes both Utility and Non-utility facilities	Recirculating with Wet Towers	Freshwater

It should be noted that a once-through, freshwater model plant was not developed because none of the NEWGen facilities fell into this baseline scenario. Within each baseline scenario, EPA developed combined cycle model facilities to represent low, medium and high MW capacity plants, using a similar methodology to that used to develop the coal-fired model facilities. Table 1-3 below presents the baseline intake and cooling flow values used in estimating the compliance costs for these model combined cycle power plants.

Table 1-3: Additional Combined Cycle Power Plant Model Facility Baseline Intake and Cooling Flow Values					
Model Facility ID	**Baseline Cooling Water System**	**Waterbody Type**	**Capacity (MW)**	**Baseline Intake Flow (MGD)**	**Baseline Cooling Flow (MGD)**
CC OT/M-1	Once Through	Marine	1031	613	613
CC R/M-1	Recirculating	Marine	489	8	106
CC R/M-2	Recirculating	Marine	1030	18	223
CC R/FW-1	Recirculating	Freshwater	439	10	198
CC R/FW-2	Recirculating	Freshwater	699	12	230
CC R/FW-3	Recirculating	Freshwater	1061	14	283

Coal Facilities

EPA's analysis projected 14 new in-scope coal facilities. The same approach was used to assign cooling water and economic characteristics to these 14 facilities as was used for combined-cycle facilities (see discussion in the previous section). EPA determined the characteristics of the 14 projected new coal facilities based on the characteristics of the 41 existing in-scope coal facilities. EPA developed eight model facility types based on the 41 facilities' source water body and their type of cooling system. Within each source water body/cooling system group, EPA created between one and three model facilities, depending on the number of facilities within that group and the range of their steam electric capacities. Based on the distribution of the 41 survey facilities by source water body group, cooling system type, and size group, EPA determined how many of the 14 projected new coal facilities are represented by each of the eight model facility types. Table 1-4 below presents the eight model facility types, their estimated steam electric capacity, the number of survey facilities upon which each model facility type was based, and the number of projected new coal facilities that are represented by each type.

Table 1-4: Coal Model Facilities					
Model Facility Type	Cooling System Type	Source Water Body	Steam Electric Capacity (MW)	Number of Existing Survey Facilities	Number of Projected New Facilities
Coal R/M-1	Recirculating	Marine	812	3	1
Coal OT/FW-1	Once Through	Freshwater	63	3	1
Coal OT/FW-2	Once Through	Freshwater	515	5	1
Coal OT/FW-3	Once Through	Freshwater	3,564	1	1
Coal R/FW-1	Recirculating	Freshwater	173	10	3
Coal R/FW-2	Recirculating	Freshwater	625	7	3
Coal R/FW-3	Recirculating	Freshwater	1,564	8	3
Coal RL/FW-1	Recirculating with Lake[a]	Freshwater	660	4	1
Total				41	14

[a] For this analysis, recirculating facilities with cooling lakes are assumed to exhibit characteristics like a once-through facility.

Source: EPA Analysis, 2001.

Data taken from the surveys included both design intake flow and average intake flows, where available. With the exception of monitoring costs, all cost components used either the design intake flow or the design cooling water flow (which was estimated from the design intake flow as described in Section 2.3.5 of Chapter 2: Wet Tower Intake Flow Factors) as the input variable for deriving the cost. However, design intake flow data were not available for the SQ and screener facilities. It was therefore necessary to estimate design intake flows for these facilities. To do this, EPA calculated ratios of design to average intake flow (D/A) for those DQ facilities for which both design intake and average intake flows were available. These facilities were then grouped according to cooling water system (CWS) type (i.e., once-through vs. recirculating), and an average D/A ratio was calculated for each CWS type. This yielded average D/A ratios of 1.18 for once-through coal-fired plants and 2.94 for recirculating coal-fired plants. EPA then used these average D/A ratios to estimate design flows for those facilities for which design flows were not available (D/A ratio was multiplied by average flow to yield estimated design flow).

Where design condenser flows were available from EEI 1996 data, EPA compared the estimated design intake flows to the design condenser flows as a check of their reasonableness. For once-through facilities, the design intake flow would be expected to be similar in magnitude to the design condenser flow, while for recirculating facilities with cooling towers, the design intake flows would be expected to be only a fraction of the design condenser flows. In almost all cases, the estimated design flows were found to meet these expectations.

For a few facilities, however (notably, the facilities that had recirculating CWSs with cooling ponds), EPA found the estimated design flows (calculated using the recirculating system D/A ratio of 2.94) to be several times higher than the design condenser flows. Therefore, for these facilities, the design condenser flows were used as being more representative of the design intake flows that might be expected for such facilities (in fact, the design condenser flows were much more in line with estimated design flows calculated using the once-through D/A ratio of 1.18). See Chapter 2 for additional discussion of these recirculating facilities with cooling ponds.

Four survey facilities with estimated design flows less than the regulatory threshold of 2 million gallons per day (MGD) were then eliminated from the flow analysis as being out of scope. The regulatory threshold represents the intake flow rate at which intake systems would be required to comply with the regulation. Only those survey facilities that were in scope (i.e., met the 2 MGD regulatory threshold) were included in the analysis to develop the model facilities.

EPA then normalized the design flows for the in-scope facilities by dividing the design flow for each facility by the corresponding MW capacity for that facility to yield a ratio of design flow to MW capacity (MGD/MW). This was necessary in order to apply the flow values for plants with a range of MW capacities to average capacity model plants.

EPA then grouped the surveyed facilities according to CWS type and water body type to yield several baseline scenarios. The various water body types were divided into two general categories: freshwater, which included facilities located on freshwater rivers, streams, lakes or reservoirs; and marine, which included facilities located on tidal rivers, estuaries and oceans. The baseline scenarios for coal-fired power plants are listed in Table 1-5 below.

Table 1-5: Baseline Coal-Fired Power Plant Scenarios

Industry Category	Industry Description	Baseline Cooling Technology	Water Body Type
Coal-fired Power Plants	Includes both Utility and Non-utility facilities	Once-through	Freshwater (includes freshwater rivers, streams, lakes, and reservoirs
Coal-fired Power Plants	Includes both Utility and Non-utility facilities	Recirculating with Wet Towers	Freshwater
Coal-fired Power Plants	Includes both Utility and Non-utility facilities	Recirculating with Wet Towers	Marine (includes tidal rivers, estuaries, and oceans)
Coal-fired Power Plants	Includes both Utility and Non-utility facilities	Recirculating with Cooling Ponds	Freshwater

It should be noted that EPA did not develop a once-through, marine baseline scenario for coal-fired power plants because none of the surveyed facilities (and therefore none of the projected new facilities) fell into this baseline scenario. It should also be noted that EPA developed a separate baseline scenario for coal-fired power plants that had recirculating CWSs with cooling ponds. The design intake flows and MGD/MW ratios for these facilities were found to be much higher than those for the coal-fired power plants that had recirculating systems with wet cooling towers–more in line with what might be expected for once-through facilities. This would not be entirely unexpected, if the reported flows for these facilities represented the flows of water withdrawn from the cooling ponds for cooling use within the plants, rather than the flows of make-up intake water to the cooling ponds. EPA therefore decided that these recirculating plants with cooling ponds deserved to be treated as a separate baseline scenario. For purposes of cost estimation, these facilities were treated the same as once-through facilities. This represented a conservative approach since, if anything, it would tend to overestimate the size of the baseline cooling water system that would have to be replaced, as well as the corresponding compliance cost.

Within each baseline scenario, EPA ranked the survey facilities in ascending order of their MW capacities. EPA then divided the ranked survey facilities into groups to yield low, medium and high MW capacity model facilities. For baseline scenarios where only a single new facility was projected, only average MW capacities were calculated. EPA developed corresponding average MGD/MW ratios for each grouping. The low, medium and high MW capacities for each baseline scenario were then multiplied by the corresponding average MGD/MW ratios to yield normalized design flow estimates for low, medium and high MW capacity model facilities. EPA then estimated the cooling water flows for the model facilities based on the design intake flows, as described below under Chapter 2, Section 2.3.5: Wet Tower Intake Flow Factors. Table 1-6 below presents the baseline intake and cooling flow values used in estimating the compliance costs for the different model coal-fired plants.

Table 1-6: Coal-Fired Power Plant Model Facility Baseline Intake and Cooling Flow Values

Model Facility ID	Baseline Cooling Water System	Waterbody Type	Capacity (MW)	Baseline Intake Flow (MGD)	Baseline Cooling Flow (MGD)
Coal OT/FW-1	Once Through	Freshwater	63	64	64
Coal OT/FW-2	Once Through	Freshwater	515	420	420
Coal OT/FW-3	Once Through	Freshwater	3564	1550	1550
Coal R/M-1	Recirculating	Marine	812	44	547
Coal R/FW-1	Recirculating	Freshwater	173	5	103
Coal R/FW-2	Recirculating	Freshwater	625	20	405
Coal R/FW-3	Recirculating	Freshwater	1564	77	1538
Coal RL/FW-1	Recirculating with Cooling Pond	Freshwater	660	537	537

1.1.3 Summary of Forecasts for New Electric Generators

EPA estimates that a total of 276 new steam electric generators will begin operation between 2001 and 2020. Of the total number of new plants, EPA projects that 83 will be in scope of the final § 316(b) New Facility Rule. Sixty-nine are expected to be combined-cycle facilities and 14 coal-fired facilities. Table 1-7 summarizes the results of the analysis.

Table 1-7: Number of Projected New Electric Generators (2001 to 2020)								
Facility Type	Total Number of New Facilities	Facilities In Scope of the Final Rule						
		Recirculating		Recirc. with Lake		Once-Through		Total
		Freshwater	Marine	Freshwater	Marine	Freshwater	Marine	
Combined-Cycle	241	58	6	0	0	0	5	69
Coal	35	9	1	1	0	3	0	14
Total	276	67	7	1	0	3	5	83

Source: EPA Analysis, 2001.

1.2 NEW MANUFACTURING FACILITIES

EPA estimates that 38 new manufacturing facilities subject to the final § 316(b) New Facility Rule will begin operation between 2001 and 2020. Of the 38 facilities, 22 are chemical facilities, ten are steel facilities, two are petroleum refineries, two are paper mills, and two are aluminum facilities. The projection is based on a combination of industry-specific forecasts and information on the characteristics of existing manufacturing facilities. For more detailed information regarding new manufacturing facilities, see *Economic Analysis of the Final Regulations Addressing Cooling Water Intake Structures for New Facilities*.

1.2.1 Methodology

EPA used several steps to estimate the number of new manufacturing facilities subject to the final rule. For each industry sector, EPA:

identified the SIC codes with potential new in-scope facilities;
obtained industry growth forecasts;
determined the share of growth from new (greenfield and stand alone) facilities;
projected the number of new facilities;
determined cooling water characteristics of existing facilities; and
developed model facilities.

The remainder of this section briefly outlines each of these six steps. The following Section 5.2.2 describes the baseline projections of new manufacturing facilities for each of the five industry sectors.[6]

SIC codes with potential new in-scope facilities

EPA used results from the § 316(b) *Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures* to identify the SIC codes within each of the five industry sectors that are likely to have one or more new (greenfield

[6] This analysis divides the Primary Metals sector (SIC 33) into two subsectors: steel (SIC 331) and aluminum (SIC 333/335). Section 5.2.2 therefore discusses five separate sectors, not four.

and stand alone) facilities subject to the final § 316(b) New Facility Rule. SIC codes that were included in this analysis are those that, based on the Detailed Industry Questionnaire, have at least one existing facility that meets the in-scope criteria of the final rule. Facilities meet the in-scope criteria of the final rule if they:

use a CWIS to withdraw from a water of the U.S.;
hold an NPDES permit;
withdraw at least two million gallons per day (MGD); and
use 25 percent or more of their intake flow for cooling purposes.[7]

For each SIC code with at least one in-scope survey respondent, EPA estimated the total number of facilities in the SIC code (based on the sample weighted estimate from EPA's § 316(b) industry survey of existing facilities), the number of in-scope survey respondents, and the in-scope percentage.

Industry growth forecasts

Forecasts of the number of new (greenfield and stand alone) facilities that will be built in the various industrial sectors are generally not available over the 20-year time period required for this analysis. Projected growth rates for value of shipments in each industry were used to project future growth in capacity. A number of sources provided forecasts, including the annual *U.S. Industry Trade & Industry Outlook (2000)*, the *Assumptions to the Annual Energy Outlook 2001*, and other sources specific to each industry. EPA assumed that the growth in capacity will equal growth in the value of shipments, except where industry-specific information supported alternative assumptions.

Share of growth from new facilities

There are three possible sources of industry growth: (1) construction of new (greenfield and stand alone) facilities; (2) higher or more efficient utilization of existing capacity; and (3) capacity expansions at existing facilities. Where available, information from industry sources provided the basis for estimating the potential for construction of new facilities. Where this information was not available, EPA assumed as a default that 50 percent of the projected growth in capacity will be attributed to new facilities. This assumption likely overstates the actual number of new (greenfield and stand alone) facilities that will be constructed.

Projected number of new facilities

EPA projected the number of new facilities in each SIC code by multiplying the total number of existing facilities by the forecasted 10-year growth rate for that SIC code. The resulting value was then multiplied by the share of growth from new facilities to derive the total number of new facilities over ten years. However, not all of the projected new facilities will be subject to requirements of the final § 316(b) New Facility Rule. Information on the likely water use characteristics of new facilities that will determine their in-scope status under the final rule is generally not available for future manufacturing facilities. EPA estimated that the characteristics of new facilities will be similar to the characteristics of existing survey respondents (i.e., the percentage of new facilities subject to the final rule would be the same as the percentage of existing facilities that meet the rule's in-scope criteria). EPA

[7]For convenience, existing facilities that meet the criteria of the final § 316(b) New Facility Rule are referred to as "existing in-scope facilities" or "in-scope survey respondents." As existing facilities, they will not in fact be subject to the rule. However, they would be subject to the final § 316(b) New Facility Rule if they were *new* facilities.

then calculated the number of new *in-scope* facilities by multiplying the 10-year forecast of new facilities by the in-scope percentage of existing facilities. To derive the 20-year estimate, both the estimated total number of new facilities and the estimated number of new in-scope facilities were doubled. This approach most likely overstates the number of new facilities that will incur regulatory costs, because new facilities may be more likely than existing ones to recycle water and use cooling water sources other than a water of the U.S.

Cooling water characteristics of existing in- scope facilities

EPA used information from EPA's § 316(b) *Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures* to determine the characteristics of the in-scope survey respondents. The survey requested technical information, including the facility's cooling system type, source water body, and intake flow in addition to economic and financial information. Cooling water characteristics of interest to the analysis are the facility's baseline cooling system type (i.e., once-through or recirculating system) and its cooling water source (i.e., freshwater or marine water). In addition, the facility's design intake flow was used in the costing analysis.

Development of model facilities

The final step in the baseline projection of new manufacturing facilities was the development of model facilities for the costing and economic impact analyses. This step required translating characteristics of the existing in-scope facilities into characteristics of the projected new facilities. Again, the characteristics of interest are: (1) the facility's type of cooling system in the baseline (once-through or recirculating system) and (2) the type of water body from which the intake structure withdraws (freshwater or marine water). EPA developed one model facility for each cooling system/water body combination within each 4-digit SIC code. Based on the distribution of the in-scope survey respondents by cooling system type and source water body, EPA assigned the projected new in-scope facilities to model facility types.

EPA developed model manufacturing facilities using DQ data for 178 manufacturing facilities, regardless of their year of construction. Because the DQ manufacturing facilities represent only a sampling of the total population of manufacturing facilities, EPA used survey weights in developing flow estimates for these model facilities.

EPA first sorted the DQ manufacturing facilities according to their 4-digit SIC Codes, and then according to CWS type (once-through vs. recirculating) and water body type (freshwater vs. marine) to yield one or more baseline scenarios within each 4-digit SIC Code. Many of the DQ manufacturing facilities were found to use mixed once-through and recirculating CWSs. For purposes of cost estimation, EPA treated these facilities the same as once-through CWSs. This represented a conservative approach since, if anything, it would tend to overestimate the size of the baseline CWS that would have to be replaced, and thus overestimate the corresponding compliance costs.

Eighteen survey facilities with estimated design flows less than the regulatory threshold of 2 million gallons per day (MGD) were then eliminated from the flow analysis as being out of scope. The regulatory threshold represents the intake flow rate at which intake systems would be required to comply with the regulation. Only those survey facilities that were in scope (i.e., met the 2 MGD regulatory threshold) were included in the analysis to develop the model facilities.

The baseline scenarios for manufacturing facilities are listed in Table 1-8 below.

Table 1-8: Baseline Manufacturing Facility Scenarios			
Industry Category	**Industry Description**	**Baseline Cooling Technology**	**Water Body Type**
SIC 2621	Paper and Allied Products - Paper Mills	Once Through	Freshwater
SIC 2812	Chemical and Allied Products - Alkalies and Chlorines	Once Through	Marine
SIC 2812	Chemical and Allied Products - Alkalies and Chlorines	Once Through	Freshwater
SIC 2812	Chemical and Allied Products - Alkalies and Chlorines	Reuse/Recycle	Freshwater
SIC 2819	Chemicals and Allied Products - Industrial Inorganic Chemicals, Not Elsewhere Classified (NEC)	Once Through	Freshwater
SIC 2819	Chemicals and Allied Products - Industrial Inorganic Chemicals, NEC	Reuse/Recycle	Freshwater
SIC 2819	Chemicals and Allied Products - Industrial Inorganic Chemicals, NEC	Once Through	Marine
SIC 2821	Chemicals and Allied Products - Plastics Materials and Synthetic Resins	Once Through	Marine
SIC 2821	Chemicals and Allied Products - Plastics Materials and Synthetic Resins	Once Through	Freshwater
SIC 2821	Chemicals and Allied Products - Plastics Materials and Synthetic Resins	Reuse/Recycle	Freshwater
SIC 2834	Chemicals and Allied Products - Pharmaceuticals	Once Through	Freshwater
SIC 2834	Chemicals and Allied Products - Pharmaceuticals	Reuse/Recycle	Freshwater
SIC 2869	Chemicals and Allied Products - Industrial Organic Chemicals, NEC	Once Through	Marine
SIC 2869	Chemicals and Allied Products - Industrial Organic Chemicals, NEC	Once Through	Freshwater
SIC 2869	Chemicals and Allied Products - Industrial Organic Chemicals, NEC	Reuse/Recycle	Freshwater
SIC 2873	Chemicals and Allied Products - Nitrogenous Fertilizers	Once Through	Freshwater
SIC 2873	Chemicals and Allied Products - Nitrogenous Fertilizers	Reuse/Recycle	Freshwater
SIC 2911	Petroleum Refining	Reuse/Recycle	Freshwater
SIC 2911	Petroleum Refining	Once Through	Freshwater
SIC 3312	Primary Metal Industries - Steel Works, Blast Furnaces and Rolling	Once Through	Freshwater

Table 1-8: Baseline Manufacturing Facility Scenarios			
Industry Category	Industry Description	Baseline Cooling Technology	Water Body Type
SIC 3312	Primary Metal Industries - Steel Works, Blast Furnaces and Rolling	Reuse/Recycle	Freshwater
SIC 3316	Primary Metal Industries - Cold-Rolled Steel Sheet, Strip and Bars	Once Through	Freshwater
SIC 3316	Primary Metal Industries - Cold-Rolled Steel Sheet, Strip and Bars	Reuse/Recycle	Freshwater
SIC 3317	Primary Metal Industries - Steel Pipe and Tubes	Once Through	Freshwater
SIC 3317	Primary Metal Industries - Steel Pipe and Tubes	Reuse/Recycle	Freshwater
SIC 3353	Primary Metal Industries - Aluminum Sheet, Plate and Foils	Once Through	Freshwater
SIC 3353	Primary Metal Industries - Aluminum Sheet, Plate and Foils	Reuse/Recycle	Freshwater

Within each baseline scenario, EPA ranked the DQ facilities in ascending order based on their design intake flows. Design intake flows were not available for two of the DQ manufacturing facilities. However, average intake flows were available for these facilities. EPA estimated design intake flows for these facilities by multiplying their average intake flows by the average ratio of design intake to average intake flow for the other facilities within their baseline scenarios.

EPA then divided the DQ facilities within each baseline scenario into thirds. EPA then calculated weighted average design intake flows for the middle third to yield design flow values for medium-sized (as reflected by design flow) manufacturing facilities; the lower and upper thirds were excluding from the averaging to minimize the effects of unusually small or unusually large facilities on the average. Table 1-9 below presents the baseline intake and cooling flow values used in estimating the compliance costs for the different model manufacturing facilities.

Table 1-9: Manufacturing Model Facility Baseline Intake and Cooling Flow Values				
Model Facility ID	Baseline Cooling Water System	Waterbody Type	Baseline Intake Flow (MGD)	Baseline Cooling Flow (MGD)
MAN OT/FW-2621	Once Through	Freshwater	24	24
MAN OT/M-2812	Once Through	Marine	94	94
MAN OT/FW-2812	Once Through	Freshwater	265	265
MAN R/FW-2812	Reuse/Recycle	Freshwater	6	60
MAN OT/FW-2819	Once Through	Freshwater	19	19

Table 1-9: Manufacturing Model Facility Baseline Intake and Cooling Flow Values

Model Facility ID	Baseline Cooling Water System	Waterbody Type	Baseline Intake Flow (MGD)	Baseline Cooling Flow (MGD)
MAN R/FW-2819	Reuse/Recycle	Freshwater	2	20
MAN OT/M-2819	Once Through	Marine	27	27
MAN OT/FW-2821	Once Through	Freshwater	78	78
MAN R/FW-2821	Reuse/Recycle	Freshwater	14	140
MAN OT/M-2821	Once Through	Marine	30	30
MAN OT/FW-2834	Once Through	Freshwater	18	18
MAN R/FW-2834	Reuse/Recycle	Freshwater	2	20
MAN OT/FW-2869	Once Through	Freshwater	40	40
MAN OT/M-2869	Once Through	Marine	26	26
MAN R/FW-2869	Reuse/Recycle	Freshwater	4	40
MAN OT/FW-2873	Once Through	Freshwater	33	33
MAN R/FW-2873	Reuse/Recycle	Freshwater	30	300
MAN R/FW-2911	Reuse/Recycle	Freshwater	8	80
MAN OT/FW-2911	Once Through	Freshwater	105	105
MAN OT/FW-3312	Once Through	Freshwater	124	124
MAN R/FW-3312	Reuse/Recycle	Freshwater	85	850
MAN OT/FW-3316	Once Through	Freshwater	23	23
MAN R/FW-3316	Reuse/Recycle	Freshwater	12	120
MAN OT/FW-3317	Once Through	Freshwater	39	39
MAN R/FW-3317	Reuse/Recycle	Freshwater	4	40
MAN OT/FW-3353	Once Through	Freshwater	35	35
MAN R/FW-3353	Reuse/Recycle	Freshwater	6	60

1.2.2 Projected Number of New Manufacturing Facilities

Paper and Allied Products (SIC 26)

This analysis assumes that two new in-scope paper mills (SIC code 2621) will begin operation during the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 88 percent of all existing in-scope paper mills operate a once-through system and withdraw from a freshwater body. EPA therefore assumed that both projected new in-scope paper mills will be freshwater facilities with a once-through system. Table 1-10 below presents the model facility type, the number of in-scope survey facilities upon which the model facility type was based, and the number of projected new facilities that belong to that model type.

Table 1-10: SIC 26 Model Facilities					
Model Facility Type	SIC Code	Cooling System Type	Source Water Body	Number of In-Scope Survey Respondents	Number of New In-Scope Facilities
MAN OT/F-2621	2621	Once-Through	Freshwater	47	2

Source: EPA Analysis.

Chemicals Manufacturing (SIC 28)

EPA projected that 22 new in-scope chemical facilities will begin operation during the next 20 years. Based on the distribution of the in-scope survey respondents across water body and cooling system types, EPA assigned the 22 new facilities to 11 different model facility types, by SIC code:

SIC code 2812: EPA projects that two new in-scope facilities will begin operation during the next 20 years. The distribution of existing in-scope facilities across water body and cooling system types showed that 36 percent of the existing facilities operate a once-through system and withdraw from a freshwater body and 36 percent operate a once-through system and withdraw from a marine body. EPA therefore projected one new once-through/freshwater facility and new once-through system/marine facility.

SIC code 2819: Four new industrial inorganic chemicals, not elsewhere classified are projected to begin operation during the 20-year analysis period. The distribution of existing facilities across water body and cooling system types showed that 47 percent of the existing in-scope facilities operate a once-through system and withdraw from a freshwater body, 39 percent operate a once-through system and withdraw from a marine water body, and 14 percent operate a recirculating system and withdraw from a freshwater body. EPA therefore projected two new once-through/freshwater facilities and two new once-through/marine facilities.

SIC code 2821: EPA projects that four new in-scope facilities will begin operation during the next 20 years. The distribution of existing facilities across water body and cooling system types showed that all existing in-scope plastics material and synthetic resins, and nonvulcanizable elastomer facilities operate a once-through system and withdraw from a freshwater body. EPA therefore assumed that all four projected new in-scope facilities will be freshwater facilities with a once-through system.

SIC code 2834: EPA projects that two new in-scope facilities will begin operation during the next 20 years. The distribution of existing facilities across water body and cooling system types showed that all existing in-scope pharmaceutical preparation facilities operate a once-through system and withdraw from a freshwater body. EPA therefore assumed that both projected new in-scope facilities will be freshwater facilities with a once-through system.

SIC code 2869: Eight new facilities in the Industrial Organic Chemical, Not Elsewhere Classified sector are projected to begin operation during the 20-year analysis period. The distribution of existing facilities across water body and cooling system types showed that 89 percent of the existing facilities operate a once-through system and withdraw from a freshwater body and 11 percent operate a recirculating system and withdraw from a freshwater body. Therefore EPA projected that seven new once-through/freshwater facilities and one new recirculating/freshwater facility.

SIC code 2873: EPA projected that two new in-scope nitrogenous fertilizer facilities will begin operation in the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 50 percent of the existing facilities operate a recirculating system and withdraw from a freshwater body and 50 percent operate once-through systems and withdraw from a freshwater body. EPA therefore projected one new recirculating/freshwater facility and one new once-through/freshwater facility.

Table 1-11 below presents the model facility type, the number of in-scope survey facilities upon which the model facility type was based, and the number of projected new facilities that belong to that model type.

Table 1-11: SIC 28 Model Facilities

Model Facility Type	SIC	Cooling System Type	Source Water Body	Number of Existing In-Scope Facilities	Number of Projected New Facilities
MAN OT/M-2812	2812	Once-Through	Marine	6	1
MAN RE/F-2812	2812	Once-Through	Freshwater	6	1
MAN OT/M-2819	2819	Once-Through	Marine	13	2
MAN OT/F-2819	2819	Once-Through	Freshwater	16	2
MAN OT/F-2821	2821	Once-Through	Freshwater	10	4
MAN OT/F-2834	2834	Once-Through	Freshwater	4	2
MAN OT/F-2869	2869	Once-Through	Freshwater	35	7
MAN RE/F-2869	2869	Recirculating	Freshwater	4	1
MAN OT/F-2873	2873	Once-Through	Freshwater	4	1
MAN RE/F-2873	2873	Recirculating	Freshwater	4	1
Total				**102**	**22**

Source: EPA Analysis.

Petroleum and Coal Products (SIC 29)

EPA projected that two new in-scope petroleum refineries (SIC code 2911) will begin operation during the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 52 percent of the existing petroleum refineries operate a recirculating system and withdraw from a freshwater body and 30 percent operate once-through systems and withdraw from a freshwater body. EPA therefore assumed that the two new projected facilities would have those characteristics. Table 1-12 below presents the model facility type, the number of in-scope survey facilities upon which the model facility type was based, and the number of projected new facilities that belong to that model type.

Table 1-12: SIC 29 Model Facilities					
Model Facility Type	SIC Code	Cooling System Type	Source Water Body	Number of Existing In-Scope Facilities	Number of Projected New Facilities
MAN OT/F-2911	2911	Once Through	Freshwater	9	1
MAN RE/F-2911	2911	Recirculating	Freshwater	15	1
Total				24	2

Source: EPA Analysis.

Steel (SIC 331)

EPA projected that 10 new in-scope steel facilities will begin operation during the next 20 years. Based on the distribution of the in-scope survey respondents across water body and cooling system types, EPA assigned the 10 new facilities to six different model facility types, by SIC code:

> ***SIC code 3312:*** Six steel mills are projected to begin operation during the 20-year analysis period. The distribution of existing facilities across water body and cooling system types showed that 91 percent of the existing facilities operate a once-through system and withdraw from a freshwater body and nine percent operate a recirculating system and withdraw from a freshwater body. Therefore EPA projected that five new once-through/freshwater facilities and one recirculating/freshwater facility.
> ***SIC code 3316:*** EPA projected that two new in-scope cold-rolled steel sheet, strip, and bar facilities will begin operation in the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 67 percent of the existing facilities operate a once-through system and withdraw from a freshwater body and 33 percent operate a recirculating system and withdraw from a freshwater body. EPA therefore projected one once-through/freshwater and one recirculating/freshwater facility.
> ***SIC code 3317:*** EPA projected that two new in-scope steel pipe and tube facilities will begin operation in the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 50 percent of the existing facilities operate a recirculating system and withdraw from a freshwater body and 50 percent operate once-through systems and withdraw from a freshwater body. EPA therefore assumed that the two new projected facilities would have those characteristics.

Table 1-13 below presents the model facility type, the number of in-scope survey facilities upon which the model facility type was based, and the number of projected new facilities that belong to that model type.

Table 1-13: SIC 331 Model Facilities					
Model Facility Type	SIC Code	Cooling System Type	Source Water Body	Number of Existing In-Scope Facilities	Number of Projected New Facilities
MAN OT/F-3312	3312	Once-Through	Freshwater	32	5
MAN RE/F-3312	3312	Recirculating	Freshwater	3	1
MAN OT/F-3316	3316	Once-Through	Freshwater	6	1
MAN RE/F-3316	3316	Recirculating	Freshwater	3	1
MAN OT/F-3317	3317	Once-Through	Freshwater	3	1
MAN RE/F-3317	3317	Recirculating	Freshwater	3	1
Total				**50**	**10**

Source: EPA Analysis.

Aluminum (SIC 333/335)

EPA projected that two new in-scope aluminum facilities will begin operation in the next 20 years. The distribution of existing facilities across water body and cooling system types showed that 50 percent of the existing aluminum facilities operate a recirculating system and withdraw from a freshwater body and 50 percent operate once-through systems and withdraw from a freshwater body. EPA therefore assumed that the two new projected facilities would have those characteristics. Table 1-14 below presents the model facility type, the number of in-scope survey facilities upon which the model facility type was based, and the number of projected new facilities that belong to that model type.

Table 1-14: SIC 3353 Model Facilities					
Model Facility Type	SIC Code	Cooling System Type	Source Water Body	Number of Existing In-Scope Facilities	Number of Projected New Facilities
MAN OT/F-3353	3353	Once-Through	Freshwater	3	1
MAN RE/F-3353	3353	Recirculating	Freshwater	3	1
Total				**6**	**2**

Source: EPA Analysis.

1.2.3 Summary of Forecasts for New Manufacturing Facilities

EPA estimates that a total of 380 new manufacturing facilities will begin operation between 2001 and 2020. Thirty-eight of these are expected to be in scope of the final § 316(b) New Facility Rule. Of the 38 facilities, 22 are chemical facilities, ten are steel facilities, two are petroleum refineries, two are paper mills, and two are aluminum facilities. Table 1-15 summarizes the results of the analysis.

Table 1-15: Number of Projected New Manufacturers (2001 to 2020)

Facility Type	Total Number of New Facilities	Facilities In Scope of the Final Rule				
		Recirculating		Once-Through		Total
		Freshwater	Marine	Freshwater	Marine	
Paper and Allied Products (SIC 26)	2	0	0	2	0	2
Chemicals and Allied Products (SIC 28)	282	2	0	17	3	22
Petroleum Refining And Related Industries (SIC 29)	2	1	0	1	0	2
Blast Furnaces and Basic Steel Products (SIC 331)	78	3	0	7	0	10
Aluminum Sheet, Plate, and Foil (SIC 3353)	16	1	0	1	0	2
Total	380	7	0	28	3	38

Source: EPA Analysis, 2001.

1.3 SUMMARY OF BASELINE PROJECTIONS

EPA estimates that over the next 20 years a total of 656 new greenfield and stand alone facilities will be built in the industry sectors analyzed for this final regulation. Two hundred and seventy-six of these new facilities will be steam electric generating facilities and 380 will be manufacturing facilities. As Table 1-16 shows, only 121 of the 656 new facilities are projected to be in scope of the final § 316(b) New Facility Rule, including 83 electric generators, 22 chemical facilities, 12 primary metals facilities, two new pulp and paper, and two petroleum facilities. For more detailed information, see *Economic Analysis of the Final Regulations Addressing Cooling Water Intake Structures for New Facilities.*

Table 1-16: Projected Number of New In Scope Facilities (2001 to 2020)

SIC	SIC Description	Projected Number of New Facilities	
		Total	In-Scope
	Electric Generators		
SIC 49	Electric Generators	276	83
	Manufacturing Facilities		
SIC 26	Paper and Allied Products	2	2
SIC 28	Chemicals and Allied Products	282	22
SIC 29	Petroleum Refining And Related Industries	2	2
SIC 33	Primary Metals Industries		
SIC 331	Blast Furnaces and Basic Steel Products	78	10
SIC 333 SIC 335	Primary Aluminum, Aluminum Rolling, and Drawing and Other Nonferrous Metals	16	2
Total Manufacturing		*380*	*38*
Total		**656**	**121**

Source: EPA Analysis, 2001.

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Chapter 2: Costing Methodology

INTRODUCTION

This chapter presents the methodology used to estimate the costs to facilities of complying with the final §316(b) New Facility Rule. This chapter presents detailed information on the development of unit cost estimates for a set of technologies that may be used to meet requirements. This chapter describes how the technology unit costs were used to develop facility-level cost estimates for each projected in-scope facility.

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2.1 BACKGROUND

Facilities using cooling water may be subject to the final §316(b) New Facility Rule. A facility using cooling water can have either a once-through or a recirculating cooling system.

In a once-through system, the cooling water that is drawn in from a waterbody travels through the cooling system once to provide cooling and is then discharged, typically back to the waterbody from which it was withdrawn. The cooling water is withdrawn from a water source, typically a surface waterbody, through a cooling water intake structure (CWIS). Many facilities using cooling water (e.g., steam electric power generation facilities, chemical and allied products manufacturers, pulp and paper plants) need large volumes of cooling water, so the water is generally drawn in through one or more large CWIS, potentially at high velocities. Because of this, debris, tree limbs, and many fish and other aquatic organisms can be drawn toward or into the CWIS. Since a facility's cooling water system can be damaged or clogged by large debris, most facilities have protective devices such as trash racks, fixed screens, or traveling screens, on their CWIS. Some of these devices provide limited protection to fish and other aquatic organisms, but other measures such as the use of passive (e.g., wedgewire) screens, velocity caps, traveling screens with fish baskets, or the use of a recirculating cooling system may provide better protection and have greater capability to minimize adverse environmental impacts.[1]

In a recirculating system, the cooling water is used to cool equipment and steam, absorbing heat in the process, and is then cooled and recirculated to the beginning of the system to be used again for cooling. The heated cooling water is generally cooled in either a cooling tower or in a cooling pond. In the process of being cooled, some of the water evaporates or escapes as steam. Flow lost through evaporation typically ranges from 0.5 percent to 1 percent of the total flow (Antaya, 1999). Also, because of the heating and cooling of recirculating water, mineral deposition occurs which necessitates some bleeding of water from the system. The water that is purged from the system to maintain chemical balance is called blowdown. The amount of blowdown is generally around 1 percent of the flow. Cooling towers may also have a small amount of drift, or windage loss, which occurs when some recirculating water is blown out of the tower by the wind or the velocity of the air flowing through the tower. The water lost to evaporation, blowdown, and drift needs to be replaced by what is typically called makeup water. Overall, makeup water is generally 3 percent or less of the recirculating water flow.[2] Therefore, recirculating systems still need to draw in water and may have cooling water intakes. However, the volume of water drawn in is significantly less than in once-through systems, so the likelihood of adverse environmental impacts as a result of the CWIS is much lower.[3] Also, some recirculating systems obtain their makeup water from ground water sources or public water supplies, and a small but growing number use treated wastewater from municipal wastewater treatment plants for makeup water.

The final §316(b) New Facility Rule establishes a two-track approach for regulating cooling water intake structures at new facilities.[4] Facilities have the opportunity to choose which track (Track I or Track II) they will follow. Facilities choosing to comply with Track I requirements would be required to meet flow reduction, velocity, and design and construction technology requirements. These requirements include reducing cooling water intake flow to a level commensurate with that achievable with a closed-cycle, recirculating cooling system; achieving a through-screen intake velocity of 0.5 feet per second; meeting location- and capacity-based limits on proportional intake flow; and implementing design and construction technologies for minimizing impingement and entrainment and maximizing impingement survival. Facilities choosing to comply with Track II requirements would be required to perform a comprehensive demonstration study to demonstrate that proposed technologies reduce the level of impingement and entrainment to the same level that would be achieved by implementing the requirements of Track I.

2.2 Overview of Costing Methodology

Based on information provided by vendors and industry representatives, EPA first developed unit costs and cost curves, including both capital costs and operations and maintenance (O&M) costs, for a number of primary technologies such as traveling screens and cooling towers that facilities may use to meet requirements under the final §316(b) New Facility Rule. Unit costs are estimated costs of certain activities or actions, expressed on a uniform basis (i.e., using the same units), that a facility may take to meet the regulatory requirements. Unit costs are developed to facilitate comparison of the costs of different actions. For this analysis, the unit basis is dollars per gallon per minute ($/gpm) of flow. For most technologies, EPA used the cooling water intake flow as the basis for unit costs; for cooling towers, EPA used the cooling water recirculating flow through the tower as the basis for unit costs. EPA estimated all capital and operating and maintenance (O&M) costs in these units. These unit costs and cost curves are the building blocks for developing costs at the facility and national levels.

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[1]CWIS devices used in an effort to protect fish also include other fish diversion and avoidance systems (e.g., barrier nets, strobe lights, electric curtains), which may be effective in certain conditions and for certain species. See Chapter 5 of this document.

[2]In some saltwater cooling towers, however, makeup water can be as much as 15 percent.

[3]Manufacturer Brackett Green notes that closed loop systems (i.e., recirculating systems) normally require one-sixth the number of traveling screens as a power plant of equal size that has a once-through cooling system.

[4]See *Economic Analysis of the Final Regulations Addressing Cooling Water Intake Structures for New Facilities* (hereinafter referred to as the *Economic Analysis*), Chapter 1: Introduction and Overview for a summary of this rule's requirements.

While EPA developed unit costs for a number of available technologies, EPA used only a limited set of these technologies to develop facility-level capital and O&M cost estimates. For purposes of cost estimation, EPA assumed that facilities would meet the flow reduction requirement by installing cooling towers. EPA assumed that facilities would meet the velocity and design and construction technology requirements by installing traveling screens with fish handling features, with an intake velocity of 0.5 ft/s.

EPA used unit cost curves to develop facility-level capital and O&M cost estimates for 41 model facilities. These model facilities were then scaled to represent total industry compliance costs for the 121 facilities projected to begin operation between 2001 and 2020. Individual facilities will incur only a subset of the unit costs, depending on the extent to which they would have already complied with the requirements as originally designed (in the baseline) and on the compliance response they select. To account for this, EPA established a number of baseline scenarios (reflecting different baseline cooling water system types and waterbody types) so that the unit costs could be applied to the various model facilities to obtain facility-level costs.

The cost estimates developed for various technologies are intended to represent a National "typical average" cost estimate. The cost estimates should not be used as a project pricing tool as they cannot account for all the site-specific conditions for a particular project.

The facility-level capital and O&M costs presented in this chapter represent the net increase in costs for each set of compliance technology performance requirements as compared to the technology the facility would have installed absent this regulation. To calculate net costs for each model facility, EPA first calculated the cost for the entire cooling system for the baseline technology combination, and then subtracted those costs from the calculated cost of the entire cooling system for each compliance technology combination.

Development of the facility-level capital and O&M costs for the final §316(b) New Facility Rule is discussed in detail in Section 2.3 below. In addition to the facility-level cost estimates developed for the preferred two-track option adopted for the final rule, EPA also developed facility-level cost estimates for several additional options that EPA considered but did not adopt for the final rule. Development of the facility-level capital and O&M cost estimates for these options are also discussed in Section 2.3.

In addition, EPA applied an energy penalty cost to those electric generators switching to recirculating systems to account for performance penalties that may result in reductions of energy or capacity produced because of adoption of recirculating cooling tower systems. These performance penalties are associated with reduced turbine efficiencies due to higher back pressures associated with cooling towers, as well as with power requirements to operate cooling tower pumps and fans. EPA's costing methodology for performance penalties is based on the concept of lost operating revenue due to a mean annual performance penalty. EPA estimated the mean annual performance penalty for recirculating cooling tower systems as compared to once-through cooling systems. EPA then applied this mean annual penalty to the annual revenue estimates for each facility projected to install a recirculating cooling tower technology as a result of the rule. It should be noted that EPA took a conservative approach and double-counted some parts of the energy penalty, since fan and pump power costs were included in both the energy penalty and the cooling tower O&M costs. Energy penalties are discussed in detail in Chapter 3 of this document and their costs are presented in the *Economic Analysis*.

Compliance with the final section §316(b) New Facility Rule also requires facilities to carry out certain administrative functions. These are either one-time requirements (compilation of information for the initial NPDES permit) or recurring requirements (compilation of information for NPDES permit renewal, and monitoring and record keeping), and depend on the facility's water body type and the permitting track the facility follows. Development of these administrative costs is discussed in the *Information Collection Request for Cooling Water Intake Structures, New Facility Final Rule* (referred to as the ICR) and in the *Economic Analysis*.

All costs presented in this chapter are expressed in 1999 dollars. For the *Economic Analysis* for the final §316(b) New Facility Rule, EPA escalated these costs to 2000 dollars.

2.3 FACILITY LEVEL COSTS

2.3.1 General Approach

The facility-level cost estimates presented in this section are based on a limited set of the unit costs presented in detail in the following sections of this Chapter. For purposes of cost estimation, EPA assumed that facilities would meet the flow reduction requirement by switching to recirculating systems. EPA assumed that all planned facilities switching to recirculating systems would use cooling towers (the most common type of recirculating system). This is consistent with the requirement of the final section 316(b) New Facility Rule to reduce intake flow to a level commensurate with that which could be obtained by use of a closed-cycle recirculating system. EPA assumed that facilities would meet the velocity and design and construction technology requirements by installing traveling screens with fish handling features, with an intake velocity of 0.5 ft/s. This is a conservative assumption because such technologies are among the more expensive technologies available for reducing velocity and I&E.

EPA used 41 model facilities to develop facility-level capital and O&M cost estimates for the 121 facilities projected to begin operation between 2001 and 2020. The development of model facilities is described in Chapter 1. Individual facilities subject to the regulation will incur differing costs depending on site specific conditions, technologies projected to be installed in the baseline (i.e., regardless of this regulation), and on the compliance response they select. To account for this, EPA established a number of baseline scenarios (reflecting different baseline cooling water system types and waterbody types) so that the unit costs could be applied to the various model facilities to obtain facility-level costs.

In this analysis, the baseline technology represents an estimation of the technologies that would be constructed at new facilities prior to implementation of the final New Facility Rule regulatory requirements. Specifically, the costs presented in the cost tables represent the net increase in costs for each set of compliance technology/monitoring requirements as compared to the baseline technology. EPA accomplished this by calculating the cost for the entire cooling system for the baseline technology combination and then subtracting those costs from the calculated cost of the entire cooling system for each compliance technology combination.

The final New Facility Rule allows for facilities to comply with one of two alternative sets of permitting requirements (Track 1 and Track 2). Facilities choosing to comply with Track 1 permitting requirements would be required to meet flow reduction, velocity, and design and construction technology requirements. Facilities choosing to comply with Track 2 permitting requirements would be required to perform a comprehensive demonstration study to confirm that proposed technologies reduce the level of impingement and entrainment mortality to the same level that would be achieved by implementing the flow reduction, velocity, and design and construction technology requirements of Track I.

EPA assumed that facilities that were projected to have recirculating baseline cooling water systems would follow Track I. EPA developed cost estimates for these facilities based on the assumption that they would already be installing cooling towers, and thus would only have to install velocity reducing design and construction technologies of traveling screens with fish handling features.

EPA assumed that facilities that were projected to have once-through baseline cooling water systems would follow Track II. EPA developed cost estimates for these facilities based on the assumption that they would perform comprehensive demonstration studies, but would still have to install cooling towers and design and construction technologies of traveling screens with fish return systems to meet the regulatory requirements. This is a conservative assumption that may overestimate compliance costs if a significant number of Track II facilities are able to demonstrate that lower cost alternative technologies will reduce the level of impingement and entrainment to the same level that would be achieved by implementing the flow reduction, velocity, and design and construction technology requirements of Track I.

Some facilities were projected to have mixed once-through and recirculating baseline cooling water systems. EPA treated these facilities the same as facilities with baseline once-through cooling water systems. This represents a conservative approach since it will tend to overestimate the size of the baseline cooling water system that would have to be replaced, and thus overestimate the corresponding compliance cost. In addition, one coal facility was projected to have a recirculating system with a cooling pond. This facility was also costed to switch to a cooling tower.[5]

2.3.2 Capital Costs

Capital cost estimates used in calculating the net compliance costs include individual estimates for the following initial one-time cost components where applicable:

- Once-through system including intake structure, pumps, and piping costs.
- Recirculating wet towers.
- Intake for wet tower make-up water including intake pumps and piping.
- Intake screens.

EPA summed these individual cost elements together to derive the total capital costs for each baseline and compliance scenario. EPA then subtracted the total baseline cost from the total compliance cost to determine the incremental cost of compliance with the final §316(b) New Facility Rule.

EPA concluded that the cooling water flow through the condenser at a given facility to be the same when switching from once-through to wet towers because the design specifications of surface condensers for both types of systems are similar enough that the condenser costs would also be similar. Thus, when comparing wet cooling systems, differences in costs from baseline for the surface condensers were assumed to be zero.

2.3.3 Operation & Maintenance Costs

O&M cost estimates used in calculating the net compliance costs include individual estimates for the following cost components where applicable:

- Operating costs for pumping intake water.
- O&M costs for operating recirculating wet towers.
- O&M cost for operating intake screen technology.
- Annual post-compliance operational monitoring.

EPA summed these individual cost elements together to derive the total O&M costs for each baseline and compliance scenario. EPA then subtracted the total baseline cost from the total compliance cost to determine the incremental cost of compliance with the final §316(b) New Facility Rule.

It should be noted that EPA overcosted the costs of post-compliance operational monitoring, since these costs were also included in the annual administrative costs as described in the ICR and the *Economic Analysis*.

[5] In some states, a cooling pond is considered a water of the U.S. In these states, a plant with such a cooling system would have to comply with the recirculating requirements of the final section 316(b) New Facility Rule. In those states where a cooling pond is not considered a water of the U.S., a plant would not have to comply with the recirculating requirements of this final New Facility Rule. This costing analysis made the conservative assumption that facilities with a cooling pond would have to comply with the recirculating requirements. These facilities were therefore costed as if they had a once-through system in the baseline.

2.3.4 Development of Model Facilities

EPA developed cost estimates for 41 model facilities within three industry categories: coal-fired power plants, combined cycle power plants and manufacturers. These model facilities were developed to reflect a range of potential design intake flows and (for power plants) megawatt (MW) capacities. The methodology for developing model facilities for each of these three industry groups is described in Chapter 1.

2.3.5 Wet Tower Intake Flow Factors

EPA based all model facility flow values, including both intake and cooling water, upon projected intake flows for the baseline technology. When switching from baseline once-through to recirculating wet tower cooling systems, EPA assumed that the recirculating cooling flows through the wet towers would be equivalent to the baseline once-through flows. When either the intake flow or the cooling flow had been projected for wet towers, EPA then calculated the corresponding cooling flow or intake flow using a wet tower make-up water intake flow factor.

EPA used different make-up flow factors for power plants versus manufacturers, as well as for facilities using marine versus freshwater source waters. Since seawater and brackish water in marine cooling water sources have higher dissolved solids (TDS) content than freshwater, the blowdown rate should be higher to avoid the build-up of high TDS in the recirculating water as the cooling water evaporates in the tower. The build-up of high TDS can affect the performance of the cooling system, increase corrosion, and create potential water quality problems for the blowdown discharge. Therefore, the portion of the cooling water that must be removed (blowdown) and replaced is greater for higher TDS source waters. Note that seawater represents the worst-case scenario, but in most cases the intakes within the group of facilities attributed to this water body type will be withdrawing brackish water (i.e., the TDS content will be somewhere between that of seawater and freshwater).

The make-up water must replace all cooling water losses, which include blowdown, evaporation, drift, and other uses. One measure of the blowdown requirement is the "concentration factor," which is the ratio of the concentration of a conservative pollutant, such as TDS, in the blowdown divided by the concentration in the make-up water. For freshwater, the concentration factor can range from 2.0 to 10 (Kaplan 2000) depending on site-specific conditions. For marine sources including brackish and saltwater, the concentration factor can range from 1.5 to 2.0 (Burns and Micheletti 2000).

Cooling Tower Fundamentals (Hensley, 1985) provides a set of equations and default values for estimating the rate of evaporation, drift, and blowdown using the temperature rise (20 °F) and concentration factor. The make-up volume is the sum of these three components. Input values in this calculation include the concentration factor and the temperature rise. The temperature rise used (20 °F) is consistent with the design values used throughout the wet tower cost estimation efforts. Since the estimate was for national average values, the default values for estimating evaporation and drift presented in the reference were used. Table 2-1 provides the calculated make-up and blowdown rates as a percentage of the recirculating flow for different concentration factors ranging from 1.1 to 10.0, for a wet tower with a recirculating rate of 100,000 gpm. Note that the selection of the recirculating flow rate is not important, since the output values are percentages which would be the same regardless of the flow rate chosen.

Table 2-1: Make-Up and Blowdown Volumes for Different Wet Tower Concentration Factors

Concentration Factor	Evaporation[a] (gpm)	Drift[b] (gpm)	Blowdown (gpm)	Blowdown (%)	Make-Up (gpm)	Make-Up (%)
1.1	1600	20	15,980	16.0%	17,600	17.6%
1.2	1600	20	7980	8.0%	9600	9.6%
1.25	1600	20	6380	6.4%	8000	8.0%
1.3	1600	20	5313	5.3%	6933	6.9%
1.5	1600	20	3180	3.2%	4800	4.8%
2	1600	20	1580	1.6%	3200	3.2%
3	1600	20	780	0.8%	2400	2.4%
5	1600	20	380	0.4%	2000	2.0%
10	1600	20	158	0.2%	1778	1.8%

Based on methodology presented in *Cooling Tower Fundamentals* (Hensley 1985).
[a]Evaporation = 0.0008 x Range (°F) x Recirculating Flow (gpm)
[b]Drift = 0.0002 x Recirculating flow (gpm)
Range = 20 °F
Recirculating Flow = 100,000 gpm

To be conservative, EPA selected the lower concentration factor for each of the two ranges of literature values (2.0 for freshwater and 1.5 for marine water). Note that a lower concentration factor results in a higher make-up rate. EPA used the equations presented in Hensley 1985 to derive the make-up water rates that correspond to the selected concentration factors of 1.5 and 2.0. This method generated make-up rates of 3.2 percent and 4.8 percent for freshwater and marine water, respectively. These factors were then compared to intake flow and generating capacity values of existing facilities. The resulting estimated cooling water flow rates were somewhat high for the plant generating capacity. To correct for this observation and to account for site variations and other cooling water uses, EPA increased the calculated make-up factors by approximately 50 percent and rounded off, resulting in factors of 5 percent and 8 percent for freshwater and marine water, respectively. These values produced estimated cooling flow values that were consistent with data from power plants with similar generating capacities.

Manufacturers use cooling water for numerous processes, some of which may not be amenable to use of recirculating wet towers or to reuse/recycle. While wet towers are being used as a model for estimating cooling system water reduction technology costs for manufacturers, the aggregate make-up water rates may be greater due to these limitations. In order to account for these potential limitations, EPA set the make-up rates for manufacturers equal to twice the rate for power plants using similar water source types. Thus, the makeup water rates for manufacturers were estimated at 10 percent and 16 percent for freshwater and marine water, respectively.

2.3.6 Baseline Cost Components

EPA selected the baseline technologies based upon the projected type of baseline cooling system and the type of facility. The type of water body affects the costs, but not the selection of technologies. The basic components and assumptions for each baseline technology are described below:

2.3.7 Baseline Once-through Cooling

- The intake is located near shoreline and water is pumped using constant speed pumps through steel pipes to and from a surface condenser and is then discharged back to the water body. The once-through cost estimate includes the intake structure, pumps and piping costs. The development of these costs is described in greater detail below.
- For all types of power plants, baseline intakes are equipped with traveling screens (without fish handling systems) with an intake velocity of 1.0 fps. For manufacturing facilities, intakes are equipped only with trash racks which were assumed to be included in the cost of the intake system. Cost curve charts at the end of this chapter were used to generate the intake screen cost estimates.

2.3.8 Baseline Recirculating Wet Towers

- The cost estimates are for recirculating wet towers with redwood construction and splash fill. This is not the most common construction material for cooling towers, it represents a median cost for cooling tower construction. The wet tower approach was 10 °F with a temperature rise of 20 °F. Cost curve Charts presented at the end of the chapter were used to generate the wet tower capital cost estimates.
- O&M costs are based on Scenario 1 described in Section 2.2.2.1, in which make-up water is withdrawn from the surface waterbody and blowdown is treated and discharged. Cost curve charts at the end of this chapter was used to generate the wet tower O&M cost estimates.
- EPA assumed that the make-up water volume would be a proportion of the recirculating flow. A separate cost estimate for an appropriately sized cooling water intake with constant speed pumps was added to serve this purpose. EPA developed intake costs in the same manner as for once-though intakes and included costs for an appropriately sized surface condenser.
- For all types of power plants, baseline intakes are equipped with traveling screens (without fish handling systems) with an intake velocity of 1.0 fps. For manufacturing facilities, intakes are equipped only with trash racks which were assumed to be included in the cost of the intake system. Cost curve charts at the end of this chapter were used to generate the intake screen cost estimates.

2.4 COMPLIANCE COST COMPONENTS

2.4.1 Recirculating Wet Towers

- EPA developed costs for recirculating wet towers as the compliance technology using the same assumptions as for baseline recirculating wet tower costs as described above, with the exception of the intake screen technology and the use of variable speed pumps at the intake. All compliance costs included the cost of traveling screens with fish baskets and fish returns with an intake velocity of 0.5 fps at the intake structure. EPA derived costs for traveling screens with fish baskets and fish returns from cost curve data found at the end of this chapter.
- As described above, the make-up water (intake flow) factors used for power plants were 5 percent for freshwater and 8 percent for marine water.

2.4.2 Reuse/recycle

- Water reuse/recycle technologies at manufacturing facilities are expected to produce reductions in intake water use of a similar degree as recirculating wet towers. However, due to the integrated nature and variable uses of cooling water at manufacturing facilities, EPA did not consider the development of a model technology other than recirculating wet towers to be practical. Since it is possible to use recirculating wet towers as a replacement for once-through cooling at manufacturing facilities, the costs for reuse/recycle technologies were estimated to be similar to the cost of using recirculating wet towers. Therefore, at manufacturing facilities, EPA developed the costs for water reuse/recycle and the water intakes using recirculating wet towers as the model. EPA used the same methodology as described above for recirculating wet towers, with the exception that the make-up factors used for reuse/recycle were set at twice the rate used for power plants (10 percent for freshwater and 16 percent for marine water). The higher rate is intended to account for possible limitations in the degree of water use reduction that may be attained by reuse/recycle.

2.5 Cost Estimation Assumptions and Methodology

The assumptions and cost data sources for each of the technologies is described below.

2.5.1 Once-through Capital Costs

The capital costs for the once-through system includes costs for the following:

- Intake structure
- Pumps, pump well, and pump housing
- Piping to and from the condenser
- Service road to the intake structure adjacent to the cooling water pipes

The maximum cooling flow value used to develop the once-through cost equations was 350,000 gpm. If the model facility flow value exceeded this maximum by 10 percent (i.e., $\geq$ 385,000 gpm), EPA costed multiple parallel once-through units. Assumptions for each of the cost components are described below:

Intake Structure

- Size equivalent to a box with one side equal to the area needed for a traveling screen with an intake velocity of 1.0 fps. 10 ft were added to the height and the minimum side dimension was 8 ft. An adjacent pump well was also added.
- Concrete thickness of 1.5 ft.
- Excavated volume equal to 2.5 times box and pump well volume.
- Dredged volume equal to 2.5 times box and pump well volume.
- Installation of temporary bulkhead with 20 ft added to width.
- Installation of temporary sheet piling to shore up excavation equal to 1.5 times side area for intake and pump well.
- Area cleared was assumed to be 6 times intake and pump well area.

Service Road

- The service road for the intake was made of 6-inch thick reinforced concrete, and a 12-ft width was assumed. An estimated length of road (which is also the cooling water piping distance) was assigned to different intake volumes. EPA based the lengths on the cooling water flow, since the cooling water flow should be proportional to the plant size and does not change between types of cooling systems. The cooling flow corresponding to a freshwater system was used in the case of wet towers, since it represented the greatest flow. For intake volumes corresponding to a cooling flow of 500 to 10,000 gpm, a 1,000 ft length was assigned, for >10,000 gpm to 100,000 gpm a 1,500 ft length was used, and for >100,000 gpm a length of 2,000 ft was used.

- Area cleared was assumed to be length times 24 ft.

Pumps and Pump Well

- Assumed 3 pumps with each pump sized at 50 percent of design flow (i.e., one pump served as a back-up). Constant speed pumps were used for baseline costs and variable speed pumps were used for compliance costs.
- Pump installation was set equal to 40 percent to 60 percent of pump and motor costs (60 percent at 500 gpm scaled to 40 percent at 350,000 gpm).
- Pump and motor costs were from vendor quotes based on a 50 ft pumping head. Purchase costs were increased by 15 percent to account for taxes, insurance, and freight.
- Pump housing unit cost was estimated at $130/ft².
- Pump and pump well area was established using the per pump footprints in Table 2-2 below.

Table 2-2: Assumed Pump Pad and Well Area

Pump Design Flow (gpm)	Footprint (ft)
250	5x5
500	5x5
2,500	7x6
5,000	7x7
25,000	10x10
50,000	11x11
175,000	12x12

Piping to and from the Condenser

- Pipe length in one direction is equal to service road length, which is described above. Total length is twice this distance.
- Pipe diameters were selected to correspond to pipe velocities ranging from 6 fps for smaller diameter (i.e., 6 inch) to 12 fps for larger diameter pipe.
- Pipe unit cost ranged from $5.50 /in. dia - ft length for smaller pipe to $7.50 /in. dia - ft length for larger pipe.

Intake Screens

As described in Section 2.2.2.3 above, EPA developed cost curves for intake screens of varying widths. The cost curves for each screen width covered a range of flow volumes that tended to overlap those with larger and smaller widths. For purposes of estimating intake screen costs, EPA sized the intake screens according to intake flow volumes. Table 2-3 below summarizes the screen width sizes that were selected for each intake flow volume for the given technology and design specification. Note that the maximum flow volume listed is approximately 10 percent greater than the maximum cost curve input value. For intake flow volumes that exceeded this maximum value, multiple parallel screens of the maximum width listed are costed.

Table 2-3: Intake Flow Volume Criteria for Screen Width Selection		
Screen Width	Intake Flow for Traveling Screens @ 1.0 fps (gpm)	Intake Flow for Traveling Screens @ 0.5 fps (gpm)
2 - Foot	0 - 10,000	0 - 5,000
5 - Foot	>10,000 - 24,000	>5,000 - 12,000
10 - Foot	>24,000 - 60,000	>12,000 - 30,000
14 - Foot	>60,000 - 220,000	>30,000 - 110,000
Maximum Flow*	220,000	110,000

* Intake volumes above this value were costed for multiple parallel screens using the maximum screen width shown.

Additional Unit Costs

Table 2-4 below summarizes additional unit costs that were used in deriving the capital costs for the items described above.

Table 2-4: Additional Unit Costs			
Cost Item	Unit	Cost/Unit	Comment
Foundation Concrete	Cubic Yard	$259	RS Means Cost Works 2001
Structural Concrete	Cubic Yard	$1,125	Based on 16 in column costs- RS Means Cost Works 2001
Excavation	Cubic Yard	$26	RS Means Cost Works 2001
Bulkhead	Linear foot	$254	RS Means Cost Works 2001
Sheet Piling	Square Foot	$15	RS Means Cost Works 2001
Area Clearing	Acre	$2,975	Clear, grub, cut light trees to 6 in.- RS Means Cost Works 2001
Road Paving	Square Yard	$23.30	Concrete pavement 6 in. thick with reinforcement -RS Means Cost Works 2001

Miscellaneous Costs

EPA factored the following miscellaneous costs into the estimated capital costs as a percentage of the total capital cost. Values were selected from the ranges given in Section 2.2.1.2 above:

- Mobilization and demobilization was estimated to be 3 percent.
- Process engineering was estimated to be 10 percent.
- Contractor overhead and profit are included in the unit cost estimates.
- Electrical was estimated to be 10 percent.
- Site work was estimated to be 10 percent.
- Controls were estimated to be 3 percent.
- The contingency cost was estimated at 10 percent.

2.5.2 Once-through O&M

- The O&M costs are estimated using the cooling water intake pumping energy requirements.
- Pumping head was assumed to be 50 ft for all systems.
- Pump and motor efficiency was 70 percent.
- Annual hours of operation was assumed to be 7860.
- Energy cost was estimated at $0.08/KWH. Note that this value is set near the average consumer costs and is higher than the energy cost to the power plant. This overestimation of the unit energy cost is intended to account for other O&M costs, such as for intake cleaning and maintenance and pumping equipment maintenance, that are not included as separate items.

2.5.3 Recirculating Wet Tower Capital Costs

- For wet towers, it is assumed that recirculating (i.e., cooling) flow would be same as baseline once-through flow.
- Capital costs for the recirculating wet tower include costs for all basic tower components, such as structure, foundation, wiring, piping and recirculating pump costs. Wet tower costs are based on cost data for redwood towers with splash fill and an approach of 10 °F taken from chart at the end of this chapter.
- The maximum cooling flow value used to develop the wet tower cost equations (both Capital and O&M) was 204,000 gpm. If the model facility flow value exceeded this maximum by 10 percent (i.e., > 225,000 gpm), EPA costed multiple parallel wet tower units.
- Costs include installing an inlet structure and pumps using the same assumptions as the once-through intake, except they are sized based on the make-up water requirements described above. Similarly, EPA developed the pipe and service road lengths using same method as for once-through intakes except that road and piping length were based on a recirculating flow corresponding to a freshwater system.

2.5.4 Wet Tower O&M Cost

- Wet tower O&M costs have two components; one for the intake and one for the wet tower. EPA took wet tower O&M costs from cost charts at the end of this chapter. Intake O&M costs were based on intake pumping energy requirements in a similar manner as for once-through pumping described above.
- EPA based the intake O&M costs on cooling water intake pumping energy requirements using the same cost assumptions as for the once-through O&M costs. As with the once-through costs, the energy costs were inflated to account for O&M costs in addition to the pumping energy requirements.

2.6 ALTERNATIVE REGULATORY OPTIONS

In addition to the preferred two-track option adopted for the final §316(b) New Facility Rule, EPA also developed facility-level cost estimates for several additional options that EPA considered but did not adopt for the final rule. These additional regulatory options include the following:

- Option 1: Technology-Based Performance Requirements for Different Types of Waterbodies. Under this option, only facilities located on marine waterbodies would be required to reduce intake flow commensurate with the level that can be achieved using a closed-cycle recirculating wet cooling system. For all other waterbody types, the only capacity requirements would be proportional flow reduction requirements. In all waterbodies, velocity limits and a requirement to study, select and install design and construction technologies would apply.

- Option 2A: Flow Reduction Commensurate with the Level Achieved by Closed-Cycle Recirculating Wet Cooling Systems. Under this option, all facilities would be required to reduce intake flow commensurate with the level that can be achieved using a closed-cycle recirculating cooling water system, regardless of the type of waterbody from which they withdraw cooling water. In addition, facilities would need to meet velocity limits, comply with proportional flow requirements, and study, select and install design and construction technologies.

- Option 2B: Flow Reduction Commensurate with the Level Achieved by Use of a Dry Cooling System. Under this option, all steam electric power plants would be required to reduce intake flow commensurate with zero or very low-level intake (i.e., dry cooling). Manufacturing facilities would be required to comply with the national requirement of capacity reduction based on closed-cycle recirculating wet cooling. This option does not distinguish between facilities on the basis of the waterbody from which they withdraw cooling water.

- Option 3: Industry Two-Track Option. Under this option, an applicant choosing Track I would install "highly protective" technologies in return for expedited permitting without the need for pre-operational or operational studies in the source waterbody. Such fast-track technologies might include technologies that reduce intake flow to a level commensurate with closed-cycle recirculating wet cooling and that achieve an average approach velocity of no more than 0.5 ft/s, or any technologies that achieve a level of protection from impingement and entrainment within the expected range for a closed-cycle recirculating wet cooling system. Examples of candidate technologies include: (a) wedgewire screens, where there is constant flow, as in rivers; (b) traveling fine mesh screens with a fish return system designed to minimize impingement and entrainment; and (c) aquatic filter barrier systems, at sites where they would not be rendered ineffective by high flows or fouling. Track II would provide an applicant who does not want to commit to any of the above technology options with an opportunity to demonstrate that site-specific characteristics would justify another cooling water intake structure technology, such as once-through cooling.

EPA used the same model facilities and baseline technologies that were used for the preferred two-track option to develop cost estimates for the alternative regulatory options. In general, EPA used the same assumptions as described above when developing cost estimates for the alternative regulatory options. Exceptions are noted below for each of the alternative regulatory options.

2.6.1 Option 1: Technology-Based Performance Requirements for Different Types of Waterbodies

Freshwater Facilities

- Compliance cooling system remains the same as baseline, but with variable speed intake pumps.
- Compliance intake screen technology consists of traveling screens with fish handling features with an intake velocity of 0.5 fps.

Marine Facilities

- Compliance cooling system consists of recirculating wet towers with variable speed intake pumps.
- Compliance intake screen technology consists of traveling screens with fish handling features with an intake velocity of 0.5 fps.

Administrative costs for this option will differ from the preferred two-track option, as noted in the *Economic Analysis*.

2.6.2 Option 2A: Flow Reduction Commensurate with the Level Achieved by Closed-Cycle Recirculating Wet Cooling Systems

Compliance technologies for this option are the same as for the preferred two-track option adopted in the final rule. Therefore, EPA did not develop separate capital and O&M costs for this option. Administrative costs for this option will differ from the administrative costs for the preferred two-track option, as noted in the *Economic Analysis*.

2.6.3 Option 2B: Flow Reduction Commensurate with the Level Achieved by Use of a Dry Cooling System

Power Plants

- Compliance cooling system consists of dry cooling towers (air cooled condensers).
- No surface water intakes are needed.

Manufacturing Facilities

- Compliance cooling system consists of recirculating wet towers with variable speed intake pumps.
- Compliance intake screen technology consists of traveling screens with fish handling features with an intake velocity of 0.5 fps.

Capital Costs

The use of air cooled condensers (dry cooling system) instead of wet cooling involves the substitution of the surface condenser as well as the cold water system. Thus, the cost of surface condensers needs to be included in the baseline capital costs for once-through and wet tower cooling systems for this option. For baseline once-through systems, EPA incorporated the condenser capital costs into the cooling system cost component that includes intake structure, pumps, pipes, etc. For baseline wet towers, EPA incorporated the condenser costs into the intake system cost component that includes intake structure, pumps, pipes, etc. In the case of wet tower intake costs, the cost equation uses the intake flow as the input variable. Since the condenser cost is based on the cooling water flow, EPA developed a separate intake/condenser cost curve for each scenario that uses a different make-up water factor. For the dry cooling compliance systems, EPA included the air cooled condenser cost in the cooling cost.

Wet Cooling Surface Condensers

- EPA obtained equipment costs for condensers sized to handle 12 cooling flow values ranging from 4,650 gpm to 329,333 gpm from a condenser manufacturer (Graham Corporation). Condenser capital costs include an air removal package plus accessories.
- Condenser installation was set equal to 40 percent to 60 percent of condenser equipment costs (60 percent at 500 gpm scaled to 40 percent at 350,000 gpm).

Air Cooled Condensers

- Costs for dry cooling are based on steel towers sized to handle the equivalent heat rejection rate of the replaced cooling water flow. This conversion is factored into the cost formula, which uses the replaced cooling water flow as the input variable. Development of the unit costs and cost curves for dry cooling systems is discussed in Chapter 4 of this document.
- Dry cooling systems do not require water intakes.

O&M Costs

While EPA explicitly included consideration of surface condenser costs in the capital cost estimates where dry cooling systems were involved, EPA did not directly incorporate corresponding costs for operation and maintenance of the surface condensers into the O&M costs. In general, O&M costs for the condensers will involve maintenance only, since the condensers are static and any energy or other consumable material is already considered in other cost components. Some maintenance, including cleaning of fouled tubes and replacement of damaged tubes may be necessary. However, EPA has concluded that such costs are a small portion of baseline operation of a power plant and would be similarly offset with O & M costs of drying cooling condenser tubes.

2.6.4 Option 3: Industry Proposed Two-Track Option

Facilities with Baseline Once-through Cooling

- Compliance cooling system consists of once-through cooling with variable speed intake pumps.
- Compliance intake screen technology consists of wedgewire (passive) screens with an intake velocity of 0.5 fps.

Facilities with Baseline Recirculating Wet Towers

- Compliance cooling system consists of recirculating wet towers with variable speed intake pumps.
- Compliance intake screen technology consists of traveling screens with fish handling features with an intake velocity of 0.5 fps.

Wedgewire (Passive) Screens

- Where applicable, compliance costs included the cost of wedgewire (passive) screens at the intake structure. Intake velocity was 0.5 fps.
- Costs for passive screens were derived from cost curve data presented at the end of this chapter.
- Table 2-5 below summarizes the screen width sizes that were selected for each intake flow volume for the given technology and design specification. Note that the maximum flow volume listed is approximately 10 percent greater than the maximum cost curve input value. For intake flow volumes that exceeded this maximum value, multiple parallel screens of the maximum width listed are costed.

Table 2-5: Intake Flow Volume Criteria for Screen Width Selection

Screen Width	Intake Flow for Wedgewire Screens @ 0.5 fps (gpm)
2 - Foot	0 - 5,000
5 - Foot	>5,000 - 12,000
10 - Foot	>12,000 - 25,000
Maximum Flow*	25,000

* Intake volumes above this value were costed for multiple parallel screens using the maximum screen width shown.

Administrative costs for this option will differ from the administrative costs for the preferred two-track option, as noted in the *Economic Analysis*.

2.7 Summary of Costs by Regulatory Option

2.7.1 Final Rule

Table 2-6 summarizes the baseline, compliance and net technology costs for each model facility for the preferred two-track option adopted for the final rule. These costs are presented in 1999 dollars. For the *Economic Analysis*, EPA escalated these values to 2000 dollars. Note that not all of the manufacturing model facility costs are used in the economic analysis model.

Table 2-6: Baseline, Compliance and Incremental Technology Costs for Model Facilities Preferred Two-Track Option (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
Coal-Fired Power Plants:						
Coal OT/FW-1	$2,310,000	$389,000	$3,766,000	$600,000	$1,456,000	$211,000
Coal OT/FW-2	$9,991,000	$2,522,000	$19,967,000	$3,423,000	$9,976,000	$901,000
Coal OT/FW-3	$33,411,000	$9,280,000	$68,135,000	$12,141,000	$34,724,000	$2,861,000
Coal R/M-1	$25,265,000	$4,396,000	$25,739,000	$4,484,000	$474,000	$88,000
Coal R/FW-1	$5,546,000	$849,000	$5,641,000	$919,000	$95,000	$70,000
Coal R/FW-2	$19,148,000	$3,241,000	$19,365,000	$3,311,000	$217,000	$70,000
Coal R/FW-3	$66,928,000	$11,970,000	$67,698,000	$12,054,000	$770,000	$84,000
Coal RL/FW-1	$11,372,000	$3,219,000	$24,585,000	$4,296,000	$13,213,000	$1,077,000
Combined Cycle Power Plants:						
CC OT/M-1	$15,989,000	$3,673,000	$28,273,000	$4,979,000	$12,284,000	$1,306,000
CC R/M-1	$5,796,000	$890,000	$5,911,000	$971,000	$115,000	$81,000
CC R/M-2	$10,936,000	$1,819,000	$11,133,000	$1,899,000	$197,000	$80,000
CC R/FW-1	$9,650,000	$1,585,000	$9,776,000	$1,655,000	$126,000	$70,000
CC R/FW-2	$10,968,000	$1,831,000	$11,106,000	$1,902,000	$138,000	$71,000
CC R/FW-3	$12,999,000	$2,223,000	$13,157,000	$2,294,000	$158,000	$71,000
Manufacturing Facilities:						
MAN OT/FW-2621	$1,012,000	$141,000	$1,871,000	$281,000	$859,000	$140,000
MAN OT/M-2812	$6,420,000	$1,556,000	$13,717,000	$2,349,000	$7,297,000	$793,000
MAN OT/FW-2812	$2,814,000	$552,000	$5,450,000	$877,000	$2,636,000	$325,000
MAN R/FW-2812	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000
MAN OT/FW-2819	$875,000	$112,000	$1,598,000	$236,000	$723,000	$124,000
MAN R/FW-2819	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/M-2819	$1,094,000	$159,000	$2,117,000	$328,000	$1,023,000	$169,000
MAN OT/FW-2821	$2,419,000	$458,000	$4,639,000	$741,000	$2,220,000	$283,000
MAN R/FW-2821	$7,367,000	$1,175,000	$7,616,000	$1,254,000	$249,000	$79,000
MAN OT/M-2821	$1,172,000	$176,000	$2,277,000	$354,000	$1,105,000	$178,000
MAN OT/FW-2834	$848,000	$106,000	$1,550,000	$228,000	$702,000	$122,000
MAN R/FW-2834	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/FW-2869	$1,440,000	$235,000	$2,713,000	$419,000	$1,273,000	$184,000
MAN OT/M-2869	$1,067,000	$153,000	$2,062,000	$319,000	$995,000	$166,000
MAN R/FW-2869	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000
MAN OT/FW-2873	$1,253,000	$194,000	$2,342,000	$358,000	$1,089,000	$164,000
MAN R/FW-2873	$13,997,000	$2,424,000	$14,435,000	$2,506,000	$4,380,000	$82,000
MAN R/FW-2911	$4,564,000	$683,000	$4,743,000	$758,000	$179,000	$75,000
MAN OT/FW-2911	$3,079,000	$617,000	$5,959,000	$966,000	$2,880,000	$349,000
MAN OT/FW-3312	$3,527,000	$728,000	$6,866,000	$1,123,000	$3,339,000	$395,000

Table 2-6: Baseline, Compliance and Incremental Technology Costs for Model Facilities Preferred Two-Track Option (1999 $)						
Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
MAN R/FW-3312	$35,922,000	$6,664,000	$39,993,000	$7,000,000	$4,071,000	$336,000
MAN OT/FW-3316	$985,000	$135,000	$1,815,000	$272,000	$830,000	$137,000
MAN R/FW-3316	$6,449,000	$1,012,000	$6,711,000	$1,092,000	$262,000	$80,000
MAN OT/FW-3317	$1,414,000	$229,000	$2,658,000	$410,000	$1,244,000	$181,000
MAN R/FW-3317	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000
MAN OT/FW-3353	$1,306,000	$206,000	$2,445,000	$375,000	$1,139,000	$169,000
MAN R/FW-3353	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000

2.7.2 Option 1: Technology-Based Performance Requirements for Different Types of Waterbodies

Table 2-7 summarizes the baseline, compliance and net technology costs for each model facility for alternative regulatory Option 1. These costs are presented in 1999 dollars. For the *Economic Analysis*, EPA escalated these values to 2000 dollars. Note that not all of the manufacturing model facility costs are used in the economic analysis model.

Table 2-7: Baseline, Compliance and Incremental Technology Costs for Model Facilities Option 1 (1999 $)						
Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
Coal-Fired Power Plants:						
Coal OT/FW-1	$2,310,000	$389,000	$2,964,000	$470,000	$654,000	$81,000
Coal OT/FW-2	$9,991,000	$2,522,000	$14,110,000	$2,689,000	$4,119,000	$167,000
Coal OT/FW-3	$33,411,000	$9,280,000	$49,121,000	$9,741,000	$15,710,000	$461,000
Coal R/M-1	$25,265,000	$4,396,000	$25,739,000	$4,484,000	$474,000	$88,000
Coal R/FW-1	$5,546,000	$849,000	$5,641,000	$919,000	$95,000	$70,000
Coal R/FW-2	$19,148,000	$3,241,000	$19,365,000	$3,311,000	$217,000	$70,000
Coal R/FW-3	$66,928,000	$11,970,000	$67,698,000	$12,054,000	$770,000	$84,000
Coal RL/FW-1	$11,372,000	$3,219,000	$16,733,000	$3,423,000	$5,361,000	$204,000
Combined Cycle Power Plants:						
CC OT/M-1	$15,989,000	$3,673,000	$28,273,000	$4,979,000	$12,284,000	$1,306,000
CC R/M-1	$5,796,000	$890,000	$5,911,000	$971,000	$115,000	$81,000
CC R/M-2	$10,936,000	$1,819,000	$11,133,000	$1,899,000	$197,000	$80,000
CC R/FW-1	$9,650,000	$1,585,000	$9,776,000	$1,655,000	$126,000	$70,000
CC R/FW-2	$10,968,000	$1,831,000	$11,106,000	$1,902,000	$138,000	$71,000
CC R/FW-3	$12,999,000	$2,223,000	$13,157,000	$2,294,000	$158,000	$71,000
Manufacturing Facilities:						
MAN OT/FW-2621	$1,012,000	$141,000	$1,386,000	$221,000	$374,000	$80,000

Table 2-7: Baseline, Compliance and Incremental Technology Costs for Model Facilities Option 1 (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
MAN OT/M-2812	$6,420,000	$1,556,000	$13,717,000	$2,349,000	$7,297,000	$793,000
MAN OT/FW-2812	$2,814,000	$552,000	$4,058,000	$657,000	$1,244,000	$105,000
MAN R/FW-2812	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000
MAN OT/FW-2819	$875,000	$112,000	$1,193,000	$190,000	$318,000	$78,000
MAN R/FW-2819	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/M-2819	$1,094,000	$159,000	$2,117,000	$328,000	$1,023,000	$169,000
MAN OT/FW-2821	$2,419,000	$458,000	$3,484,000	$558,000	$1,065,000	$100,000
MAN R/FW-2821	$7,367,000	$1,175,000	$7,616,000	$1,254,000	$249,000	$79,000
MAN OT/M-2821	$1,172,000	$176,000	$2,277,000	$354,000	$1,105,000	$178,000
MAN OT/FW-2834	$848,000	$106,000	$1,154,000	$183,000	$306,000	$77,000
MAN R/FW-2834	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/FW-2869	$1,440,000	$235,000	$1,984,000	$320,000	$544,000	$85,000
MAN OT/M-2869	$1,067,000	$153,000	$2,062,000	$319,000	$995,000	$166,000
MAN R/FW-2869	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000
MAN OT/FW-2873	$1,253,000	$194,000	$1,723,000	$277,000	$470,000	$83,000
MAN R/FW-2873	$13,997,000	$2,424,000	$14,435,000	$2,506,000	$438,000	$82,000
MAN R/FW-2911	$4,564,000	$683,000	$4,743,000	$758,000	$179,000	$75,000
MAN OT/FW-2911	$3,079,000	$617,000	$4,448,000	$724,000	$1,369,000	$107,000
MAN OT/FW-3312	$3,527,000	$728,000	$5,122,000	$841,000	$1,595,000	$113,000
MAN R/FW-3312	$38,851,000	$6,898,000	$39,993,000	$7,000,000	$1,142,000	$102,000
MAN OT/FW-3316	$985,000	$135,000	$1,348,000	$215,000	$363,000	$80,000
MAN R/FW-3316	$6,449,000	$1,012,000	$6,674,000	$1,089,000	$225,000	$77,000
MAN OT/FW-3317	$1,414,000	$229,000	$1,947,000	$314,000	$533,000	$85,000
MAN R/FW-3317	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000
MAN OT/FW-3353	$1,306,000	$206,000	$1,798,000	$289,000	$492,000	$83,000
MAN R/FW-3353	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000

2.7.3 Option 2A: Flow Reduction Commensurate with Closed-Cycle recirculating Wet Cooling Systems

Baseline, compliance and incremental technology capital and O&M costs for this option are the same as for the preferred two-track option.

2.7.4 Option 2B: Flow Reduction Commensurate with Dry Cooling Systems

Table 2-8 summarizes the baseline, compliance and net technology costs for each model facility for alternative regulatory Option 2B. These costs are presented in 1999 dollars. For the *Economic Analysis*, EPA escalated these values to 2000 dollars.

Table 2-8: Baseline, Compliance and Incremental Technology Costs for Model Facilities Option 2B (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
Coal-Fired Power Plants:						
Coal OT/FW-1	$3,757,000	$389,000	$9,397,000	$2,363,000	$5,640,000	$1,974,000
Coal OT/FW-2	$17,139,000	$2,522,000	$62,634,000	$11,427,000	$45,495,000	$8,905,000
Coal OT/FW-3	$59,509,000	$9,280,000	$234,182,000	$38,505,000	$174,673,000	$29,225,000
Coal R/M-1	$34,738,000	$4,396,000	$79,792,000	$16,882,000	$45,054,000	$12,486,000
Coal R/FW-1	$7,643,000	$849,000	$14,892,000	$3,669,000	$7,249,000	$2,820,000
Coal R/FW-2	$26,241,000	$3,241,000	$60,315,000	$11,173,000	$34,074,000	$7,932,000
Coal R/FW-3	$94,286,000	$11,970,000	$232,222,000	$38,355,000	$137,936,000	$26,385,000
Coal RL/FW-1	$20,397,000	$3,219,000	$81,323,000	$13,074,000	$60,926,000	$9,855,000
Combined Cycle Power Plants:						
CC OT/M-1	$26,663,000	$3,673,000	$93,582,000	$13,790,000	$66,919,000	$10,117,000
CC R/M-1	$7,933,000	$590,000	$15,277,000	$3,757,000	$7,344,000	$2,867,000
CC R/M-2	$14,985,000	$1,819,000	$32,319,000	$7,177,000	$17,334,000	$5,358,000
CC R/FW-1	$13,298,000	$1,585,000	$28,513,000	$6,486,000	$15,215,000	$4,901,000
CC R/FW-2	$15,137,000	$1,831,000	$33,374,000	$7,362,000	$18,237,000	$5,531,000
CC R/FW-3	$18,025,000	$2,223,000	$41,410,000	$8,677,000	$23,385,000	$6,454,000

Baseline, compliance and incremental technology capital and O&M costs for manufacturing facilities for this option are the same as for the preferred two-track option.

2.7.5 Option 3: Industry Two-Track Option

Table 2-9 summarizes the baseline, compliance and net technology costs for each model facility for alternative regulatory Option 2B. These costs are presented in 1999 dollars. For the *Economic Analysis*, EPA escalated these values to 2000 dollars. Note that not all of the manufacturing model facility costs are used in the economic analysis model.

Table 2-9: Baseline, Compliance and Incremental Technology Costs for Model Facilities Option 3 (1999 $)

Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
Coal-Fired Power Plants:						
Coal OT/FW-1	$2,310,000	$389,000	$2,595,000	$440,000	$285,000	$51,000
Coal OT/FW-2	$9,991,000	$2,522,000	$12,178,000	$2,530,000	$2,187,000	$8,000
Coal OT/FW-3	$33,411,000	$9,280,000	$41,751,000	$9,168,000	$8,340,000	$0*
Coal R/M-1	$25,265,000	$4,396,000	$25,739,000	$4,484,000	$474,000	$88,000
Coal R/FW-1	$5,546,000	$849,000	$5,641,000	$919,000	$95,000	$70,000
Coal R/FW-2	$19,148,000	$3,241,000	$19,365,000	$3,311,000	$217,000	$70,000
Coal R/FW-3	$66,928,000	$11,970,000	$67,698,000	$12,054,000	$770,000	$84,000
Coal RL/FW-1	$11,372,000	$3,219,000	$14,247,000	$3,219,000	$2,875,000	$0*
Combined Cycle Power Plants:						
CC OT/M-1	$15,989,000	$3,673,000	$19,289,000	$3,677,000	$3,300,000	$4,000
CC R/M-1	$5,796,000	$890,000	$5,911,000	$971,000	$115,000	$81,000
CC R/M-2	$10,936,000	$1,819,000	$11,133,000	$1,899,000	$197,000	$80,000
CC R/FW-1	$9,650,000	$1,585,000	$9,776,000	$1,655,000	$126,000	$70,000
CC R/FW-2	$10,968,000	$1,831,000	$11,106,000	$1,902,000	$138,000	$71,000
CC R/FW-3	$12,999,000	$2,223,000	$13,157,000	$2,294,000	$158,000	$71,000
Manufacturing Facilities:						
MAN OT/FW-2621	$1,012,000	$141,000	$1,229,000	$206,000	$217,000	$65,000
MAN OT/M-2812	$6,420,000	$1,556,000	$8,632,000	$1,631,000	$2,212,000	$75,000
MAN OT/FW-2812	$2,814,000	$552,000	$3,608,000	$617,000	$794,000	$65,000
MAN R/FW-2812	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000
MAN OT/FW-2819	$875,000	$112,000	$1,059,000	$177,000	$184,000	$65,000
MAN R/FW-2819	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/M-2819	$1,094,000	$159,000	$1,331,000	$234,000	$237,000	$75,000
MAN OT/FW-2821	$2,419,000	$458,000	$3,108,000	$523,000	$689,000	$65,000
MAN R/FW-2821	$7,367,000	$1,175,000	$7,616,000	$1,254,000	$249,000	$79,000
MAN OT/M-2821	$1,172,000	$176,000	$8,632,000	$1,631,000	$2,212,000	$75,000
MAN OT/FW-2834	$848,000	$106,000	$1,025,000	$171,000	$177,000	$65,000
MAN R/FW-2834	$1,572,000	$175,000	$1,655,000	$246,000	$83,000	$71,000
MAN OT/FW-2869	$1,440,000	$235,000	$1,821,000	$300,000	$381,000	$65,000
MAN OT/M-2869	$1,067,000	$153,000	$1,297,000	$228,000	$230,000	$75,000
MAN R/FW-2869	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000

Table 2-9: Baseline, Compliance and Incremental Technology Costs for Model Facilities Option 3 (1999 $)						
Model Facility ID	Baseline		Compliance		Incremental	
	Capital	O&M	Capital	O&M	Capital	O&M
MAN OT/FW-2873	$1,253,000	$194,000	$1,528,000	$259,000	$275,000	$65,000
MAN R/FW-2873	$13,997,000	$2,424,000	$14,435,000	$2,506,000	$438,000	$82,000
MAN R/FW-2911	$4,564,000	$683,000	$4,743,000	$758,000	$179,000	$75,000
MAN OT/FW-2911	$3,079,000	$617,000	$3,945,000	$682,000	$866,000	$65,000
MAN OT/FW-3312	$3,527,000	$728,000	$4,577,000	$793,000	$1,050,000	$65,000
MAN R/FW-3312	$38,851,000	$6,898,000	$39,993,000	$7,000,000	$1,142,000	$102,000
MAN OT/FW-3316	$985,000	$135,000	$1,195,000	$200,000	$210,000	$65,000
MAN R/FW-3316	$6,449,000	$1,012,000	$6,674,000	$1,089,000	$225,000	$77,000
MAN OT/FW-3317	$1,414,000	$229,000	$1,787,000	$294,000	$373,000	$65,000
MAN R/FW-3317	$2,589,000	$346,000	$2,713,000	$419,000	$124,000	$73,000
MAN OT/FW-3353	$1,306,000	$206,000	$1,595,000	$271,000	$289,000	$65,000
MAN R/FW-3353	$3,586,000	$515,000	$3,749,000	$590,000	$163,000	$75,000

*For this model facility, O&M costs for wedgewire screens are actually less than the O&M costs for the baseline traveling screens. To be conservative, EPA has set the incremental O&M cost at $0; this does not reflect potential savings to the facility associated with switching intake screen types.

2.8 Technology Unit Costs

2.8.1 General Cost Information

The cost estimates presented in this analysis include both capital costs and operations and maintenance (O&M) costs and are for primary technologies such as traveling screens and cooling towers. Facilities may install these technologies to meet requirements of the final §316(b) New Facility Rule. Cooling tower cost estimates are presented for various types of cooling towers including towers fitted with features such as plume abatement and noise reduction. Estimated costs for traveling screens were developed mainly from cost information provided by vendors. The cost of installing other CWIS technologies such as passive screens and velocity caps are calculated by applying a cost factor based on the cost of traveling screens. All of the base cost estimates are for new sources.

To provide a relative measurement of the differences in cost across technologies, costs need to be developed on a uniform basis. The cost for many of the CWIS and flow reduction technologies depends on many factors, including site-specific conditions, and the relative importance of many of these factors varies from technology to technology. The factor that is most relevant is the total flow. Therefore, EPA selected total flow as the factor on which to base unit costs and thus use for basic cost comparisons. EPA developed cost estimates, in $/gallons per minute (gpm), for most of the technologies for use at a range of different total intake flow volumes. For cooling towers, EPA developed cost estimates for use at a range of different total recirculating flow volumes.

EPA assumed average values or typical situations for the other factors that also impact the cost components. For example, EPA assumed an average debris level and an intake flow velocity of 0.5 feet per second (fps); EPA also used 1.0 fps for cost comparison purposes. EPA separately assessed the cost effect of variations from these average conditions as add-on costs. For instance, if the water being drawn in has a high debris level, this would tend to increase cost by about 20 percent.

EPA determined the specifications for each factor based on a review of information about the characteristics most likely to be encountered at a typical facility withdrawing cooling water. Cost factors used in this analysis and the assumed values/scenarios are listed below in Table 2-10. EPA's unit cost estimates for the selected technologies are based on the information provided by vendors, industry representative, and published documents.

Table 2-10. Basis for Development of Unit Costs

Base Factor for Developing Unit Costs	Assumed Values of Other Factors for Base Costs
Costs were developed for flows of: [1] < 10,000 gpm - 4 flows 10,000 to < 100,000 gpm - 20 flows 100,000 to 200,000 gpm - 4 flows > 200,000 gpm - 1 flow.	Intake flow velocity = 0.5 fps, and 1.0 fps for comparison Amount and type of debris = average/typical Water quality = fresh water Waterbody flow velocity = moderate flow Accessability to intake = average/typical (no dredging needed, use of crane possible)
Cost Elements	
Cost estimates of screens include non-metallic fish handling panels, a spray system, a fish trough, housings and transitions, continuous operating features (intermittent operation feature for traveling screens without fish baskets), a drive unit, frame seals, engineering, and installation. EPA separately estimated costs for spray wash pumps, permitting, and pilot studies. Cooling towers cost estimates are based on unit costs that include all costs associated with the design, construction, and commissioning of a standard fill cooling tower. Costs of cooling towers with various features, building materials, and types are calculated based on cost comparisons with standard cooling towers. O&M costs were estimated for each type of technology. These costs were estimated, in part, using a percent of capital costs as a basis and considering additional factors.	
Potential Add-Ons to Cost	
Amount and type of debris = high or need for smaller than typical openings Depth of waterbody = particularly shallow or deep Water quality = salt or brackish water (extra cost for non-corrosive material for device and shorter life expectancy/higher replacement cost) Waterbody flow velocity = stagnant or rapidly moving Accessability to intake = cost of difficult installation (extra cost for dredging, extra cost for unusual installation due to site-specific conditions) Existing intake structure = costs associated with retrofit and what existing structure(s) or conditions would cause the extra costs. For example, if an existing structure has an intake flow of 2.0 fps and the intake velocity will be reduced to 0.5 fps with a new device, additional equipment or changes to other equipment/structures of that part of the intake system may increase capital costs (albeit minimally) when compared to installing a new system.	
1) Cost estimates were developed for selected flows in each range (e.g., 4 different flows less than 10,000 gpm). 10,000 gpm = 14.4 MGD	

The costs estimated for fish protection equipment are linked to both flow rates and intake width and depth. Cooling towers costs are based on the recirculating flow rate, temperature approach (defined later), and the type of cooling tower. Several industry representatives provided information on how they conduct preliminary cost estimates for cooling towers. This is considered to be the "rule of thumb" in costing cooling towers (i.e., $/gallons per minute). Regional variations in costs do exist. However, EPA has based its cost estimates on average flow designs representing model facilities. EPA often used conservative (i.e. high cost) assumptions in order to develop model facility costs that accurately represent average costs applicable to affected facilities across the country. In addition to the costs presented below, cost curves and equations are provided at the end of this chapter. The cost curves and equations can be used to estimate costs for implementing technologies or taking actions for facilities across a range of intake flows. Additional supporting information can be found in *Cost Research and Analysis of Cooling Water Technologies for 316(b) Regulatory Options* (SAIC, 2000).

2.8.2 Flow

EPA determined preliminary intake flow values for the base factor based on data from the ICR (Information Collection Request) for the §316(b) industry questionnaire, a sampling of responses to the §316(b) industry screener questionnaire, a Utility Data Institute database (UDI, 1995), and industry brochures and technology background papers.[6] Data from these sources represent utility and nonutility steam electric facilities and industrial facilities that could be subject to prospective §316(b) requirements and are provided in Table 2-11. EPA used these data to determine the range of typical intake flows for these types of facilities to ensure that the flows included in the cost estimates were representative. Through data provided by equipment vendors, EPA determined the flows typically handled by available CWIS equipment and cooling towers. Facilities with greater flows would generally either use multiple screens, towers, or other technologies, or use a special design. Considering this information together, EPA selected flows for various screen sizes, water depths, and intake velocities for use in collecting cost data directly from industry representatives.

Table 2-11. Flow Data for Unit Costs

ICR (average intake flows by utility/industry category)			
Steam electric utilities:	178 MGD (124,000 gpm) for 1,093 facilities		
Steam electric non-utilities:	2.8 MGD (1,944 gpm) for 1,158 facilities		
Chemicals & allied products:	0.339 MGD (235 gpm) for 22,579 facilities		
Primary metals:	0.327 MGD (227 gpm) for 10,999 facilities		
Petroleum & coal products:	0.461 MGD (320 gpm) for 3,509 facilities		
Paper & allied products:	0.148 MGD (103 gpm) for 9,881 facilities		
UDI Database (design intake flow for steam electric utilities) (UDI, 1995)			
Up to 11,219 gpm (16.15 MGD)	401 units		
11,220-44,877 gpm (16.16-64.62 MGD)	465 units		
44,878-134,630 gpm (64.63-193.9 MGD)	684 units		
134,631-448,766 gpm (194-646.2 MGD)	453 units		
More than 448,766 gpm (646.2 MGD)	68 units		
Sampling of Responses from Industry Screener Questionnaire (daily intake flow for non-utilities)			
Up to 0.5 MGD (347 gpm)	6 facilities	>20-30.0 MGD (13,890-20,833 gpm)	2 facilities
>0.5-1.0 MGD (348-694 gpm)	1 facilities	>30-40.0 MGD (20,834-27,778 gpm)	2 facilities
>1-5.0 MGD (695-3,472 gpm)	3 facilities	>40-50.0 MGD (27,779-34,722 gpm)	1 facility
>5.0-10.0 MGD (3,473-6,944 gpm)	8 facilities	>50-100.0 MGD (34,723-69,444 gpm)	0 facilities
>10-20.0 MGD (6,945-13,889 gpm)	2 facilities	>100 MGD (>69,444 gpm)	1 facility
US Filter/Johnson Screens Brochure (ranges for flow definitions) (US Filter, 1998)			
Low flow:	200 to 4,000 gpm (0.288 to 5.76 MGD)		
Intermediate flow:	1,500 to 15,000 gpm (2.16 to 21.6 MGD)		
High flow:	5,000 to 30,000 gpm (7.2 to 43.2 MGD)		
Background Technology Papers (SAIC, 1994; SAIC, 1996)			
"Relatively low intake flow":	1-30 MGD (694-20,833 gpm)		
"Relatively small quantities of water":	up to 50,000 gpm (70 MGD)		

[6]EPA sent the *Industry Screener Questionnaire: Phase I Cooling Water Intake Structures* to about 2,500 steam electric non-utility power producers and manufacturers. This sample included most of the non-utility power producers that were identified by EPA and a subset of the identified manufacturers in industry groups that EPA determined use relatively large quantities of cooling water.

2.8.3 Additional Cost Considerations Included in the Analysis

The cost estimates include costs, such as design/engineering, process equipment, and installation, that are clearly part of getting a CWIS structure or cooling tower in place and operational. However, there are additional associated capital costs that may be less apparent but may also be incurred by a facility and have been included in the cost estimates either as stand-alone cost items or included in installation and construction costs. EPA included the following costs as part of the unit cost estimates:

Mobilization and demobilization,
Architectural fees,
Contractor's overhead and profit,
Process engineering,
Sitework and yard piping,
Standby power,
Electrical allowance,
Instrumentation and controls, and
Contingencies.
Installation.

Following is a brief description of these miscellaneous capital cost items to provide an indication of their general effect on capital costs. These descriptions are also intended to help economists adjust costs to account for regional variations within the U.S. EPA notes that for the costs of cooling towers, each of these items is included the total installed capital costs estimates, but these specific items are not necessarily itemized due to EPA's use of a total inclusive cost per gallon estimate for cooling towers.

Mobilization and Demobilization

Mobilization and demobilization costs are costs incurred by the contractor to assemble crews and equipment on-site and to dismantle semi-permanent and temporary construction facilities once the job is completed. The equipment that may be needed includes backhoes, bulldozers, front-end loaders, self-propelled scrapers, pavers, pavement rollers, sheeps-foot rollers, rubber tire rollers, cranes, temporary generators, trucks (including water and fuel trucks), and trailers. Mobilization costs also include bonds and insurance. To account for mobilization and demobilization costs, a range of 2 percent to 5 percent is was added to the total capital cost, depending on the specific site characteristics.

Architectural Fees

Estimates need to include the cost of the building design, architectural drawings, building construction supervision, construction engineering, and travel, not to exceed 8 percent of the capital cost.

Contractor's Overhead and Profit

This element includes field supervision, main office expenses, tools and minor equipment, workers' compensation and employer's liability, field office expenses, performance and payment bonds, unemployment tax, profit, Social Security and Medicare, builder's risk insurance, and public liability insurance. This was estimated at 12 percent of the capital cost.

Process Engineering

Costs for this category include treatment process engineering, unit operation construction supervision, travel, system start-up engineering, study, design, operation and maintenance (O&M) manuals, and record drawings. These costs were estimated by adding a range of 10 percent to 20 percent to the estimated capital cost.

Sitework and Yard Piping

Cost estimates for sitework include site preparation, excavation, backfilling, roads, walls, landscaping, parking lots, fencing, storm water control, yard structures, and yard piping (interconnecting piping between treatment units). These costs were estimated by adding a range of 5 percent to 15 percent to the estimated capital cost for sitework and a range of 3 percent to 7 percent for yard piping.

For installation of CWIS technologies (e.g., screens), a yard piping cost of 5 percent of the total capital cost is sometimes used based on site-specific conditions. Cooling towers require a significant amount of piping (for both new facilities and retrofits to existing facilities) and these costs are already included in the capital cost estimate for cooling towers so an additional 5 percent was not applied.

Standby Power

Standby generators may be needed to produce power to the treatment and distribution system during power outages and should be included in cost estimates. These costs are estimated by adding a range of 2 percent to 5 percent to the estimated construction cost.

Electrical Allowance (including yard wiring)

An electrical allowance should be made for electric wiring, motors, duct banks, MCCs, relays, lighting, etc. These costs are estimated by adding a range of 10 percent to 15 percent to the estimated construction cost.

Instrumentation and Controls

Instrumentation and control (I&C) costs may include a facility control system, software, etc. The cost depends on the degree of automation desired for the entire facility. These costs are estimated by adding a range of 3 percent to 8 percent to the estimated construction cost.

Contingencies

Contingency cost estimates include compensation for uncertainty within the scope of labor, materials, equipment, and construction specifications. This uncertainty factor is estimated to range from 5 percent to 25 percent of all capital costs, with an average of 10 percent for general engineering projects.

Contingency costs can range from 2 percent to 20 percent for construction projects. CWIS technology projects are not typical construction projects since most of the construction is done at the manufacturing facility and site work mainly involves installation. So some of the uncertainties that could occur in typical construction projects are less likely in CWIS projects. Design and manufacture of the technology can be around 90 percent of the total cost for a project that involves a straightforward installation (e.g., no dredging). The approach used in this cost estimate is conservative and is considered to cover contingencies for typical CWIS technology or cooling tower projects.

In its 1992 study of cooling tower retrofit costs, Stone and Webster (1992) included, in its line item costs, an allowance for indeterminates (e.g., contingencies) of 15 percent for future utility projects. The Stone and Webster study involved major retrofit work on existing plants (i.e., converting a once through cooling system plant to recirculating), so the contingencies allowance fell in the higher end of the typical range.

Installation costs

Installation costs are estimated at 80 percent of cooling tower equipment cost based on information provided by equipment vendors. See the end of this chapter for cost curves and equations.

2.8.4 Replacement Costs

Cooling towers may require replacement of equipment during the financing period that is necessary for the upkeep of the cooling tower. These costs tend to increase over the useful life of the tower and constitute an O&M expenditure that needs to be accounted for. Therefore, EPA factored these periodic equipment replacement costs into the O&M cost estimates presented herein. However, EPA has not included the replacement costs for other equipment because the life expectancy is generally expected to last over the financial life of the facility.

2.9 SPECIFIC COST INFORMATION FOR TECHNOLOGIES AND ACTIONS

The following sections present information on potential compliance actions that a facility might take, including the installation of certain technologies, in order to meet requirements under the §316(b) New Facility Rule. The information presented includes the cost curves and unit costs developed for each potential compliance action. Estimated costs are presented in 1999 dollars. The cost equations and cost curves can be used to estimate costs. The equations and cost curves generally use flow as the basis for determining estimated costs (i.e., unit costs are in $/gpm). For screens, since flow is dependent on the flow velocity through the screen, different equations and cost curves are included for the two velocities of 0.5 fps and 1.0 fps.

2.9.1 Reducing Design Intake Flow

Switching to a recirculating system

As noted earlier, in a recirculating system cooling water is used to cool equipment and steam, and absorbs heat in the process. The cooling water is then cooled and recirculated to the beginning of the system to be used again for cooling. Recirculating the cooling water in a system vastly reduces the amount of cooling water needed. The method most frequently used to cool the water in a recirculating system is putting the cooling water through a cooling tower. Therefore, EPA chose to cost cooling towers as the technology used to switch a once-through cooling system to a recirculating system.

The factors that generally have the greatest impact on cost are the flow, approach (the difference between cold water temperature and ambient wet bulb temperature), tower type, and environmental considerations. Physical site conditions (e.g., topographic conditions, soils and underground conditions, water quality) affect cost, but in most situations are secondary to the primary cost factors. Table 2-12 presents relative capital and operation cost estimates for various cooling towers in comparison to the conventional, basic Douglas Fir cooling tower as a standard. EPA notes that based on its data collection for recent cooling tower projects, for most cases, environmental considerations such as plume abatement and noise abatement are rarely installed. Therefore, EPA is presenting costs in the following sections for comparison purposes only and these types of costs are not uniformly applicable to a national rule.

Table 2-12. Relative Cost Factors for Various Cooling Tower Types[1]

Tower Type	Capital Cost Factor (%)	Operation Cost Factor (%)
Douglas Fir	100	100
Redwood	112[2]	100
Concrete	140	90
Steel	135	98
Fiberglass Reinforced Plastic	110	98
Splash Fill	120	150

Table 2-12: Relative Cost Factors for Various Cooling Tower Types[1]

Non-Fouling Film Fill	110	102
Mechanical draft	100	100
Natural draft (concrete)	175	35
Hybrid [Plume abatement (32DBT)]	250-300	125-150
Dry/wet	375	175
Air condenser (steel)	250-325	175-225
Noise reduction (10dBA)	130	107

1) Percent estimates are relative to the Douglas Fir cooling tower.
2) Redwood cooling tower costs may be higher because redwood trees are a protected species, particularly in the Northwest.

Sources: Mirsky et al. (1992), Mirsky and Bauthier (1997), and Mirsky (2000).

There are two general types of cooling towers, wet and dry. Wet cooling towers, which are the far more common type, reduce the temperature of the water by bringing it directly into contact with large amounts of air. Through this process, heat is transferred from the water to the air which is then discharged into the atmosphere. Part of the water evaporates through this process thereby having a cooling effect on the rest of the water. This water then exits the cooling tower at a temperature approaching the wet bulb temperature of the air.

For dry cooling towers, the water does not come in direct contact with the air, but instead travels in closed pipes through the tower. Air going through the tower flows along the outside of the pipe walls and absorbs heat from the pipe walls which absorb heat from the water in the pipes. Dry cooling towers tend to be much larger and more costly than wet towers because the dry cooling process is less efficient. Also, the effluent water temperature is warmer because it only approaches the dry bulb temperature of the air (not the cooler wet bulb temperature). Development of unit costs and cost curves for dry cooling towers is discussed in Chapter 4 of this document.

Hybrid wet-dry towers, which combine dry heat exchange surfaces with standard wet cooling towers, are plume abatement towers. These towers tend to be used most where plume abatement is required by local authorities. Technologies for achieving low noise and low drift can be fitted to all types of towers.

Other characteristics of cooling towers include:

Air flow: Mechanical draft towers use fans to induce air flow, while natural draft (i.e., hyperbolic) towers induce natural air flow by the chimney effect produced by the height and shape of the tower. For towers of similar capacity, natural draft towers typically require significantly less land area and have lower power costs (i.e., fans to induce air flow are not needed) but have higher initial costs (particularly because they need to be taller) than mechanical draft towers. Both mechanical draft and natural draft towers can be designed for air to flow through the fill material using either a crossflow (air flows horizontally) or counterflow (air flows vertically upward) design, while the water flows vertically downward. Counterflow towers tend to be more efficient at achieving heat reduction but are generally more expensive to build and operate because clearance needed at the bottom of the tower means the tower needs to be taller.

Mode of operation: Cooling towers can be either recirculating (water is returned to the condenser for reuse) or non-recirculating (tower effluent is discharged to a receiving waterbody and not reused). Facilities using non-recirculating types (i.e., "helper" towers) draw large flows for cooling and therefore do not provide fish protection for §316(b) purposes, so the information in this chapter is not intended to address non-recirculating towers.

Construction materials: Towers can be made from concrete, steel, wood, and/or fiberglass.

Generally, all cooling towers with plume abatement features are hybrid towers. According to the Standard Handbook of Power Plant Design, attempts to modify towers with special designs and construction features to abate plumes has been tested but not accepted as an effective technology. Natural draft towers are concrete towers, although some old natural draft wood cooling towers do exist. Therefore, for costing purposes, concrete is assumed to be the material used for building natural draft cooling towers.

Capital Cost of Cooling Towers

Typically, the cost of the project is determined based on the following factors: type of equipment to be cooled (e.g., coal fired equipment, natural gas powered equipment); location of the water intake (on a river, lake, or seashore); amount of power to-be-generated (e.g., 50 Megawatt vs. 200 Megawatt); and volume of water needed. The volume of water needed for cooling depends on the following critical parameters: water temperature, make of equipment to be used (e.g, G.E turbine vs. ABB turbine, turbine with heat recovery system and turbine without heat recovery system), discharge permit limits, water quality (particularly for wet cooling towers), and type of wet cooling tower (i.e., whether it is a natural draft or a mechanical draft).

Two cooling tower industry managers with extensive experience in selling and installing cooling towers to power plants and other industries provided information on how they estimate budget capital costs associated with a wet cooling tower. The rule of thumb they use is \$30/gpm for a delta of 10 degrees and \$50/gpm for a delta of 5 degrees.[7] This cost is for a "small" tower (flow less than 10,000 gpm) and equipment associated with the "basic" tower, and does not include installation. Ancillary costs are included in the installation factor estimate listed below. Above 10,000 gpm, to account for economy of scale, the unit cost was lowered by \$5/gpm over the flow range up to 204,000 gpm. For flows greater than 204,000 gpm, a facility may need to use multiple towers or a custom design. Combining this with the variability in cost among various cooling tower types, costs for various tower types and features were calculated for the flows used in calculating screen capacities at 1 ft/sec and 0.5 ft/sec.

To estimate costs specifically for installing and operating a particular cooling tower, important factors include:

Condenser heat load and wet bulb temperature (or approach to wet bulb temperature): Largely determine the size needed. Size is also affected by climate conditions.

Plant fuel type and age/efficiency: Condenser discharge heat load per Megawatt varies greatly by plant type (nuclear thermal efficiency is about 33 percent to 35 percent, while newer oil-fired plants can have nearly 40 percent thermal efficiency, and newer coal-fired plants can have nearly 38 percent thermal efficiency).[8] Older plants typically have lower thermal efficiency than new plants.

Topography: May affect tower height and/or shape, and may increase construction costs due to subsurface conditions. For example, sites requiring significant blasting, use of piles, or a remote tower location will typically have greater installation/construction cost.

Material used for tower construction: Wood towers tend to be the least expensive, followed by fiberglass reinforced plastic, steel, and concrete. However, some industry sources claim that Redwood capital costs might be much higher compared to

[7]The delta is the difference between the cold water (tower effluent) temperature and the tower wet bulb temperature. This is also referred to as the design approach. For example, at design conditions with a delta or design approach of 5 degrees, the tower effluent and blowdown would be 5 degrees warmer than the wet bulb temperature. A smaller delta (or lower tower effluent temperature) requires a larger cooling tower and thus is more expensive.

[8]With a 33 percent efficiency, one-third of the heat is converted to electric energy and two-thirds goes to waste heat in the cooling water.

other wood cooling towers, particularly in the Northwest U.S., because Redwood trees are a protected species. Factors that affect the material used include chemical and mineral composition of the cooling water, cost, aesthetics, and local/regional availability of materials.

Pollution control requirements: Air pollution control facilities require electricity to operate. Local requirements to control drift, plume, fog, and noise and to consider aesthetics can also increase costs for a given site (e.g., different design specifications may be required).

Summaries of some EPRI research on dry cooling systems and wet-dry supplemental cooling systems note that dry cooling towers may cost as much as four times more than conventional wet towers (EPRI, 1986a and 1986b).

Table 2-13: Estimated Capital Costs of Cooling Towers without Special Environmental Impact Mitigation Features (1999 Dollars)

Flow (gpm)	Basic Douglas Fir Cooling Tower Cost[1]	Redwood Tower	Concrete Tower	Steel Tower	Fiberglass Reinforced Plastic Tower
2000	$108,000	$121,000	$151,000	$146,000	$119,000
4000	$216,000	$242,000	$302,000	$ 292,000	$238,000
7000	$378,000	$423,000	$529,000	$ 510,000	$416,000
9000	$486,000	$544,000	$680,000	$ 656,000	$535,000
11,000	$594,000	$665,000	$832,000	$ 802,000	$653,000
13,000	$702,000	$786,000	$983,000	$ 948,000	$772,000
15,000	$810,000	$907,000	$1,134,000	$1,094,000	$891,000
17,000	$918,000	$1,028,000	$1,285,000	$1,239,000	$1,010,000
18,000	$972,000	$1,089,000	$1,361,000	$1,312,000	$1,069,000
22,000	$1,148,400	$1,286,000	$1,608,000	$1,550,000	$1,263,000
25,000	$1,305,000	$1,462,000	$1,827,000	$1,762,000	$1,436,000
28,000	$1,461,600	$1,637,000	$2,046,000	$1,973,000	$1,608,000
29,000	$1,513,800	$1,695,000	$2,119,000	$2,044,000	$1,665,000
31,000	$1,618,200	$1,812,000	$2,265,000	$2,185,000	$1,780,000
34,000	$1,774,800	$1,988,000	$2,485,000	$2,396,000	$1,952,000
36,000	$1,879,200	$2,105,000	$2,631,000	$2,537,000	$2,067,000
45,000	$2,268,000	$2,540,000	$3,175,000	$3,062,000	$2,495,000
47,000	$2,368,800	$2,653,000	$3,316,000	$3,198,000	$2,606,000
56,000	$2,822,400	$3,161,000	$3,951,000	$3,810,000	$3,105,000
63,000	$3,175,200	$3,556,000	$4,445,000	$4,287,000	$3,493,000
67,000	$3,376,800	$3,782,000	$4,728,000	$4,559,000	$3,714,000
73,000	$3,679,200	$4,121,000	$5,151,000	$4,967,000	$4,047,000
79,000	$3,839,400	$4,300,000	$5,375,000	$5,183,000	$4,223,000
94,000	$4,568,400	$5,117,000	$6,396,000	$6,167,000	$5,025,000
102,000	$4,957,200	$5,552,000	$6,940,000	$6,692,000	$5,453,000
112,000	$5,443,200	$6,096,000	$7,620,000	$7,348,000	$5,988,000
146,000	$7,095,600	$7,947,000	$9,934,000	$9,579,000	$7,805,000
157,000	$7,347,600	$8,229,000	$10,287,000	$9,919,000	$8,082,000
204,000	$9,180,000	$10,282,000	$12,852,000	$12,393,000	$10,098,000

1) Includes installation at 80 percent of equipment cost for a delta of 10 degrees.

Using the estimated costs, EPA developed cost equations using a polynomial curve fitting function. Table 2-14 presents cost equations for basic tower types built with different building materials and assuming a delta of 10 degrees. The cost equations presented in Table 2-13 include installation costs. The "x" in the presented cost equations is for flow in gpm and the "y" is in dollars.

Table 2-14. Capital Cost Equations of Cooling Towers without Special Environmental Impact Mitigation Features (Delta 10 degrees)

Tower Type	Capital Cost Equation[1]	Correlation Coefficient
Douglas Fir	$y = -9E\text{-}11x^3 - 8E\text{-}06x^2 + 50.395x + 44058$	$R^2 = 0.9997$
Redwood	$y = -1E\text{-}10x^3 - 9E\text{-}06x^2 + 56.453x + 49125$	$R^2 = 0.9997$
Steel	$y = -1E\text{-}10x^3 - 1E\text{-}05x^2 + 68.039x + 59511$	$R^2 = 0.9997$
Concrete	$y = -1E\text{-}10x^3 - 1E\text{-}05x^2 + 70.552x + 61609$	$R^2 = 0.9997$
Fiberglass Reinforced Plastic	$y = -1E\text{-}10x^3 - 9E\text{-}06x^2 + 55.432x + 48575$	$R^2 = 0.9997$

1) x is for flow in gpm and y is cost in dollars.

Using the cost comparison information published by Mirsky et al. (1992), EPA calculated the costs of cooling towers with various additional features. These costs are presented in Table 2-15. Table 2-15 presents capital costs of the Douglas Fir Tower with various features. The costs for other types of cooling towers were calculated in a similar manner.

Table 2-16 presents cost equations for Douglas fir cooling towers with special environmental mitigation features, built with different building materials and assuming a delta of 10 degrees. The cost equations presented in Table 2-16 include installation costs. The "x" in the presented cost equations is for flow in gpm and the "y" is in dollars. The final costs were based on cost curves constructed for redwood splash fill towers. Costs and cost equations for Douglas fir towers are listed here as an example of how cost equation curves were developed, although these are not the costs used to develop the facility costs.

At the end of this chapter, cost curves with equations are also presented for other types of cooling towers.

Table 2-15: Capital Costs of Douglas Fir Cooling Towers with Special Environmental Impact Mitigation Features (Delta 10 degrees) (1999 Dollars)

Flow (gpm)	Douglas Fir Cooling Tower	Splash Fill	Non-fouling Film Fill	Noise Reduction 10 dBA	Dry/wet	Hybrid Tower (32DBT Plume Abatement)
2000	$108,000	$130,000	$119,000	$140,000	$405,000	$324,000
4000	$216,000	$259,000	$238,000	$281,000	$810,000	$648,000
7000	$378,000	$454,000	$416,000	$491,000	$1,418,000	$1,134,000
9000	$486,000	$583,000	$535,000	$632,000	$1,823,000	$1,458,000
11,000	$594,000	$713,000	$653,000	$772,000	$2,228,000	$1,782,000
13,000	$702,000	$842,000	$772,000	$913,000	$2,633,000	$2,106,000
15,000	$810,000	$972,000	$891,000	$1,053,000	$3,038,000	$2,430,000
17,000	$918,000	$1,102,000	$1,010,000	$1,193,000	$3,443,000	$2,754,000
18,000	$972,000	$1,166,000	$1,069,000	$1,264,000	$3,645,000	$2,916,000
22,000	$1,148,400	$1,378,000	$1,263,000	$1,493,000	$4,307,000	$3,445,000
25,000	$1,305,000	$1,566,000	$1,436,000	$1,697,000	$4,894,000	$3,915,000
28,000	$1,461,600	$1,754,000	$1,608,000	$1,900,000	$5,481,000	$4,385,000
29,000	$1,513,800	$1,817,000	$1,665,000	$1,968,000	$5,677,000	$4,541,000
31,000	$1,618,200	$1,942,000	$1,780,000	$2,104,000	$6,068,000	$4,855,000
34,000	$1,774,800	$2,130,000	$1,952,000	$2,307,000	$6,656,000	$5,324,000
36,000	$1,879,200	$2,255,000	$2,067,000	$2,443,000	$7,047,000	$5,638,000
45,000	$2,268,000	$2,722,000	$2,495,000	$2,948,000	$8,505,000	$6,804,000
47,000	$2,368,800	$2,843,000	$2,606,000	$3,079,000	$8,883,000	$7,106,000
56,000	$2,822,400	$3,387,000	$3,105,000	$3,669,000	$10,584,000	$8,467,000
63,000	$3,175,200	$3,810,000	$3,493,000	$4,128,000	$11,907,000	$9,526,000
67,000	$3,376,800	$4,052,000	$3,714,000	$4,390,000	$12,663,000	$10,130,000
73,000	$3,679,200	$4,415,000	$4,047,000	$4,783,000	$13,797,000	$11,038,000
79,000	$3,839,400	$4,607,000	$4,223,000	$4,991,000	$14,398,000	$11,518,000
94,000	$4,568,400	$5,482,000	$5,025,000	$5,939,000	$17,132,000	$13,705,000
102,000	$4,957,200	$5,949,000	$5,453,000	$6,444,000	$18,590,000	$14,872,000
112,000	$5,443,200	$6,532,000	$5,988,000	$7,076,000	$20,412,000	$16,330,000
146,000	$7,095,600	$8,515,000	$7,805,000	$9,224,000	$26,609,000	$21,287,000
157,000	$7,347,600	$8,817,000	$8,082,000	$9,552,000	$27,554,000	$22,043,000
204,000	$9,180,000	$11,016,000	$10,098,000	$11,934,000	$34,425,000	$27,540,000

Table 2-16. Capital Cost Equations of Douglas Fir Cooling Towers with Special Environmental Impact Mitigation Features (Delta 10 degrees)

Tower Type	Capital Cost Equation[1]	Correlation Coefficient
Douglas Fir	$y = -9E\text{-}11x^3 - 8E\text{-}06x^2 + 50.395x + 44058$	$R^2 = 0.9997$
Splash Fill	$y = -4E\text{-}05x^2 + 62.744x + 22836$	$R^2 = 0.9996$
Non-fouling Film Fill	$y = -1E\text{-}10x^3 - 9E\text{-}06x^2 + 55.432x + 48575$	$R^2 = 0.9997$
Noise Reduction 10 dBA	$y = -1E\text{-}10x^3 - 1E\text{-}05x^2 + 65.517x + 57246$	$R^2 = 0.9997$
Dry/Wet	$y = -0.0001x^2 + 196.07x + 71424$	$R^2 = 0.9996$
Hybrid Tower (Plume Abatement 32DBT)	$y = -3E\text{-}10x^3 - 2E\text{-}05x^2 + 151.18x + 132225$	$R^2 = 0.9997$

1) x is flow in gpm and y is cost in dollars.

Validation of Cooling Tower Capital Cost Equations

To validate the cooling tower capital cost curves and equations, EPA compared the costs predicted by the cooling tower capital cost equations to actual costs for cooling tower construction projects provided by cooling tower vendors. EPA obtained data for 20 cooling tower construction projects: nine Douglas fir towers, eight fiberglass towers, one redwood tower, and two towers for which the construction material was unknown (for purposes of comparison, EPA compared these last two towers to predicted costs for redwood towers). In some cases, the project costs did not include certain components such as pumps or basins. Where this was the case, EPA adjusted the project costs as follows:

- where project costs did not include pumps, EPA added $10/gpm to the project costs to account for pumps.
- where project costs did not include pumps and basins, EPA doubled the project costs to account for pumps and basins.

Chart 2-7 at the end of this chapter compares actual capital costs for wet cooling tower projects against predicted costs from EPA's cooling tower capital cost curves, with 25 percent error bars around the cost curve predicted values. This chart shows that, in almost all cases, EPA's cost curves provide conservative cost estimates (erring on the high side) and are within 25 percent or less of actual project costs. In those few cases where the cost curve predictions are not within 25 percent of the actual costs, the difference can generally be attributed to the fact that the constructed cooling towers were designed for temperature deltas different than the 10 °F used for EPA's cost curves.

Operation and Maintenance (O&M) Cost of Cooling Towers

EPA has included the following variables in estimating O&M costs for cooling towers:

Size of the cooling tower,
Material from which the cooling tower is built,
Various features that the cooling tower may include,
Source of make-up water,
How blowdown water is disposed, and
Increase in maintenance costs as the tower useful life diminishes.

For example, if make-up water is obtained from a lesser quality source, additional treatment may be required to prevent biofouling in the tower.

The estimated annual O&M costs presented below are for cooling towers designed at a delta of 10 degrees. To calculate annual O&M costs for various types of cooling towers, EPA made the following assumptions:

For small cooling towers, the annual O&M costs for chemical costs and routine preventive maintenance is estimated at 5 percent of capital costs. To account for economy of scale in these components of the O&M cost, that percentage is gradually decreased to 2 percent for the largest size cooling tower. EPA notes that, while there appear to be economies of scale for these components of O&M costs, chemical and routine preventive maintenance costs represent a small percentage of the total O&M costs and EPA does not believe there to be significant economies of scale in the total O&M costs.

2 percent of the tower flow is lost to evaporation and/or blowdown.

To account for the costs of makeup water and disposal of blowdown water, EPA used three scenarios at proposal, as documented in the *Economic and Engineering Analyses of the Proposed §316(b) New Facility Rule* (EEA). The first scenario is based on the facility using surface water sources for makeup water and disposing of blowdown water either to a pond or back to the surface water source at a combined cost of $0.5/1000 gallons. The second scenario is based on the facility using gray water (treated municipal wastewater) for makeup water and disposing of the blow down water into a POTW sewer line at a combined cost of $3/1000 gallons. The third scenario is based on the facility using municipal sources for clean makeup water and disposing of the blowdown water into a POTW sewer line at a combined cost of $4/1000 gallons. For the final §316(b) New Facility Rule, EPA based all cooling tower O&M costs on Scenario 1 (use of surface water sources for makeup water and disposal of blowdown water either to a pond or back to the surface water source).

Based on discussions with industry representatives, the largest component of total O&M costs is the requirement for major maintenance of the tower that occurs after years of tower service, such as around the 10th year and 20th years of service. These major overhauls include repairs to mechanical equipment and replacement of 100 percent of fill material and eliminators.

To account for the variation in maintenance costs among cooling tower types, a scaling factor is used. Douglas Fir is the type with the greatest maintenance cost, followed by Redwood, steel, concrete, and fiberglass. For additional cooling tower features, a scaling factor was used to account for the variations in maintenance (e.g., splash fill and non-fouling film fill are the features with the lowest maintenance costs).

Using the operation cost comparison information published by Mirsky et al. (1992) and maintenance cost assumptions set out above, EPA calculated estimated costs of O&M for various types of cooling towers with and without additional features. EPA then developed cost equations from the generated cost data points, as documented in the proposal EEA. In preparing O&M cost estimates for the final rule, EPA discovered an error in how the costs for major maintenance were calculated in the proposal EEA. In the proposal EEA, these costs were calculated as annual costs following the years that they were to occur. However, some of these costs actually represent one-time costs. This calculation error caused the O&M cost estimates in the proposal EEA to be in error on the high side. EPA's total O&M cost estimates in the proposal EEA were (for Douglas fir cooling towers, for example) about 25-30 percent of the cooling tower capital cost. EPA's revised calculations indicate that the correct value for total O&M costs should be about 50 percent lower. EPA updated the O&M cost curves for the first scenario for the redwood towers which were used in developing cost estimates for the final rule, and for the concrete towers which were used in the sensitivity analysis for the final rule cost estimates. The updated equations and costs are shown in Tables 2-17 through 2-20 for the first scenario for redwood towers with various features. Updated cost curves and equations for O&M costs for redwood and concrete cooling towers are also presented at the end of the chapter. O&M cost curves and equations contained in the EEA for other types of towers and for the other scenarios would need to be updated in a similar manner before being used to develop cost estimates.

Note that these cost estimates and equations are for total O&M costs. Stone and Webster (1992) presents a value for additional annual O&M costs equal to approximately 0.7 percent of the capital costs for a retrofit project. Stone and Webster's estimate is for the amount O&M costs are expected to *increase* when plants with once-through cooling systems are retrofit with cooling towers to become recirculating systems, and therefore do not represent total O&M costs.

Table 2-17. Total Annual O&M Cost Equations for Redwood Towers - 1st Scenario		
Cooling Tower Material Type	Total Annual O&M Cost Equations[1]	Correlation Coefficient
Redwood	$y = -4E\text{-}06x^2 + 10.617x + 2055.2$	$R^2 = 0.9999$

1) x is flow in gpm and y is annual O&M cost in dollars.

Table 2-18. Total Estimated Annual O&M Costs for Redwood Towers - 1st Scenario (1999 Dollars)

Flow (gpm)	Redwood Tower
2000	$22,000
4000	$43,000
7000	$76,000
9000	$97,000
11,000	$119,000
13,000	$140,000
15,000	$162,000
17,000	$184,000
18,000	$194,000
22,000	$234,000
25,000	$265,000
28,000	$297,000
29,000	$308,000
31,000	$329,000
34,000	$361,000
36,000	$382,000
45,000	$469,000
47,000	$490,000
56,000	$584,000
63,000	$657,000
67,000	$699,000
73,000	$761,000
79,000	$809,000
94,000	$963,000
102,000	$1,045,000
112,000	$1,147,000
146,000	$1,496,000
157,000	$1,580,000
204,000	$2,015,000

Table 2-19. Total Annual O&M Cost Equations - 1st scenario for Redwood Towers with Environmental Mitigation Features[1]

Type of Tower	O&M Cost Equations[2]	Correlation Coefficient
Non-Fouling Film Fill tower	$y = -4E\text{-}06x^2 + 11.163x + 2053.7$	$R^2 = 0.9999$
Noise reduction (10dBA)	$y = -5E\text{-}06x^2 + 12.235x + 2512.5$	$R^2 = 0.9999$
Hybrid tower (Plume Abatement 32DBT)	$y = -1E\text{-}05x^2 + 21.36x + 5801.6$	$R^2 = 0.9998$
Splash Fill tower	$y = -4E\text{-}06x^2 + 11.163x + 2053.7$	$R^2 = 0.9999$
Dry/wet tower	$y = -1E\text{-}05x^2 + 25.385x + 7328.1$	$R^2 = 0.9998$

1) Features include non-fouling film, noise reduction, plume abatement, or splash fill
2) x is flow in gpm and y is annual O&M cost in dollars.

Table 2-20. Total Estimated Annual O&M Costs - 1st scenario for Redwood with Environmental Mitigation Features (1999 Dollars)

Flows (gpm)	Splash Fill Tower	Non-Fouling Film Fill Tower	Hybrid Tower (Plume abatement (32DBT	Dry/Wet Tower	Noise Reduction (10dBA)
2000	$24,000	$23,000	$44,000	$25,000	$52,000
4000	$47,000	$45,000	$88,000	$50,000	$104,000
7000	$83,000	$79,000	$153,000	$87,000	$182,000
9000	$106,000	$102,000	$197,000	$112,000	$234,000
11,000	$130,000	$125,000	$241,000	$137,000	$286,000
13,000	$153,000	$148,000	$284,000	$162,000	$339,000
15,000	$177,000	$170,000	$328,000	$187,000	$391,000
17,000	$201,000	$193,000	$372,000	$212,000	$443,000
18,000	$212,000	$204,000	$394,000	$224,000	$469,000
22,000	$256,000	$245,000	$469,000	$269,000	$558,000
25,000	$290,000	$279,000	$533,000	$306,000	$634,000
28,000	$325,000	$312,000	$597,000	$342,000	$710,000
29,000	$337,000	$323,000	$619,000	$354,000	$735,000
31,000	$360,000	$346,000	$661,000	$379,000	$786,000
34,000	$395,000	$379,000	$725,000	$416,000	$862,000
36,000	$418,000	$402,000	$768,000	$440,000	$913,000
45,000	$514,000	$493,000	$935,000	$539,000	$1,110,000
47,000	$537,000	$515,000	$977,000	$563,000	$1,159,000
56,000	$640,000	$613,000	$1,164,000	$671,000	$1,381,000
63,000	$720,000	$690,000	$1,309,000	$755,000	$1,554,000
67,000	$766,000	$733,000	$1,392,000	$803,000	$1,652,000
73,000	$834,000	$799,000	$1,517,000	$875,000	$1,800,000
79,000	$888,000	$849,000	$1,598,000	$928,000	$1,893,000
94,000	$1,057,000	$1,010,000	$1,901,000	$1,104,000	$2,253,000
102,000	$1,147,000	$1,096,000	$2,063,000	$1,198,000	$2,445,000
112,000	$1,259,000	$1,203,000	$2,265,000	$1,315,000	$2,684,000
146,000	$1,642,000	$1,569,000	$2,953,000	$1,714,000	$3,499,000
157,000	$1,737,000	$1,655,000	$3,088,000	$1,806,000	$3,654,000
204,000	$2,219,000	$2,109,000	$3,900,000	$2,298,000	$4,607,000

Variable speed pumps

For a power plant operating at near constant power output (e.g., at or near capacity), the amount of heat rejected through the cooling system will also remain nearly constant regardless of changes in ambient conditions. In cooling systems where heat from steam condensation is transferred to cooling water (i.e., those that use surface condensers), the amount of heat rejected can be measured as the product of the cooling water flow rate times the difference in temperature of the cooling water between the condenser inlet and outlet. If the cooling water flow rate remains constant, then the temperature difference will also remain relatively constant regardless of changes in the inlet temperature. Therefore, a decrease in the cooling water temperature at the condenser inlet will result in a similar decrease in the condenser outlet temperature and a corresponding decrease in the temperature of the condenser surface where steam is condensed.

As described in Chapter 3 on the energy penalty, a decrease in condenser temperatures will produce a decrease in the turbine exhaust, which can result in an increase in the turbine efficiency. Thus, seasonal changes in ambient source water temperature will result in changes in the condenser temperatures, which can affect the steam turbine efficiency. However, as the ambient and condenser temperatures progressively drop, the system performance can approach a point where turbine efficiency no longer increases and may begin to decrease. In addition, significantly reduced turbine exhaust pressures can result in condensed moisture within the turbine, which can damage turbine blades and further reduce turbine efficiency. Thus, progressive reductions in the cooling water temperature in a cooling system operating at a constant cooling water flow rate may approach a point where continued reduction in ambient temperatures results in detrimental or less than optimal operating conditions. The ambient conditions at which this begins to occur will be dependent on the cooling and turbine system design, which is often subject to site-specific and economic considerations.

In a once-through cooling system, one method of controlling the steam condenser temperature is to control the cooling water flow rate. If the heat rejection rate remains relatively constant (near constant plant output), a reduction in the cooling water flow rate will result in an increase in the difference in temperature of the cooling water between the condenser inlet and outlet (referred to as the "range"). An increase in the range will result in an increase in the temperature of the steam condensing surface. Therefore, through careful control of the cooling water flow rate, the condenser temperature can be controlled such that the power plant turbine performance does not degrade and damaging conditions are avoided. Thus, the ability to reduce cooling water flow rate can provide for improved plant operation as well as reducing the environmental impacts of cooling water withdrawals from surface waters.

Use of variable speed pumps is an efficient method for attaining control of the cooling water flow rate and thus the condenser performance. Variable frequency drives are used to vary the pump speed, which in turn allows the flow rate to be adjusted through a range from zero to its maximum output.

There are some limitations on the range of flow rates that can be used. Most once-through cooling systems discharge to surface waters under an NPDES permit, which often includes discharge limits on both the maximum temperature (a concern during the warmer months) and the temperature increase of the discharge over the intake temperature (a concern if flow rates are adjusted). Exceedence of the maximum temperature limit can be avoided by operating at the maximum cooling water flow rate and, when necessary, reducing the plant output (i.e., the heat rejection rate). The limit on temperature increase may create an effective lower limit on the cooling water flow rate (at a given heat rejection rate) in the sense that further reduction in cooling water flow rate would result in a temperature rise that exceeded the NPDES temperature increase limitation. These constraints, however, do not prevent varying the cooling water flow rate; rather, they set the range in flow rates (for a given plant power output level) over which the system may operate. Note that varying the cooling water flow rate does not change the amount of heat being discharged. Rather, it only affects the "concentration" of the heat. Limitation of the temperature increase is intended to reduce detrimental impacts on entrained organisms, as well as on those in the mixing zone downstream.

EPA chose to include the cost of variable frequency drives as part of the pump costs for the post-compliance cost estimates for all once-though systems and for wet tower system intakes. While condenser performance is not affected by using variable speed pumps in the wet tower make-up water intake, EPA included them to provide greater process control. For the baseline system costs to which post-compliance costs are compared, EPA used the costs for constant speed pumps even though facilities may install variable speed pumps regardless of the rule's implementation. EPA chose this approach as a means for generating a conservative (on the high side) compliance cost estimate.

A recent evaluation of the equipment cost for variable speed pumps indicates that EPA may have underestimated the cost for the variable frequency drive component of the pumping system. Recent investigation of estimated costs for VFDs from other sources indicates that the unit cost of $100/Hp obtained from the original contact is lower than estimates from these other sources. EPA has re-evaluated the costs for addition of VFDs using data from these other sources. See DCN 3-3038. EPA finds that the contribution to capital cost from the uncertainty of variable speed drive costs is not appreciable for the final annualized compliance costs of the effected facilities. Analogous to the sensitivity analysis performed on the material of construction of the cooling towers of coal-fired plants (i.e., concrete vs. redwood), the percentage of capital cost due to the uncertainty, when amortized over the appropriate period would not significantly influence total annualized compliance costs.

Pump Equipment Cost Development

The distinction between constant and variable speed pumping systems is the presence of variable frequency drives (VFD). A pump supplier estimated that the unit cost of the variable frequency drives was approximately $100/Hp (Flory 2001). This unit cost is consistent with the cost of a VFD of $20,000 to $30,000 cited for a 200 Hp fan for an air cooled condenser (Tallon 2001). Table 2-21 provides a summary of the data that EPA used to develop the equipment costs for constant speed and variable speed pumps.

Table 2-21: Pump Cost Data (Source: Flory 2001)

Flow (gpm)	Brake-Hp at 50 ft Pumping Head[1]	Pump and Motor with Freight and Tax[2]	Variable Frequency Drive	Total with Variable Frequency Drive
5,000	90	$23,000	$9,015	$32,015
50,000	902	$115,000	$90,150	$205,150
250,000	3,606	$402,500	$360,600	$763,100

[1] Based on flow and a pumping head of 50 ft.
[2] Includes 15 percent for cost of freight and tax.

EPA also included pump installation costs, with the value scaled from 60 percent of equipment costs at 500 gpm to 40 percent at 350,000 gpm.

Table 2-22 presents cost equations for estimating capital costs for variable speed pumps. Cost curves and equations for variable speed pumps are also presented at the end of this chapter.

Table 2-22. Capital Cost Equations for Constant Speed and Variable Speed Pumps

Pump Type	Capital Cost Equation[1]	Correlation Coefficient
Constant Speed	$y = 1.6859x + 13369$	$R^2 = 0.9998$
Variable Speed	$y = 3.1667x + 16667$	$R^2 = 1$

1) x is flow in gpm and y is cost in dollars.

Using non-surface water sources

A facility may be able to obtain some of its cooling water from a source other than the surface water it is using (WWTP gray water, ground water, or municipal water supply) and thereby reduce the volume of its withdrawals from the surface water and meet the percent of flow requirements. Some facilities may only need to use this alternate source during low flow periods in the surface water source. To use this option, a facility would need to build a pond or basin for the supplemental cooling water.

A facility using gray water may need to install some water treatment equipment (e.g., sedimentation, filtration) to ensure that its discharge of the combined source water and gray water meets any applicable effluent limits. For costing purposes, EPA has assumed that a facility would only need to install treatment for gray water in situations where treatment would have been required for river intake water. Therefore, no additional (i.e., "new") costs are incurred for treatment of gray water after intake or before discharge.

See the end of this chapter for cost curves and equations for estimating gray water and municipal water costs.

2.9.2 Reducing Design Intake Velocity

Passive screens

Passive screens, typically made of wedge wire, are screens that use little or no mechanical activity to prevent debris and aquatic organisms from entering a cooling water intake. The screens reduce impingement and entrainment by using a small mesh size for the wedge wire and a low through-slot velocity that is quickly dissipated. The main components of a passive screening system are typically the screen(s), framing, an air backwash system if needed, and possibly guide rails depending on the installation location.

Passive screens vary in shape and form and include flat panels, curved panels, tee screens, vee screens, and cylinder screens. Screen dimensions (width and depth) vary; they are generally made to order with sizing as required by site conditions. Panels can be of any size, while cylinders are generally in the 12" to 96" diameter range. The main advantages of passive intake systems are:

They are fish-friendly due to low slot velocities (peak <0.5 fps), and
They have no moving parts and thus minimal O&M costs.

New passive intake screens have higher capacity (due to higher screen efficiency) than older versions of passive screens. Wedge wire screens are effective in reducing impingement and entrainment as long as a sufficiently small screen slot size is used and ambient currents have enough velocity to move aquatic organisms around the screen and flush debris away.

The key parameters and additional features that are considered in estimating the cost of passive/wedge wire screening systems on CWIS are:

Size of screen and flow rate (i.e., volume of water used),
Size of screen slots/openings,
Screen material,
Water depth,
Water quality (debris, biological growth, salinity), and
Air backwash systems.

The size and material of a screen most affect cost. Branched intakes, with a screen on each branch, can be used for large flows. Screen slot size also impacts the size of a screen. A smaller slot opening will result in a larger screen being required to keep the peak slot velocity under 0.5 fps.

Site-specific conditions significantly affect costs of the screen(s). The water depth affects equipment and installation costs because structural reinforcement is required as depth increases, air backwash system capacities need to be increased due to the reduced air volume at greater depths, and installation is generally more difficult. The potential for clogging from debris and fouling from biogrowth are water quality concerns that affect costs. The amount and type of debris influence the size of openings in the screen, which affects water flow through the screen and thus screen size. Finer debris may require a smaller slot opening to prevent debris from entering and clogging the openings.

Generally, speed and flow of water do not affect the installation cost or the operation of passive intakes, however there must be adequate current in the source water to carry away debris that is backwashed from the screen so that it does not become (re)clogged. It is recommended as good engineering practice that the axis of the screen cylinder be oriented parallel with the water flow to minimize fish entrainment and to aid in removal of debris during air backwash. The effects of the presence of sensitive species or certain types of species affect the design of the screen and may increase screen cost. For example, the lesser strength of a local species could result in the need for a peak velocity less than 0.5 fps which would result in a larger screen. Biofouling from the attachment of zebra mussels and barnacles and the growth of algae may necessitate the use of a special screen material, periodic flushing with biocides, and in limited cases, manual cleaning by divers. For example, the presence of zebra mussels often requires the use of a special alloy material to prevent attachment to the screen assembly.

The level of debris in the water also affects whether an air backwash system is needed and how often it is used. Heavy debris loadings may dictate the need for more frequent air backwashing. If the air backwash frequency is high enough, a larger compressor may be required to recharge the accumulator tank more quickly.

Another water quality factor that affects screen cost is water corrosiveness (e.g., whether the intake water is seawater, freshwater, or brackish). Most passive screens are manufactured in either 304 or 316 stainless steel for freshwater installations. The 316L stainless steel can be used for some saltwater installations, but has limited life. Screens made of copper-nickel alloys (70/30 or 90/10) have shown excellent corrosion resistance in saltwater, however they are significantly more expensive than stainless steel (50 percent to 100 percent greater in cost, i.e., can be double the cost).

Capital Costs

EPA assumed that the capital cost of passive screens will be 60 percent of the capital cost of a basic traveling screen of similar size. This assumption is based on discussions with industry representatives. The lower capital cost is because passive screen systems have lower onshore site preparation and installation costs (no extensive mechanical equipment as in the traveling screens) and are easier to install in offshore situations. The estimated capital costs for passive screens are shown in Table 2-23, corresponding to the flows shown in Table 2-31 for a through screen velocity of 0.5 fps. Passive screens for sizes larger than those shown in Table 2-23 will generate flows higher than 50,000 gpm. For flows greater than 50,000 gpm, particularly when water is drawn in from a river, the size of the CWIS site becomes very big and the necessary network fanning for intake points and screens generally makes passive screen systems unfeasible.

Table 2-23 Estimated Capital Costs for a Through Flow Passive Water Screen Stainless Steel 304 - Standard Design[1] (1999 Dollars)

Well Depth (ft)	Screen Panel Width (ft) 2	5	10	14
10	$34,200	$56,100	$91,800	$128,700
25	$49,800	$84,900	$140,400	(2)
50	$74,400	$122,700	(2)	(2)
75	$99,000	(2)	(2)	(2)
100	$135,600	(2)	(2)	(2)

1) Cost estimate includes stainless steel 304 structure.
2) Not estimated because passive screen systems of this size are not feasible.

As noted above, the capital costs for special screen materials (e.g., copper-nickel alloys) are typically 50 percent to 100 percent higher.

Table 2-24 presents cost equations for estimating capital costs for passive screens. The "x" in the equation represents the flow volume in gpm and the "y" value is the passive screen total capital cost. Cost equations associated with a flow of 1 fps are provided for comparative purposes.

Table 2-24. Capital Cost Equations for Passive Screens

Screen Width (ft)	Passive Screens Velocity 0.5 ft/sec: Equation[1]	Correlation Coefficient	Passive Screens Velocity 1ft/sec: Equation[1]	Correlation Coefficient
2	$y = 3E\text{-}08x^3 - 0.0008x^2 + 12.535x + 11263$	$R^2 = 0.9991$	$y = 5E\text{-}09x^3 - 0.0002x^2 + 6.5501x + 9792.6$	$R^2 = 0.9991$
5	$y = 0.0002x^2 + 1.5923x + 47041$	$R^2 = 1$	$y = 4E\text{-}05x^2 + 1.0565x + 43564$	$R^2 = 1$
10	$y = 3.7385x + 58154$	$R^2 = 1$	$y = 1.8x + 59400$	$R^2 = 1$

1) x is the flow in gpm y is the capital cost in dollars.

See the end of this chapter for cost curves and equations.

Operation and Maintenance (O&M) Costs for Passive Screens

Generally, there are no appreciable O&M costs for passive screens unless there are biofouling problems or zebra mussels in the environment. Biofouling problems can be remedied through the proper choice of materials and periodic mechanical cleaning. Screens equipped with air backwash systems require periodic compressor/motor/valve maintenance. Therefore, EPA has estimated zero O&M costs for passive screens.

Velocity Caps

The cost driver of velocity caps is the installation cost. Installation is carried out underwater where the water intake mouth is modified to fit the velocity cap over the intake. EPA estimated capital costs for velocity caps based on the following assumptions:

- Four velocity caps can be installed in a day,
- Cost of the installation crew is similar to the cost of the water screen installation crew (see Box 2-1),
- To account for the difficulty in installing in deep water, an additional work day is assumed for every increase in depth size category, and
- Equipment cost for a velocity cap is assumed to be 25 percent of the velocity cap installation cost. In our BPJ, this is a conservatively high estimate of the cost of velocity cap material and delivery to the installation site.

Based on these assumptions, EPA calculated estimated costs for velocity caps, which are shown in Tables 2-25 and 2-26. EPA calculated the number of velocity caps needed for various flow sizes based on a flow velocity of 0.5ft/sec and assuming that the intake area to be covered by the velocity cap is 20 ft^2 which is the area comparable to a pipe diameter of about 5 feet. For flows requiring pipes larger than this, EPA assumed, for velocity cap costing purposes, that multiple intake pipes with a standard, easy-to-handle pipe diameter will be used rather than larger-diameter, custom made pipes (based on BPJ). Cost curves and equations are at the end of the chapter.

Table 2-25. Estimated Velocity Cap Installation Costs (1999 Dollars)

Flow (gpm) (No. of velocity caps)	Water Depth (ft)				
	8	20	30	50	65
Up to 18,000 (4 VC)	$8000	$12,500	$17,000	$21,500	$26,000
18,000 ≤ flow <35,000 (9 VC)	$12,500	$17,000	$21,500	$26,000	$30,500
35,000≤ flow <70,000 (15 VC)	$21,500	$26,000	$30,500	$35,000	$39,500
70,000≤ flow <100,000 (23 VC)	$30,500	$35,000	$39,500	$44,000	$48,500
157,000 (35 VC)	$44,000	$48,500	$53,000	$57,500	$62,000
204,000 (46 VC)	$57,500	$62,000	$66,500	$71,000	$75,500

Table 2-26. Estimated Velocity Cap Equipment and Installation Costs (1999 Dollars)					
Flow (gpm) (No. of velocity caps)	Water Depth (ft)				
	8	20	30	50	65
Up to 18,000 (4 VC)	$10,000	$15,625	$21,250	$26,875	$32,500
18,000 ≤ flow <35,000 (9 VC)	$15,625	$21,250	$26,875	$32,500	$38,125
35,000≤ flow <70,000 (15 VC)	$26,875	$32,500	$38,125	$43,750	$49,375
70,000≤ flow <100,000 (23 VC)	$38,125	$43,750	$49,375	$55,000	$60,625
157,000 (35 VC)	$55,000	$60,625	$66,250	$71,875	$77,500
204,000 (46 VC)	$71,875	$77,500	$83,125	$88,750	$94,375

Table 2-27. Cost Equations for Velocity Cap Capital Costs		
Flow (gpm) (No. of velocity caps)	Velocity Cap Capital Cost Equation	Correlation Coefficient
Up to 18,000 (4 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 4212.7$	$R^2 = 0.9962$
18,000 ≤ flow <35,000 (8 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 9837.7$	$R^2 = 0.9962$
35,000≤ flow <70,000 (16 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 21088$	$R^2 = 0.9962$
70,000≤ flow <100,000 (24 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 32338$	$R^2 = 0.9962$
157,000 (35 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 49213$	$R^2 = 0.9962$
204,000 (46 VC)	$y = 0.071x^3 - 9.865x^2 + 775.03x + 66088$	$R^2 = 0.9962$
1) x represents the water depth in feet and y is the capital cost in dollars.		

Installation of Gunderboom Marine Life Exclusion Systems (MLES)

A Gunderboom Marine Life Exclusion System (MLES) utilizes a stationary double-layered filter barrier curtain to prevent entrainment and impingement of aquatic organisms around the CWIS. The MLES consists of a patented filter curtain made of polypropylene/polyester fabric suspended through the full depth of the water column.

Gunderbooms allow for the passage of water, while preventing the passage of aquatic life and particulates into the CWIS. This is achieved by surrounding the intake structure with the filter curtain and sealing the curtain against the seafloor and shoreline structures. Water passing through the curtain does so at a lower velocity than that of the surrounding stream or water body. The MLES system is designed to allow a through-fabric velocity of approximately 0.01 to 0.05 feet/second (fps), yielding an average velocity of approximately 0.02 fps. The system may be designed for lower or higher flows, as needed.

The Gunderboom is enhanced by an automated "Air Burst" cleaning system. This system uses periodic bursts of air between the two fabric layers to free any organisms or debris caught against the filter curtain.

Based on information provided by the manufacturer, the main advantages of the MLES system are:

- The system has been demonstrated to reduce entrainment by at least 80 percent. According to Gunderboom, the MLES can produce up to 100 percent exclusion for many applications.
- The Gunderboom fabric consists of a minute fiber matting with an Apparent Opening Size (AOS) of approximately 20 microns. As such, the system has been shown to significantly reduce turbidity, suspended solids, coliform bacteria, and other particulate-associated contaminants. For MLES systems, perforations ranging in diameter from 0.4 mm to 3.0 mm or more are added to increase the flow of water through the fabric. Perforation size can be customized to prevent entrainment of the specific eggs or fish larvae that are present at the installation site.
- The double fabric layer system with an "Air Burst" Technology cleaning system reduces overall O&M costs. Since debris and sediment are excluded, the Gunderboom may also help reduce O&M costs for intake screens, condensers and other parts of the cooling water system.
- Once the anchoring and "Air Burst" Technology have been installed, deployment of the MLES can be achieved in two to three weeks, barring logistics or weather problems, and requires no or minimal plant shutdown.

Gunderbooms are designed and engineered for the specific site at which they are to be installed. The designs may include plant intakes, floating walkways, pile-supported structures, concrete submerged structures, removable panels and solid frames. However, and in general, the key parameters that may have a significant impact on estimating the cost of the Gunderboom system are:

- CWIS flow rates,
- Physical factors of the water body and facility intake structure,
- Target species and life stages,
- Water body characteristics, including elevation changes, currents, wind-induced wave action and suspended sediment concentrations,
- Degree of automation, and
- Water quality

Factors such as the CWIS flow rates and physical factors of the water body and intake structure affect the capital cost because they determine the required size of the Gunderboom filter curtain. Other factors such as water quality and degree of automation contribute to greater O&M costs.

Installation

The Gunderboom MLES installation cost is largely a function of site conditions. Strong current flow, winds, wave action, and low accessibility can make installation more difficult. However, for the purpose of developing national cost estimates, EPA did not consider abnormal conditions in developing its cost equations and cost curves.

Capital Costs

EPA estimated capital costs of the MLES system based on information submitted by representatives of Gunderboom, Inc. Low and high capital cost estimates were provided for flows of 10,000, 104,000, and 347,000 gpm. EPA then calculated average capital costs as shown in Table 2-28. For purposes of estimating costs, EPA assumed that a simple floating configuration, as opposed to a rigid configuration, would be used.

Table 2-28. Estimated Capital Costs for a Simple Floating Gunderboom Structure			
Flow (gpm)	Low Cost	High Cost	Average Cost
10,000	$500,000	$700,000	$600,000
104,000	$1,800,000	$2,500,000	$2,150,000
347,000	$5,700,000	$7,800,000	$6,750,000

According to the manufacturers, the cost of a fixed system for a CWIS of 10,000 gpm capacity ranges between $0.7M and $1.5M while the cost of a complete independent system can be greater than $2M.

Operation and Maintenance (O&M) Costs

EPA also estimated O&M costs of the MLES system based on information submitted by representatives of Gunderboom, Inc. Low and high O&M cost estimates were provided for flows of 10,000, 104,000, and 347,000 gpm. EPA then calculated average O&M costs as shown in Table 2-29. Again, a simple floating configuration was assumed.

Table 2-29. Estimated O&M Costs for a Simple Floating Gunderboom Structure			
Flow (gpm)	Low Cost	High Cost	Average Cost
10,000	$100,000	$300,000	$200,000
104,000	$150,000	$300,000	$225,000
347,000	$500,000	$700,000	$600,000

EPA plotted the high, low and average capital as well as the average O&M costs, then fitted equations and curves to the data as shown in Chart 2-30. In the cost equations, "x" represents the flow volume in gpm, and "y" represents the total capital or annual O&M cost.

Branching the intake pipe to increase the number of openings or widening the intake pipe

Branching an intake pipe involves the use of fittings to attach the separate pipe sections. See the end of this chapter for costs curves and equations.

2.9.3 Design and Construction Technologies to Reduce Damage from I&E

Installation of traveling screens with fish baskets

Single-entry, single-exit vertical traveling screens (conventional traveling screens) contain a series of wire mesh screen panels that are mounted end to end on a band to form a vertical loop. As water flows through the panels, debris and fish that are larger than the screen openings are caught on the screen or at the base of each panel in a basket. As the screen rotates around, each panel in turn reaches a top area where a high-pressure jet spray wash pushes debris and fish from the basket into a trash trough for disposal. As the screen rotates over time, the clean panels move down, back into the water to screen the intake flow.

Conventional traveling screens can be operated continuously or intermittently. However, when these screens are fitted with fish baskets (also called modified conventional traveling screens or Ristroph screens), the screens must be operated continuously so that fish that are collected in the fish baskets can be released to a bypass/return using a low pressure spray wash when the basket reaches the top of the screen. Once the fish have been removed, a high pressure jet spray wash is typically used to remove debris from the screen. In recent years, the design of fish baskets has been refined (e.g., deeper baskets, smoother mesh, better balance) to decrease chances of injury and mortality and to better retain fish (i.e., prevent them from flopping out and potentially being injured). Methods used to protect fish include the Stabilized Integral Marine Protective Lifting Environment (S.I.M.P.L.E.) developed by Brackett Green and the Modified Ristroph design by U.S. Filter.

U.S. Filter's conventional (through flow) traveling screens are typically manufactured in widths ranging from two feet to at least 14 feet, for channel depths of up to 100 feet, although custom design is possible to fit other dimensions.

Flow

To calculate the flow through a screen panel, the width of the screen panel is multiplied by the water depth and, using the desired flow velocities (1 foot per second and 0.5 foot per second), is converted to gallons per minute assuming a screen efficiency of 50 percent. The calculated flows for selected screen widths, water depths, and well depths are presented in Tables 2-30 and 2-31. For flows greater than this, a facility would generally install multiple screens or use a custom design.

Well depth includes the height of the structure above the water line. The well depth can be more than the water depth by a few to tens of feet. The flow velocities used are representative of a flow speed that is generally considered to be fish friendly particularly for sensitive species (0.5 fps), and a flow speed that may be more practical for some facilities to achieve but typically provides less fish protection. The water depths and well depths are approximate and may vary based on actual site conditions.

Table 2-30. Average Flow Through A Traveling Water Screen (gpm) for a Flow Velocity of 1.0 fps

Well Depth (ft)	Water Depth (ft)	Basket Panel Screening Width (ft) 2	5	10	14
10	8	4000	9000	18,000	25,000
25	20	9000	22,000	45,000	63,000
50	30	13,000	34,000	67,000	94,000
75	50	22,000	56,000	112,000	157,000
100	65	29,000	73,000	146,000	204,000

Table 2-31. Average Flow Through A Traveling Water Screen (gpm) for a Flow Velocity of 0.5 fps

Well Depth (ft)	Water Depth (ft)	Basket Screening Panel Width (ft) 2	5	10	14
10	8	2000	4000	9000	13,000
25	20	4000	11,000	22,000	31,000
50	30	7000	17,000	34,000	47,000
75	50	11,000	28,000	56,000	79,000
100	65	15,000	36,000	73,000	102,000

Capital Costs

Equipment Cost

Basic costs for screens with flows comparable to those shown in the above tables are presented in Tables 2-32 and 2-33. Table 2-32 contains estimated costs for basic traveling screens without fish handling features, that have a carbon steel structure coated with epoxy paint. The costs presented in Table 2-33 are for traveling screens with fish handling features including a spray system, a fish trough, housings and transitions, continuous operating features, a drive unit, frame seals, and engineering. Installation costs and spray pump costs are presented separately below.

Table 2-32. Estimated Equipment Cost for Traveling Water Screens Without Fish Handling Features[1] (1999 Dollars)

Well Depth (ft)	Basket Screening Panel Width (ft)			
	2	5	10	14
10	$30,000	$35,000	$45,000	$65,000
25	$35,000	$45,000	$60,000	$105,000
50	$55,000	$70,000	$105,000	$145,000
75	$75,000	$100,000	$130,000	$175,000
100	$115,000	$130,000	$155,000	$200,000

1) Cost includes carbon steel structure coated with epoxy paint and non-metallic trash baskets with Type 304 stainless mesh and intermittent operation components.

Source: Vendor estimates.

Table 2-33. Estimated Equipment Cost for Traveling Water Screens With Fish Handling Features[1] (1999 Dollars)

Well depth (ft)	Basket Screening Panel Width (ft)			
	2	5	10	14
10	$63,500	$73,500	$94,000	$135,500
25	$81,250	$97,500	$133,000	$214,000
50	$122,500	$152,000	$218,000	$319,500
75	$163,750	$210,000	$283,000	$414,500
100	$225,000	$267,500	$348,000	$504,500

1) Cost includes carbon steel screen structure coated with epoxy paint and non-metallic fish handling panels, spray systems, fish trough, housings and transitions, continuous operating features, drive unit, frame seals, and engineering (averaged over 5 units). Costs do *not* include differential control system, installation, and spray wash pumps.

Source: Vendor estimates.

Installation Cost

Installation costs of traveling screens are based on the following assumptions of a typical average installation requirement for a hypothetical scenario. Site preparation and earth work are calculated based on the following assumptions:

Clearing and grubbing: Clearing light to medium brush up to 4" diameter with a bulldozer.
Earthwork: Excavation of heavy soils. Quantity is based on the assumption that earthwork increases with screen width.
Paving and surfacing: Using concrete 8" thick and assuming that the cost of pavement attributed to screen installation is 6x3 yards for the smallest screen and 25x6 yards for the largest screen.
Structural concrete: The structural concrete work attributed to screen installation is four 12"x12" reinforced concrete columns with depths varying between 1.5 yards and 3 yards. There is more structural concrete work for a water intake structure, however, for new source screens and retrofit screens, only a portion of the intake structural cost can be justifiably attributed to the screen costs. For new screens, most of the concrete structure work is for developing the site to make it accessible for equipment and protect it from hydraulic elements, which are necessary for constructing the intake itself. For retrofits, some of the structural concrete will already exist and some of it will not be needed since the intake is already in place and only the screen needs to be installed. All unit costs used in calculating on-shore site preparation were obtained from *Heavy Construction Cost Data 1998* (R. S. Means, 1997b).

Table 2-34 presents site preparation installation costs that apply to traveling screens both with and without fish handling features. The total onshore construction costs are for a screen to be installed in a 10-foot well depth. Screens to be installed in deeper water are assumed to require additional site preparation work. Hence for costing purposes it is assumed that site preparation costs increase at a rate of an additional 25 percent per depth factor (calculated as the ratio of the well depth to the base well depth of 10 feet) for well depths greater than 10 feet. Table 2-35 presents the estimated costs of site preparation for four sizes of screen widths and various well depths.

Table 2-34. Estimated Installation (Site Preparation) Costs for Traveling Water Screens Installed at a 10-foot Well Depth (1999 Dollars)

Screen Width (ft)	Clearing and Grubbing (acre)	Clearing Cost[1]	Earth Work (cy)	Earth Work Cost[1]	Paving and Surfacing Using Concrete (sy)	Paving Cost[1]	Structural Concrete (cy)	Structural Cost	Total Onshore Construction Costs
2	0.1	$250	200	$17,400	18	$250	0.54	$680	$19,000
5	0.35	$875	500	$43,500	40	$560	0.63	$790	$46,000
10	0.7	$1,750	1000	$87,000	75	$1,050	0.72	$900	$91,000
14	1	$2,500	1400	$121,800	150	$2,100	1.08	$1,350	$128,000

ft = feet, cy=cubic yard, sy=square yard
1) Clearing cost @ $2,500/acre, earth work cost @ $87/cubic yard, paving cost @ $14/square yard, structural cost @ $1,250/cubic yard.
Source of unit costs: *Heavy Construction Cost Data 1998* (R.S. Means, 1997b).

Table 2-35. Estimated Installation (Site Preparation, Construction, and Onshore Installation) Costs for Traveling Water Screens of Various Well Depths (1999 Dollars)

Well Depth (ft)	Screen Panel Width (ft)			
	2	5	10	14
10	$19,000	$46,000	$91,000	$128,000
25	$31,000	$75,000	$148,000	$208,000
50	$43,000	$104,000	$205,000	$288,000
75	$55,000	$132,000	$262,000	$368,000
100	$67,000	$161,000	$319,000	$448,000

Source: R.S. Means (1997b) and vendor estimates.

EPA developed a hypothetical scenario of a typical underwater installation to estimate an average cost for underwater installation costs. EPA estimated costs of personnel and equipment per day, as well as mobilization and demobilization. Personnel and equipment costs would increase proportionately based on the number of days of a project, however mobilization and demobilization costs would be relatively constant regardless of the number of days of a project since the cost of transporting personnel and equipment is largely independent of the length of a project. The hypothetical project scenario and estimated costs are presented in Box 2-1. Hypothetical scenario was used to develop installation cost estimates as function of screen width/well depth. Installation costs were then included with total cost equations. To cost facilities, EPA selected appropriate screen width based on flow.

As shown in the hypothetical scenario in Box 2-1, the estimated cost for a one-day installation project would be $8,000 ($4,500 for personnel and equipment, plus $3,500 for mobilization and demobilization). Using this one-day cost estimate as a basis, EPA generated estimated installation costs for various sizes of screens under different scenarios. These costs are presented in Table 2-35. The baseline costs for underwater installation include the costs of a crew of divers and equipment including mobilization and demobilization, divers, a barge, and a crane. The number of days needed is based on a minimum of one day for a screen of less than 5 feet in width and up to 10 feet in well depth. Using best professional judgement (BPJ), EPA estimated the costs for larger jobs assuming an increase of two days for every increase in well depth size and of one day for every increase in screen width size.

Box 2-1. Example Scenario for Underwater Installation of an Intake Screen System

This project involves the installation of 12, t-24 passive intake screens onto a manifold inlet system. Site conditions include a 20-foot water depth, zero to one-foot underwater visibility, 60-70 °F water temperature, and fresh water at an inland. The installation is assumed to be 75 yards offshore and requires the use of a barge or vessel with 4-point anchor capability and crane.

Job Description:
Position and connect water intake screens to inlet flange via 16 bolt/nut connectors. Lift, lower, and position intake screens via crane anchored to barge or vessel. Between 4 and 6 screens of the smallest size can be installed per day per dive team, depending on favorable environmental conditions.

Estimated Personnel Costs:
Each dive team consists of 5 people (1 supervisor, 2 surface tenders, and 2 divers), the assumed minimum number of personnel needed to operate safely and efficiently. The labor rates are based on a 12-hour work day. The day rate for the supervisor is $600. The day rate for each diver is $400. The day rate for each surface tender is $200. Total base day rate per dive team is $1,800.

Estimated Equipment Costs:
Use of hydraulic lifts, underwater impact tools, and other support equipment is $450 per day. Shallow water air packs and hoses cost $100 per day. The use of a crane sufficient to lift the 375 lb t-24 intakes is $300 per day. A barge or vessel with 4-point anchor capability can be provided by either a local contractor or the dive company for $1,800 per day (cost generally ranges from $1,500-$2,000 per day). This price includes barge/vessel personnel (captain, crew, etc) but the barge/vessel price does not include any land/waterway transportation needed to move barge/vessel to inland locations. Using land-based crane and dive operations can eliminate the barge/vessel costs. Thus total equipment cost is $2,650 per day.

Estimated Mobilization and Demobilization Expenses:
This includes transportation of all personnel and equipment to the job site via means necessary (air, land, sea), all hotels, meals, and ground transportation. An accurate estimate on travel can vary wildly depending on job location and travel mode. For this hypothetical scenario, costs are estimated for transportation with airfare, and boarding and freight and would be $3,500 for the team (costs generally range between $3,000 and $4,000 for a team).

Other Considerations:
Uncontrollable factors like weather, water temperature, water depth, underwater visibility, currents, and distance to shore can affect the daily production of the dive team. These variables always have to be considered when a job is quoted on a daily rate. Normally, the dive-company takes on the risks for these variables because the job is quoted on a "to completion" status. These types of jobs usually take a week or more for medium to large-size installations.

Total of Estimated Costs:
The final estimated total for this hypothetical job is nearly $4500 per day for personnel and equipment. For a three-day job, this would total about $13,500. Adding to this amount about $3,500 for mobilization and demobilization, the complete job is estimated at $17,000.

Note: Costs for a given project vary greatly depending on screen size, depth of water, and other site-specific conditions such as climate and site accessibility.

Table 2-36. Estimated Underwater Installation Costs for Various Screen Widths and Well Depths[1] (1999 Dollars)

Well Depth (ft)	Basket Screening Panel Width (ft) 2	5	10	14
10	$8,000	$12,500	$17,000	$21,500
25	$17,000	$21,500	$26,000	$30,500
50	$26,000	$30,500	$35,000	$39,500
75	$35,000	$39,500	$44,000	$48,500
100	$44,000	$48,500	$53,000	$57,500

1) Based on hypothetical scenario of crew and equipment costs of $4,500 per day and mobilization and demobilization costs of $3,500 (see Box 2-1).

Table 2-37 presents total estimated installation costs for traveling screens. Installation costs for traveling screens with fish handling features and those without fish handling features are assumed to be similar.

Table 2-37. Estimated Total Installation Costs for Traveling Water Screens[1] (1999 Dollars)

Well Depth (ft)	Basket Screening Panel Width (ft) 2	5	10	14
10	$27,000	$58,500	$108,000	$149,500
25	$48,000	$96,500	$174,000	$238,500
50	$69,000	$134,500	$240,000	$327,500
75	$90,000	$171,500	$306,000	$416,500
100	$111,000	$209,500	$372,000	$505,500

1) Includes site preparation, and onshore and underwater construction and installation costs.

Total Estimated Capital Costs

The installation costs in Table 2-37 were added to the equipment costs in Tables 2-32 and 2-33 to derive total equipment and installation costs for traveling screens with and without fish handling features. These estimated costs are presented in Tables 2-38 and 2-39. The flow volume corresponding to each screen width and well depth combination varies based on the through screen flow velocity. These flow volumes were presented in Tables 2-30 and 2-31 for flow velocities of 1.0 fps and 0.5 fps, respectively.

Table 2-38. Estimated Total Capital Costs for Traveling Screens Without Fish Handling Features (Equipment and Installation)[1] (1999 Dollars)				
Well Depth (ft)	Screening Basket Panel Width (ft)			
	2	5	10	14
10	$57,000	$93,500	$153,000	$214,500
25	$83,000	$141,500	$234,000	$343,500
50	$124,000	$204,500	$345,000	$472,500
75	$165,000	$271,500	$436,000	$591,500
100	$226,000	$339,500	$527,000	$705,500

1) Costs include carbon steel structure coated with an epoxy paint, non-metallic trash baskets with Type 304 stainless mesh, and intermittent operation components and installation.

Table 2-39. Estimated Total Capital Costs for Traveling Screens With Fish Handling Features (Equipment and Installation)[1] (1999 Dollars)				
Well Depth (ft)	Screening Basket Panel Width (ft)			
	2	5	10	14
10	$90,500	$132,000	$202,000	$285,000
25	$129,250	$194,000	$307,000	$453,000
50	$191,500	$287,000	$458,000	$647,000
75	$253,750	$381,500	$589,000	$831,000
100	$336,000	$477,000	$720,000	$1,010,000

1) Costs include non-metallic fish handling panels, spray systems, fish trough, housings and transitions, continuous operating features, drive unit, frame seals, engineering (averaged over 5 units), and installation. Costs do *not* include differential control system and spray wash pumps.

Tables 2-40 and 2-41 present equations that can be used to estimate costs for traveling screens at 0.5 fps and 1.0 fps, respectively. See the end of this chapter for cost curves and equations.

Table 2-40. Capital Cost Equations for Traveling Screens for Velocity of 0.5 fps				
Screen Width (ft)	Traveling Screens with Fish Handling Equipment		Traveling Screens without Fish Handling Equipment	
	Equation[1]	Correlation Coefficient	Equation[1]	Correlation Coefficient
2	$y = 6E\text{-}08x^3 - 0.0014x^2 + 28.994x + 36372$	$R^2 = 0.9992$	$y = 5E\text{-}08x^3 - 0.0013x^2 + 20.892x + 18772$	$R^2 = 0.9991$
5	$y = 1E\text{-}09x^3 - 8E\text{-}05x^2 + 12.223x + 80790$	$R^2 = 0.994$	$y = 2E\text{-}09x^3 - 0.0001x^2 + 9.7773x + 54004$	$R^2 = 0.9995$
10	$y = 5E\text{-}10x^3 - 9E\text{-}05x^2 + 12.726x + 88302$	$R^2 = 0.9931$	$y = 5E\text{-}03x^3 - 9E\text{-}05x^2 + 10.143x + 63746$	$R^2 = 0.9928$
14	$y = 6E\text{-}10x^3 - 0.0001x^2 + 15.874x + 91207$	$R^2 = 0.995$	$y = 5E\text{-}10x^3 - 0.0001x^2 + 12.467x + 65934$	$R^2 = 0.9961$

1) x is the flow in gpm y is the capital cost in dollars.

Table 2-41. Capital Cost Equations for Traveling Screens for Velocity of 1 fps				
Screen Width (ft)	Traveling Screens with Fish Handling Equipment		Traveling Screens without Fish Handling Equipment	
	Equation[1]	Correlation Coefficient	Equation[1]	Correlation Coefficient
2	$y = 8E\text{-}09x^3 - 0.0004x^2 + 15.03x + 33044$	$R^2 = 0.9909$	$y = 8E\text{-}09x^3 - 0.0004x^2 + 10.917x + 16321$	$R^2 = 0.9911$
5	$y = 2E\text{-}10x^3 - 3E\text{-}05x^2 + 6.921x + 68688$	$R^2 = 0.9948$	$y = 3E\text{-}10x^3 - 4E\text{-}05x^2 + 5.481x + 44997$	$R^2 = 0.9962$
10	$y = 5E\text{-}11x^3 - 2E\text{-}05x^2 + 6.2849x + 88783$	$R^2 = 0.9906$	$y = 5E\text{-}11x^3 - 2E\text{-}05x^2 + 5.0073x + 64193$	$R^2 = 0.9902$
14	$y = 5E\text{-}11x^3 - 2E\text{-}05x^2 + 7.1477x + 113116$	$R^2 = 0.9942$	$y = 5E\text{-}11x^3 - 2E\text{-}05x^2 + 5.6762x + 81695$	$R^2 = 0.9952$

1) x is the flow in gpm y is the capital cost in dollars.

Operation and Maintenance (O&M) Costs for Traveling Screens

O&M costs for traveling screens vary by type, size, and mode of operation of the screen. Based on discussions with industry representatives, EPA estimated annual O&M cost as a percentage of total capital cost. The O&M cost factor ranges between 8 percent of total capital cost for the smallest size traveling screens with and without fish handling equipment and 5 percent for the largest traveling screen since O&M costs do not increase proportionately with screen size. Estimated annual O&M costs for traveling screens with and without fish handling features are presented in Tables 2-32 and 2-33, respectively. As noted earlier, the flow volume corresponding to each screen width and well depth combination varies based on the through screen flow velocity. These flow volumes were presented in Tables 2-42 and 2-43 for flow velocities of 1.0 fps and 0.5 fps, respectively.

Table 2-42. Estimated Annual O&M Costs for Traveling Water Screens Without Fish Handling Features (Carbon Steel - Standard Design)[1] (1999 Dollars)				
	Screen Panel Width (ft)			
Well Depth (ft)	2	5	10	14
10	$4560	$6545	$7650	$12,870
25	$5810	$9905	$14,040	$17,175
50	$8680	$12,270	$17,250	$23,625
75	$11,550	$16,290	$21,800	$29,575
100	$13,560	$16,975	$26,350	$35,275

1) Annual O&M costs range between 8 percent of total capital cost for the smallest size traveling screens with and without fish handling equipment and 5 percent for the largest traveling screen.

Table 2-43. Estimated Annual O&M Costs for Traveling Water Screens With Fish Handling Features (Carbon Steel Structure, Non-Metallic Fish Handling Screening Panel)[1] (1999 Dollars)

Well Depth (ft)	Screen Panel Width (ft) 2	5	10	14
10	$7240	$9240	$10,100	$17,100
25	$9048	$13,580	$18,420	$22,650
50	$13,405	$17,220	$22,900	$32,350
75	$17,763	$22,890	$29,450	$41,550
100	$20,160	$23,850	$36,000	$50,500

1) Annual O&M costs range between 8 percent of total capital cost for the smallest size traveling screens with and without fish handling equipment and 5 percent for the largest traveling screen.

The tables below present O&M cost equations generated from the above tables for various screen sizes and water depths at velocities of 0.5 fps and 1 fps, respectively. The "x" value of the equation is the flow and the "y" value is the O&M cost in dollars.

Table 2-44: Annual O&M Cost Equations for Traveling Screens Velocity 0.5 fps

Screen Width (ft)	Traveling Screens with Fish Handling Equipment: Equation[1]	Correlation Coefficient	Traveling Screens without Fish Handling Equipment: Equation[1]	Correlation Coefficient
2	$y = -3E\text{-}05x^2 + 1.6179x + 3739.1$	$R^2 = 0.9943$	$y = -2E\text{-}05x^2 + 1.0121x + 2392.4$	$R^2 = 0.9965$
5	$y = -1E\text{-}05x^2 + 0.8563x + 5686.3$	$R^2 = 0.9943$	$y = -7E\text{-}06x^2 + 0.6204x + 4045.7$	$R^2 = 0.9956$
10	$y = -2E\text{-}06x^2 + 0.5703x + 5864.4$	$R^2 = 0.9907$	$y = 9E\text{-}11x^3 - 1E\text{-}05x^2 + 0.8216x + 1319.5$	$R^2 = 0.9997$
14	$y = 5E\text{-}12x^3 - 1E\text{-}06x^2 + 0.4835x + 10593$	$R^2 = 0.9912$	$y = 8E\text{-}12x^3 - 2E\text{-}06x^2 + 0.3899x + 7836.7$	$R^2 = 0.9922$

1) x is the flow in gpm and y is the annual O&M cost in dollars.

Table 2-45. Annual O&M Cost Equations for Traveling Screens Velocity 1 fps

Screen Width (ft)	Traveling Screens with Fish Handling Equipment: Equation[1]	Traveling Screens with Fish Handling Equipment: Correlation Coefficient	Traveling Screens without Fish Handling Equipment: Equation[1]	Traveling Screens without Fish Handling Equipment: Correlation Coefficient
2	$y = -8E\text{-}06x^2 + 0.806x + 3646.7$	$R^2 = 0.982$	$y = -4E\text{-}06x^2 + 0.5035x + 2334$	$R^2 = 0.9853$
5	$y = -3E\text{-}06x^2 + 0.4585x + 5080.7$	$R^2 = 0.9954$	$y = -2E\text{-}06x^2 + 0.3312x + 3621.1$	$R^2 = 0.9963$
10	$y = -6E\text{-}07x^2 + 0.2895x + 5705.3$	$R^2 = 0.9915$	$y = 1E\text{-}11x^3 - 3E\text{-}06x^2 + 0.4047x + 1359.4$	$R^2 = 1$
14	$y = -3E\text{-}13x^3 - 4E\text{-}08x^2 + 0.2081x + 11485$	$R^2 = 0.9903$	$y = 4E\text{-}13x^3 - 3E\text{-}07x^2 + 0.1715x + 8472.1$	$R^2 = 0.9913$

1) x is the flow in gpm and y is the annual O&M cost in dollars.

Adding fish baskets to existing traveling screens

Capital Costs

Table 2-46 presents estimated costs of fish handling equipment without installation costs. These estimated costs represent the difference between costs for equipment with fish handling features (Table 2-33) and costs for equipment without fish handling features (Table 2-32), plus a 20 percent add-on for upgrading existing equipment (mainly to convert traveling screens from intermittent operation to continuous operation).[9] These costs would be used to estimate equipment capital costs for upgrading an existing traveling water screen to add fish protection and fish return equipment.

Table 2-46. Estimated Capital Costs of Fish Handling Equipment (1999 Dollars)

Well Depth (ft)	Basket Screening Panel Width (ft): 2	5	10	14
10	$40,200	$46,200	$58,800	$84,600
25	$55,500	$63,000	$87,600	$131,400
50	$81,000	$99,000	$135,600	$209,400
75	$106,500	$132,000	$183,600	$287,400
100	$132,000	$165,000	$231,600	$365,400

Source: Vendor estimates.

Installation of Fish Handling Features to Existing Traveling Screens

As stated earlier, the basic equipment cost of fish handling features (presented in Table 2-46) is calculated based on the difference in cost between screens with and without fish handling equipment, plus a cost factor of 20 percent for upgrading the existing system from intermittent to continuous operation. Although retrofitting existing screens with fish handling

[9]This 20 percent additional cost for upgrades to existing equipment was included based on recommendations from one of the equipment vendors supplying cost data for this research effort.

equipment will require upgrading some mechanical equipment, installing fish handling equipment generally will not require the use of a costly barge that is equipped with a crane and requires a minimum number of crew to operate it. EPA assumed that costs are 75 percent of the underwater installation cost (Table 2-36) for a traveling screen (based on BPJ). Table 2-47 shows total estimated costs (equipment and installation) for adding fish handling equipment to an existing traveling screen.

Table 2-47. Estimated Capital Costs of Fish Handling Equipment and Installation[1] (1999 Dollars)

Well Depth (ft)	Basket Screening Panel Width (ft)			
	2	5	10	14
10	$46,200	$55,575	$71,550	$100,725
25	$68,250	$79,125	$107,100	$154,275
50	$100,500	$121,875	$161,850	$239,025
75	$132,750	$161,625	$216,600	$323,775
100	$165,000	$201,375	$271,350	$408,525

1) Installation portion of the costs estimated as 75 percent of the *underwater* installation cost for installing a traveling water screen.

The additional O&M costs due to the installation of fish baskets on existing traveling screens can be calculated by subtracting the O&M costs for basic traveling screens from the O&M costs for traveling screens with fish baskets. See the end of this chapter for cost curves and equations.

2.10 Additional Cost Considerations

To account for other minor cost elements, EPA estimates that 5 percent may need to be added to the total cost for each alteration. Minor cost elements include:

Permanent buoys for shallow waters to warn fishing boats and other boats against dropping anchor over the pipes. Temporary buoys and warning signs during construction.

Additional permit costs. Permit costs may increase because of the trenching and dredging for pipe installation.

Facility replanning/redesign costs may be incurred if the facility is far enough along in the facility planning and development process. This cost would likely be minimal to negligible for most of the alterations discussed above, but could be much higher for switching a facility to a recirculating cooling system.

Monitoring costs (e.g., to test for contaminated sediments).

As noted earlier, if the intake structure installation involves disturbance of contaminated sediments, the permitting authority may require special construction procedures, including hauling the sediments to an appropriate disposal facility offsite. This may increase the cost of the project by more than two to three times the original cost estimate.

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In addition to the references listed below, EPA recognizes contributions from the following individuals and organizations: Russel Bellman and Brian Julius, Acting Chief, Gulf Coast Branch NOAA Damage Assessment Center, Silver Spring, MD, of the National Oceanic and Atmospheric Administration; Adnan Alsaffar, Arman Sanver, and John Gantnier, Bechtel Power Corporation, Fredrick, MD; Gary R. Mirsky Vice President, Hamon Cooling Towers, Somerville, NJ; Jim Prillaman, Prillaman Cooling Towers, Richmond, VA; Ken Campbell GEA Power Systems, Denver, CO and David Sanderlin, GEA Power Systems, San Diego, CA; Michael D. Quick, Manager - Marketing / Communications, U.S. Filter - Envirex Products, Waukesha, WI; Trent T. Gathright, Fish Handling Band Screen Specialist, Marketing Manager, Brackett Geiger USA, Inc., Houston, TX; Richard J. Sommers, U.S. Filter Intake Systems, Chalfont, PA; Ken McKay, VP Sales/Marketing, USF Intake Products; and Larry Sloan, District Representative, Sloan Equipment Sales Co.,Inc., Owings Mills, MD.

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Chapter 3: Energy Penalties, Air Emissions, and Cooling Tower Side-Effects

INTRODUCTION

This chapter discusses the topics of energy penalties, air emissions, and other environmental impacts of cooling tower systems. The final rule projects that nine new facility power plants will install recirculating closed-cycle wet cooling systems as a result of this rule. These systems, mainly represented by natural-draft wet cooling towers, may present trade-offs in energy efficiency, associated air emissions increases, and some other environmental issues.

The energy penalty is an important and controversial topic for the electricity generation industry. The topic is widely discussed and debated, yet precise theoretical or empirical measures of energy penalties were not readily available to met the Agency's needs. Therefore, the Agency researched and derived energy penalty estimates, based on empirical data and proven theoretical concepts, for a variety of conditions. This chapter presents the research, methodology, public comments, results, and conclusions for the Agency's thorough effort to estimate energy penalties due to the operational performance of power plant cooling systems.

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As a consequence of energy penalties for some cooling systems, increased air pollutant emissions may occur for some power plants as compared to a baseline system. This chapter presents estimates of the increased air emissions for the four key pollutants that are currently well researched and monitored for at power plants in the United States: carbon dioxide (CO2), sulfur dioxide (SO2), nitrogen oxides (NOx), and mercury (Hg).

The remainder of this chapter is organized as follows:

Section 3.1 presents the energy penalty estimates developed for the final rule and the dry cooling regulatory alternative.

Section 3.2 presents the air emissions estimates developed for the final rule and the dry cooling regulatory alternative.

Section 3.3 presents the background, research, and methodology of the energy penalty evaluation. The section focuses on power plants that use steam turbines and the changes in efficiency associated with using alternative cooling systems.

Section 3.4 presents the methodology for estimation of air emissions increases.

Section 3.5 discusses side effects of recirculating wet cooling towers, such as vapor plumes, displacement of habitat or wetlands, noise, salt or mineral drift, water consumption through evaporation, and solid waste generation due to wastewater treatment of tower blowdown.

3.1 Energy Penalty Estimates for Cooling

Tables 3-1 through 3-6 present the energy penalty estimates developed for the final rule and the dry cooling regulatory alternative. The Agency presents the methodology for estimation of energy penalties in Section 3.3 of this chapter.

Table 3-1: National Average Annual Energy Penalty, Summary Table

Cooling Type	Percent Maximum Load[a]	Nuclear Percent of Plant Output	Combined-Cycle Percent of Plant Output	Fossil-Fuel Percent of Plant Output
Wet Tower vs. Once-Through	67	1.7	0.4	1.7
Dry Tower vs. Once-Through	67	8.5	2.1	8.6
Dry Tower vs. Wet Tower	67	6.8	1.7	6.9

[a] Average annual penalties occur at non-peak loads..

Table 3-2: National Peak Summer Energy Penalty, Summary Table

Cooling Type	Percent Maximum Load[a]	Nuclear Percent of Plant Output	Combined-Cycle Percent of Plant Output	Fossil-Fuel Percent of Plant Output
Wet Tower vs. Once-Through	100	1.9	0.4	1.7
Dry Tower vs. Once-Through	100	11.4	2.8	10.0
Dry Tower vs. Wet Tower	100	9.6	2.4	8.4

[a] Peak-summer shortfalls occur when plants are at or near maximum capacity.

Table 3-3: Total Energy Penalties at 67 Percent Maximum Load[a]				
Location	**Cooling Type**	**Nuclear Annual Average**	**Combined-Cycle Annual Average**	**Fossil-Fuel Annual Average**
Boston	Wet Tower vs. Once-Through	1.6	0.4	1.6
	Dry Tower vs. Once-Through	7.4	1.8	7.1
	Dry Tower vs. Wet Tower	5.8	1.4	5.5
Jacksonville	Wet Tower vs. Once-Through	1.9	0.4	1.7
	Dry Tower vs. Once-Through	12.0	3.0	12.5
	Dry Tower vs. Wet Tower	10.1	2.5	10.8
Chicago	Wet Tower vs. Once-Through	1.8	0.4	1.8
	Dry Tower vs. Once-Through	7.8	1.9	7.7
	Dry Tower vs. Wet Tower	5.9	1.5	5.9
Seattle	Wet Tower vs. Once-Through	1.5	0.4	1.5
	Dry Tower vs. Once-Through	7.0	1.7	6.9
	Dry Tower vs. Wet Tower	5.5	1.3	5.4

[a] Average annual penalties occur at non-peak loads.

Table 3-4: Total Energy Penalties at 100 Percent Maximum Load[a]				
Location	**Cooling Type**	**Nuclear Percent of Plant Output**	**Combined-Cycle Percent of Plant Output**	**Fossil-Fuel Percent of Plant Output**
Boston	Wet Tower vs. Once-Through	2.1	0.5	1.9
	Dry Tower vs. Once-Through	11.6	2.9	10.2
	Dry Tower vs. Wet Tower	9.5	2.4	8.3
Jacksonville	Wet Tower vs. Once-Through	1.6	0.4	1.4
	Dry Tower vs. Once-Through	12.3	3.1	10.7
	Dry Tower vs. Wet Tower	10.7	2.7	9.3
Chicago	Wet Tower vs. Once-Through	2.2	0.5	2.0
	Dry Tower vs. Once-Through	11.9	2.9	10.4
	Dry Tower vs. Wet Tower	9.6	2.4	8.4
Seattle	Wet Tower vs. Once-Through	1.6	0.4	1.5
	Dry Tower vs. Once-Through	10.0	2.4	8.9
	Dry Tower vs. Wet Tower	8.4	2.0	7.4

[a] Peak-summer shortfalls occur when plants are at or near maximum capacity.

Table 3-5: Annual Penalties (in MW) for the Final Rule by Online Year[a]

Year	Coal-Fired Once-Through Cooling at Baseline	Combined-Cycle, Once-Through Cooling at Baseline
2001		
2002		
2003		
2004		4
2005	70	
2006		
2007	9	4
2008	1	
2009		
2010		4
2011		
2012		
2013		4
2014		
2015		
2016		
2017		4
2018		
2019		
2020		
Total	79	21

[a] The total energy penalty for the final rule is 100 MW, or 0.027 percent of all new generating capacity in the US over the next twenty years.

Table 3-6: Annual Penalties (in MW) for the Dry Cooling-Based Alternative by Online Year[a]

	Coal-Fired			Combined-Cycle		
Year	Recirculating Wet Cooling Baseline		Once-Through Baseline	Recirculating Wet Cooling Baseline		Once-Through Baseline
	Freshwater	Estuary	Freshwater	Freshwater	Estuary	Estuary
2001						
2002						
2003						
2004						22
2005			362	71	8	
2006	164			54	17	
2007	164	56	44	40		22
2008			5	77	8	
2009	108			46		
2010				61		22
2011				102	8	
2012				38		
2013				33		22
2014				54	8	
2015				35		
2016				34		
2017				30		22
2018				37	8	
2019	43			37		
2020	12			31		
Total	491	56	412	779	58	108

[a] The total energy penalty for the dry cooling option (at a total of 83 potentially impacted plants) would be 1900 MW, or 0.5 percent of all new capacity in the US over the next twenty years.

3.2 Air Emissions Estimates for Cooling Systems Upgrades

Tables 3-7 and 3-8 present the incremental air emissions estimates developed for the final rule and the dry cooling regulatory alternative. The Agency presents the methodology for estimation of air emissions increases in section 3.4 of this Chapter.

Table 3-7: Air Emissions Increases for the Final Rule[a]

Fuel Type	Total Effected Capacity (MW)	Annual CO_2 (tons)	Annual SO_2 (tons)	Annual NO_X (tons)	Annual Hg (lbs)
All	9,957	485,860	2,561	1,214	16

[a] These emissions increases represent an increase for the entire US electricity generation industry of approximately 0.02 percent per pollutant.

Table 3-8: Air Emissions Increases for the a Dry Cooling-Based Alternative[a]

Fuel Type	Total Effected Capacity (MW)	Annual CO_2 (tons)	Annual SO_2 (tons)	Annual NO_X (tons)	Annual Hg (lbs)
All	64,070	8,931,056	47,074	22,313	300

[a] These emissions increases represent an increase for the US electricity generation industry of approximately 0.35 percent. For the mercury emissions alone, these emissions are equivalent to the addition of three 800-MW coal-fired power plants operating at near full capacity.

3.3 Background, Research, and Methodology of Energy Penalty Estimates

This energy penalty discussion references the differences in steam power plant efficiency or output associated with the effect of using alternative cooling systems. In particular, this evaluation focuses on power plants that use steam turbines and the changes in efficiency associated with using alternative cooling systems. The cooling systems evaluated include: once-through cooling systems; wet tower closed-cycle systems; and dry cooling systems using air cooled condensers. However, the methodology is flexible as to be extended to other alternative types of cooling systems so long as the steam condenser performance or the steam turbine exhaust pressure can be estimated. A summary and discussion of public comments on EPA's energy penalty analysis is presented in Attachment F to this chapter.

3.3.1 Power Plant Efficiencies

Most power plants that use a heat-generating fuel as the power source use a steam cycle referred to as a "Rankine Engine," in which water is heated into steam in a boiler and the steam is then passed through a turbine (Woodruff 1998). After exiting the turbine, the spent steam is condensed back into water and pumped back into the boiler to repeat the cycle. The turbine, in turn, drives a generator that produces electricity. As with any system that converts energy from one form to another, not all of the energy available from the fuel source can be converted into useful energy in a power plant.

Steam turbines extract power from steam as the steam passes from high pressure and high temperature conditions at the turbine inlet to low pressure and lower temperature conditions at the turbine outlet. Steam exiting the turbine goes to the condenser, where it is condensed to water. The condensation process is what creates the low pressure conditions at the turbine outlet. The steam turbine outlet or exhaust pressure (which is often a partial vacuum) is a function of the temperature maintained at the condensing surface (among other factors) and the value of the exhaust pressure can have a direct effect on the energy available to drive the turbine. The lower the exhaust pressure, the greater the amount of energy that is available to drive the turbine, which in turn increases the overall efficiency of the system since no additional fuel energy is involved.

The temperature of the condensing surface is dependent on the design and operating conditions within the condensing system (e.g., surface area, materials, cooling fluid flow rate, etc.) and especially the temperature of the cooling water or air used to absorb heat and reject it from the condenser. Thus, the use of a different cooling system can affect the temperature maintained at the steam condensing surface (true in many circumstances). This difference can result in a change in the efficiency of the power plant. These efficiency differences vary throughout the year and may be more pronounced during the warmer months. Equally important is the fact that most alternative cooling systems will require a different amount of power to operate equipment such as fans and pumps, which also can have an effect on the overall plant energy efficiency. The reductions in energy output resulting from the energy required to operate the cooling system equipment are often referred to as parasitic losses.

In general, the penalty described here is only associated with power plants that utilize a steam cycle for power production. Therefore, this analysis will focus only on steam turbine power plants and combined-cycle gas plants. The most common steam turbine power plants are those powered by steam generated in boilers heated by the combustion of fossil fuels or by nuclear reactors.

Combined-cycle plants use a two-step process in which the first step consists of turbines powered directly by high pressure hot gases from the combustion of natural gas, oil, or gasified coal. The second step consists of a steam cycle in which a turbine is powered by steam generated in a boiler heated by the low pressure hot gases exiting the gas turbines. Consequently, the combined-cycle plants have much greater overall system efficiencies. However, the energy penalty associated with using alternative cooling systems is only associated with the steam cycle portion of the system. Because steam plants cannot be quickly started or stopped, they tend to be operated as base load plants which are continuously run to serve the minimum load required by the system. Since combined-cycle plants obtain only a portion of their energy from the slow-to-start/stop steam power step, the inefficiency of the start-up/stop time period is more economically acceptable and therefore they are generally used for intermediate loads. In other words, they are started and stopped at a greater frequency than base load steam plant facilities.

One measure of the plant thermal efficiency used by the power industry is the Net Plant Heat Rate (NPHR), which is the ratio of the total fuel heat input (BTU/hr) divided by the net electric generation (kW). The net electric generation includes only electricity that leaves the plant. The total energy plant efficiency can be calculated from the NPHR using the following formula:

$$\text{Plant Energy Efficiency} = 3473 / \text{NPHR} \times 100 \qquad (1)$$

Table 3-9 presents the NPHR and plant efficiency numbers for different types of power plants. Note that while there may be some differences in efficiencies for steam turbine systems using different fossil fuels, these differences are not significant enough for consideration here. The data presented to represent fossil fuel plants is for coal-fired plants, which comprise the majority in that category.

Table 3-9: Heat Rates and Plant Efficiencies for Different Types of Steam Powered Plants

Type of Plant	Net Plant Heat Rate (BTU/kWh)	Efficiency (%)
Steam Turbine - Fossil Fuel	9,355	37 to 40
Steam Turbine – Nuclear	10,200	34
Combined Cycle – Gas	6,762	51
Combustion Turbine	11,488	30

Source: Analyzing Electric Power Generation under the CAAA. Office of Air and Radiation U.S. Environmental Protection Agency. April 1996 (Projections for year 2000-2004).

Overall, fossil fuel steam electric power plants have net efficiencies with regard to the available fuel heat energy ranging from 37 to 40 percent. Attachment A at the end of this chapter (Ishigai, S. 1999.) shows a steam power plant heat diagram in which approximately 40 percent of the energy is converted to the power output and 44 percent exits the system through the condensation of the turbine exhaust steam, which exits the system primarily through the cooling system with the remainder exiting the system through various other means including exhaust gases. Note that the exergy diagram in Attachment A shows that this heat passing through the condenser is not a significant source of plant inefficiency, but as would be expected it shows a similar percent of available energy being converted to power as shown in Table 3-9 and Attachment A.

Nuclear plants have a lower overall efficiency of approximately 34 percent, due to the fact that they generally operate at lower boiler temperatures and pressures and the fact that they use an additional heat transfer loop. In nuclear plants, heat is extracted from the core using a primary loop of pressurized liquid such as water. The steam is then formed in a secondary boiler system. This indirect steam generation arrangement results in lower boiler temperatures and pressures, but is deemed necessary to provide for safer operation of the reactor and to help prevent the release of radioactive substances. Nuclear reactors generate a near constant heat output when operating and therefore tend to produce a near constant electric output.

Combustion turbines are shown here for comparative purposes only. Combustion turbine plants use only the force of hot gases produced by combustion of the fuel to drive the turbines. Therefore, they do not require much cooling water since they do not use steam in the process, but they are also not as efficient as steam plants. They are, however, more readily able to start and stop quickly and therefore are generally used for peaking loads.

Combined cycle plants have the highest efficiency because they combine the energy extraction methods of both combustion turbine and steam cycle systems. Efficiencies as high as 58 percent have been reported (Woodruff 1998). Only the efficiency of the second stage (which is a steam cycle) is affected by cooling water temperatures. Therefore, for the purposes of this analysis, the energy penalty for combined cycle plants is applicable only to the energy output of the steam plant component, which is generally reported to be approximately one-third of the overall combined-cycle plant energy output.

3.3.2 Turbine Efficiency Energy Penalty

a. Effect of Turbine Exhaust Pressure

The temperature of the cooling water (or air in air-cooled systems) entering the steam cycle condensers affects the exhaust pressure at the outlet of the turbine. In general, a lower cooling water or air temperature at the condenser inlet will result in a lower turbine exhaust pressure. Note that for a simple steam turbine, the available energy is equal to the difference in the enthalpy of the inlet steam and the combined enthalpy of the steam and condensed moisture at the turbine outlet. A reduction in the outlet steam pressure results in a lower outlet steam enthalpy. A reduction in the enthalpy of the turbine exhaust steam, in combination with an increase in the partial condensation of the steam, results in an increase in the efficiency of the turbine system. Of course, not all of this energy is converted to the torque energy (work) that is available to turn the generator, since steam and heat flow through the turbine systems is complex with various losses and returns throughout the system.

The turbine efficiency energy penalty as described below rises and drops in direct response to the temperature of the cooling water (or air in air-cooled systems) delivered to the steam plant condenser. As a result, it tends to peak during the summer and may be substantially diminished or not exist at all during other parts of the year.

The design and operation of the steam condensing system can also affect the system efficiency. In general, design and operational changes that improve system efficiency such as greater condenser surface areas and coolant flow rates will tend to result in an increase in the economic costs and potentially the environmental detriments of the system. Thus, the design and operation of individual systems can differ depending on financial decisions and other site-specific conditions. Consideration of such site-specific design variations is beyond the scope of this evaluation. Therefore, conditions that represent a typical, or average, system derived from available information for each technology will be used. However, regional and annual differences in cooling fluid temperatures are considered. Where uncertainty exists, a conservative estimate is used. In this context, conservative means the penalty estimate is biased toward a higher value.

Literature sources indicate that condenser inlet temperatures of 55 °F and 95 °F will produce turbine exhaust pressures of 1.5 and 3.5 inches Hg, respectively, in a typical surface condenser (Woodruff 1998). If the turbine steam inlet conditions remain constant, lower turbine exhaust pressures will result in greater changes in steam enthalpy between the turbine inlet and outlet. This in turn will result in higher available energy and higher turbine efficiencies.

The lower outlet pressures can also result in the formation of condensed liquid water within the low pressure end of the turbine. Note that liquid water has a significantly lower enthalpy value which, based on enthalpy alone, should result in even greater turbine efficiencies. However, the physical effects of moisture in the turbines can cause damage to the turbine blades and can result in lower efficiencies than would be expected based on enthalpy data alone. This damage and lower efficiency is due to the fact that the moisture does not follow the steam path and impinges upon the turbine blades. More importantly, as the pressure in the turbine drops, the steam volume increases. While the turbines are designed to accommodate this increase in volume through a progressive increase in the cross-sectional area, economic considerations tend to limit the size increase such that the turbine cannot fully accommodate the expansion that occurs at very low exhaust pressures.

Thus, for typical turbines, as the exhaust pressure drops below a certain level, the increase in the volume of the steam is not fully accommodated by the turbine geometry, resulting in an increase in steam velocity near the turbine exit. This increase in steam velocity results in the conversion of a portion of the available steam energy to kinetic energy, thus reducing the energy that could otherwise be available to drive the turbine. Note that kinetic energy is proportional to the square of the velocity. Consequently, as the steam velocity increases, the resultant progressive reduction in available energy tends to offset the gains in available energy that would result from the greater enthalpy changes due to the reduced pressure. Thus, the expansion of the steam within the turbine and the formation of condensed moisture establishes a practical lower limit for turbine exhaust pressures, reducing the efficiency advantage of even lower condenser surface temperatures particularly at higher turbine steam loading rates. As can be seen in the turbine performance curves presented below, this reduction in efficiency at lower exhaust pressures is most pronounced at higher turbine steam loading rates. This is due to the fact that higher steam loading rates will produce proportionately higher turbine exit velocities.

Attachment B presents several graphs showing the change in heat rate resulting from differences in the turbine exhaust pressure at a nuclear power plant, a fossil fueled power plant, and a combined-cycle power plant (steam portion). The first graph (Attachment B-1) is for a GE turbine and was submitted by the industry in support of an analysis for a nuclear power plant. The second graph (Attachment B-2) is from a steam turbine technical manual and is for a turbine operating at steam temperatures and pressures consistent with a sub-critical fossil fuel plant (2,400 psig, 1,000 °F). The third graph (Attachment B-3) is from an engineering report analyzing operational considerations and design of modifications to a cooling system for a combined-cycle power plant.

The changes in heat rate shown in the graphs can be converted to changes in turbine efficiency using Equation 1. Several curves on each graph show that the degree of the change (slope of the curve) decreases with increasing loads. Note that the amount of electricity being generated will also vary with the steam loading rates such that the more pronounced reduction in efficiency at lower steam loading rates applies to a reduced power output. The curves also indicate that, at higher steam loads, the plant efficiency optimizes at an exhaust pressure of approximately 1.5 inches Hg. At lower exhaust pressures the effect of increased steam velocities actually results in a reduction in overall efficiency. The graphs in Attachment B will serve as the basis for estimating the energy penalty for each type of facility.

Since the turbine efficiency varies with the steam loading rate, it is important to relate the steam loading rates to typical operating conditions. It is apparent from the heat rate curves in Attachment B that peak loading, particularly if the exhaust pressure is close to 1.5 inches Hg, presents the most efficient and desirable operating condition. Obviously, during peak loading periods, all turbines will be operating near the maximum steam loading rates and the energy penalty derived from the maximum loading curve would apply. It is also reasonable to assume that power plants that operate as base load facilities will operate near maximum load for a majority of the time they are operating. However, there will be times when the power plant is not operating at peak capacity. One measure of this is the capacity factor, which is the ratio of the average load on the plant over a given period to its total capacity. For example, if a 200 MW plant operates, on average, at 50 percent of capacity (producing an average of 100 MW when operating) over a year, then its capacity factor would be 50 percent.

The average capacity factor for nuclear power plants in the U.S. has been improving steadily and recently has been reported to be approximately 89 percent. This suggests that for nuclear power plants, the majority appear to be operating near capacity most of the time. Therefore, use of the energy penalty factors derived from the maximum load curves for nuclear power plants is reasonably valid. In 1998, utility coal plants operated at an average capacity of 69 percent (DOE 2000). Therefore, use of the energy penalty values derived from the 67 percent load curves would appear to be more appropriate for fossil-fuel plants. Capacity factors for combined-cycle plants tend to be lower than coal-fired plants and use of the energy penalty values derived from the 67 percent load curves rather than the 100 percent load curves would be appropriate.

b. Estimated Changes in Turbine Efficiency

Table 3-10 below presents a summary of steam plant turbine inlet operating conditions for various types of steam plants described in literature. EPA performed a rudimentary estimation of the theoretical energy penalty based on steam enthalpy data using turbine inlet conditions similar to those shown in Table 3-10. EPA found that the theoretical values were similar to the changes in plant efficiency derived from the changes in heat rate shown in Attachment B. The theoretical calculations indicated that the energy penalties for the two different types of fossil fuel plants (sub-critical and super-critical) were similar in value, with the sub-critical plant having the larger penalty. Since the two types of fossil fuel plants had similar penalty values, only one was selected for use in the analysis in order to simplify the analysis. The type of plant with the greater penalty value (i.e., sub-critical fossil fuel) was selected as representative of both types.

Table 3-10: Summary of Steam Plant Operating Conditions from Various Sources

System Type	Inlet Temp. / Pressure	Outlet Pressure	Comments	Source
Fossil Fuel - Sub-critical Recirculating Boiler	Not Given / 2,415 psia	1.5 In. Hg	Large Plants (>500MW) have three (high, med, low) pressure turbines. Reheated boiler feed water is 540 °F.	Kirk-Othmer 1997
Fossil Fuel - Super-critical Once-through Boiler	1,000 °F / 3,515 psia	Not Given		Kirk-Othmer 1997
Nuclear	595 °F / 900 psia	2.5 In. Hg	Plants have two (high, low) pressure turbines with low pressure turbine data at left. Reheated boiler feed water is 464 °F.	Kirk-Othmer 1997
Combined Cycle	Gas - 2,400 °F Steam - 900 °F	Not Given	Operating efficiency ranges from 45-53%	www.greentie.org
Fossil Fuel Ranges	900-1,000 °F / 1,800-3,600 psia	1.0-4.5 In Hg	Outlet pressures can be even higher with high cooling water temperatures or air cooled condensers.	Woodruff 1998.

The three turbine performance curve graphs in Attachment B present the change in heat rate from which changes in plant efficiency were calculated. The change in heat rate value for several points along each curve was determined and then converted to changes in efficiency using Equation 1. The calculated efficiency values derived from the Attachment B graphs representing the 100 percent or maximum steam load and the 67 percent steam load conditions have been plotted in Figure 1. Curves were then fitted to these data to obtain equations that can be used to estimate energy penalties. Figure 1 establishes the energy efficiency and turbine exhaust pressure relationship. The next step is to relate the turbine exhaust pressure to ambient conditions and to determine ambient conditions for selected locations.

Note that for fossil fuel plants the energy penalty affects mostly the amount of fuel used, since operating conditions can be modified, within limits, to offset the penalty. However, the same is not true for nuclear plants, which are constrained by the limitations of the reactor system.

Figure 1
Plot of Various Turbine Exhaust Pressure Correction Curves for 100% and 67% Steam Loads

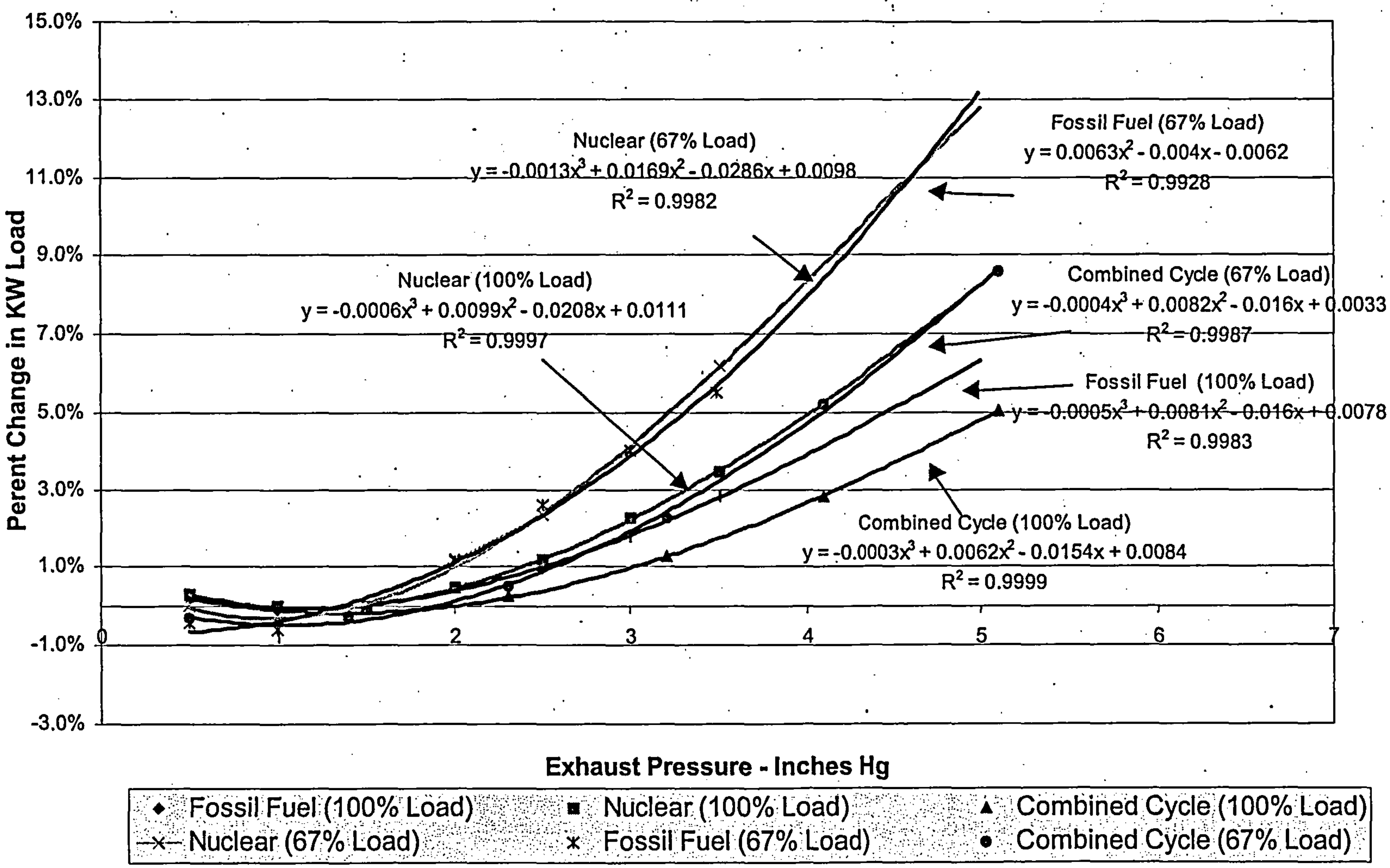
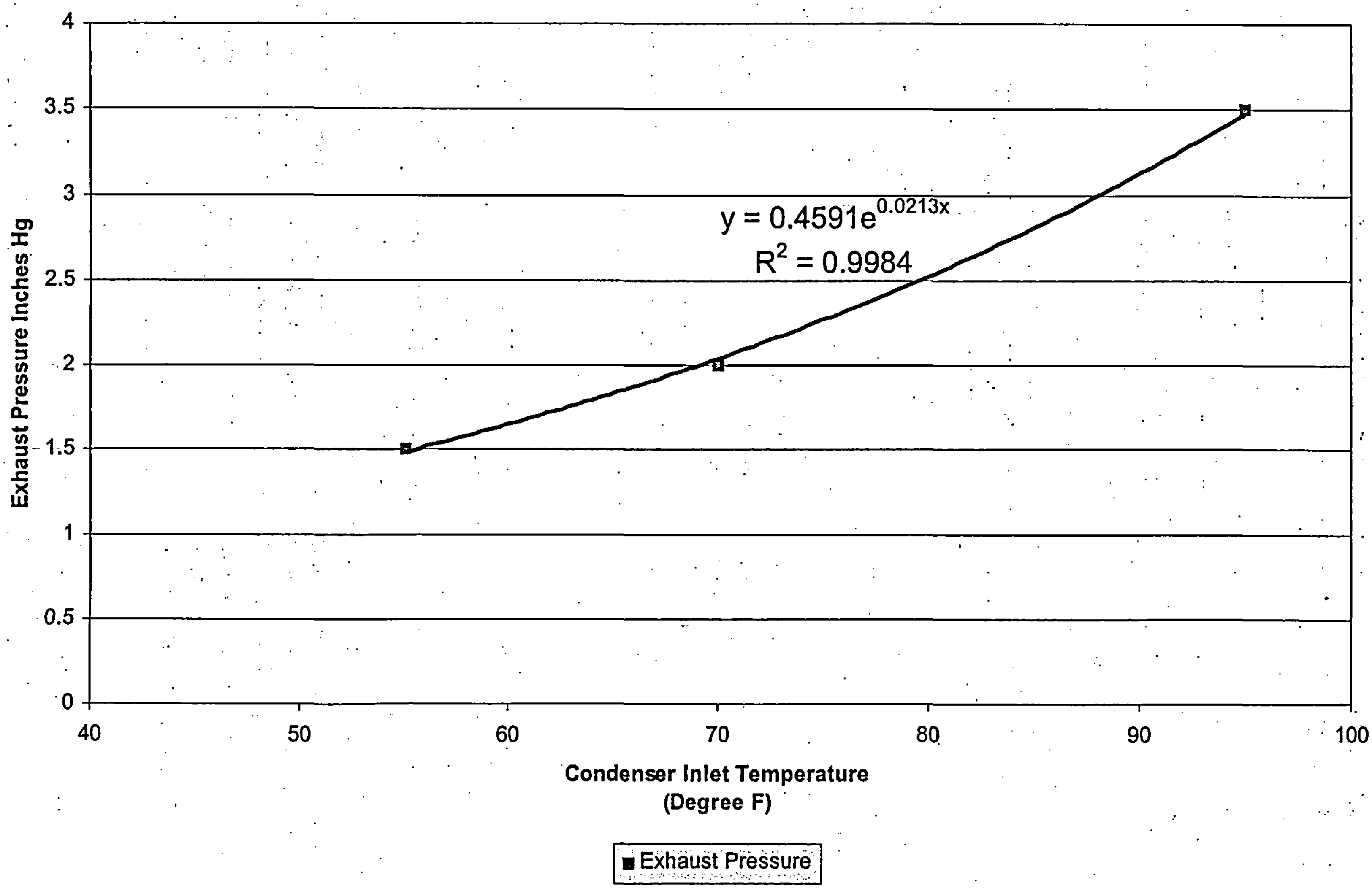


Figure 2
Surface Condenser Cooling Water Inlet Temperature and Steam Pressure Relationship



c. Relationship of Condenser Cooling Water (or Air) Temperature to Steam Side Pressure for Different Cooling System Types and Operating Conditions

Surface Condensers

Both once-through and wet cooling towers use surface condensers. As noted previously, condenser inlet temperatures of 55 °F and 95 °F will produce turbine exhaust pressures of 1.5 and 3.5 inches Hg, respectively. Additionally, data from the Calvert Cliffs nuclear power plant showed an exhaust pressure of 2.0 inches Hg at a cooling water temperature of 70 °F. Figure 2 provides a plot of these data which, even though they are from two sources, appear to be consistent. A curve was fitted to these data and was used as the basis for estimating the turbine exhaust pressure for different surface condenser cooling water inlet temperatures. Note that this methodology is based on empirical data that simplifies the relationship between turbine exhaust pressure and condenser inlet temperature, which would otherwise require more complex heat exchange calculations. Those calculations, however, would require numerous assumptions, the selection of which may produce a different curve but with a similar general relationship.

Once-through Systems

For once-through cooling systems, the steam cycle condenser cooling water inlet temperature is also the temperature of the source water. Note that the outlet temperature of the cooling water is typically 15 - 20 °F higher than the inlet temperature. This difference is referred to as the "range." The practical limit of the outlet temperature is approximately 100 °F, since many NPDES permits have limitations in the vicinity of 102 - 105 °F . This does not appear to present a problem, since the maximum monthly average surface water temperature at Jacksonville, Florida (selected by EPA as representing warmer U.S. surface waters) was 83.5 °F which would, using the range values above, result in an effluent temperature of 98.5 - 103.5 °F. To gauge the turbine efficiency energy penalty for once-through cooling systems, the temperature of the source water must be known. These temperatures will vary with location and time of year and estimates for several selected locations are presented in Table 3 below.

Wet Cooling Towers

For wet cooling towers, the temperature of the cooling tower outlet is the same as the condenser cooling water inlet temperature. The performance of the cooling tower in terms of the temperature of the cooling tower outlet is a function of the wet bulb temperature of the ambient air and the tower type, size, design, and operation. The wet bulb temperature is a function of the ambient air temperature and the humidity. Wet bulb thermometers were historically used to estimate relative humidity and consist of a standard thermometer with the bulb encircled with a wet piece of cloth. Thus, the temperature read from a wet bulb thermometer includes the cooling effect of water evaporation.

Of all of the tower design parameters, the temperature difference between the wet bulb temperature and the cooling tower outlet (referred to as the "approach") is the most useful in estimating tower performance. The wet cooling tower cooling water outlet temperature of the systems that were used in the economic analysis for the final §316(b) New Facility Rule had a design approach of 10 °F. Note that the design approach value is equal to the difference between the tower cooling water outlet temperature and the ambient wet bulb temperature only at the design wet bulb temperature. The actual approach value at wet bulb temperatures other than the design value will vary as described below.

The selection of a 10 °F design approach is based on the data in Attachment C for recently constructed towers. Moreover, a 10 °F approach is considered conservative. As can be seen in Attachment D, a plot of the tower size factor versus the approach shows that a 10 °F approach has a tower size factor of 1.5. The approach is a key factor in sizing towers and has significant cost implications. The trade-off between selecting a small approach versus a higher value is a trade-off between greater capital cost investment versus lower potential energy production. In states where the rates of return on energy investments are fixed (say between 12% and 15%), the higher the capital investment, the higher the return.

For the wet cooling towers used in this analysis, the steam cycle condenser inlet temperature is set equal to the ambient air wet bulb temperature for the location plus the estimated approach value. A design approach value of 10 °F was selected as the common design value for all locations. However, this value is only applicable to instances when the ambient wet bulb temperature is equal to the design wet bulb temperature. In this analysis, the design wet bulb temperature was selected as the 1 percent exceedence value for the specific selected locations.

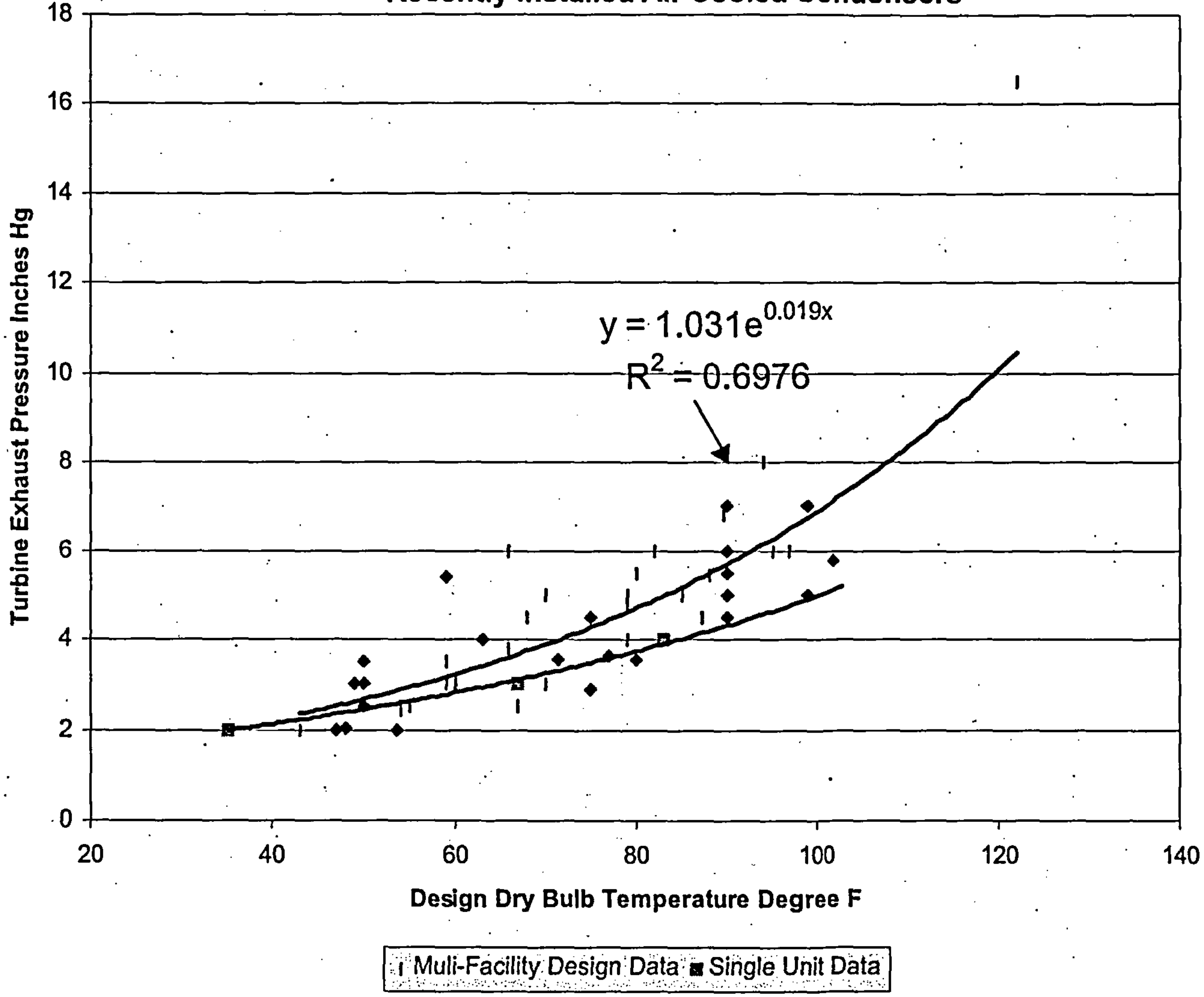
Attachment E provides a graph showing the relationship between different ambient wet bulb temperatures and the corresponding approach for a "typical" wet tower. The graph shows that as the ambient wet bulb temperature decreases, the approach value increases. The graph in Attachment E was used as the basis for estimating the change in the approach value as the ambient wet bulb temperature changes from the design value for each location. Differences in the location-specific design wet bulb temperature were incorporated by fitting a second order polynomial equation to the data in this graph. The equation was then modified by adjusting the intercept value such that the approach was equal to 10 °F when the wet bulb temperature was equal to the design 1 percent wet bulb temperature for the selected location. The location-specific equations were then used to estimate the condenser inlet temperatures that correspond to the estimated monthly values for wet bulb temperatures at the selected locations.

Air Cooled Condensers

Air cooled condensers reject heat by conducting it directly from the condensing steam to the ambient air by forcing the air over the heat conducting surface. No evaporation of water is involved. Thus, for air cooled condensers, the condenser performance with regard to turbine exhaust pressure is directly related to the ambient (dry bulb) air temperature, as well as to the condenser design and operating conditions. Note that dry bulb temperature is the same as the standard ambient air temperature with which most people are familiar. Figure 3 presents a plot of the design ambient air temperature and corresponding turbine exhaust pressure for air cooled condensers recently installed by a major cooling system manufacturer (GEA Power Cooling Systems, Inc.). An analysis of the multiple facility data in Figure 3 did not find any trends with respect to plant capacity, location, or age that could justify the separation of these data into subgroups. Three facilities that had very large differences (i.e., >80 °F) in the design dry bulb temperature compared to the temperature of saturated steam at the exhaust pressure were deleted from the data set used in Figure 3.

A review of the design temperatures indicated that the design temperatures did not always correspond to annual temperature extremes of the location of the plant as might be expected. Thus, it appears that the selection of design values for each application included economic considerations. EPA concluded that these design data represent the range of condenser performance at different temperatures and design conditions. A curve was fitted to the entire set of data to serve as a reasonable means of estimating the relationship of turbine exhaust pressure to different ambient air (dry bulb) temperatures. To validate this approach, condenser performance data for a power plant from an engineering contractor report (Litton, no date) was also plotted. This single plant data produced a flatter curve than the multi-facility plot. In other words, the multi-facility curve predicts a greater increase in turbine exhaust pressure as the dry bulb temperature increases. Therefore, the multi-facility curve was selected as a conservative estimation of the relationship between ambient air temperatures and the turbine exhaust pressure. Note that in the case of air cooled condensers, the turbine exhaust steam pressure includes values above 3.5 inches Hg.

Figure 3
Design Dry Bulb and Design Exhaust Pressure for Recently Installed Air Cooled Condensers



Regional and Seasonal Data

As noted above, both the source water temperature for once-through cooling systems and the ambient wet bulb and dry bulb temperatures for cooling towers will vary with location and time of year. To estimate average annual energy penalties, EPA sought data to estimate representative monthly values for selected locations. Since plant-specific temperature data may not be available or practical, the conditions for selected locations in different regions are used as examples of the range of possibilities. These four regions include Northeast (Boston, MA), Southeast (Jacksonville, FL), Midwest (Chicago, IL) and Northwest (Seattle, WA). The Southwest Region of the US was not included, since there generally are few once-through systems using surface water in this region.

Table 3-11 presents monthly average coastal water temperatures at the four selected locations. Since the water temperatures remain fairly constant over short periods of time, these data are considered as representative for each month.

Table 3-11: Monthly Average Coastal Water Temperatures (°F)

Location	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Boston, MA[a]	40	36	41	47	56	62	64.5	68	64.5	57	51	42
Jacksonville, FL[a]	57	56	61	69.5	75.5	80.5	83.5	83	82.5	75	67	60
Chicago, IL[b]	39	36	34	36	37	48	61	68	70	63	50	45
Seattle, WA[a]	47	46	46	48.5	50.5	53.5	55.5	56	55.5	53.5	51	49

[a] Source: NOAA Coastal Water Temperature Guides, (www.nodc.noaa.gov/dsdt/cwtg).
[b] Source: Estimate from multi-year plot "Great Lakes Average GLSEA Surface Water Temperature" (http://coastwatch.glerl.noaa.gov/statistics/).

Wet and Dry Bulb Temperatures

Table 3-12 presents design wet bulb temperatures (provided by a cooling system vendor) for the selected locations as the wet bulb temperature that ambient conditions will equal or exceed at selected percent of time (June through September) values. Note that 1 percent represents a period of 29.3 hours. These data, however, represent relatively short periods of time and do not provide any insight as to how the temperatures vary throughout the year. The Agency obtained the *Engineering Weather Data Published by the National Climatic Data Center* to provide monthly wet and dry bulb temperatures. In this data set, wet bulb temperatures were not summarized on a monthly basis, but rather were presented as the average values for different dry bulb temperature ranges along with the average number of hours reported for each range during each month. These hours were further divided into 8-hour periods (midnight to 8AM, 8AM to 4PM, and 4PM to midnight).

Unlike surface water temperature, which tends to change more slowly, the wet bulb and dry bulb temperatures can vary significantly throughout each day and especially from day-to-day. Thus, selecting the temperature to represent the entire month requires some consideration of this variation. The use of daily maximum values would tend to overestimate the overall energy penalty and conversely, the use of 24-hour averages may underestimate the penalty, since the peak power production period is generally during the day.

Since the power demand and ambient wet bulb temperatures tend to peak during the daytime, a time- weighted average of the hourly wet bulb and dry bulb temperatures during the daytime period between 8AM and 4PM was selected as the best method of estimating the ambient wet bulb and dry bulb temperature values to be used in the analysis. The 8AM - 4PM time-weighted average values for wet bulb and dry bulb temperatures were selected as a reasonable compromise between using daily maximum values and 24-hour averages. Table 3-13 presents a summary of the time-weighted wet bulb and dry bulb temperatures for each month for the selected locations. Note that the highest monthly 8AM - 4PM time-weighted average tends to correspond well with the 15 percent exceedence design values. The 15 percent values represent a time period of approximately 18 days which are not necessarily consecutive.

Table 3-12: Design Wet Bulb Temperature Data for Selected Locations

Location	Wet Bulb Temp (°F)			Corresponding Cooling Tower Outlet Temperature (°F)		
	% Time Exceeding			% Time Exceeding		
	1%	5%	15%	1%	5%	15%
Boston, MA	76	73	70	86	83	80
Jacksonville, FL	80	79	77	90	89	87
Chicago, IL	78	75	72	88	85	82
Seattle, WA	66	63	60	76	73	70

Source: www.deltacooling.com

Table 3-13: Time-Weighted Averages for Eight-Hour Period from 8am to 4pm (°F)

Location		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Design 1%
Boston	Wet Bulb	27.5	29.3	36.3	44.6	53.9	62.7	67.9	67.4	61.5	52.0	42.6	32.6	74.0
	Dry Bulb	33.0	35.3	43.2	53.5	63.8	73.9	80.0	78.2	70.4	59.9	49.5	38.4	88.0
Jacksonville	Wet Bulb	52.9	55.3	59.6	64.5	70.3	75.1	77.1	77.1	75.1	69.1	63.1	55.9	79.0
	Dry Bulb	59.8	63.6	70.3	76.6	83.0	87.2	89.3	88.1	85.1	77.8	70.6	62.6	93.0
Chicago	Wet Bulb	23.3	27.0	37.2	46.6	56.6	64.9	69.8	69.3	62.2	51.2	39.1	27.9	76.0
	Dry Bulb	27.6	31.8	43.9	55.7	67.9	77.4	82.5	80.6	72.4	59.9	45.0	32.2	89.0
Seattle	Wet Bulb	39.4	41.8	44.2	47.2	52.0	56.0	59.2	59.6	57.2	51.0	44.0	39.7	65.0
	Dry Bulb	44.3	47.8	51.5	55.6	61.8	67.2	71.6	71.6	67.3	58.1	49.0	44.3	82.0

c. Calculation of Energy Penalty

Since the energy penalty will vary over time as ambient climatic and source water temperatures vary, the calculation of the total annual energy penalty for a chosen location would best be performed by combining (integrating) the results of individual calculations performed on a periodic basis. For this analysis, a monthly basis was chosen.

The estimated monthly turbine exhaust pressure values for alternative cooling system scenarios were derived using the curves in Figures 2 and 3 in conjunction with the monthly temperature values in Tables 3-11 and 3-13. These turbine exhaust pressure values were then used to estimate the associated change in turbine efficiency using the equations from Figure 1. EPA then calculated the energy penalty for each month. Annual values were calculated by averaging the 12 monthly values.

Tables 3-14 and 3-15 present a summary of the calculated annual average energy penalty values for steam rates of 100 percent and 67 percent of maximum load. These values can be applied directly to the power plant output to determine economic and other impacts. In other words, an energy penalty of 2 percent indicates that the plant output power would be reduced by 2 percent. In addition, Tables 3-14 and 3-15 include the maximum turbine energy penalty associated with maximum design conditions such as once-through systems drawing water at the highest monthly average, and wet towers and air cooled condensers operating in air with a wet bulb and dry bulb temperature at the 1 percent exceedence level. EPA notes that the maximum design values result from using the maximum monthly water temperatures from Table 3-11 and the 1% percent exceedence wet bulb and dry bulb temperatures from Table 3-12.

EPA notes that the penalties presented in Tables 3-14 and 3-15 **do not** comprise the total energy penalties (which incorporate all three components of energy penalties: turbine efficiency penalty, fan energy requirements, and pumping energy usage) as a percent of power output. The total energy penalties are presented in section 3.1 above. The tables below only present the turbine efficiency penalty. Section 3.3.3 presents the fan and pumping components of the energy penalty.

Table 3-14: Calculated Energy Penalties for the Turbine Efficiency Component at 100 Pecent of Maximum Steam Load

Location	Cooling Type	Percent Maximum Load	Nuclear Maximum Design	Nuclear Annual Average	Combined Cycle Maximum Design	Combined Cycle Annual Average	Fossil Fuel Maximum Design	Fossil Fuel Annual Average
Boston	Wet Tower vs. Once-through	100%	1.25%	0.37%	0.23%	0.05%	1.09%	0.35%
	Dry Tower vs. Once-through	100%	9.22%	2.85%	2.04%	0.55%	7.76%	2.48%
	Dry Tower vs. Wet Tower	100%	7.96%	2.48%	1.81%	0.50%	6.66%	2.13%
Jacksonville	Wet Tower vs. Once-through	100%	0.71%	0.54%	0.14%	0.10%	0.61%	0.38%
	Dry Tower vs. Once-through	100%	9.86%	6.21%	2.30%	1.35%	8.22%	5.16%
	Dry Tower vs. Wet Tower	100%	9.14%	5.68%	2.16%	1.25%	7.61%	4.78%
Chicago	Wet Tower vs. Once-through	100%	1.39%	0.42%	0.26%	0.05%	1.21%	0.40%
	Dry Tower vs. Once-through	100%	9.47%	3.09%	2.12%	0.60%	7.96%	2.68%
	Dry Tower vs. Wet Tower	100%	8.08%	2.67%	1.85%	0.55%	6.75%	2.28%
Seattle	Wet Tower vs. Once-through	100%	0.77%	0.29%	0.12%	0.03%	0.70%	0.28%
	Dry Tower vs. Once-through	100%	7.60%	2.63%	1.61%	0.49%	6.46%	2.30%
	Dry Tower vs. Wet Tower	100%	6.83%	2.34%	1.48%	0.45%	5.76%	2.02%
Average	Wet Tower vs. Once-through	100%	1.03%	0.40%	0.19%	0.06%	0.90%	0.35%
	Dry Tower vs. Once-through	100%	9.04%	3.70%	2.02%	0.75%	7.60%	3.15%
	Dry Tower vs. Wet Tower	100%	8.00%	3.29%	1.83%	0.69%	6.70%	2.80%

Note: See Section 3-1 for the total energy penalties. This table presents only the turbine component of the total energy penalty.

Table 3-15: Calculated Energy Penalties for the Turbine Efficiency Component at 67% Pecent of Maximum Steam Load								
Location	Cooling Type	Percent Maximum Load	Nuclear Maximum Design	Nuclear Annual Average	Combined Cycle Maximum Design	Combined Cycle Annual Average	Fossil Fuel Maximum Design	Fossil Fuel Annual Average
Boston	Wet Tower vs. Once-through	67%	2.32%	0.73%	0.42%	0.14%	2.04%	0.88%
	Dry Tower vs. Once-through	67%	13.82%	4.96%	3.20%	0.98%	15.15%	4.69%
	Dry Tower vs. Wet Tower	67%	11.50%	4.23%	2.78%	0.84%	13.11%	3.81%
Jacksonville	Wet Tower vs. Once-through	67%	1.22%	1.03%	0.24%	0.18%	1.08%	0.93%
	Dry Tower vs. Once-through	67%	13.61%	9.63%	3.50%	2.14%	16.96%	10.06%
	Dry Tower vs. Wet Tower	67%	12.39%	8.60%	3.27%	1.96%	15.88%	9.14%
Chicago	Wet Tower vs. Once-through	67%	2.53%	0.98%	0.47%	0.16%	2.23%	1.02%
	Dry Tower vs. Once-through	67%	14.03%	5.39%	3.30%	1.07%	15.67%	5.30%
	Dry Tower vs. Wet Tower	67%	11.50%	4.41%	2.83%	0.91%	13.44%	4.27%
Seattle	Wet Tower vs. Once-through	67%	1.60%	0.67%	0.27%	0.11%	1.50%	0.74%
	Dry Tower vs. Once-through	67%	12.16%	4.60%	2.60%	0.90%	12.31%	4.50%
	Dry Tower vs. Wet Tower	67%	10.56%	3.93%	2.33%	0.79%	10.81%	3.75%
Average	Wet Tower vs. Once-through	67%	1.92%	0.85%	0.35%	0.15%	1.71%	0.89%
	Dry Tower vs. Once-through	67%	13.41%	6.14%	3.15%	1.27%	15.02%	6.14%
	Dry Tower vs. Wet Tower	67%	11.49%	5.29%	2.80%	1.12%	13.31%	5.24%

Note: See Section 3-1 for the total energy penalties. This table presents only the turbine component of the total energy penalty.

3.3.3 Energy Penalty Associated with Cooling System Energy Requirements

This analysis is presented to evaluate the energy requirements associated with the operation of the alternative types of cooling systems. As noted previously, the reductions in energy output resulting from the energy required to operate the cooling system equipment are often referred to as parasitic losses. In evaluating this component of the energy penalty, it is the differences between the parasitic losses of the alternative systems that are important. In general, the costs associated with the cooling system energy requirements have been included within the annual O&M cost values developed in Chapter 2 of this document. Thus, the costs of the cooling system operating energy requirements do not need to be factored into the overall energy penalty cost analysis as a separate value, but may have been in some instances as part of a conservative approach.

Alternative cooling systems can create additional energy demands primarily through the use of fans and pumps. There are other energy demands such as treatment of tower blowdown, but these are insignificant compared to the pump and fan requirements and will not be included here. Some seasonal variation may be expected due to reduced requirements for cooling media flow volume during colder periods. These reduced requirements can include reduced cooling water pumping for once-through systems and reduced fan energy requirements for both wet and dry towers. However, no adjustments were made concerning the potential seasonal variations in cooling water pumping. The seasonal variation in fan power requirements is accounted for in this evaluation by applying an annual fan usage rate. The pumping energy estimates are calculated using a selected cooling water flow rate of 100,000 gpm (223 cfs).

a. Fan Power Requirements

Wet Towers

In the reference *Cooling Tower Technology* (Burger 1995), several examples are provided for cooling towers with flow rates of 20,000 gpm using 4 cells with either 75 (example #1) or 100 Hp (example #2) fans each. The primary difference between these two examples is that the tower with the higher fan power requirement has an approach of 5 °F compared to 11 °F for the tower with the lower fan power requirement. Using an electric motor efficiency of 92 percent and a fan usage factor of 93 percent (Fleming 2001), the resulting fan electric power requirements are equal to 0.236 MW and 0.314 MW for the four cells with 75 and 100 Hp fan motors, respectively. These example towers both had a heat load of 150 million BTU/hr. Table 3-16 provides the percent of power output penalty based on equivalent plant capacities derived using the heat rejection factors described below. Note that fan gear efficiency values are not applicable because they do not affect the fan motor power rating or the amount of electricity required to operate the fan motors.

A third example was provided in vendor-supplied data (Fleming 2001), in which a cooling tower with a cooling water flow rate of 243,000 gpm had a total fan motor capacity brake-Hp of 250 for each of 12 cells. This wet tower had a design temperature range of 15 °F and an approach of 10 °F. The percent of power output penalty shown in Table 7 is also based on equivalent plant capacities derived using the heat rejection factors described below.

A fourth example is a cross-flow cooling tower for a 35 MW coal-fired plant in Iowa (Litton, no date). In this example, the wet tower consists of two cells with one 150 Hp fan each, with a cooling water flow rate of 30,000 gpm. This wet tower had a design temperature range of 16 °F, an approach of 12 °F, and wet bulb temperature of 78 °F. The calculated energy penalty in this example is 0.67 percent.

Example #2, which has the smallest approach value, represents the high end of the range of calculated wet tower fan energy penalties presented in Table 3-16. Note that smaller approach values correspond to larger, more expensive (both in capital and O&M costs) towers. Since the fossil fuel plant penalty value for example #4, which is based mostly on empirical data, is just below the fossil fuel penalty calculated for example #2, EPA has chosen the calculated values for example #2 as representing a conservative estimate for the wet tower fan energy penalty.

EPA notes that the penalties presented in Tables 3-16 **do not** comprise the total energy penalty (which incorporates all three components of energy penalties: turbine efficiency penalty, fan energy requirements, and pumping energy usage) as a percent of power output. The total energy penalties are presented in section 3.1 above. The table below only presents the fan component of the penalty.

Table 3-16: Wet Tower Fan Power Energy Penalty

Example Plant	Range/ Approach (Degree F)	Flow (gpm)	Fan Power Rating (Hp)	Fan Power Required (MW)	Plant Type	Plant Capacity (MW)	Percent of Output (%)
#1	15/11	20,000	300	0.236	Nuclear	35	0.68%
					Fossil Fuel	43	0.55%
					Comb. Cycle	130	0.18%
#2	15/5	20,000	400	0.314	Nuclear	35	0.91%
					Fossil Fuel	43	0.73%
					Comb. Cycle	130	0.24%
#3	15/10	243,000	3,000	2.357	Nuclear	420	0.56%
					Fossil Fuel	525	0.45%
					Comb. Cycle	1574	0.15%
#4	16/12	30,000	300.0	0.236	Fossil Fuel	35	0.67%

Note: See Section 3-1 for the total energy penalties. This table presents only the fan component of the total energy penalty.

Air Cooled Condensers

Air cooled condensers require greater air flow than recirculating wet towers because they cannot rely on evaporative heat transfer. The fan power requirements are generally greater than those needed by wet towers by a factor of 3 to 4 (Tallon 2001). While the fan power requirements can be substantial, at least a portion of this increase over wet cooling systems is offset by the elimination of the pumping energy requirements associated with wet cooling systems described below.

The El Dorado power plant in Boulder, Nevada which was visited by EPA is a combined-cycle plant that uses air cooled condensers due to the lack of sufficient water resources. This facility is located in a relatively hot section of the U.S. Because the plant has a relatively low design temperature (67 °F) in a hot environment, it should be considered as representative of a conservative situation with respect to the energy requirements for operating fans in air cooled condensers. The steam portion of the plant has a capacity of 150 MW (1.1 million lb/hr steam flow).

The air cooled condensers consist of 30 cells with a 200 Hp fan each. A fan motor efficiency of 92 percent is assumed. Each fan has two operating speeds, with the low speed consuming 20 percent of the fan motor power rating.

The facility manager provided estimates of the proportion of time that the fans were operated at low or full speed during different portions of the year (Tatar 2001). Factoring in the time proportions and the corresponding power requirements results in an overall annual fan power factor of 72 percent for this facility. In other words, over a one year period, the fan power requirement will average 75 percent of the fan motor power rating. A comparison of the climatic data for Las Vegas (located nearby) and Jacksonville, Florida shows that the Jacksonville mean maximum temperature values were slightly warmer in the winter and slightly cooler in the summer. Adjustments in the annual fan power factor calculations to address Jacksonville's slightly warmer winter months resulted in a projected annual fan power factor of 77 percent. EPA chose a factor of 75 percent as representative of warmer regions of the U.S. Due to lack of available operational data for other locations, this value is used for facilities throughout the U.S. and represents an conservative value for the much cooler regions.

Prior to applying this factor, the resulting maximum energy penalty during warmer months is 3.2 percent for the steam portion only. This value is the maximum instantaneous penalty that would be experienced during high temperature conditions. When the annual fan power factor of 75 percent is applied, the annual fan energy penalty becomes 2.4 percent of the plant power output. An engineer from an air cooled condenser manufacturer indicated that the majority of air cooled condensers being installed today also include two-speed fans and that the 20 percent power ratio for the low speed was the factor that they used also. In fact, some dry cooling systems, particularly those in very cold regions, use fans with variable speed drives to provide even better operational control. Similar calculations for a waste-to-energy plant in Spokane, Washington resulted in a maximum fan operating penalty of 2.8 percent and an annual average of 2.1 percent using the 75 percent fan power factor. Thus, the factor of 2.4 percent selected by EPA as a conservative annual penalty value appears valid.

b. Cooling Water Pumping Requirements

The energy requirements for cooling water pumping can be estimated by combining the flow rates and the total head (usually given in feet of water) that must be pumped. Estimating the power requirements for the alternative cooling systems that use water is somewhat complex in that there are several components to the total pumping head involved. For example, a once-through system must pump water from the water source to the steam condensers, which will include both a static head from the elevation of the source to the condenser (use of groundwater would represent an extreme case) and friction head losses through the piping and the condenser. The pipe friction head is dependent on the distance between the power plant and the source plus the size and number of pipes, pipe fittings, and the flow rate. The condenser friction head loss is a function of the condenser design and flow rate.

Wet cooling towers must also pump water against both a static and friction head. A power plant engineering consultant estimated that the total pumping head at a typical once-through facility would be approximately 50 ft (Taylor 2001). EPA performed a detailed analysis of the cooling water pumping head that would result from different combinations of piping velocities and distances. The results of this analysis showed that the pumping head was in many scenarios similar in value for both once-through and wet towers, and that the estimated pumping head ranged from approximately 40 to 60 feet depending on the assumed values. Since EPA's analysis produced similar values as the 50 ft pumping head provided by the engineering consultant, this value was used in the estimation of the pumping requirements for cooling water intakes for both once-through and wet tower systems. The following sections describe the method for deriving these pumping head values.

Friction Losses

In order to provide a point of comparison, a cooling water flow rate of 100,000 gpm (223 cfs) was used. A recently reported general pipe sizing rule indicating that a pipe flow velocity of 5.7 fps is the optimum flow rate with regards to the competing cost values was used as the starting point for flow velocity (Durand et al. 1999). Such a minimum velocity is needed to prevent sediment deposition and pipe fouling. Using this criterion as a starting point, four 42-inch steel pipes carrying 25,000 gpm each at a velocity of 5.8 fps were selected. Each pipe would have a friction head loss of 0.358 ft/100 ft of pipe (Permutit 1961), resulting in a friction loss of 3.6 ft for every 1,000 ft of length. Since capital costs may dictate using fewer pipes with greater pipe flow rates, two other scenarios using either three or two parallel 42-inch pipes were also evaluated. Three pipes would result in a flow rate and velocity of 33,000 gpm and 7.7 fps, which results in a friction head loss of 6.1 ft/1000ft. Two pipes would result in a flow rate and velocity of 50,000 gpm and 11.6 fps, which results in a friction head loss of 12.8 ft/1000ft. The estimated 50 ft total pumping head was most consistent with a pipe velocity of 7.7 fps (three 42-inch pipes).

The relative distances of the power plant condensers to the once-through cooling water intakes as compared to the distance from the plant to the alternative cooling tower can be an important factor. In general, the distances that the large volumes of cooling water must be pumped will be greater for once-through cooling systems. For this analysis, a fixed distance of 300 ft was selected for the cooling tower. Various distances ranging from 300 ft to 3,000 ft are used for the once-through system. The friction head was also assumed to include miscellaneous losses due to inlets, outlets, bends, valves, etc., which can be calculated using equivalent lengths of pipe. For 42-in. steel pipe, each entrance and long sweep elbow is equal to about 60 ft in added pipe length. For the purposes of this analysis, both systems were assumed to have five such fittings for an added length of 300 ft. The engineering estimate of 50 ft for pumping head was most consistent with a once-through pumping distance of approximately 1,000 ft.

Static Head

Static head refers to the distance in height that the water must be pumped from the source elevation to the destination. In the case of once-through cooling systems, this is the distance in elevation between the source water and the condenser inlet. However, many power plants eliminate a significant portion of the static head loss by operating the condenser piping as a siphon. This is done by installing vacuum pumps at the high point of the water loop. In EPA's analysis, a static head of 20 ft produced a total pumping head value that was most consistent with the engineering consultant's estimate of 50 feet.

In the case of cooling towers, static head is related to the height of the tower, and vendor data for the overall pumping head through the tower is available. This pumping head includes both the static and dynamic heads within the tower, but was included as the static head component for the analysis. Vendor data reported a total pumping head of 25 ft for a large cooling tower sized to handle 335,000 gpm (Fleming 2001). The tower is a counter-flow packed tower design. Adding the condenser losses and pipe losses resulted in a total pumping head of approximately 50 feet.

Condenser Losses

Condenser design data provided by a condenser manufacturer, Graham Corporation, showed condenser head losses ranging from 21 ft of water for small condensers (cooling flow <50,000 gpm) to 41 ft for larger condensers (Hess

2001). Another source showed head losses through the tubes of a large condenser (311,000 gpm) to be approximately 9 ft of water (HES. 2001). For the purposes of this analysis, EPA estimated condenser head losses to be 20 ft of water. For comparable systems with similar cooling water flow rates, the condenser head loss component should be the same for both once-through systems and recirculating wet towers.

Flow Rates

In general, the cooling water flow rate is a function of the heat rejection rate through the condensers and the range of temperature between the condenser inlet and outlet. The flow rate for cooling towers is approximately 95 percent that of once-through cooling water systems, depending on the cooling temperature range. However, cooling tower systems also still require some pumping of make-up water. For the purposes of this analysis, the flow rates for each system will be assumed to be essentially the same. All values used in the calculations are for a cooling water flow rate of 100,000 gpm. Values for larger and smaller systems can be factored against these values. The total pump and motor efficiency is assumed to be equal to 70 percent.

c. Analysis of Cooling System Energy Requirements

This analysis evaluates the energy penalty associated with the operation of cooling system equipment for conversion from once-through systems to wet towers and for conversion to air cooled systems by estimating the net difference in required pumping and fan energy between the systems. This penalty can then be compared to the power output associated with a cooling flow rate of 100,000 gpm to derive a percent of plant output figure that is a similar measure to the turbine efficiency penalty described earlier. The power output was determined by comparing condenser heat rejection rates for different types of systems. As noted earlier, the cost of this energy penalty component has already been included in the alternative cooling system O&M costs discussed in Chapter 2 of this document, but was derived independently for this analysis.

Table 3-17 shows the pumping head and energy requirements for pumping 100,000 gpm of cooling water for both once-through and recirculating wet towers using the various piping scenario assumptions. In general, the comparison of two types of cooling systems shows offsetting energy requirements that essentially show zero pumping penalty between once-through and wet towers as the pumping distance for the once-through system increases to approximately 1,000 ft. In fact, it is apparent that for once-through systems with higher pipe velocities and pumping distances, more cooling water pumping energy may be required for the once-through system than for a wet cooling tower. Thus, when converting from once-through to recirculating wet towers, the differences in pumping energy requirements may be relatively small.

As described above, wet towers will require additional energy to operate the fans, which results in a net increase in the energy needed to operate the wet tower cooling system compared to once-through. Note that the average calculated pumping head across the various scenarios for once-through systems was 54 ft. This data suggests that an average pumping head of 50 feet for once-through systems appears to be a reasonable assumption where specific data are not available.

EPA notes that the penalties presented in Tables 3-17 and 3-18 **do not** comprise the total energy penalties (which incorporate all three components of energy penalties: turbine efficiency penalty, fan energy requirements, and pumping energy usage) as a percent of power output. The total energy penalties are presented in section 3.1 above. The tables below only present the pumping components.

Table 3-17: Cooling Water Pumping Head and Energy for 100,000 gpm System Wet Towers Versus Once-through At 20' Static Head

Cooling System Type	Distance Pumped	Static Head	Condenser Head	Equiv. Length Misc. Losses	Pipe Velocity	Friction Loss Rate	Friction Head	Total Head	Net Difference	Flow Rate	Hydraulic-Hp	Brake-Hp	Power Required	Energy Penalty
	ft.	ft.	ft	ft.	fps	ft/1,000ft	ft.	ft.	ft	gpm	Hp	Hp	kW	kW
Once-through at 20' Static Head Using 4: 42" Pipes at 300' Length														
Once-through	300	20	21	300	5.8	3.6	2	43		100,000	1089	1556	1161	
Wet Tower	300	25	21	300	5.8	3.6	2	48	5	100,000	1216	1737	1296	135
Once-through at 20' Static Head Using 3: 42" Pipes at 300' Length														
Once-through	300	20	21	300	7.7	6.1	4	45		100,000	1127	1610	1201	
Wet Tower	300	25	21	300	7.7	6.1	4	50	5	100,000	1254	1791	1336	135
Once-through at 20' Static Head Using 2: 42" Pipes at 300' Length														
Once-through	300	20	21	300	11.6	12.8	8	49		100,000	1229	1755	1310	
Wet Tower	300	25	21	300	11.6	12.8	8	54	5	100,000	1355	1936	1444	135
Once-through at 20' Static Head Using 4: 42" Pipes at 1000' Length														
Once-through	1000	20	21	300	5.8	3.6	5	46		100,000	1153	1647	1229	
Wet Tower	300	25	21	300	5.8	3.6	2	48	2	100,000	1216	1737	1296	67
Once-through at 20' Static Head Using 3: 42" Pipes at 1000' Length														
Once-through	1000	20	21	300	7.7	6.1	8	49		100,000	1235	1764	1316	
Wet Tower	300	25	21	300	7.7	6.1	4	50	1	100,000	1254	1791	1336	20
Once-through at 20' Static Head Using 2: 42" Pipes at 1000' Length														
Once-through	1000	20	21	300	11.6	12.8	17	58		100,000	1455	2079	1551	
Wet Tower	300	25	21	300	11.6	12.8	8	54	-4	100,000	1355	1936	1444	-107
Once-through at 20' Static Head Using 4: 42" Pipes at 3000' Length														
Once-through	3000	20	21	300	5.8	3.6	12	53		100,000	1335	1907	1423	
Wet Tower	300	25	21	300	5.8	3.6	2	48	-5	100,000	1216	1737	1296	-127
Once-through at 20' Static Head Using 3: 42" Pipes at 3000' Length														
Once-through	3000	20	21	300	7.7	6.1	20	61		100,000	1543	2204	1644	
Wet Tower	300	25	21	300	7.7	6.1	4	50	-11	100,000	1254	1791	1336	-309
Once-through at 20' Static Head Using 2: 42" Pipes at 3000' Length														
Once-through	3000	20	21	300	11.6	12.8	42	83		100,000	2101	3002	2239	
Wet Tower	300	25	21	300	11.6	12.8	8	54	-30	100,000	1355	1936	1444	-795

Note: Wet Towers are assumed to always be at 300' distance and have the same tower pumping head of 25' in all scenarios shown.
The same flow rate of 100,000gpm (223 cfs) is used for all scenarios.
See Section 3-1 for the total energy penalties. This table presents only the pumping component of the total energy penalty.

Cooling System Energy Requirements Penalty as Percent of Power Output

One method of estimating the capacity of a power plant associated with a given cooling flow rate is to compute the heat rejected by the cooling system and determine the capacity that would match this rejection rate for a "typical" power plant in each category. In order to determine the cooling system heat rejection rate, both the cooling flow (100,000 gpm) and the condenser temperature range between inlet and outlet must be estimated. In addition, the capacity that corresponds to the power plant heat rejection rate must be determined. The heat rejection rate is directly related to the type, design, and capacity of a power plant. The method used here was to determine the ratio of the plant capacity divided by the heat rejection rate as measured in equivalent electric power.

An analysis of condenser cooling water flow rates, temperature ranges and power outputs for several existing nuclear plants provided ratios of the plant output to the power equivalent of heat rejection ranging from 0.75 to 0.92. A similar analysis for coal-fired power plants provided ratios ranging from 1.0 to 1.45. Use of a lower factor results in a lower power plant capacity estimate and, consequently, a higher value for the energy requirement as a percent of capacity. Therefore, EPA chose to use values near the lower end of the range observed. EPA selected ratios of 0.8 and 1.0 for nuclear and fossil-fueled plants, respectively. The steam portion of a combined cycle plant is assumed to have a factor similar to fossil fuel plants of 1.0. Considering that this applies to only one-third of the total plant output, the overall factor for combined-cycle plants is estimated to be 3.0.

In order to correlate the cooling flow energy requirement data to the power output, a condenser temperature range must also be estimated. A review of data from newly constructed plants in Attachment C showed no immediately discernable pattern on a regional basis for approach or range values. Therefore, these values will not be differentiated on a regional basis in this analysis. The data did, however, indicate a median approach of 10 °F (average 10.4 °F) and a median range of 20 °F (average 21.1 °F). This range value is consistent with the value assumed in other EPA analyses and therefore a range of 20 °F will be used. Table 3-18 presents the energy penalties corresponding to the pumping energy requirements from Table 3-17 using the above factors.

Table 3-18: Comparison of Pumping Power Requirement and Energy Penalty to Power Plant Output

Cooling system Type	Distance Pumped ft.	Static Head ft.	Power Required kW	Flow Rate gpm	Range °F	Nuclear Power/ Heat Ratio	Nuclear Equiv. Output (MW)	Nuclear Pumping % of Output	Fossil Fuel Power/ Heat Ratio	Fossil Fuel Equiv. Output (MW)	Fossil Fuel Pumping % of Output	Comb.-Cycle Power/ Heat Ratio	Comb.-Cycle Equiv. Output (MW)	Comb.-Cycle Pumping % of Output
Once-through at 20' Static Head Using 4: 42" Pipes at 300' Length														
Once-through	300	20	1161.1	100,000	20	0.8	235	0.49%	1	294	0.39%	3	882	0.13%
Wet Tower	300	25	1295.6	100,000	20	0.8	235	0.55%	1	294	0.44%	3	882	0.15%
Once-through at 20' Static Head Using 3: 42" Pipes at 300' Length														
Once-through	300	20	1201.4	100,000	20	0.8	235	0.51%	1	294	0.41%	3	882	0.14%
Wet Tower	300	25	1335.9	100,000	20	0.8	235	0.57%	1	294	0.45%	3	882	0.15%
Once-through at 20' Static Head Using 2: 42" Pipes at 300' Length														
Once-through	300	20	1309.6	100,000	20	0.8	235	0.56%	1	294	0.45%	3	882	0.15%
Wet Tower	300	25	1444.1	100,000	20	0.8	235	0.61%	1	294	0.49%	3	882	0.16%
Once-through at 20' Static Head Using 4: 42" Pipes at 1000' Length														
Once-through	1000	20	1228.8	100,000	20	0.8	235	0.52%	1	294	0.42%	3	882	0.14%
Wet Tower	300	25	1295.6	100,000	20	0.8	235	0.55%	1	294	0.44%	3	882	0.15%
Once-through at 20' Static Head Using 3: 42" Pipes at 1000' Length														
Once-through	1000	20	1316.3	100,000	20	0.8	235	0.56%	1	294	0.45%	3	882	0.15%
Wet Tower	300	25	1335.9	100,000	20	0.8	235	0.57%	1	294	0.45%	3	882	0.15%
Once-through at 20' Static Head Using 2: 42" Pipes at 1000' Length														
Once-through	1000	20	1550.6	100,000	20	0.8	235	0.66%	1	294	0.53%	3	882	0.18%
Wet Tower	300	25	1444.1	100,000	20	0.8	235	0.61%	1	294	0.49%	3	882	0.16%
Once-through at 20' Static Head Using 4: 42" Pipes at 3000' Length														
Once-through	3000	20	1422.5	100,000	20	0.8	235	0.60%	1	294	0.48%	3	882	0.16%
Wet Tower	300	25	1295.6	100,000	20	0.8	235	0.55%	1	294	0.44%	3	882	0.15%
Once-through at 20' Static Head Using 3: 42" Pipes at 3000' Length														
Once-through	3000	20	1644.5	100,000	20	0.8	235	0.70%	1	294	0.56%	3	882	0.19%
Wet Tower	300	25	1335.9	100,000	20	0.8	235	0.57%	1	294	0.45%	3	882	0.15%
Once-through at 20' Static Head Using 2: 42" Pipes at 3000' Length														
Once-through	3000	20	2239.3	100,000	20	0.8	235	0.95%	1	294	0.76%	3	882	0.25%
Wet Tower	300	25	1444.1	100,000	20	0.8	235	0.61%	1	294	0.49%	3	882	0.16%

Note: Wet Towers are assumed to always be at 300' distance and have the same tower pumping head of 25' in all scenarios shown. The same flow rate of 100,000gpm (223 cfs) is used for all scenarios. Power/Heat Ratio refers to the ratio of Power Plant Output (MW) to the heat (in equivalent MW) transferred through the condenser. See Section 3-1 for the total energy penalties. This table presents only the pumping component of the total energy penalty

d. Summary of Cooling System Energy Requirements

EPA chose the piping scenario in Table 3-17 where pumping head is close to 50 ft for both (i.e., once-through at 1,000 ft and 3-42 in. pipes in Table 3-17). Thus, the cooling water pumping requirements for once-through and recirculating wet towers are nearly equal using the chosen site-specific conditions. Table 3-19 summarizes the fan and pumping equipment energy requirements as a percent of power output for each type of power plant. Table 3-20 presents the net difference in energy requirements shown in Table 3-19 for the alternative cooling systems. The net differences in Table 3-20 are the equipment operating energy penalties associated with conversion from one cooling technology to another.

EPA notes that the penalties presented in Tables 3-19 and 3-20 **do not** comprise the total energy penalties (which incorporate all three components of energy penalties: turbine efficiency penalty, fan energy requirements, and pumping energy usage) as a percent of power output. The total energy penalties are presented in section 3.1 above. The tables below only present the pumping and fan components. Section 3.3.2 presents the turbine efficiency components of the energy penalty.

Table 3-19: Summary of Fan and Pumping Energy Requirements as a Percent of Power Output

	Wet Tower Pumping	Wet Tower Fan	Wet Tower Total	Once-through Total (Pumping)	Dry Tower Total (Fan)
Nuclear	0.57%	0.91%	1.48%	0.56%	3.04%
Fossil Fuel	0.45%	0.73%	1.18%	0.45%	2.43%
Combined-Cycle	0.15%	0.24%	0.39%	0.15%	0.81%

Note: See Section 3.1 for the total energy penalties.

Table 3-20: Fan and Pumping Energy Penalty Associated with Alternative Cooling System as a Percent of Power Output

	Wet Tower Vs Once-through	Dry Tower Vs Wet Tower	Dry Tower Vs Once-through
Nuclear	0.92%	1.56%	2.48%
Fossil Fuel	0.73%	1.25%	1.98%
Combined-Cycle	0.24%	0.42%	0.66%

Note: See Section 3.1 for the total energy penalties.

3.4 Air Emissions Increases

Due to the cooling system energy penalties, as described in section 3.3 and presented in section 3.1 above, EPA estimates that air emissions will marginally increase from power plants which upgrade cooling systems. The energy penalties reduce the efficiency of the electricity generation process and thereby increase the quantity of fuel consumed per unit of electricity generated. In estimating annual increases in air emissions, the Agency based its calculations on the mean annual energy penalties provided in Table 3-1 above. EPA presents the annual air emissions increases for the final rule and the dry cooling regulatory alternative in Tables 3-7 and 3-8 in section 3.2 above.

EPA developed estimates of incremental air emissions estimates for the two types of power plants projected to upgrade cooling systems as a result of this rule (or a regulatory alternative): combined-cycle and coal-fired power plants. Generally, combined-cycle plants produce significantly less air emissions per kilowatt-hour of electricity generated than coal-fired plants. Because the combined-cycle plant requires cooling for approximately one-third of its process (on a megawatt capacity basis) and because of the differences in combustion products from natural gas versus coal, the combined-cycle plant produces less air emissions, even after coal-fired plants are equipped with state-of-the-art emissions controls. However, for the case of the air emissions estimates for the final rule and regulatory alternatives considered, EPA estimates that plants incurring an energy penalty will not increase their fuel consumption on-site to overcome incurred energy penalties. Instead, the Agency estimates that energy penalties at facilities affected by the requirements of this rule (or the regulatory alternatives) would purchase replacement power from the grid and the air emissions increases associated with a particular energy penalty at an effected plant would be released by the rest of the grid as a whole (thereby comprising negligible increases at a large number and variety of power plants). EPA received comments asserting that not all facilities, especially during times of peak demand, would be able to increase their fuel consumption to overcome energy penalties. Therefore, the air emissions increases presented in section 3.2 of this chapter represent uniform national air emissions increases per unit of energy penalty, regardless of the plant at which the energy penalty is occurring. For the final rule and regulatory alternatives considered, the key difference between air emissions increases estimated at facilities projected to upgrade cooling systems is directly related to the size of the energy penalty that the plant will incur. For the sake of comparison, EPA also calculated the air emissions increases for the final rule and regulatory alternatives in the case where the effected plants would increase fuel consumption to overcome the penalties. The comparative results are presented in Tables 3-21 and 3-22. EPA found small national differences between increased air emissions as calculated on the plant versus grid basis. For more information on the supporting calculations see DCN 3-3085.

The data source for the Agency's air emissions estimates of CO_2, SO_2, NO_X, and Hg is the EPA developed database titled E-GRID 2000. This database is a compendium of reported air emissions, plant characteristics, and industry profiles for the entire US electricity generation industry in the years 1996 through 1998. The database relies on information from power plant emissions reporting data from the Energy Information Administration of the Department of Energy. The database compiles information on every power plant in the United States and includes statistics such as plant operating capacity, air emissions, electricity generated, fuel consumed, etc. This database provided ample data for the Agency to conduct air emissions increases analyses for this rule. The emissions reported in the database are for the power plants' actual emissions to the atmosphere and represent emissions after the influence of air pollution control devices. To test the veracity of the database for the purposes of this rule, the Agency compared the information to other sources of data available on power plant capacities, fuel-types, locations, owners, and ages. Without exception, the E-GRID 2000 database provided accurate estimates of each of these characteristics versus information that EPA was able to obtain from other sources.

As noted above, the E-GRID 2000 database contains data on existing power plants. For the national analysis presented in section 3.2 above, EPA estimated that the annual generation of electricity would not increase over the life of the rule. Therefore, the emissions increases as a percent of national capacity presented in Tables 3-7 and 3-8 above are conservatively estimated and ignore projected growth rates of power plant capacity. For the comparative analysis of plant versus grid based emissions the Agency purposefully chose, when analyzing specific power plants (and not just the grid as a whole), to focus on the most recently constructed plants with multiple years of operating data (where possible). In addition, the Agency selected a variety of plants from different regions of the country with different urban versus rural locations. The capacity of the model plants was chosen as closely as possible to the average size plant within scope of the rule. Therefore, the Agency's comparative estimates of the air emissions increases from the scenario where individual plants are able to consume more fuel to overcome the energy penalties present nationally applicable results for the variety of plants and locations expected for the new facility rule. The model facility plant information along with the supporting calculations for this analysis can be found in DCN 3-3085.

Because the Agency estimates that the air emissions increases for the final rule (and regulatory alternatives) will come from the mix of plant types across the nation, the issue of baseline cooling systems is moot. However, for the scenario where EPA estimated (for the sake of comparison) that plants would increase fuel consumption to overcome energy penalties, and the air emissions would occur at the site, the issue of cooling system is more relevant. EPA attempted to consider baseline cooling systems when selecting the model facilities upon which to base the air emissions profiles for combined-cycle and coal-fired plants. However, because the emissions would be used to estimate changes in cooling systems from once-through to wet towers and, for the case of regulatory alternatives, from once-through to dry towers and wet towers to dry towers, the Agency ultimately determined that age, size, and location of the plant were more important factors to consider than the baseline cooling system. The effect is such, for the comparative example of plants increasing fuel consumption to overcome energy penalties as a result of the final rule, the Agency may have marginally overestimated the air emissions increases due to cooling system changes. EPA reiterates that this has no bearing on the estimated air emissions for the final rule and is relevant only for the comparative analysis presented in Tables 3-21 and 3-22. The basis for the Agency stating that it may have overestimated emissions in this comparative case for the final rule is due to the fact that several of the plants used as model facilities in the air emissions analysis actually utilize wet-cooling towers at baseline. Therefore, the baseline energy efficiency would be lower than a once-through system and the related baseline air emissions rates per unit of fuel consumed would be higher. Thus, for the case of the upgrades from once-through to wet cooling towers, EPA likely is overestimating the compliance air emissions rates per unit of fuel consumed in this comparative case. For the case of the dry cooling alternative, the effect is less pronounced and the Agency may be underestimating, in the end, the comparative air emissions increases. This is due to the fact that the majority of power plants have wet cooling towers at baseline. For the case of 90 percent of the plants to be upgraded to dry cooling in this regulatory alternative, the proper baseline cooling system is wet cooling towers. Therefore, the baseline air emissions rates per unit of electricity generated are lower than would represent a majority of plants employing wet cooling at baseline.

Table3-21: Comparison of Calculation Techniques for Net Air Emissions Increases of the Final Rule

Compensation Technique	Total Energy Penalty MW	Annual CO2 (tons)	Annual SO2 (tons)	Annual NOx (tons)	Annual Hg (lbs)
Increased Fuel Consumption	100	712,886	1,543	1,518	23
Market Power Replacement	100	485,860	2,561	1,214	16

Table3-22. Comparison of Calculation Techniques for Net Air Emissions Increases of Dry Cooling

Compensation Technique	Total Energy Penalty MW	Annual CO_2 (tons)	Annual SO_2 (tons)	Annual NOx (tons)	Annual Hg (lbs)
Increased Fuel Consumption	1,900	11,427,552	18,649	23,432	272
Market Power Replacement	1,900	8,931,036	47,074	22,313	300

3.5 OTHER ENVIRONMENTAL IMPACTS

Recirculating wet cooling towers can produce side effects such as vapor plumes, displacement of habitat or wetlands, noise, salt or mineral drift, water consumption through evaporation, and increased solid waste generation due to wastewater treatment of tower blowdown. The *Generic Environmental Impact Statement for License Renewal of Nuclear Plants* (NUREG-1437 Vol. 1, Nuclear Regulatory Commission) addresses the majority of these issues in depth, and the Agency refers to the detailed research contained therein several times in this discussion.

The Agency considered non-aquatic impacts of recirculating cooling towers for the proposal. While the Agency did not present quantified information regarding these side effects in the proposal, the Agency discussed the effects of both wet and dry cooling towers in the proposal. Specifically, the Agency discussed discharge water quality, salt drift, water conditioning chemicals and biocides, vapor plumes, energy efficiency, land use, and air emissions increases (65 FR 49080-49081). The Agency invited comments to the proposal on the subject of adverse environmental impact and whether or not it should consider non-aquatic impacts such as salt/mineral drift and reductions in the efficiency of electricity generation leading to increased air emissions as examples of adverse environmental impact (65 FR 49075). In turn, the Agency received no usable data (only anecdotal information) from commenters supporting assertions that these "side effects" pose significant environmental problems. The Agency researched the subjects further after proposal and provided some of the information in the notice of data availability and has cited other information from NUREG-1437.

The vast majority (90 percent) of power plants projected within the scope of this rule would install recirculating wet cooling towers in absence of this rule. Of these 74 power plants, the Agency projects that the cooling towers to be constructed will be of the mechanical draft type. (Stone & Webster 1992). For the other nine power plants for which EPA has projected the compliance costs associated with wet cooling towers, the Agency projects that the towers to be installed would be of the mechanical draft type, also.

3.5.1 Vapor Plumes

Natural draft or mechanical draft cooling towers can produce vapor plumes. Plumes can create problems for fogging and icing, which have been recorded to create dangerous conditions for local roads and for air and water navigation. Plumes are in some cases disfavored for reasons of aesthetics. Generally, mechanical draft cooling towers have significantly shorter plumes than those for natural draft towers (by approximately 30 percent). A "treatment" technique for these plumes in very rare cases is the installation of plume abatement (wet/dry hybrid cooling towers) on the tower. This is currently practiced at a small portion of recently constructed facilities (See DCN #2-037). As such, EPA's capital costs are not adjusted to reflect this type of plume abatement for this nationally applicable rule in which only 9 facilities are projected to install wet cooling towers.

Regarding aesthetics of cooling tower plumes, the Agency points to the Track II compliance option as an alternative for new facility power plants, in addition to the plume abatement controls, which are an option for new plants that choose to site where plume aesthetics are a public nuisance. The Agency notes that land area buffers may also be a simple means for reducing the effects of visible plumes, though this would be highly site-specific. As such, EPA has considered the subject of visible plumes to be a small issue when weighed against the serious aquatic environmental impacts of once-through cooling.

In the development of the final rule, the Agency considered the land area required for installation of cooling towers at new power plants. The Agency examined the sensitivity of costs to new power plants of purchasing additional land for (1) installing mechanical draft cooling towers in lieu of once-through cooling (for those power plants expected to incur the costs of cooling towers only) and (2) providing land area buffers for plumes at a portion of facilities. The Agency determined the final annualized costs were not sensitive to the described changes in land costs. The Agency also understands that the costs of these land acquisitions as a portion of total project costs for new power plants are negligible. In addition, because this rule applies to new facilities which have the ability, in the majority of cases, to alter the design and location of their facilities without encountering most of the hurdles associated with retrofitting existing facilities, the issue of additional land acquisition is not as significant.

The Agency considers the issue of plume "re-entrainment" to be an issue that has been well addressed by designers and operators of wet cooling towers. The technology is mature and well designed after many decades of use throughout the world in a variety of climates. The Agency considers plume re-entrainment at the nine power plants projected to upgrade their cooling system to be a small effect. For wet cooling towers, the plume re-entrainment value occasionally referenced is 2 percent (Burns & Micheletti 2000). This value, in the Agency's estimates would not appreciably impact cooling tower performance, nor have a discernable environmental impact.

3.5.2 Displacement of Wetlands or Other Land Habitats

Mechanical draft cooling towers can require land areas (footprints) approaching 1.5 acres for the average sized new cooling tower projected for this rule. When determining the area needed for wet cooling towers, plants generally consider the possible plume effects, and plan for the amount of space needed to minimize the effects of local fogging and icing and to minimize re-entrainment of the plume by the tower. The land requirements of mechanical draft wet cooling towers at new combined-cycle power plants generally do not approach the size of the campus. Dry cooling towers generally require approximately 3 to 4 times the area of a wet tower for a comparable cooling capacity. In consideration of displacement of wetlands or other land and habitat due to the moderate plant size increases due to cooling tower installations at nine facilities, the Agency determined that existing 404 programs would more than adequately protect wetlands and habitats for these modest land uses.

3.5.3 Salt or Mineral Drift

The operation of cooling towers using either brackish water or salt water can release water droplets containing soluble salts, including sodium, calcium, chloride, and sulfate ions. Additionally, salt drift may occur at fresh water systems that operate recirculating cooling water systems at very high cycles of concentration. Salt drift from such towers may be carried by prevailing winds and settle onto soil, vegetation, and waterbodies. Commenters expressed the concern that salt drift may cause damage to crops through deposition directly on the plants or accumulation of salts in the soil. The cooling tower system design and the salt content of the source water are the primary factors affecting the amount of salt emitted as drift. In addition, modern cooling towers utilize advanced fill materials that have been developed to minimize salt or mineral drift effects. The Agency estimates that the typical plant installing a cooling tower as a result of the requirements of this rule will equip the tower with modern splash fill materials. As such, the Agency has applied capital costs for the abatement of drift in the compliance costs of this rule.

In the cases where it is necessary, salt drift effects (if any) may also be mitigated by additional means that are similar to those used to minimize migrating vapor plumes (that is, through acquisition of buffer land area surrounding the tower). Additionally, modern cooling towers are designed as to minimize drift through the use of drift elimination technologies such as those costed by the Agency. NUREG-1437 states the following concerning salt/mineral drift from cooling towers: "generally, drift from cooling towers using fresh water has low salt concentrations and, in the case of mechanical draft towers, falls mostly within the immediate vicinity of the towers, representing little hazard to vegetation off-site. Typical amounts of salt or total dissolved solids in freshwater environments are around 1000 ppm (ANL/ES-53)." The Agency projects that four of the nine power plants which will upgrade their cooling system from once-through to recirculating closed-cycle will utilize freshwater sources, where salt drift will not be an issue. The Agency anticipates that the other five plants (each a combined-cycle design) will utilize estuarine/tidal water sources for cooling and that the issue of salt drift at these plants is of small significance and can be mitigated. This conclusion is supported by those reached in NUREG about salt-drift upon extensive study at existing nuclear plants: "monitoring results from the sample of [eighteen] nuclear plants and from the coal-fired Chalk Point plant, in conjunction with the literature review and information provided by the natural resource agencies and agricultural agencies in all states with nuclear power plants, have revealed no instances where cooling tower operation has resulted in measurable productivity losses in agricultural crops or measurable damage to ornamental vegetation. Because ongoing operational conditions of cooling towers would remain unchanged, it is expected that there would continue to be no measurable impacts on crops or ornamental vegetation as a result of license renewal. The impact of cooling towers on agricultural crops and ornamental vegetation will therefore be of small significance. Because there is no measurable impact, there is no need to consider mitigation. Cumulative impacts on crops and ornamental vegetation are not a consideration because deposition from cooling tower drift is a localized phenomenon and because of the distance between nuclear power plant sites and other facilities that may have large cooling towers."

3.5.4 Noise

Noise from mechanical draft cooling towers is generated by falling water inside the towers plus fan or motor noise or both. However, power plant sites generally do not result in off-site levels more than 10 dB(A) above background (NUREG-1437 Vol. 1). Noise abatement features are an integral component of modern cooling tower designs, and as such are reflected in the capital costs of this rule, which were empirically verified against real-life, turn-key costs of recently installed cooling towers. A very small fraction of recently constructed cooling towers also further install noise abatement features associated with low noise fans. The Agency collected data on recently constructed cooling tower projects from cooling tower vendors. The Agency obtained detailed project descriptions for these 20 projects and none utilize low noise fans. In addition, the cost contribution of low noise fans, in the rare case in which they may be installed at a new facility, would comprise a very small portion of the total installed capital cost of the cooling system. As such, the Agency is confident that the issue of noise abatement is not critical to the evaluation of the environmental side-effects of cooling towers. In addition, this issue is primarily in terms of adverse public reactions to the noise and not environmental or human health (i.e., hearing) impacts. The NRC adds further, "Natural-draft and mechanical-draft cooling towers emit noise of a broadband nature...Because of the broadband character of the cooling towers, the noise associated with them is largely indistinguishable and less obtrusive than transformer noise or loudspeaker noise."

3.5.5 Solid Waste Generation

For cooling towers, recirculation of cooling water increases solid wastes generated because some facilities treat the cooling tower blowdown in a wastewater treatment system, and the concentrated pollutants removed from the blowdown add to the amount of wastewater sludge generated by the facility.

EPA has accounted for solid waste disposal from cooling tower blow-down wastewater treatment in the operation and maintenance costs of this rule. EPA reiterates that only nine power plants would incur the costs to install wet cooling towers as a result of this rule. The associated solid waste disposal increases for these plants would be extremely small compared to the scope of facilities covered by the rule and negligible for the industry as a whole.

3.5.6 Evaporative Consumption of Water

Cooling tower operation is designed to result in a measurable evaporation of water drawn from the source water. Depending on the size and flow conditions of the affected waterbody, evaporative water loss can affect the quality of aquatic habitat and recreational fishing. Once-through cooling consumes water, in and of itself. According to NUREG-1437, "water lost by evaporation from the heated discharge of once-through cooling is about 60 percent of that which is lost through cooling towers." NUREG-1437 goes on to further state, "with once-through cooling systems, evaporative losses...occur externally in the adjacent body of water instead of in the closed-cycle system." Therefore, evaporation does occur due to heating of water in once-through cooling systems, even though the majority of this loss happens down-stream of the plant in the receiving water body.

The Agency has considered evaporation of water and finds these issues not to be significant for this rule. The Agency notes, again, that 90 percent of the in-scope power plants will install cooling towers regardless of the requirements of this rule. The nine other facilities, which may comply with the rule either through installation of flow reduction technologies similar to cooling towers (such as recirculating cooling lakes, cooling canals, or hybrid wet-dry cooling towers) or compliance with track II, are expected to consume approximately 127,000 gallons per minute (evaporative loss) when all new plants are operating. This represents less than three (3) percent of the baseline intake flow of the power plants within the scope of the rule. As a percentage of the total flow of water used for electricity generation in the US, this represents 0.1 percent. See DCN 3-3085.

3.5.7 Manufacturers

The Agency notes that the discussion thus far concerning side effects has focused exclusively on power plants. The Agency expects that 29 manufacturers will incur costs equivalent to installations of closed-cycle wet cooling towers as a result of this rule. However, even though these costs reflect cooling tower installations, the Agency projects that manufacturing facilities will comply, in the majority of cases, with this rule through the adoption of recycling and reuse design changes and operational practices at their plants. Therefore, the majority of issues discussed in this section are not of concern to manufacturing facilities for the final rule nor is the issue of energy penalties.

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ATTACHMENT A TO CHAPTER 3: HEAT DIAGRAM FOR STEAM POWER PLANT

(Source: Ishigai 1999)

See Hard Copy

Attachment B to Chapter 3: Exhaust Pressure Correction Factors

FOR A NUCLEAR POWER PLANT (Attachment B-1)
(Source: Entergy 2001)

See Hard Copy

FOR A FOSSIL FUEL PLANT (Attachment B-2)
(Source: General Electric. Steam Turbine Technology)

See Hard Copy

FOR A COMBINED CYCLE PLANT (Attachment B-3)
(Source: Litton)

See Hard Copy

Attachment C to Chapter 3: Design Approach Data for Recent Cooling Tower Projects

(Source: Mirsky 2001)

Table AA-1. Cooling Tower Design Temperature, Range and Approach

STATE	YEAR	FLOW (GPM)	TEMPERATURE (DEG F) HOT WATER	COLD WATER	WET BULB	RANGE (DEG F)	APPROACH (DEG F)	# OF CELLS
AL	2000	208000	85	72	62	13	10	10
OR	2000	152000	98	77.8	68.35	20.2	9.45	11
CA	2000	99746	94.3	72.5	55.5	21.8	17	8
NJ	2000	146000	90.3	75	52	15.3	23	10
AL	2000	278480	105	89	81	16	8	14
AL	2000	147361	112.5	96.7	84.7	15.8	12	7
IL	2000	189041	96.87	85.46	76	11.41	9.46	10
TX	2000	192300	104.3	87	79	17.3	8	12
TX	2000	106400	89.2	78.5	64.2	10.7	14.3	5
MO	1999	60000	85.3	67	52.4	18.3	14.6	4
FL	1999	21500	120	93	80	27	13	1
TX	1999	277190	105	89	81	16	8	14
CA	1999	101000	111.05	89	75	22.05	14	6
AL	1999	50000	107	86	80	21	6	4
MO	1999	25000	98	83	78	15	5	2
MS	1998	230846	106.2	91.2	84.7	15	6.5	12
SC	1998	150000	110	90	80	20	10	11
TX	1998	90000	110	90	83	20	7	5
TX	1998	278480	105	89	81	16	8	14
AL	1998	125000	105.7	85.7	80	20	5.7	10
LA	1998	45000	110	90	82	20	8	3
TX	1998	90400	117.1	94.1	82.68	23	11.42	5
SC	1998	8500	114	95	81	19	14	2
SC	1998	14000	116	95	81	21	14	2
AR	1998	13200	116	95	81	21	14	2
NJ	1998	4400	100	71	66	29	5	4
TX	1998	18000	105	85	72	20	13	2
CA	1998	7000	105	80	71	25	9	1
TX	1998	15000	115	90	81	25	9	2
SC	1998	15000	123	95	81	28	14	1
LA	1998	1000	124	90	80	34	10	1
OH	1998	6400	135	90	77	45	13	2
LA	1997	20000	104	86	81	18	5	2
MO	1997	60000	85.3	67.5	52.4	17.8	15.1	4
PA	1997	30000	105	85	78	20	7	6
AL	1997	16000	114	90	79	24	11	2
OK	1997	8350	112	89	79	23	10	2
WA	1997	14000	120	74	58	46	16	2
MT	1997	12000	96	74	64	22	10	2
GA	1997	3000	97.6	87.6	80	10	7.6	1
OH	1997	6000	118	86	77	32	9	2
MN	1997	7500	106	87	74	19	13	1
LA	1997	12000	110	85	80	25	5	3
NY	1997	4800	103.5	85	78	18.5	7	1
SC	1997	50000	93	81	72	12	9	3
	Maximum	278480	135	96.7	84.7	46	23	14
	Minimum	1000	85	67	52	10	5	1
	Average	75775.42222	106.3	85.2	74.8	21.1	10.4	5
	Median	30000	105.7	87	79	20	10	3
	Mode	278480	105	90	81	20	10	2

Attachment D to Chapter 3: Tower Size Factor Plot

(Source: Hensley 1985)

See Hard Copy

Attachment E to Chapter 3: Cooling Tower Wet Bulb versus Cold Water Temperature Typical Performance Curve

(Source: Hensley 1985)

See Hard Copy

Attachment F to Chapter 3: Summary and Discussion of Public Comments on Energy Penalties

For the November 2000 proposal, the Agency presented a discussion on energy penalties for dry cooling systems, but did not present detailed estimates of penalties. The Agency also stated that energy penalties at wet cooling towers were negligible in their effect on final cost estimates for the proposed rule. Subsequent to the proposal, the Agency recognized, based, in part, on public comments, that the proposal did not sufficiently consider energy penalties for the regulatory options considered and proposed. In turn, EPA began a thorough program to assess the state of research into energy penalties that would meet its broad needs. After learning that the appropriate energy penalty data did not exist or was not well documented and explained, EPA began a project to assess the energy penalty of a variety of cooling systems for a variety of conditions. In order to notify the public of its intention, the Agency included information in the June 2001 notice of data availability that explained the status of the research project, the types of information the Agency was considering, the methodology for estimating the penalties, and the ultimate methodology for assessing the cost of the penalties and the associated air emissions increases.

In addition to a host of general comments on the proposal and notice of data availability that urged consideration of the energy penalty in the technical, economic, and environmental analyses of the final rule, the Agency primarily received its most technical comments in response to the notice of data availability. The Agency fully considered all of the comments received on the subject of energy penalties (see the response to comment document), which came from all manner of stakeholders. However, due to the detailed technical nature of select comments, the Agency devotes the following discussion to evaluation of public comments received from the Department of Energy (DOE) and the Utility Water Act Group (UWAG) concerning EPA's energy penalty estimates and the methodology presented in the draft report, titled "Steam Plant Energy Penalty Evaluation, April 20, 2001," which was included in the public record for the notice of data availability. For the sake of clarity and simplicity, this discussion will address the commenters by their representative organizations, even though select individuals within, legal firms representing, or contractors hired by the organizations may have prepared the comments.

The DOE comments were the more general of the comments in nature. The Agency addresses these comments first, along with general comments made by UWAG on energy consumption for different cooling systems. The UWAG technical comments (Appendix B of their comments) on the draft energy penalty report are then addressed, followed by a brief discussion of other issues related to EPA's notice of data availability draft report (here after referred to as the "draft report"). Finally, EPA provides conclusions on the comments and their influence on the final energy penalty estimates.

F.1 General Comments from DOE and UWAG

F.1.1 The Components of Energy Penalties

Both the Agency and the commenters agree that the total energy penalty consists of three components: 1) changes in turbine efficiency, 2) changes in cooling water pumping requirements, and 3) changes in cooling system fan energy requirements. The commenters make no references to other significant components, implying that no other additional factors need to be considered.

In the draft report, the Agency estimated the three components and presented them separately to allow flexibility in application and to avoid double counting. For example, the fan and pumping energy costs were incorporated into the Agency estimates for the cooling tower O&M costs. Therefore, the notice of data availability presented each component separately and factored them in separately, where necessary, depending on the analysis being performed. However, from an energy output perspective (i.e., ignoring costs), the DOE comment is correct that for the total energy penalty, all three components should be added together. The Agency intended to do this all along.

F.1.2 Turbine Efficiency and the Presentation of Energy Penalty

The Agency agrees with DOE that the energy penalty should be expressed as a "percentage reduction in plant output." Again, the Agency had intended to do so and, as noted by DOE, presented the pumping and fan power components as such in the draft report. While the Agency intended for the calculated values for changes in turbine efficiency to be representative of percent changes in plant output, the calculation method, as presented by the Agency, unfortunately led to other interpretations. Therefore, for the sake of clarity, the Agency developed a revised method for determining the changes in turbine efficiency, now based on turbine exhaust pressure response curves, for the final rule. This method removes the confusion cited above but does not change results dramatically.

F.1.3 Energy Penalties for Dry Cooling Towers and the Basis of Comparison

The draft report only addressed the energy penalty for once-through versus recirculating wet cooling towers. Subsequent to the draft report, the Agency developed energy penalty estimates for dry towers (air cooled condensers) for comparison to either once-through or wet tower cooling baseline systems. These estimates are presented in section 3.1. The estimates in the draft report were for alternative cooling systems to be installed at new facilities (in other words, they represented a change in design from once-through to wet tower cooling systems). As such, the Agency did not consider factors that would be associated with retrofitting an existing facility, contrary to the commenter's assertion.

F.1.4 Condenser Inlet Temperature

Both the UWAG and DOE comments noted that the Agency only considered the condenser inlet temperature. The commenters correctly point out that condenser inlet temperature is not the only factor that will affect the turbine exhaust pressure. However, in the Agency's view, it is the major driving factor. While condenser inlet temperature is the starting point, temperature rise (or "range") through the condenser and the design of the condenser will influence the exhaust steam pressure. The Agency chose cooling system design parameters that best represent the wide range of systems recently constructed. These same design parameters are used as the basis for the compliance cost estimates for installing recirculating wet towers. The representativeness of these numbers will be discussed in more detail below. The trade-off is that plants with smaller temperature rises must accomplish the cooling by using a larger volume of cooling water flow. UWAG only notes that the method neglects the influence of condenser performance (Comment 2).

F.2 Detailed Technical Comments from UWAG

F.2.1 Turbine Exhaust Pressure, Performance, and Loading

In the Agency's view, UWAG is correct in noting that the exhaust pressure at which condensed moisture may cause damage to the turbine will vary depending upon throttle conditions, the shape of the expansion curve, and blade metallurgy. If the throttle settings are low (that is, the plant is operating much below capacity), then the exhaust pressure at which damaging moisture levels may occur will be lower. Agency evaluation of energy penalty focused primarily on turbines operating close to their capacity, which is supported by the results of the Agency's data collection efforts for the final new facility rule. For instance, the Agency projects that the mean capacity factor at new plants is approximately 85 percent (that is, near to full capacity). See the Economic Analysis.

Condensed moisture is but one of several factors that may prevent more efficient operation at lower exhaust pressures. Another more important factor is the dynamic losses mentioned in UWAG Technical Comment 2. As can be seen in the turbine response graph showing turbine exhaust pressure versus turbine heat rate (included as Attachment B to the draft report), the curve representing the maximum steam loading rates straightens and begins to increase (that is, the efficiency decreases) as the pressure drops below approximately 1.5 inches Hg. This efficiency decrease is, for the most part, due to dynamic exhaust losses which occur when the expansion of steam (due to steam pressure progressively dropping through the turbine) results in an increase in the velocity of the steam as it exits the turbine.

In general, manufacturers design steam turbines to prevent a steam velocity increase by increasing the turbine cross-sectional area as the steam passes through the turbine. However, as the exhaust pressure approaches a vacuum, the amount of area required at the outlet end increases rapidly and the corresponding cross-sectional area needed increases the turbine costs such that the economic trade-off (increased cost vs. increased efficiency) compels the designer to lose efficiency at low exhaust pressures. For standard turbines at low exhaust pressures, the steam velocity increases and a portion of the steam energy is converted to kinetic energy (proportional to the square of the velocity). This increase in the steam kinetic energy reduces the net amount of energy available to the turbine. Thus, the commenters are correct: rather than condensed moisture, it is dynamic exhaust losses that set a practical minimum exhaust pressure (at higher steam loading rates) for turbines of conventional design.

The Agency bases the final energy penalty estimates on actual turbine response curves representing the different types of plants, rather than on theoretical calculations. The Agency developed two sets of values representing maximum load and 67 percent load (that is, 67 percent of maximum steam load). Finally, the Agency bases its estimates for reduced capacity at peak demand periods on the maximum load values and the estimate of mean annual energy penalty (for the purpose of estimating economic impact over the entire year) based on the 67 percent load values. In the Agency's view, the nuclear penalty estimate based on the theoretical calculations is validated by the turbine response curve for that facility. A comparison of this curve with the estimated penalty curve (based on theoretical calculations) showed that the two curves were very close in value. In these estimates, the Agency used the data from Attachment B to these comments (the turbine response curve) for the nuclear power plant penalty estimates.

F.2.2 Optimal Turbine Back Pressures

UWAG argues that the use of 1.5 inches Hg as the optimal operating back pressure does not consider that many U.S. plants operate below 1.5 inches Hg during substantial portions of the year. It then states that this assumption is not likely to have a huge effect on the penalty (although it will tend to understate the penalty). As discussed above, the 1.5 inches Hg value corresponds to turbines operating near capacity. Rather than assume that plants will optimize the operation of the cooling system, the turbine efficiency analysis in the Agency's final energy penalty study uses the values from the turbine response curves. Therefore, the Agency avoided setting any minimum exhaust pressure value, about which the commenter expresses concern.

The Agency agrees with the point raised that some U.S. plants operate below 1.5 inches Hg for substantial portions of the year. In some cases, the design of the plant does not provide for control of the cooling system (for example, a once-through system with constant speed pumps). However, unless the plant is specifically designed to operate efficiently at low pressures (with higher turbine capital costs), the turbine response curves indicate that typical turbines operating at low exhaust pressures either operate efficiently but at well below the turbine capacity, or operate in a less than optimal mode near full capacity. In fact, the curves suggest that turbines of standard design operating at exhaust pressures below 1.5 inches Hg and near capacity may be experiencing an energy penalty by not controlling the cooling system such that the exhaust pressure does not drop below the optimum pressure. Turbines operating at low load experience improved efficiency at lower exhaust pressures, but the diminished output tempers the overall effect. Therefore, the Agency's methodology does not underestimate energy penalties as the commenters suggest.

F.2.3 Empirical Data Versus Subtle Effects

The Agency agrees that the estimation methodology simplifies complex relationships including subtle impacts of turbine design. The use of empirical data simplifies the modeling of complex factors with subtle effects. This is the fundamental approach of design engineering and is a reasonable approach for this rule.

The commenter takes exception to the Agency's perceived reliance on a cooling tower manufacturer for comparison of its estimates. The Agency used data in Attachment C of the draft report (to which the commenter questions) only as a benchmark value for comparison/validation. Since the Agency's estimates were derived independently, the qualifications as a cooling tower manufacturer do not affect their validity.

F.2.4 Thermal Design Approach Values

The Agency disagrees that there is a disadvantage with using the median value (it is also the mean and the mode, in this case) for the design approach of the model cooling tower used for the regulatory impact analysis. The data in Attachment G of the draft report represents 45 wet cooling towers installed from 1997 through 2000 in locations throughout the country. The Agency reviewed this data and did not discern any pattern, such as regional trends, that would warrant use of values different than the statistical median. The Agency intended for these estimates to support national estimates. Therefore, the Agency included regional and seasonal differences in the cooling media (surface water, wet bulb, dry bulb) temperatures in the estimates for the final rule. Similar to other construction projects, economic considerations, such as availability of capital and the desired time period to recoup investment, among other factors, influence the selection of the design approach, design range, and other design parameters. The Agency believes it is difficult to estimate these factors and variables and notes that the commenter did not suggest a reasonable way to take these variables into consideration in the national energy penalty estimates. In the Agency's view, the statistical median for recently constructed cooling towers throughout the country best represents the full range of design operating conditions employed throughout the country. In addition, the commenters do not take issue with the validity or representativeness of the data in Attachment G to the draft report. See also Attachment C to Chapter 3 for the data supporting the Agency's estimates of a design approach value of 10 deg F.

The Agency notes that the design approach value is for comparison to ambient wet bulb conditions and not to the wet bulb temperature of the tower inlet, which can be slightly higher when air recirculation occurs. The Agency also notes that air recirculation occurs intermittently and only at times when winds are high and are blowing from a direction perpendicular (broadside) to the tower orientation. Where possible, towers, in their design, are oriented so as to minimize this effect. In general, the installed tower is certified by the manufacturer to perform within the design specifications with a wind velocity of up to 10 mph (Hensley 1985). Thus, the tower size and other design criteria that apply to the towers used in the cost estimates do include consideration of air recirculation.

The commenters take issue with the use of a constant approach value throughout the year. The approach value that the Agency used for the draft report represents design conditions which generally apply to the worst-case design (i.e., summer) conditions. As such, the use of a constant value throughout the year will not result in inaccurate estimates for the maximum penalty value. After further review of this issue, the Agency agreed that the commenters are correct that it is inappropriate to use the design approach value for estimating the average energy penalty throughout the year. EPA has found within the suggested reference (Hensley 1985) a graph for the relation between wet bulb temperature and cold water temperature for a tower that can be used as the basis for estimating the approach at wet bulb temperatures other than the design temperature. The revised penalty estimates in the final report incorporate this suggestion for estimating seasonal changes in the approach values.

F.2.5 Turbine Exhaust Pressure and Cooling Water Inlet Temperatures

For the final energy penalty report, the Agency investigated whether the Heat Exchange Institute Standards for Steam Surface Condensers assist in more "precisely" estimating the relationship between turbine exhaust pressure and cooling water inlet temperatures. The Agency notes that a revised method would in itself require assumed values (for example, condenser heat transfer coefficient, number and arrangement of tubes, etc.) that given the nature of the comments are then subject to the same arguments made by the commenter that they do not represent the full variety of condenser designs being employed. In the end, the revised method suggested by the commenter generated very similar results to EPA's method in the draft report, and, therefore, was not used.

F.2.6 Fan Energy Requirements

UWAG implicitly agrees with the EPA methodology for estimating wet cooling tower fan energy requirements. The commenters only take issue with using an "optimistic" motor efficiency of 95 percent instead of 92 percent, and failure to include a factor for fan gear efficiency (typically 96 percent). The factors used in the draft report, including a fan usage factor of 93 percent, were obtained from a cooling tower manufacturer (Fleming 2001). Incorporation of the UWAG suggestions increased the fan energy component by a total of 7.6 percent of a component that itself is less than 1 percent of plant output. Regardless, the Agency incorporated the factors suggested by the commenter.

F.2.7 Recirculating Water Pumping Velocity

UWAG's comments dispute the use of a cooling water velocity of 5.7 ft/s in the circulating water pipes, reporting that their past observation was that cooling water velocities in all three types of power plants were in the range of 8 to 11 ft/s. EPA notes that the 5.7 ft/s value was used as the minimum design starting point. The draft report showed that the results of piping designs resulting in three different flow velocities of 5.8, 7.7, and 11.6 ft/s, along with three different piping distances, were used in the analysis.

As a follow-up, the Agency contacted a Bechtel power systems engineer to obtain typical values for pumping head and learned that a 50 ft total pumping head was typical for a once-through system (Taylor 2001). The notice of data availability analysis shows that for a pumping distance of 1,000 ft, the total calculated pumping heads were 49 ft and 58 ft at pipes sized to produce velocities of 7.7 and 11.6 ft/s, respectively. These values compare favorably with the Bechtel estimate. Final Agency estimates for once-through pumping costs use this 50 ft pumping head value.

F.2.8 Static Head

UWAG states that the two static head values assumed by the Agency are inaccurate based upon reference to Power Engineering sources. The commenters did not specify in what way the values used by the Agency were inaccurate except to imply (as indicated in comment 10 below) that they may be overstated. The Agency reviewed the cited reference (Handbook of Energy Systems Engineering) to see if useful data was available for inclusion in the final analysis. As such, the implication made by commenters, as elsewhere, is that Agency's draft report estimates would tend to understate the penalty.

After review of the data, the Agency determined that it disagrees with the assertion made by the commenter regarding understated static head values. The Agency estimates that the siphon will continue from pump inlet to an open channel outlet, and, as a consequence, the static head would be the elevation difference between these two. In many cases this static head difference would be relatively small. Thus, the Agency's estimates of static head in the notice of data availability are reasonable. The Agency also notes that the static head is a site-specific value.

F.2.9 Gravity Versus Siphon Flow of Cooling Water

The commenters contest the Agency's estimate that cooling water will flow by gravity back to the source. The Agency was aware of the use of the siphon effect (with vacuum pumps at the high point) in condenser piping, but was not certain of its wide-spread use and therefore did not include it in the analysis for the notice of data availability. The estimate was intended to produce a more conservative (i.e., higher) pumping head. In this case, the effect of the estimate for gravity flow was a conservative estimate.

The Agency subsequently obtained information concerning head losses within condensers (Hess 2001). The pumping head component for condenser loss in the final estimates reflects consideration of this data. The addition of condenser losses offset the reduction in static head that results from the siphon effect outlined above. This appears to explain why, despite the comments, that the draft report estimates for total pumping head are similar to the estimate provided by Bechtel (Taylor 2001).

F.2.10 Pumping Head as a Function of Tower Height

UWAG disagrees with the pumping head estimates for cooling towers in the notice of data availability report, citing the Agency's lack of varying the tower height, using a small dynamic head, and neglecting to include losses in the tower spray nozzles. The Agency's based the pumping head calculations on a single cooling water flow value and therefore it is not necessary to consider variations in the tower height. The Agency chose a single tower design and a total pumping head value for an actual tower reported by a tower manufacturer (Fleming 2001) which included all of these pumping head components in combination. The tower chosen is actually sized for a slightly more conservative flow than that used in the calculations. Therefore, the tower design specifications are consistent with the tower design used in other energy penalty components and in the cost analysis.

F.2.11 Plant Operating Capacity

The commenters are correct that at times when the plant is operating near its engineering or regulatory limits, the penalty will effectively reduce capacity. They also point out that the energy penalty is not just an economic concern (that is, the penalty will require use of additional fuel or purchase of replacement power), but can also limit plant capacity during peak demand periods. However, this comment has no bearing on the penalty estimates themselves. The Agency also notes that for wet cooling tower systems, the magnitude of even the peak-summer shortfall penalties do not approach a level that will impact plant capacity at peak demand periods. The commenters make a similar statement in Appendix C of their comments to the notice availability. The same is not true for dry cooling systems, based on the Agency's estimates.

F.2.12 Turbine Efficiency Adjustment Factors

The turbine efficiency estimation methodology used in the final energy penalty analysis eliminates the need to use the 17 percent factor to which the commenters object. However, the Agency's final method continues to estimate that the steam turbine contributes approximately 1/3 of the total plant capacity for a combined-cycle plant. The commenters did not take issue with the 1/3 capacity assumption.

F.2.13 Fan and Pumping Costs

The Agency wishes to clarify the estimated fan and pumping costs, in particular, the use of an electricity cost of $0.08/kWh rather than $0.03-$0.04/kWh. The Agency uses an electricity cost value that represents the average cost to the consumer. This value was chosen as a conservative value (on the high side) to ensure that the estimates compensated for other minor O&M cost components associated with the operation of the cooling fans and pumps that the Agency has not directly included.

F.3 Conclusions Regarding Public Comments

The Agency, as described above, fully considered the substance of the comments submitted and has incorporated revisions in its final analysis based on a portion of the arguments, as noted. However, the Agency notes that the commenters generally did not present detailed data to support their positions or that would assist the Agency in revising its estimates. In turn, the Agency sought out additional reference material from a variety of sources, in addition to some references cited by the commenters, to determine the most accurate final estimates possible. These references are included in the record for the final rule.

Many of the comments take issue with the simplification of a very complex system. One of the greatest challenges of this effort for the Agency was to balance the many design and operating variables that apply to a variety of design-specific conditions with the need to develop national estimates that are valid for all of these situations. Thus, where possible, the Agency employed statistical estimates and empirical data to best represent the site-specific conditions and engineering relationships. The Agency points to the DOE comment which states that the draft report methodology "is an approach based on historical correlations, but for most plants and locations it is approximately correct." After incorporation of the revisions outlined above (which the Agency conducted in response to comment and for confirmatory reasons) the Agency's final energy penalty estimates are reasonable and defensible national estimates.

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Chapter 4: Dry Cooling

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INTRODUCTION

This chapter addresses the use and performance of dry cooling systems at power plants. Dry cooling systems transfer heat to the atmosphere without the evaporative loss of water. There are two types of dry cooling systems for power plant applications: direct dry cooling and indirect dry cooling. Direct dry cooling systems utilize air to directly condense steam, while indirect dry cooling systems utilize a closed cycle water cooling system to condense steam, and the heated water is then air cooled. Indirect dry cooling generally applies to retrofit situations at existing power plants because a water-cooled condenser would already be in place for a once-through or recirculated cooling system. Therefore, indirect dry cooling systems are not further considered in the Chapter for new sources subject to this regulation.

The most common type of direct dry cooling systems (towers) for new power plants are recirculated cooling systems with mechanical draft towers. Natural draft towers are infrequently used for installations in the United States and were not considered for evaluation in this Chapter.

For dry cooling towers the turbine exhaust steam exits directly to an air-cooled, finned-tube condenser. The arrangement of the finned tubes are most generally of an A-frame pattern to reduce the land area required. However, due to the fact that dry cooling towers do not evaporate water for heat transfer, the towers are quite large in comparison to similarly sized wet cooling towers. Because dry cooling towers rely on sensible heat transfer, a large quantity of air must be forced across the finned tubes by fans to improve heat rejection. The number of fans is therefore larger than would be used in a mechanical draft wet cooling tower.

Hybrid wet-dry cooling towers employ both a wet section and dry section and are used primarily to reduce or eliminate the vapor plumes associated with wet cooling towers. For the most common type of hybrid system, exhaust steam flows through smooth tubes, where it is condensed by a mixture of cascading water and air. The water and air move in a downward direction across the tube bundles and the air is forced upward for discharge to the atmosphere. The falling water is collected and recirculated, similarly to a wet cooling tower. The water usage of a hybrid system is generally one-third to one-half of that for a wet cooling system and the required pumping head is reduced somewhat. In the Agency's opinion, the common hybrid systems do not dramatically reduce water use as compared to wet cooling towers. The comparative cost increases of the hybrid systems to the wet cooling systems do not outweigh water use savings of approximately one-half to two-thirds. Therefore, the discussion of dry cooling towers for the remainder of the chapter focuses on direct dry cooling systems exclusively.

The key feature of dry cooling systems is that no evaporative cooling or release of heat to surface water occurs. As a result, water consumption rates are very low compared to wet cooling systems. Since the unit does not rely in principle on evaporative cooling as does a wet cooling tower, larger volumes of air must be passed through the system compared to the volume of air used in wet cooling towers. As a result, dry cooling towers need larger heat transfer surfaces and, therefore, tend to be larger in size than comparable wet cooling towers. The design and performance of the dry cooling system is based on the ambient dry bulb temperature. The dry bulb temperature is higher than the wet bulb temperature under most circumstances, being equal to the wet bulb temperature only when the relative humidity is at 100%.

The remainder of this chapter is organized as follows:

Section 4.1 provides a brief overview of the status of dry cooling projects in the United States including discussion of the types of generating facilities, their locations, and factors affecting plant performance.
Section 4.2 presents an evaluation of the dry cooling technology as a candidate for best technology available to minimize adverse environmental impact.

4.1 Demonstrated Dry Cooling Projects

This section provides a brief overview of the status of dry cooling projects in the United States. The section includes a brief discussion of the types of generating facilities, their locations, and factors affecting plant performance.

Dry cooling has been installed at a variety of power plants utilizing many fuel types. In the United States, dry cooling is most frequently applied at plants in northern climates. Additionally, arid areas with significant water scarcity concerns have also experiencing growth in dry cooling system projects. As demonstrated in Chapter 3, the comparative energy penalty of a dry cooling plant in a hot environment at peak summer conditions can exceed 12 percent, and the benefit of the water use savings must be analyzed with regard to the reduced cooling efficiency.

Table 4-1 presents a compilation of data pertaining to dry cooling systems installed at power plants within the United States and in foreign countries by a U.S. dry cooling system manufacturer from 1968 through the year 2000. The majority of these systems have been installed at combined cycle plants and at alternative fuel plants such as municipal solid waste and waste wood burning facilities. In many cases, systems with similar design dry bulb temperatures have different design exhaust pressure values, reflecting the selection of different dry tower sizes by the facility owners. Use of different relative dry tower sizes for similar facilities reflects the selection of different economic criteria with respect to size, costs, and efficiency.

Table 4-1: Air Cooled Condenser Data for Systems installed by GEA Power Cooling Systems, Inc.

Facility Name	City	State	Country	Size MW	Steam Flow lbs/hr	Turbine Exhaust Pressure In. Hg	Design Temp. °F	Year	Description	Sat. Steam Temp. °F	Temp. Difference °F
Neil Simpson I Sta.	Gillette	WY	USA	20	167,550	4.5	75	1968	Coal	130	55
NP Potter	Braintree	MA	USA	20	190,000	3.5	50	1975	Combine Cycle	120	70
Wyodak Sta.	Gillette	WY	USA	330	1,884,800	6	66	1977	Coal	141	75
Gerber Cogen	Gerber	CA	USA	3.7	52,030	2.03	48	1981	Combined Cycle Cogen	102	54
NAS North Is. Cogen	Coronado	CA	USA	4	65,000	5	70	1984	Combined Cycle Cogen	134	64
NTC Cogen	San Diego	CA	USA	2.6	40,000	5	70	1984	Combined Cycle Cogen	134	64
Chinese Sta.	China Camp	CA	USA	22.4	181,880	6	97	1984	Waste wood	141	44
Duchess Cnty. RRF	Poughkeepsie	NY	USA	7.5	50,340	4	79	1985	WTE	126	47
Sherman Sta.	Sherman Station	ME	USA	20	125,450	2	43	1985	Waste Wood	102	59
Olmstead Cnty. WTE	Rochester	MN	USA	1	42,000	5.5	80	1985	WTE	138	58
Chicago Northwest WTE	Chicago	IL	USA	1	42,000		90	1986	WTE		
SEMASS WTE	Rochester	MA	USA	54	407,500	3.5	59	1986	WTE	120	61
Haverhill RRF	Haverhill	MA	USA	46.9	351,830	5	85	1987	WTE	134	49
Cochrane Sta.	Cochrane	Ont.	CAN	10.5	90,000	3	60	1988	Combined Cycle Cogen	115	55
Grumman	Bethpage	NY	USA	13	105,700	5.4	59	1988	Combined Cycle Cogen	137	78
North Branch Power Sta.	North Branch	WV	USA	80	662,000	7	90	1989	Coal	147	57
Sayreville Cogen Pro.	Sayreville	NJ	USA	100	714,900	3	59	1989	Combined Cycle Cogen	115	56
Bellingham Cogen Pro.	Bellingham	MA	USA	100	714,900	3	59	1989	Combined Cycle Cogen	115	56
Spokane RRF	Spokane	WA	USA	26	153,950	2	47	1989	WTE	102	55
Exeter Energy L.P. Pro.	Sterling	CT	USA	30	196,000	2.9	75	1989	PAC System	114	39
Peel Energy from Waste	Brampton	Ont.	CAN	10	88,750	4.5	68	1990	WTE	130	62
Nipogen Power Plant	Nipogen	Ont.	CAN	15	169,000	3	59	1990	Combined Cycle Cogen	115	56
Linden Cogen Pro.	Linden	NJ	USA	285	1,911,000	2.44	54	1990	Combined Cycle Cogen	108	54
Maalaea Unit 15	Maui	HI	USA	20	158,250	6	95	1990	Combined Cycle	141	46
Norcon Welsh Plant	North East	PA	USA	20	150,000	2.5	55	1990	Combined Cycle Cogen	109	54
Univ of Alaska	Fairbanks	AK	USA	10	46,000	6	82	1991	Combined Cycle Cogen	141	59
Union County RRF	Union	NJ	USA	50	357,000	8	94	1991	WTE	152	58
Saranac Energy	Saranac	NY	USA	80	736,800	5	90	1992	Combined Cycle Cogen	134	44
Onondaga County RRF	Onondaga	NY	USA	50	258,000	3	70	1992	WTE	115	45
Neil Simpson II Sta.	Gillette	WY	USA	80	548,200	6	66	1992	Coal	141	75
Gordonsville Plant	Gordonsville	VA	USA	50	349,150	6	90	1993	C-Cycle (x2 Units)	141	51
Dutchess County RRF Exp.	Poughkeeksie	NY	USA	15	49,660	5	79	1993	WTE	134	55
Samalayuca II Power Sta.	Samalayuca		MEX	210	1,296,900	7	99	1993	Combined Cycle	147	48
Potter Station	Potter	Ont.	CAN	20	181,880	3.8	66	1993	Combined Cycle	124	58

Table 4-1: Air Cooled Condenser Data for Systems installed by GEA Power Cooling Systems, Inc.

Facility Name	City	State	Country	Size MW	Steam Flow lbs/hr	Turbine Exhaust Pressure In. Hg	Design Temp. °F	Year	Description	Sat. Steam Temp. °F	Temp. Difference °F
Streeter Generating Sta.	Cedar Falls	IA	USA	40	246,000	3.5	50	1993	Coal - PAC System	120	70
MacArthur RRF	Ronkonkoma	NY	USA	11	40,000	4.8	79	1993	WTE	132	53
North Bay Plant	North Bay	Ont.	CAN	30	245,000	2	53.6	1994	Combined Cycle	102	48.4
Kapuskasing Plant	Kapuskasing	Ont.	CAN	30	245,000	2	53.6	1994	Combined Cycle	102	48.4
Haverhill RRF Exp.	Haverhill	MA	USA	46.9	44,500	5	85	1994	WTE	134	49
Arbor Hills Landfill Gas Fac.	Northville	MI	USA	9	87,309	3	50	1994	Combined Cycle	115	65
Pine Bend Landfill Gas Fac	Eden Prairie	MN	USA	6	58,260	3	50	1994	Combined Cycle	115	65
Pine Creek Power Sta.	Pine Creek	N. Ter.	AUSTRAILIA	10	95,300	3.63	77	1994	Combined Cycle	122	45
Cabo Negro Plant	Punta Arenas		CHILE	6	74,540	4	63	1995	Methanol Plant	126	63
Emeraldas Refinery	Emeraldas		EQUADOR	15	123,215	4.5	87.3	1995	Combined Cycle	130	42.7
Mallard Lake Landfill Gas	Hanover Park	IL	USA	9	101,400	3	49	1996	Combined Cycle	115	66
Riyadh Power Plant 9	Riyadh		SAUDI ARABIA	107	966,750	16.5	122	1996	C-Cycle (x4 Units)	184	62
Barry CHP Project	Barry	S. Wales	UK	100	596,900	3	50	1996	Combined Cycle	115	65
Zorlu Enerji Project	Bursa		TURKEY	10	83,775	3.5	59	1997	Combined Cycle	120	61
Tucuman Power Sta.	El Bracho	Tucuman	ARGENTINA	150	1,150,000	5	99	1997	PAC System	134	35
Dighton Power Project	Dighton	MA	USA	60	442,141	5.5	90	1997	Combined Cycle	139	49
El Dorado Energy	Boulder	NV	USA	150	1,065,429	2.5	67	1998	Combined Cycle	109	42
Tiverton Power Project	Tiverton	RI	USA	80	549,999	5	90	1998	Combined Cycle	134	44
Coryton Energy Project	Corringham		ENGLAND	250	1,637,312	2.5	50	1998	Combined Cycle	109	59
Rumford Power Project	Rumford	ME	USA	80	545,800	5	90	1998	Combined Cycle	134	44
Millmerran Power Project	Toowoomba	Queensland	AUSTRAILIA	420	2,050,000	5.43	88	1999	Coal (x 2 Units)	137	49
Bajio Power Project	Quertetaro	Guananjuaro	MEX	450	1,307,000	3.54	71.4	1999	Combined Cycle	121	49.6
Monterrey Cogen Project	Monterrey		MEX	80	671,970	5.8	102	1999	Combined Cycle Cogen.	140	38
Gelugor Power Station	Penang		MALAYSIA	120	946,600	6.8	89.6	2000	Combined Cycle Cogen.	146	56.4
Front Range Power Project	Fountain	CO	USA	150	1,266,477	3.57	80	2000	Combined Cycle	121	41
Goldendale Energy Project	Goldendale	WA	USA	110	678,000	5	90	2000	C-Cycle PAC System	134	44
Athens Power Station	Athens	NY	USA	120	749,183	5	90	2000	Combined Cycle	134	44
					Average	4				Average	54
					Min	2				Min	35
					Max	16.5				Max	78
HIGH EXHAUST PRESSURE (Temperature Difference >80 °F)											
Beneccia Refinery	Beneccia	CA	USA	NA	48,950	9.5	100	1975		191	91
Beluga Unit 8	Beluga	AK	USA	65	478,400	5.6	35	1979	Combined Cycle	138	103
Univ. of Alberta	Edmonton	Alberta	CAN	25	277,780	9.15	59	1999	Gas Cogen.	158	99

As with wet cooling towers, the ambient air temperature and system design can have an effect on the steam turbine exhaust pressure, which in turn affects the turbine efficiency. Thus, the turbine efficiency can change over time as the air temperature changes. The fans used to mechanically force air through the condenser represent the greatest operational energy requirement for dry cooling systems.

A design measure comparable to the approach value used in wet towers is the difference between the design dry bulb temperature and the temperature of saturated steam at the design turbine exhaust pressure. In general, a larger, more costly dry cooling system will produce a smaller temperature difference across the condenser and, therefore, a lower turbine exhaust pressure. Three facilities in Table 4-1 had high temperature differences (>80 °F), which represent less efficient systems. Two of these facilities are from very cold climates where high temperature differences across the condenser are acceptable and one was for an industrial process (petroleum refining). The range in the temperature difference values for the remaining facilities was 35 to 78 °F. The average was 54 °F.

Steam turbines are designed to operate within certain exhaust pressure ranges. In general, steam turbines that are designed to operate at the exhaust steam pressure ranges typical of wet cooling systems, which generally operate at lower exhaust pressures (e.g., <5 in Hg), may be damaged if the exhaust pressure exceeds a certain value. New steam turbine facilities that are designed to condense steam with dry cooling systems can be equipped with steam turbines that are designed to be safely operated at higher exhaust pressures. EPA has assumed that the difference in costs for turbines that operate over different exhaust pressure ranges are insignificant compared to the total compliance cost and, therefore, no net compliance costs are estimated for the steam turbines.

The data in Table 4-1 shows that turbine exhaust pressures at the highest design dry bulb temperatures in the U.S. (which were around 100 °F) ranged from 5.0 to 9.5 inches Hg. The highest value of 9.5 inches Hg was for a refinery power system in California which, based on the steam rate, was comparable to other relatively small systems generating several megawatts and apparently did not warrant the use of an efficient cooling system. The other data show turbine exhaust pressures of around 6 to 7 inches Hg at dry bulb temperatures of around 100 °F. Maximum exhaust pressures in the range of 8 to12 inches Hg may be expected in hotter regions of the U.S.(Hensley 1985). An air cooled condenser analysis (Weeks 2000) reports that for a combined cycle plant built in Boulder City, Nevada, the maximum ambient temperature used for the maximum off-design specification was 108 °F with a corresponding turbine exhaust pressure of 7.8 inches Hg. Note that the equation used by EPA to generate the turbine exhaust pressure values in the energy penalty analysis produced an estimated exhaust pressure of 8.02 inches Hg at a dry bulb temperature of 108 °F. For wet towers, the typical turbine exhaust pressure operating range is1.5 to 3.5 inches Hg(Woodruff 1998).

For coal-fired plants, the largest operating plant in the United States with dry cooling is the Wyodak Station in Gillette, WY with a total cooling capacity of 330 MW (1.88 million lb/hr of steam). EPA notes that this is significantly smaller than 10 of the projected coal-fired power plants within the scope of the rule and slightly smaller than 25 of the combined cycle plants. The design temperature of the dry system at this plant (which directly affects the size of the dry cooling system) is below average for summer conditions throughout the United States (the Wyodak Station has a design temperature of 66 deg F, whereas recent combined-cycle systems in Rhode Island, Massachusetts, and New York have design targets above 90 deg F). EPA notes that the reported driving force behind the Wyodak Station's decision to utilize dry cooling was the fact that the plant designers wished to locate the plant immediately adjacent to a remote coal-mine mouth.

A demonstrated dry cooling system frequently recognized as the largest in the U.S. is the Linden Cogeneration Plant, in NJ. This cogeneration unit has a comparable cooling capacity to that of a small-sized coal-fired facility (such as the Wyodak Station described above). The cogeneration plant has a total steam flow which requires condensing of

1.91 million lb/hr, which just slightly exceeds the steam flow of the Wyodak station (1.88 million lb/hr). Despite the fact that the Linden plant is designed for a total generating capacity of 640 MW, only 285 MW requires steam condensing. This is because cogeneration units are designed to deliver steam to adjacent manufacturing plants for their use in processes. Therefore, the cogeneration plant has been designed such that only a portion of its steam generation requires cooling, and, for the purposes of evaluating the feasibility of dry cooling, EPA considers this a 285 MW dry cooling facility. EPA notes that the decision for this plant to adopt dry cooling over wet cooling related primarily to a highway safety issue and the visible plume of steam.

Several new combined-cycle projects with dry cooling are either planned or under-construction in the Northeastern US. EPA is aware of eight new dry cooling projects at combined cycle plants in this region that have 350 MW or greater of total plant capacity. The largest of these projects is the permitted Sithe Mystic Station in Massachusetts, which will be a 1500 MW combined-cycle plant. Because the project will utilize a combined-cycle, approximately 500 MW of steam power would require cooling. This will be the largest dry cooling system in the US when complete. However, the system size does not approach the projected cooling requirements for a majority of the coal-fired plants within the scope of this rule.

4.2 IMPACTS OF DRY COOLING

In establishing best technology available for minimizing adverse environmental impact for the final rule, EPA considered an alternative based on a zero-intake flow (or nearly zero, extremely low flow) requirement commensurate with levels achievable through the use of dry cooling systems. In evaluating dry cooling-based regulatory alternatives, EPA analyzed a zero or nearly zero intake flow requirement based on the use of dry cooling systems as the primary regulatory requirement in all waters of the U.S. The Agency also considered subcategorization strategies for the new facility regulation based on size and types of new facilities and location within regions of the country, since these factors may affect the viability of dry cooling technologies. In its evaluation, the Agency considered factors including the demonstration of existing or planned dry cooling systems, the reductions in cooling water intake flow, the environmental and energy impacts, and the associated costs of dry cooling systems.

4.2.1 Cooling Water Reduction

A dry cooling system will achieve an average reduction in cooling water intake flow greater than 99 percent over a once-through system. In comparison, the average flow reduction of a closed-cycle wet cooling system for an estuarine/tidal source is approximately 92 percent, and is 95 percent for a freshwater source. Dry cooling systems therefore achieve an incremental flow reduction from closed-cycle wet cooling to dry cooling of 4 to 7 percent.

4.2.2 Environmental and Energy Impacts

Dry cooling has the benefit of eliminating visual plumes, fog, mineral drift, and water treatment and disposal issues associated with wet cooling towers. The disadvantages of dry cooling include an increase in noise generation and decrease in efficiency of electricity generation which lead to an increase in air emissions as compared to wet cooling systems.

EPA notes that dry cooling systems in all climates are less efficient at removing heat than comparable wet-cooling systems. The practical limitations of the dry cooling system, as limited by the dry bulb temperature, which is always equal to or greater than the wet bulb temperature met by wet cooling systems, prevent its performance from exceeding that of wet cooling. Moreover, increased parasitic fan loads for dry cooling systems will ensure that the technology will not operate as efficiently as a comparable wet cooling system.

Therefore, EPA assessed the negative environmental impacts caused by this loss of efficiency. For combined-cycle plants the mean annual energy penalty (averaged across climates) is 2.1 percent for dry cooling compared to once-through systems, and 1.7 percent for wet cooling compared to once-through systems. For coal-fired plants, the mean annual energy penalty (averaged across climates) is 8.6 percent for dry cooling compared to once-through systems, and 6.9 percent for wet cooling compared to once-through systems. However, for many specific cases, the energy penalty may be dramatically higher for dry cooling due to climatic conditions of the cooling towers. For example, the peak summer shortfalls during hot periods can be debilitating in certain climates due to the energy penalty reaching up to 12.3 percent. See Chapter 3 of this document for further discussion of energy penalties.

EPA projects that a dry cooling based regulatory alternative would result in 1900 MW of lost energy. This is the equivalent electricity generation of two very large (or three large) power plants that would need to be constructed to overcome the energy losses of the dry cooling alternative. The air emissions increases as a result of this replacement capacity, if they were to come from increased generation across the US market, would be equivalent to those of three new 800MW coal-fired power plants. Alternatively, if the replacement capacity comes from new capacity exclusively, it would be from dry cooling equipped plants with the associated elevated capital and annual costs and land area requirements. Therefore, EPA considers the issue of inefficiency of dry cooling, and EPA's subsequent rejection of the dry cooling alternative, to be principal to the concept of energy conservation. Considering that the State of California recently experienced shortages of demand less than the energy penalty of the dry cooling option, the imposition of 1900 MW of mean annual energy penalty capacity loss on planned new power plants does not support the Administration's Energy Plan and associated Executive Orders.

The efficiency of the electricity generation process is directly affected by the cooling system to be installed. The vast majority of projected new plants (i.e., 90 percent) would install closed-cycle recirculating cooling towers regardless of the requirements of this rule. Therefore, EPA's technology-based performance requirements for the final rule based on recirculating closed-cycle cooling would have little impact on the majority of new plants. The flow reduction requirements of the rule are projected to impose changes in cooling system designs on only nine new plants. The comparable effect on the efficiency of these plants will be small on a facility level and national basis.

In contrast, a regulatory alternative based on dry cooling is projected to impose cooling system design changes on each of the 83 power plants within the scope of the final rule. Therefore, each of the 14 projected coal-fired plants would experience mean annual energy penalties ranging from 6.9 to 8.6 percent. The typical steam electric generator (such as modern coal-fired plants) would, at peak operation, operate at less than 40 percent efficiency. The energy penalty of nearly 9 percent is very significant when compared to the system-wide energy efficiency of this type of power plant. Additionally, each of the 69 projected new combined-cycle plants would experience mean annual energy penalties ranging from 1.7 to 2.1 percent. With new design efficiencies of 60 percent, at peak operating efficiency, a 2.1 percent energy penalty is less striking than in the coal-fired cases. However, the cumulative effect for all 69 power plants is substantial.

4.2.3 Costs of Dry Cooling

The final rule analysis, which includes the contribution of the energy penalty to the recurring annual costs, projects that the total annualized cost for the dry cooling alternative is $490 million (in 2000 dollars). EPA notes that the vast majority of costs associated with this option are incurred at the 83 power plants, and not at the 38 manufacturers subject to this rule. Because dry cooling is not a feasible option for all manufacturing facilities, EPA only applied costs of recirculating wet cooling towers to these types of facilities. The present value of total compliance costs for drying cooling are projected to be $6 billion.

A comparison of capital costs between equally sized combined-cycle plants for wet and dry cooling tower systems reveals that the dry cooling plant's capital costs would exceed those of the wet cooling tower plant by 3.3 fold. The installed wet cooling tower capital cost is approximately $10 million, while the dry cooling installation would cost approximately $33 million. For a typical, modern 700-MW combined-cycle power plant, the erected capital costs for a wet cooling tower represent approximately 2 percent of the total capital costs of the power plant construction project compared to 6.5 percent for dry cooling towers.

EPA also evaluated a comparison of the operation and maintenance costs associated with these two types of cooling systems for an equally sized combined-cycle model plant. The operation and maintenance costs of the wet cooling tower (without including the effects of energy penalties) would be $1.8 million per year, while the dry cooling system would cost $7.4 million per year. Without incorporating energy penalties, the ratio of operation and maintenance costs of dry cooling to wet cooling for a typical 700-MW combined-cycle power plant would be greater than 4 to 1. After factoring in the recurring costs of energy penalties for the two systems, the recurring annual costs increase to $2.3 million for the wet tower plant and $10.4 million for the dry cooling plant. This corresponds to a dry to wet ratio also greater than 4 to 1. The total annualized costs for this model facility are estimated at $3.1 for the wet cooling tower system and $13.1 for the dry cooling system (a ratio of 4.2 to 1). Note that these are comparative cost estimates for a hypothetical facility and do not represent actual compliance costs of the rule.

4.2.4 Methodology for Dry Cooling Cost Estimates

EPA estimated the capital and O&M costs using relative cost factors for various types of wet towers and air cooled condensers, using the cost of a comparable wet tower constructed of Douglas Fir as the basis. Chapter 2 provides the capital and operating cost factors that were used by EPA. These cost factors were developed by industry experts who are in the business of manufacturing, selling and installing cooling towers, including air cooled systems, for power plants and other applications. For air cooled condensers (constructed of steel), a range of cost factors is given in Table 4-3. EPA based the capital and O&M costs on these factors with some modifications. To be conservative, EPA chose the highest value within each range as the basis. The factors chosen are 325 percent and 225 percent (of the cost of a mechanical wet tower) for capital cost (for a tower with a delta of 10 °F) and O&M cost, respectively. EPA applied a multiplier of roughly 1.7 to the dry tower capital cost estimates for a delta of 10 °F to yield capital cost estimates for a dry tower with a delta of 5 °F. EPA applied these factors to the capital costs derived for the basic steel mechanical draft wet cooling towers to yield the capital cost estimates for dry towers presented in Table 4- 2.

Note that the source document for these factors states that the factors represent comparable cooling systems for plants with the same generated electric power and the same turbine exhaust pressure. Since the cost factors generate equivalent dry cooling systems, the tower costs can still be referenced to the corresponding equivalent cooling water flow rate of the mechanical wet tower used as the cost basis. Since the final §316(b) New Facility Rule focuses primarily on water use, the use of the cooling flow or the "equivalent" was considered as the best way to compare costs. The costing methodology uses an equivalent cooling water flow rate as the independent input variable for costing dry towers.

Table 4-2: Estimated Capital Costs of Dry Cooling Towers with Delta of 5 °F and 10 °F (1999 Dollars)

Flow (gpm)	Delta 5 °F	Delta 10 °F
2000	$790,000	$450,000
4000	$1,580,000	$949,000
7000	$2,766,000	$1,658,000
9000	$3,556,000	$2,132,000
11,000	$4,345,000	$2,607,000
13,000	$5,135,000	$3,081,000
15,000	$5,925,000	$3,556,000
17,000	$6,715,000	$4,027,000
18,000	$7,108,000	$4,264,000
22,000	$8,515,000	$5,038,000
25,000	$9,675,000	$5,727,000
28,000	$10,836,000	$6,412,000
29,000	$11,222,000	$6,643,000
31,000	$11,996,000	$7,101,000
34,000	$13,156,000	$7,787,000
36,000	$13,933,000	$8,245,000
45,000	$17,059,000	$9,952,000
47,000	$17,817,000	$10,394,000
56,000	$21,229,000	$12,383,000
63,000	$23,881,000	$13,933,000
67,000	$25,399,000	$14,817,000
73,000	$27,674,000	$16,143,000
79,000	$29,325,000	$16,845,000
94,000	$34,892,000	$20,043,000
102,000	$37,859,000	$21,749,000
112,000	$41,574,000	$23,881,000
146,000	$54,194,000	$31,132,000
157,000	$57,034,000	$32,237,000
204,000	$72,498,000	$40,277,000
250,000	$100,800,000	$58,800,000
300,000	$120,000,000	$70,000,000
350,000	$140,400,000	$81,900,000
400,000	$160,800,000	$93,800,000

Using the estimated costs, EPA developed cost equations using a polynomial curve fitting function. Table 3 presents capital cost equations for dry towers with deltas of 5 and 10 degrees.

Table 4-3. Capital Cost Equations of Dry Cooling Towers with Delta of 5 °F and 10 °F

Delta	Capital Cost Equation[1]	Correlation Coefficient
5 °F	$y = -2E\text{-}10x^3 + 0.0002x^2 + 337.56x + 973608$	$R^2 = 0.9989$
10 °F.	$y = -8E\text{-}11x^3 + 0.0001x^2 + 189.77x + 800490$	$R^2 = 0.9979$

1) x is for flow in gpm and y is cost in dollars.

For purposes of estimating costs for the dry cooling option (Option 2B) for the final §316(b) New Facility Rule, EPA used the O&M cost curve for air condensers contained in Appendix A of the *Economic and Engineering Analyses of the Proposed §316(b) New Facility Rule* without modification. Thus, EPA overcosted the O&M costs for dry towers for Option 2B for the final §316(b) New Facility Rule. See Section 2.9.1 of this document and the response to comment document (#316bNFR.068.330) for discussion of EPA's revised O&M costs for the final rule.

Validation of Dry Cooling Capital Cost Curves

To validate the dry tower capital cost curves and equations, EPA compared the costs predicted by the equation for dry towers with delta of 10 °F to actual costs for five dry tower construction projects provided by industry representatives. To make this comparison, EPA first needed to estimate equivalent flows for the dry tower construction project costs. Obviously, as noted above, dry towers do not use cooling water. However, for every power plant of a given capacity there will, dependent on the selected design parameters, be a corresponding equivalent recirculating cooling water flow that would apply if wet cooling towers were installed to condense the same steam load.

EPA used the steam load rate and cooling system efficiency to determine the equivalent flow. Note that the heat rejection rate will be proportional to the plant capacity. EPA estimated the flow required for a wet cooling tower that is functionally equivalent to the dry tower by converting each plant's steam tons/hour into cooling flow in gpm using the following equations:

Steam tons/hr x 2000 lbs/ton x 1000 BTUs/lb steam = BTUs/hr
One ton/hr = 12,000 BTU/hr
BTUs/hr / 12000 = Tons of ice
Tons of Ice x 3 = Flow (gpm) for wet systems

Chart 4-2 presents a comparison of the EPA capital cost estimates for dry towers with delta of 10 °F (with 25% error bars) to actual dry tower installations. This chart shows that EPA's cost curves produce conservative cost estimates, since the EPA estimates are greater than all of the dry tower project costs based on the calculated equivalent cooling flow rate for the actual projects.

Chart 4-1. Capital Costs of Dry Cooling Towers Versus Flows Of Replaced Wet Cooling Towers (5 &10 Degrees Delta)

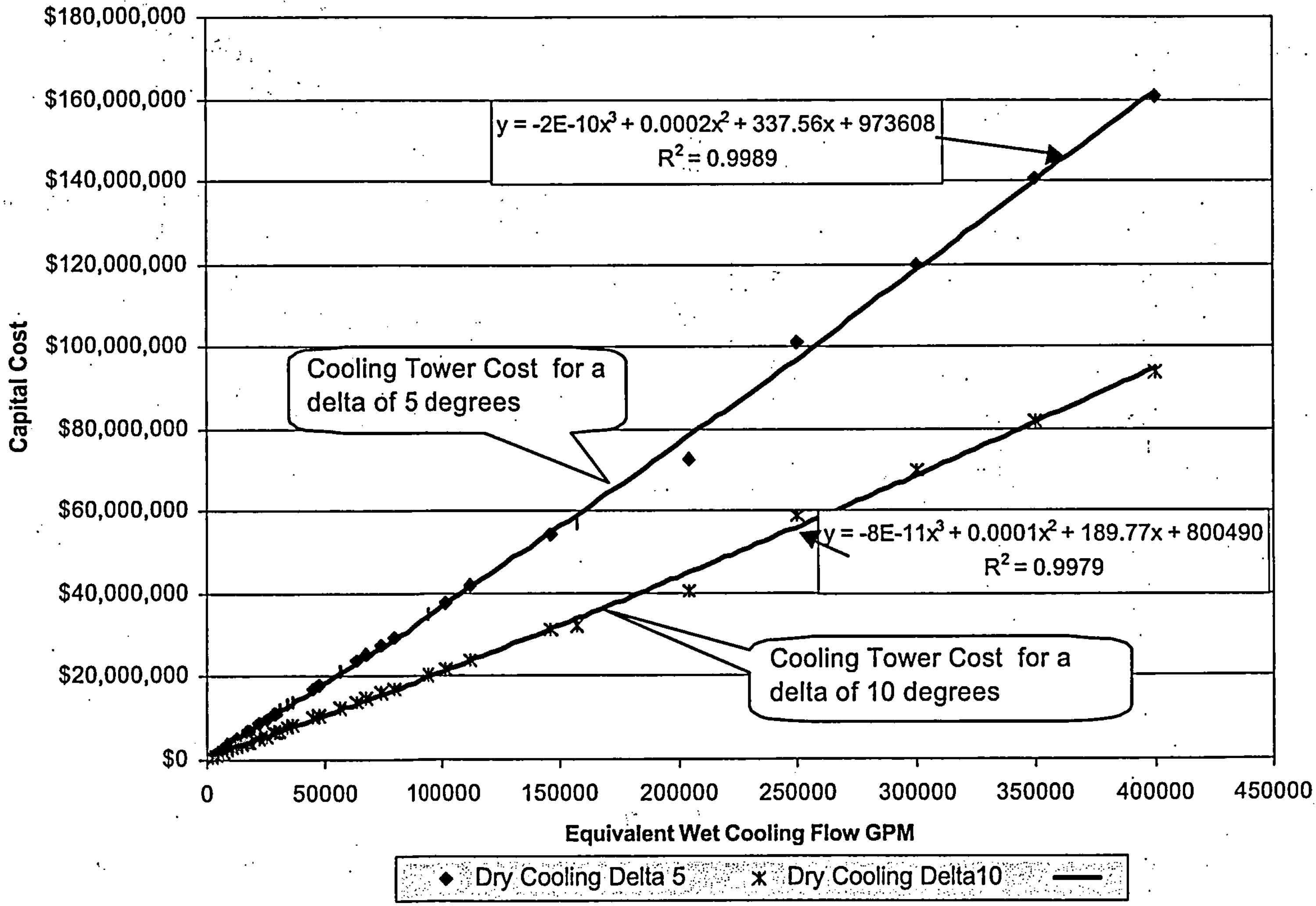
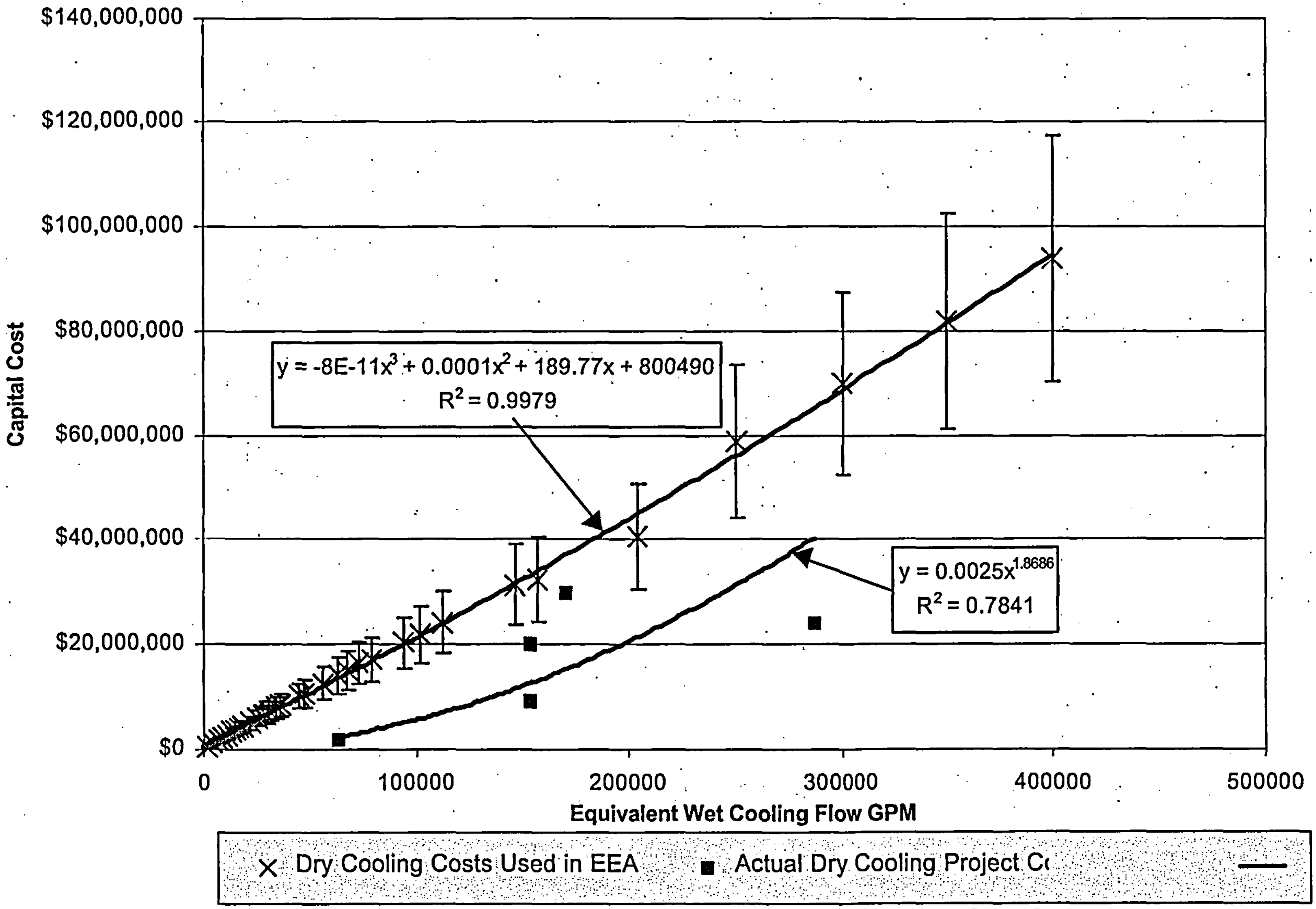


Chart 4-2. Actual Capital Costs of Dry Cooling Tower Projects and Comparable Costs from EPA Cost Curves



4.1.6 Economic Impacts of Dry Cooling

EPA concluded that the costs of dry cooling systems may be significantly prohibitive so as to pose barriers to entry for some new plants. EPA projected that the cost to revenue impacts exceed 10 percent for 12 new power plants and exceed 4 percent for all new plants under a dry cooling-based regulatory alternative. EPA considers this level of cost to revenue impacts to be significant. In comparison, the cost to revenue impacts of the final rule, which is based in part on flow reduction commensurate with that achieved using recirculating closed-cycle wet cooling, do not exceed 3 percent for a single facility, and the vast majority of the impacts are below 1 percent. A complete discussion of the cost to revenue impacts and discussion of barrier to entry analysis can be found in the Economic Analysis for the final rule. As such, regional subcategorization options would pose similar barriers to entry for new plants in the Northeastern United States, combined with imposing competitive disadvantages for the subset of facilities complying with more stringent and costly standards than the other regions of the country.

EPA is concerned that the barrier to entry, high costs, and energy penalty of dry cooling systems may remove the incentive for replacing older coal-fired power plants with more efficient and environmentally favorable new combined-cycle facilities. By basing the requirements of the rule on dry cooling, regulated entities faced with the prospects of building new facility power plants that are required to utilize dry cooling would, instead of beginning or continuing with the new facility project, turn to existing power-plants (many of which are significantly aged) and attempt to extend their operating lives further or refurbish them such that the new facility rule would not apply.

EPA notes that there have been recent advances in the efficiency of power plants, specifically combined-cycle plants, that have many environmental advantages. Combined-cycle plants produce significantly less air emissions of NOx, SO_2, and Hg per MWh generated, use less water for condensing of steam than fossil-fueled or nuclear plants (greater than one-half water use reduction per MWh of generation), and are significantly more energy efficient in their generation of electricity than comparable coal-fired plants. The Agency does not wish to create disincentives for the construction of new efficient plants such as these.

4.3 Evaluation of Dry Cooling as BTA

This section presents a summary of EPA's evaluation of the dry cooling technology as a candidate for best technology available to minimize adverse environmental impacts. Based on the information presented in the previous sections, EPA concluded that dry cooling systems do not represent the best technology available for a national requirement and under the subcategorization strategies described above.

First, EPA concluded that dry cooling is not adequately demonstrated for all facilities within the scope of this regulation. As noted previously, the majority of operating or planned dry cooling systems are located either in colder or arid climates where the average dry bulb temperatures of ambient air is amenable to dry cooling. As demonstrated in Chapter 3, the comparative energy penalty of a dry cooling plant in a hot environment at peak summer conditions can exceed 12 percent at a facility, thereby making dry cooling extremely unfavorable in many areas of the U.S. for some types of power plant types.

EPA's record demonstrates that of the demonstrated, permitted, or planned power plants in the Northeastern United States with dry cooling, the size and capacity of these dry cooling systems is considerably smaller than that necessary to condense the steam load for even below average sized coal-fired power plants projected within the scope of this rule.

Dry cooling technology has a detrimental effect on electricity production by reducing energy efficiency of steam turbines, especially in warmer climates The reduced energy efficiency of the dry cooling system will have the effect of increasing air emissions from power plants.

Lastly, EPA concluded that the costs of dry cooling systems may be significantly prohibitive so as to pose barriers to entry for some new plants that may discourage the construction of new, more energy efficient plants.

In addition to the technical feasibility and cost impacts of dry cooling, EPA also evaluated the expected benefits that would be achieved by dry cooling. EPA notes that the two-track option based on reducing intake flow to a level commensurate with wet cooling towers reduces intake flows by 92 to 95 percent over a once-through system. Dry cooling would only reduce intake flow by an additional 4 to 7 percent. Additionally, the selected option requires velocity and design and construction technology-based performance requirements for the remaining intake flow. These performance requirements are expected to further decrease the negative environmental impacts of the cooling water intake flow, thereby reducing impingement and entrainment of organisms to dramatically low levels. See Chapter 5 for discussion of design and construction technologies to reduce impingement and entrainment.

In summary, EPA concluded that dry cooling is not technically or economically feasible for all facilities subject to this rule, would increase air emissions due to the energy penalty, has a cost more than three times that of the selected regulatory option, and would not significantly reduce impingement and entrainment beyond the regulatory approach selected by EPA to offset these drawbacks. For these reasons, EPA concluded that dry cooling does not represent the "best technology available" for minimizing adverse environmental impact.

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Chapter 5: Efficacy of Cooling Water Intake Structure Technologies

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INTRODUCTION

To support the Section 316(b) new facility rulemaking, the Agency has compiled data on the performance of the range of technologies currently used to minimize impingement and entrainment (I&E) at power plants nationwide. The goal of this data collection and analysis effort has been to determine whether specific technologies can be demonstrated to provide a consistent level of proven performance. This information has been used throughout the rulemaking process including comparing specific regulatory options and their associated costs and benefits. It provides the supporting information for the selected alternatives, which require wet, closed-cycle cooling systems (under Track 1) with the option of demonstrating comparable performance (under Track II) using alternative technologies. Throughout this chapter, baseline technology performance refers to the performance of conventional, wide mesh traveling screens that are not intended to prevent I&E. Alternative technologies generally refer to those technologies, other than closed-cycle cooling systems that can be used to minimize I&E. Overall, the Agency has found that performance and applicability vary to some degree based on site-specific conditions. However, the Agency has also determined that alternative technologies can be used effectively on a widespread basis with proper design, operation, and maintenance.

5.1 SCOPE OF DATA COLLECTION EFFORTS

Since 1992, the Agency has been evaluating regulatory alternatives under Section 316(b) of the Clean Water Act. As part of these efforts, the Agency has compiled readily available information on the nationwide performance of I&E reduction technologies. This information has been obtained through:

- Literature searches and associated collection of relevant documents on facility-specific performance.
- Contacts with governmental (e.g., TVA) and non-governmental entities (e.g., EPRI) that have undertaken national or regional data collection efforts/performance studies
- Meetings with and visits to the offices of EPA Regional and State agency staff as well as site visits to operating power plants.

It is important to recognize that the Agency did not undertake a systematic approach to data collection, i.e., the Agency did not obtain all of the facility performance data that are available nor did it obtain the same level of information for each facility. The Agency is not aware of such an evaluation ever being performed nationally. The most recent national data compilation was undertaken by the Electric Power Research Institute (EPRI) in 2000, see *Fish Protection at Cooling Water Intakes, Status Report*. The findings of this report are cited extensively in the following subsections. However, EPRI's analysis was primarily a literature collection and review effort and was not intended to be an exhaustive compilation and analysis of all data.

5.2 DATA LIMITATIONS

Because the Agency did not undertake a systematic data collection effort with consistent data collection procedures, there is significant variability in the information available from different data sources. This leads to the following data limitations:

- Some facility data include all of the major species and associated life stages present at an individual facility. Other facilities only include data for selected species and/or life stages.
- Much of the data were collected in the 1970s and early 1980s when existing facilities were required to complete their initial 316(b) demonstrations.
- Some facility data includes only initial survival results, while other facilities have 48 to 96-hour survival data. These data are relevant because some technologies can exhibit significant latent mortality after initial survival.
- The Agency did not review data collection procedures, including quality assurance/quality control protocols.
- Some data come from laboratory and pilot-scale testing rather than full-scale evaluations.

The Agency recognizes that other than closed-cycle cooling and velocity reduction technologies the practicality or effectiveness of alternative technologies not be uniform under all conditions. The chemical and physical nature of the waterbody, the facility intake requirements, climatic conditions, and biology of the area all effect feasibility and performance. However, despite the above limitations, the Agency has concluded that significant general performance expectations can be implied for the range of technologies and that one or more technologies (or groups of technologies) can provide significant I&E protection at most sites. In addition, in the Agency's view many of the technologies have the potential for even greater applicability and higher performance when facilities are required to optimize their use.

The remainder of this chapter is organized by groups of technologies. A discussion of wet, closed-cycle cooling tower performance is included to present the Agency's view of the likely minimum standard that Track II facilities will be required to achieve (although each facility will have to present it's own closed-cycle system scenario). A brief description of conventional, once-through traveling screens is also provided for comparison purposes. Fact sheets describing each technology, available performance data, and design requirements and limitations are provided in Attachment A. It is important to note that this chapter does not provide descriptions of all potential CWIS technologies. (ASCE 1982 generally provides such an all-inclusive discussion). Instead, the Agency has focused on those technologies that have shown significant promise at the laboratory, pilot-scale, and/or full-scale levels in consistently minimizing impingement and/or entrainment. In addition, this chapter does not identify every facility where alternative technologies have been used but rather only those where some measure of performance in comparison to conventional screens has been made. The chapter concludes with a brief discussion of how the location of intakes (as well as the timing of water withdrawals) could also be used to limit potential I&E effects at new facilities.

Finally, under Track II in the new facility rule, facilities may use habitat restoration projects as an additional means to demonstrate consistency with Track I performance. Such projects have not had widespread application at existing facilities. Because the nature, feasibility, and likely effectiveness of such projects would be highly site-specific, the Agency has not attempted to quantify their expected performance level herein.

5.3 CLOSED-CYCLE WET COOLING SYSTEM PERFORMANCE

Under Track I, facilities are required meet requirements based on the design and installation of wet, closed-cycle cooling systems. Although flow reduction serves the purpose of reducing both impingement and entrainment, these requirements function as the primary entrainment reduction portion of Track I. Under Track II, new facilities must demonstrate I&E performance comparable to 90 percent of the performance of a wet, closed-cycle system designed for their facility. In part, to evaluate the feasibility of meeting this requirement and to allow comparison of costs/benefits of alternatives, the Agency determined the likely range in flow reductions between wet, closed-cycle cooling systems compared to once-through systems. In closed-cycle systems, certain chemicals will concentrate as they continue to be recirculated through the tower. Excess buildup of such chemicals, especially total dissolved solids, affects the tower performance. Therefore, some water (blowdown) must be discharged and make-up water added periodically to the system.

See Section 2.3.5 of Chapter 2 of this document for further discussion of flow reduction using wet, closed-cycle cooling.

An additional question that the Agency has considered is the feasibility of constructing salt-water make-up cooling towers. The Agency contacted Marley Cooling Tower (Marley), which is one of the largest cooling tower manufacturers in the world. Marley provided a list of facilities (Marley, 2001) that have installed cooling towers with marine or otherwise high total dissolved solids/brackish make-up water. It is important to recognize that this represents only a selected group of facilities constructed by Marley worldwide; there are also facilities constructed by other cooling tower manufacturers. For example, Florida Power and Light's (FPL) Crystal River Units 4 and 5 (about 1500 MW) use estuarine water make-up.

5.4 CONVENTIONAL TRAVELING SCREENS

For impingement control technologies, performance is compared to conventional traveling screens as a baseline technology. These screens are the most commonly used intakes at older existing facilities and their operational performance is well established. In general, these technologies are designed to prevent debris from entering the cooling water system, not to minimize I&E. The most common intake designs include front-end trash racks (usually consisting of fixed bars) to prevent large debris from entering system. They are equipped with screen panels mounted on an endless belt that rotates through the water vertically. Most conventional screens have 3/8-inch mesh that prevents smaller debris from clogging the condenser tubes. The screen wash is typically high pressure (80 to 120 pounds per square inch (psi)). Screens are rotated and washed intermittently and fish that are impinged often die because they are trapped on the stationary screens for extended periods. The high-pressure wash also frequently kills fish or they are re-impinged on the screens. Conventional traveling screens are used by approximately 60 percent of all existing steam electric generating units in the U.S. (EEI, 1993).

5.5 ALTERNATIVE TECHNOLOGIES

5.5.1 Modified Traveling Screens and Fish Handling and Return Systems

Technology Overview

Conventional traveling screens can be modified so that fish, which are impinged on the screens, can be removed with minimal stress and mortality. "Ristroph Screens" have water-filled lifting buckets which collect the impinged organisms and transport them to a fish return system. The buckets are designed such that they will hold approximately 2 inches of water once they have cleared the surface of the water during the normal rotation of the traveling screens. The fish bucket holds the fish in water until the screen rises to a point where the fish are spilled onto a bypass, trough, or other protected area (Mussalli, Taft, and Hoffman, 1978). Fish baskets are also a modification of a conventional traveling screen and may be used in conjunction with fish buckets. Fish baskets are separate framed screen panels that are attached to vertical traveling screens. An essential feature of modified traveling screens is continuous operation during periods where fish are being impinged. Conventional traveling screens typically operate on an intermittent basis. (EPRI, 2000 and 1989; Fritz, 1980). Removed fish are typically returned to the source water body by sluiceway or pipeline. ASCE 1982 provides guidance on the design and operation of fish return systems.

Technology Performance

Modified screens and fish handling and return systems have been used to minimize impingement mortality at a wide range of facilities nationwide. In recent years, some researchers, primarily *Fletcher 1996,* have evaluated the factors that effect the success of these systems and described how they can be optimized for specific applications. Fletcher cited the following as key design factors:

- Shaping fish buckets/baskets to minimize hydrodynamic turbulence within the bucket/basket
- Using smooth woven screen mesh to minimize fish descaling
- Using fish rails to keep fish from escaping the buckets/baskets
- Performing fish removal prior to high pressure wash for debris removal
- Optimizing the location of spray systems to provide gentler fish transfer to sloughs
- Ensuring proper sizing and design of return troughs, sluiceways, and pipes to minimize harm.

In 1993 and 1994, the Salem Generating Station specifically considered Fletcher's work in the modification of their fish handling system. In 1996, the facility subsequently reported an increase in juvenile weakfish impingement survival from 58 percent to 79 percent with an overall weakfish reduction in impingement losses of 51 percent. 1997 and 1998 test data for Units 1 and 2 showed: white perch had 93 to 98 percent survival, bay anchovy had 20 to 72 percent survival, Atlantic croaker had 58 to 98 percent survival, spot had 93 percent survival, herring had 78 to 82 percent survival, and weakfish had 18 to 88 percent survival.

Additional performance results for modified screens and fish return systems include:

- 1988 studies at the Diablo Canyon and Moss Landing Power Plants in California found that overall impingement mortality could be reduced by as much as 75 percent with modified traveling screens and fish return sluiceways.

- Impingement data collected during the 1970s from Dominion Power's Surry Station (Virginia) indicated a 93.8 percent survival rate of all fish impinged. Bay anchovies had the lowest survival 83 percent. The facility has modified Ristroph screens with low pressure wash and fish return systems.

- In 1986, the operator of the Indian Point Station (New York) redesigned fish troughs on the Unit 2 intake to enhance survival. Impingement injuries and mortality were reduced from 53 to 9 percent for striped bass, 64 to14 percent for white perch, 80 to 17 percent for Atlantic tomcod, and 47 to 7 percent for pumpkinseed.

- 1996 data for Brayton Point Units 1-3 showed 62 percent impingement survival for continuously rotated conventional traveling screens with a fish return system.

- In the 1970s, a fish pump and return system was added to the traveling screens at the Monroe Power Plant in Michigan. Initial studies showed 70 to 80 percent survival for adult and young-of-year gizzard shad and yellow perch.

- At the Hanford Generating Plant on the Columbia River, late 1970s studies of modified screens with a fish return system showed 79 to 95 percent latent survival of impinged Chinook salmon fry.

- The Kintigh Generating Station in New Jersey has modified traveling screens with low pressure sprays and a fish return system. After enhancements to the system in 1989, survivals of generally greater than 80 percent have been observed for rainbow smelt, rock bass, spottail shiner, white bass, white perch, and yellow perch. Gizzard shad survivals have been 54 to 65 percent and alewife survivals have been 15 to 44 percent.

- The Calvert Cliffs Station in Maryland has 12 traveling screens that are rotated for 10 minutes every hour or when pressure sensors show pressure differences. The screens were originally conventional and are now dual flow. A high pressure wash and return system leads back to the Chesapeake Bay. Twenty-one years of impingement monitoring show total fish survival of 73 percent.

- At the Arthur Kill Station in New York, 2 of 8 screens are modified Ristroph type; the remaining six screens are conventional type. The modified screens have fish collection troughs, low pressure spray washes, fish flap seals, and separate fish collection sluices. 24-hour survival for the unmodified screens averages 15 percent, while the two modified screens have 79 and 92 percent average survival rates, respectively.

In summary, performance data for modified screens and fish returns are somewhat variable due to site conditions and variations in unit design and operation. However, the above results generally show that at least 70-80 percent reductions in impingement can be achieved over conventional traveling screens.

5.5.2 Cylindrical Wedgewire Screens

Technology Overview

Wedgewire screens are designed to reduce entrainment by physical exclusion and by exploiting hydrodynamics. Physical exclusion occurs when the mesh size of the screen is smaller than the organisms susceptible to entrainment. The screen mesh ranges from 0.5 to 10 mm. Hydrodynamic exclusion results from maintenance of a low through-slot velocity, which, because of the screen's cylindrical configuration, is quickly dissipated, thereby allowing organisms to escape the flow field (Weisberd et al, 1984). Adequate countercurrent flow is needed to transport organisms away from the screens. The name of these screens arises from the triangular or "wedge" cross section of the wire that makes up the screen. The screen is composed of wedge-wire loops welded at the apex of their triangular cross section to supporting axial rods presenting the base of the cross section to the incoming flow (Pagano et al, 1977).

Wedgewire screens may also be referred to as profile screens or Johnson screens.

Technology Performance
Wide mesh wedgewire screens have been used at 2 Ahigh flow@ power plants: J.H. Campbell Unit 3 (770 MW) and Eddystone Units 1 and 2 (approximately 700 MW combined). At Campbell, Unit 3 withdraws 400 million gallons per day (mgd) of water from Lake Michigan approximately 1,000 feet from shore. Unit 3 impingement of gizzard shad, smelt, yellow perch, alewife, and shiner species is significantly lower than Units 1 and 2 that do not have wedgewire screens. Entrainment is not a major concern at the site because of the deep water, offshore location of the Unit 3 intake. Eddystone Units 1 and 2 withdraw over 500 mgd of water from the Delaware River. The cooling water intakes for these units were retrofitted with wedgewire screens because over 3 million fish were reportedly impinged over a 20-month period. The wedgewire screens have generally eliminated impingement at Eddystone. Both the Campbell and Eddystone wedgewire screens require periodic cleaning but have operated with minimal operational difficulties.

Other plants with lower intake flows have installed wedgewire screens but there are limited biological performance data for these facilities. The Logan Generating Station in New Jersey withdraws 19 MGD from the Delaware River through a 1-mm wedgewire screen. Entrainment data show 90 percent less entrainment of larvae and eggs then conventional screens. No impingement data are available. Unit 1 at the Cope Generating Station in South Carolina is a closed cycle unit that withdraws about 6 MGD through a 2-mm wedgewire screen, however, no biological data are available. Performance data are also unavailable for the Jeffrey Energy Center, which withdraws about 56 MGD through a 10-mm screen from the Kansas River in Kansas. The system at the Jeffrey Plant has specifically operated since 1982 with no operational difficulties. Finally, the American Electric Power Corporation has installed wedgewire screens at the Big Sandy (2 MGD) and Mountaineer (22 MGD) Power Plants, which withdraw water from the Big Sandy and Ohio Rivers, respectively. Again, no biological test data are available for these facilities.

Wedgewire screens have been considered/tested for several other large facilities. In situ testing of 1 and 2-mm wedgewire screens was performed in the St. John River for the Seminole Generating Station Units 1 and 2 in Florida in the late 1970s. This testing showed virtually no impingement and 99 and 62 percent reductions in larvae entrainment for the 1-mm and 2-mm screens, respectively, over conventional screen (9.5 mm) systems. The State of Maryland conducted testing in 1982 and 1983 of 1, 2, and 3-mm wedgewire screens at the Chalk Point Generating Station, which withdraws water from the Patuxent River in Maryland. The 1-mm wedgewire screens were found to reduce entrainment by 80 percent. No impingement data were available. Some biofouling and clogging was observed during the tests. In the late 1970s, Delmarva Power and Light conducted laboratory testing of fine mesh wedgewire screens for the proposed 1540 MW Summit Power Plant. This testing showed that entrainment of fish eggs (including striped bass) could effectively be prevented with slot widths of 1 mm or less, while impingement mortality was expected to be less than 5 percent. Actual field testing in the brackish water of the proposed intake canal required the screens to be removed and cleaned as often as once every three weeks.

As shown by the above data, it is clear that wedgewire screen technology has not been widely applied in the steam electric industry to date. It has only been installed at a handful of power plant facilities nationwide. However, the limited data for Eddystone and Campbell indicate that wide mesh screens, in particular, can be used to minimize impingement. Successful use of the wedgewire screens at Eddystone as well as Logan in the Delaware River (high debris flows) suggests that the screens can have widespread applicability. This is especially true for facilities that have relatively low intake flow requirements (i.e., closed-cycle systems). Yet, the lack of more representative full-scale plant data makes it impossible to conclusively say that wedgewire screens can be used in all environmental conditions. There are no full-scale data specifically for marine environments where biofouling and clogging are significant concerns. In addition, it is important to recognize that there must sufficient crosscurrent in the waterbody to carry organisms away from the screens.

Fine mesh wedgewire screens (0.5 - 1 mm) also have the *potential* for use to control both I&E. The Agency is not aware of any fine-mesh wedgewire screens that have been installed at power plants with high intake flows (>100 MGD). However, they have been used at some power plants with lower intake flow requirements (25-50 MGD) that would be comparable to a large power plant with a closed-cycle cooling system. With the exception of Logan, the Agency has not identified any full-scale performance data for these systems. They would be even more susceptible to clogging than wide-mesh wedgewire screens (especially in marine environments). It is unclear whether this simply would necessitate more intensive maintenance or preclude their day-to-day use at many sites. Their successful application at Logan and Cope and the historic test data from Florida, Maryland, and Delaware at least suggests promise for addressing both fish impingement and entrainment of eggs and larvae. However, based on the fine-mesh screen experience at Big Bend Units 3 and 4, it is clear that frequent maintenance would be required. Therefore, relatively deep water sufficient to accommodate the large number of screen units, would preferably be close to shore (i.e., be readily accessible). Manual cleaning needs might be reduced or eliminated through use of an automated flushing (e.g., microburst) system.

5.5.3 Fine-Mesh Screens

Technology Overview

Fine-mesh screens are typically mounted on conventional traveling screens and are used to exclude eggs, larvae, and juvenile forms of fish from intakes. These screens rely on gentle impingement of organisms on the screen surface. Successful use of fine-mesh screens is contingent on the application of satisfactory handling and return systems to allow the safe return of impinged organisms to the aquatic environment (Pagano et al, 1977; Sharma, 1978). Fine mesh screens generally include those with mesh sizes of 5 mm or less.

Technology Performance

Similar to fine-mesh wedgewire screens, fine-mesh traveling screens with fish return systems show promise for both I&E control. However, they have not been installed, maintained, and optimized at many facilities. The most significant example of long-term fine-mesh screen use has been at the Big Bend Power Plant in the Tampa Bay area. The facility has an intake canal with 0.5-mm mesh Ristroph screens that are used seasonally on the intakes for Units 3 and 4. During the mid-1980s when the screens were initially installed, their efficiency in reducing I&E mortality was highly variable. The operator, Florida Power & Light (FPL) evaluated different approach velocities and screen rotational speeds. In addition, FPL recognized that frequent maintenance (manual cleaning) was necessary to avoid biofouling. By 1988, system performance had improved greatly. The system's efficiency in screening fish eggs (primarily drums and bay anchovy) exceeded 95 percent with 80 percent latent survival for drum and 93 percent for bay anchovy. For larvae (primarily drums, bay anchovies, blennies, and gobies), screening efficiency was 86 percent with 65 percent latent survival for drum and 66 percent for bay anchovy. (Note that latent survival in control samples was also approximately 60 percent). Although more recent data are generally not available, the screens continue to operate successfully at Big Bend in an estuarine environment with proper maintenance. While egg and larvae entrainment performance are not available, fine mesh (0.5 mm) Passavant screens (single entry/double exit) have been used successfully in a marine environment at the Barney Davis Station in Corpus Christi, Texas. Impingement data for this facility show overall 86 percent initial survivals for bay anchovy, menhaden, Atlantic croaker, killfish, spot, silverside, and shrimp.

Additional full-scale performance data for fine mesh screens at large power stations are generally not available. However, some data are available from limited use/study at several sites and from laboratory and pilot-scale tests. Seasonal use of fine mesh on two of four screens at the Brunswick Power Plant in North Carolina has shown 84 percent reduction in entrainment compared to the conventional screen systems. Similar results were obtained during pilot testing of 1-mm screens at the Chalk Point Generating Station in Maryland, and, at the Kintigh Generating Station in New Jersey, pilot testing indicated 1-mm screens provided 2 to 35 times reductions in entrainment over conventional 9.5-mm screens. Finally, Tennessee Valley Authority (TVA) pilot-scale studies performed in the 1970s showed reductions in striped bass larvae entrainment up to 99 percent using a 0.5-mm screen and 75 and 70 percent for 0.97-mm and 1.3-mm screens, respectively. A full-scale test by TVA at the John Sevier Plant showed less than half as many larvae entrained with a 0.5-mm screen than 1.0 and 2.0-mm screens combined.

Despite the lack of full-scale data, the experiences at Big Bend (as well as Brunswick) show that fine-mesh screens can reduce entrainment by 80 percent or more. This is contingent on optimized operation and intensive maintenance to avoid biofouling and clogging, especially in marine environments. It also may be appropriate to have removable fine mesh that is only used during periods of egg and larval abundance, thereby reduced the potential for clogging and wear and tear on the systems.

5.5.4 Fish Net Barriers

Technology Overview
Fish net barriers are wide-mesh nets, which are placed in front of the entrance to intake structures. The size of the mesh needed is a function of the species that are present at a particular site and vary from 4 mm to 32 mm (EPRI, 2000). The mesh must be sized to prevent fish from passing through the net causing them to become gilled. Relatively low velocities are maintained because the area through which the water can flow is usually large. Fish net barriers have been used at numerous facilities and lend themselves to intakes where the seasonal migration of fish and other organisms require fish diversion facilities for only specific times of the year.

Technology Performance
Barrier nets can provide a high degree of impingement reduction. Because of typically wide openings, they do not reduce entrainment of eggs and larvae. A number of barrier net systems have been used/studied at large power plants. Specific examples include:

- At the J.P. Pulliam Station (Wisconsin), the operator installed 100 and 260-foot barrier nets across the two intake canals, which withdraw water from the Fox River prior to flowing into Lake Michigan. The barrier nets have been shown to reduce impingement by 90 percent over conventional traveling screens without the barrier nets. The facility has the barrier nets in place when the water temperature is greater than 37°F or April 1 through December 1.

- The Ludington Storage Plant (Michigan) provides water from Lake Michigan to a number of power plant facilities. The plant has a 2.5-mile long barrier net that has successfully reduced I&E. The overall net effectiveness for target species (five salmonids, yellow perch, rainbow smelt, alewife, and chub) has been over 80 percent since 1991 and 96 percent since 1995. The net is deployed from mid-April to mid-October, with storms and icing preventing use during the remainder of the year.

- At the Chalk Point Generating Station (Maryland), a barrier net system has been used since 1981, primarily to reduce crab impingement from the Patuxent River. Eventually, the system was redesigned to include two nets: a 1,200-foot wide outer net prevents debris flows and a 1,000-foot inner net prevents organism flow into the intake. Crab impingement has been reduced by 84 percent. The Agency did not obtain specific fish impingement performance data for other species, but the nets have reduced overall impingement liability for all species from over $2 million to less than $140,000. Net panels are changed twice per week to control biofouling and clogging.

- The Bowline Point Station (New York) has an approximately 150-foot barrier net in a v-shape around the intake structure. Testing during 1976 through 1985 showed that the net effectively reduces white perch and striped bass impingement by 91 percent. Based on tests of a "fine" mesh net (3.0 mm) in 1993 and 1994, researchers found that it could be used to generally prevent entrainment. Unfortunately, species' abundances were too low to determine the specific biological effectiveness.

- In 1980, a barrier net was installed at the J.R. Whiting Plant (Michigan) to protect Maumee Bay. Prior to net installation, 17,378,518 fish were impinged on conventional traveling screens. With the net, sampling in 1983 and 84 showed 421,978 fish impinged (97 percent effective), sampling in 1987 showed 82,872 fish impinged (99 percent effective), and sampling in 1991 showed 316,575 fish impinged (98 percent effective).

Barrier nets have clearly proven effective for controlling *impingement* (i.e., 80+ percent reductions over conventional screens without nets) in areas with limited debris flows. Experience has shown that high debris flows can cause significant damage to net systems. Biofouling concerns can also be a concern but this can be addressed through frequent maintenance. Barrier nets are also often only used seasonally, where the source waterbody is subject to freezing. Fine-mesh barrier nets show some promise for entrainment control but would likely require even more intensive maintenance. In some cases, the use of barrier nets may be further limited by the physical constraints and other uses of the waterbody.

5.5.5 Aquatic Microfiltration Barriers

Technology Overview

Aquatic microfiltration barrier systems are barriers that employ a filter fabric designed to allow for passage of water into a cooling water intake structure, but exclude aquatic organisms. These systems are designed to be placed some distance from the cooling water intake structure within the source waterbody and act as a filter for the water that enters into the cooling water system. These systems may be floating, flexible, or fixed. Since these systems generally have such a large surface area, the velocities that are maintained at the face of the permeable curtain are very low. One company, Gunderboom, Inc., has a patented full-water-depth filter curtain comprised of polyethylene or polypropylene fabric that is suspended by flotation billets at the surface of the water and anchored to the substrate below. The curtain fabric is manufactured as a matting of minute unwoven fibers with an apparent opening size of 20 microns. Gunderboom systems also employ an automated "air burst" system to periodically shake the material and pass air bubbles through the curtain system to clean it of sediment buildup and release any other material back into the water column.

Technology Performance

The Agency has determined that microfiltration barriers, including the Gunderboom, show significant *promise* for minimizing entrainment. However, the Agency acknowledges that Gunderboom technology is currently "experimental in nature." At this juncture, the only power plant where the Gunderboom has been used at a "full-scale" level is the Lovett Generating Station along the Hudson River in New York, where pilot testing began in the mid-1990s. Initial testing at this facility showed significant potential for reducing entrainment. Entrainment reductions up to 82 percent were observed for eggs and larvae and these levels have been maintained for extended month-to-month periods during 1999 through 2001. At Lovett, there have been some operational difficulties that have affected long-term performance. These difficulties, including tearing, overtopping, and plugging/clogging, have been addressed, to a large extent, through subsequent design modifications. Gunderboom, Inc. specifically has designed and installed a "microburst" cleaning system to remove particulates. Each of the challenges encountered at Lovett could be significantly greater concern at marine sites with higher wave action and debris flows. Gunderboom systems have been otherwise deployed in marine conditions to prevent migration of particulates and bacteria. They have been used successfully in areas with waves up to five feet. The Gunderboom system is currently being tested for potential use at the Contra Costa Plant along the San Joaquin River in Northern California.

An additional question related to the utility of the Gunderboom and other microfiltration systems is sizing and the physical limitations and other uses of the source waterbody. With a 20-micron mesh, 100,000 and 200,000 gallon per minute intakes would require filter systems 500 and 1,000 feet long (assuming 20 foot depth). In some locations, this may preclude its successful deployment due space limitations and/or conflicts with other waterbody uses.

5.5.6 Louver Systems

Technology Overview

Louver systems consist of series of vertical panels placed at 90 degree angles to the direction of water flow (Hadderingh, 1979). The placement of the louver panels provides both changes in the flow direction and velocity, which fish tend to avoid. The angles and flow velocities of the louvers create a current parallel to the face of the louvers which carries fish away from the intake and into a fish bypass system for return to the source waterbody.

Technology Performance

Louver systems can reduce impingement losses based on fishes' abilities to recognize and swim away from the barriers. Their performance, i.e., guidance efficiency, is highly dependant on the length and swimming abilities of the resident species. Since eggs and early stages of larvae cannot "swim away," they are not affected by the diversions and there is no associated reduction in entrainment.

While louver systems have been tested at a number of laboratory and pilot-scale facilities, they have not been used at many full-scale facilities. The only large power plant facility where a louver system has been used is San Onofre Units 2 and 3 (2,200 MW combined) in Southern California. The operator initially tested both louver and wide mesh, angled traveling screens during the 1970s. Louvers were subsequently selected for full-scale use at the intakes for the two units. In 1984, a total of 196,978 fish entered the louver system with 188,583 returned to the waterbody and 8,395 impinged. In 1985, 407,755 entered the louver system with 306,200 returned and 101,555 impinged. Therefore, the guidance efficiencies in 1984 and 1985 were 96 and 75 percent, respectively. However, 96-hour survival rates for some species, i.e., anchovies and croakers, were 50 percent or less. The facility also has encountered some difficulties with predator species congregating in the vicinity of the outlet from the fish return system. Louvers were originally considered for use at San Onofre because of 1970s pilot testing at the Redondo Beach Station in California where maximum guidance efficiencies of 96-100 percent were observed.

EPRI 2000 indicated that louver systems could provide 80-95 percent diversion efficiency for a wide variety of species under a range of site conditions. This is generally consistent with the American Society of Civil Engineers' (ASCE) findings from the late 1970s which showed almost all systems had diversion efficiencies exceeding 60 percent with many more than 90 percent. As indicated above, much of the EPRI and ASCE data come from pilot/laboratory tests and hydroelectric facilities where louver use has been more widespread than at steam electric facilities. Louvers were specifically tested by the Northeast Utilities Service Company in the Holyoke Canal on the Connecticut River for juvenile clupeids (American shad and blueback herring). Overall guidance efficiency was found to be 75-90 percent. In the 1970s, Alden Research Laboratory observed similar results for Hudson River species (including alewife and smelt). At the Tracy Fish Collection Facility located along the San Joaquin River in California, testing was performed from 1993 and 1995 to determine the guidance efficiency of a system with primary and secondary louvers. The results for green and white sturgeon, American shad, splittail, white catfish, delta smelt, Chinook salmon, and striped bass showed mean diversion efficiencies ranging from 63 (splittail) to 89 percent (white catfish). Also in the 1990s, an experimental louver bypass system was tested at the USGS' Conte Anadromous Fish Research Center in Massachusetts. This testing showed guidance efficiencies for Connecticut River species of 97 percent for a "wide array" of louvers and 100 percent for a "narrow array." Finally, at the T.W. Sullivan Hydroelectric Plant along the Williamette River in Oregon, the louver system is estimated to be 92 percent effective in diverting spring Chinook, 82 percent for all Chinook, and 85 percent for steelhead. The system has been optimized to reduce fish injuries such that the average injury occurrence is only 0.44 percent.

Overall, the above data indicate that louvers can be highly effective (70+ percent) in diverting fish from potential impingement. Latent mortality is a concern, especially where fragile species are present. Similar to modified screens with fish return systems, operators must optimize louver system design to minimize fish injury and mortality

5.5.7 Angled and Modular Inclined Screens

Technology Overview

Angled traveling screens use standard through-flow traveling screens where the screens are set at an angle to the incoming flow. Angling the screens improves the fish protection effectiveness since the fish tend to avoid the screen face and move toward the end of the screen line, assisted by a component of the inflow velocity. A fish bypass facility with independently induced flow must be provided (Richards 1977). Modular inclined screens (MISs) are a specific variation on angled traveling screens, where each module in the intake consists of trash racks, dewatering stop logs, an inclined screen set at a 10 to 20 degree angle to the flow, and a fish bypass (EPRI 1999).

Technology Performance

Angled traveling screens with fish bypass and return systems work similarly to louver systems. They also only provide potential reductions in impingement mortality since eggs and larvae will not generally detect the factors that influence diversion. Similar to louver systems, they were tested extensively at the laboratory and pilot scales, especially during the 1970s and early 1980s. Testing of angled screens (45 degrees to the flow) in the 1970s at San Onofre showed poor to good guidance (0-70 percent) for northern anchovies with moderate to good guidance (60-90 percent) for other species. Latent survival varied by species with fragile species only having 25 percent survival, while hardy species showed greater than 65 percent survival. The intake for Unit 6 at the Oswego Steam plant along Lake Ontario in New York has traveling screens angled to 25 degrees. Testing during 1981 through 1984 showed a combined diversion efficiency of 78 percent for all species; ranging from 53 percent for mottled sculpin to 95 percent for gizzard shad. Latent survival testing results ranged from 22 percent for alewife to nearly 94 percent for mottled sculpin.

Additional testing of angled traveling screens was performed in the late 1970s and early 1980s for power plants on Lake Ontario and along the Hudson River. This testing showed that a screen angled at 25 degrees was 100 percent effective in diverting 1 to 6 inch long Lake Ontario fish. Similar results were observed for Hudson River species (striped bass, white perch, and Atlantic tomcod). One-week mortality tests for these species showed 96 percent survival. Angled traveling screens with a fish return system have been used on the intake from Brayton Point Unit 4. Studies from 1984 through 1986 that evaluated the angled screens showed a diversion efficiency of 76 percent with latent survival of 63 percent. Much higher results were observed excluding bay anchovy. Finally, 1981 full-scale studies of an angled screen system at the Danskammer Station along the Hudson River in New York showed diversion efficiencies of 95 to 100 percent with a mean of 99 percent. Diversion efficiency combined with latent survival yielded a total effectiveness of 84 percent. Species included bay anchovy, blueback herring, white perch, spottail shiner, alewife, Atlantic tomcod, pumpkinseed, and American shad.

During the late 1970s and early 1980s, Alden Research Laboratories (Alden) conducted a range of tests on a variety of angled screen designs. Alden specifically performed screen diversion tests for three northeastern utilities. In initial studies for Niagara Mohawk, diversion efficiencies were found to be nearly 100 percent for alewife and smolt. Follow-up tests for Niagara Mohawk confirmed 100 percent diversion efficiency for alewife with mortalities only four percent higher than control samples. Subsequent tests by Alden for Consolidated Edison, Inc. using striped bass, white perch, and tomcod also found nearly 100 percent diversion efficiency with a 25 degree angled screen. The one-week mean mortality was only 3 percent.

Alden further performed tests during 1978-1990 to determine the effectiveness of fine-mesh, angled screens. In 1978, tests were performed with striped bass larvae using both 1.5 and 2.5-mm mesh and different screen materials and approach velocity. Diversion efficiency was found to clearly be a function of larvae length. Synthetic materials were also found to be more effective than metal screens. Subsequent testing using only synthetic materials found that 1.0 mm screens can provide post larvae diversion efficiencies of greater than 80 percent. However, the tests found that latent mortality for diverted species was also high.

Finally, EPRI tested modular inclined screens (MIS) in a laboratory in the early 1990s. Most fish had diversion efficiencies of 47 to 88 percent. Diversion efficiencies of greater than 98 percent were observed for channel catfish, golden shiner, brown trout, Coho and Chinook salmon, trout fry and juveniles, and Atlantic salmon smolts. Lower diversion efficiency and higher mortality were found for American shad and blueback herring but comparable to control mortalities. Based on the laboratory data, a MIS system was pilot-tested at a Niagara Mohawk hydroelectric facility on the Hudson River. This testing showed diversion efficiencies and survival rates approaching 100 percent for golden shiners and rainbow trout. High diversion and survival was also observed for largemouth and smallmouth bass, yellow perch, and bluegill. Lower diversion efficiency and survival was found for herring.

Similar to louvers, angled screens show potential to minimize impingement by greater than 80 to 90 percent. More widespread full-scale use is necessary to determine optimal design specifications and verify that they can be used on a widespread basis.

5.5.8 Velocity Caps

Technology Description
A velocity cap is a device that is placed over vertical inlets at offshore intakes. This cover converts vertical flow into horizontal flow at the entrance into the intake. The device works on the premise that fish will avoid rapid changes in horizontal flow. In general, velocity caps have been installed at many offshore intakes and have been successful in minimizing impingement.

Technology Performance
Velocity caps can reduce fish drawn into intakes based on the concept that they tend to avoid horizontal flow. They do not provide reductions in entrainment of eggs and larvae, which cannot distinguish flow characteristics. As noted in *ASCE 1981*, velocity caps are often used in conjunction with other fish protection devices. Therefore, there are somewhat limited data on their performance when used alone. Facilities that have velocity caps include:

- Oswego Steam Units 5 and 6 in New York (combined with angled screens on Unit 6).
- San Onofre Units 2 and 3 in California (combined with louver system).
- El Segundo Station in California
- Huntington Beach Station in California
- Edgewater Power Plant Unit 5 in Wisconsin (combined with 9.5 mm wedgewire screen)

- Nanticoke Power Plant in Ontario, Canada
- Nine Mile Point in New York
- Redondo Beach Station in California
- Kintigh Generation Station in New York (combined with modified traveling screens)
- Seabrook Power Plant in New Hampshire
- St. Lucie Power Plant in Florida.

At the Huntington Beach and Segundo Stations in California, velocity caps have been found to provide 80 to 90 percent reductions in fish entrapment. At Seabrook, the velocity cap on the offshore intake has minimized the number of pelagic fish entrained except for pollock. Finally, two facilities in England have velocity caps on one of each's two intakes. At the Sizewell Power Station, intake B has a velocity cap, which reduces impingement about 50 percent compared to intake A. Similarly, at the Dungeness Power Station, intake B has a velocity cap, which reduces impingement about 62 percent compared to intake A.

5.5.9 Porous Dikes and Leaky Dams

Technology Overview
Porous dikes, also known as leaky dams or dikes, are filters resembling a breakwater surrounding a cooling water intake. The core of the dike consists of cobble or gravel that permits free passage of water. The dike acts both as a physical and behavioral barrier to aquatic organisms. Tests conducted to date have indicated that the technology is effective in excluding juvenile and adult fish. The major problems associated with porous dikes come from clogging by debris and silt, ice build-up, and by colonization of fish and plant life.

Technology Performance
Porous dike technologies work on the premise that aquatic organisms will not pass through physical barriers in front of an intake. They also operate with low approach velocity further increasing the potential for avoidance. However, they will not prevent entrainment by non-motile larvae and eggs. Much of the research on porous dikes and leaky dams was performed in the 1970s. This work was generally performed in a laboratory or on a pilot level, i.e., the Agency is not aware of any full-scale porous dike or leaky dam systems currently used at power plants in the U.S. Examples of early study results include:

- Studies of porous dike and leaky dam systems by Wisconsin Electric Power at Lake Michigan plants showed generally lower I&E rates than other nearby onshore intakes.

- Laboratory work by Ketschke showed that porous dikes could be a physical barrier to juvenile and adult fish and a physical or behavioral barrier to some larvae. All larvae except winter flounder showed some avoidance of the rock dike.

- Testing at the Brayton Point Power Plant showed that densities of bay anchovy larvae downstream of the dam were reduced by 94 to 99 percent. For winter flounder, downstream densities were lower by 23 to 87 percent. Entrainment avoidance for juvenile and adult finfish was observed to be nearly 100 percent.

As indicated in the above examples, porous dikes and leaky dams show *potential* for use in limiting passage of adult and juvenile fish, and, to some degree, motile larvae. However, the lack of more recent, full-scale performance data makes it difficult to predict their widespread applicability and specific levels of performance.

5.5.10 Behavioral Systems

Technology Overview
Behavioral devices are designed to enhance fish avoidance of intake structures and/or promote attraction to fish diversion or bypass systems. Specific technologies that have been considered include:

- Light Barriers: Light barriers consist of controlled application of strobe lights or mercury vapor lights to lure fish away from the cooling water intake structure or deflect natural migration patterns. This technology is based on research that shows that some fish avoid light, however it is also known that some species are attracted by light.

- Sound Barriers: Sound barriers are non-contact barriers that rely on mechanical or electronic equipment that generates various sound patterns to elicit avoidance responses in fish. Acoustic barriers are used to deter fish from entering cooling water intake structures. The most widely used acoustical barrier is a pneumatic air gun or "popper."

- Air bubble barriers: Air bubble barriers consist of an air header with jets arranged to provide a continuous curtain of air bubbles over a cross section area. The general purpose of air bubble barriers is to repel fish that may attempt to approach the face of a CWIS.

Technology Performance
Many studies have been conducted and reports prepared on the application of behavioral devices to control I&E, see EPRI 2000. For the most part, these studies have either been inconclusive or shown no tangible reduction in impingement or entrainment. As a result, the full-scale application of behavioral devices has been limited. Where data are available, performance appears to be highly dependent on the types and sizes of species and environmental conditions. One exception may be the use of sound systems to divert alewife. In tests at the Pickering Station in Ontario, poppers were found to be effective in reducing alewife I&E by 73 percent in 1985 and 76 percent in 1986. No benefits were observed for rainbow smelt and gizzard shad. 1993 testing of sound systems at the James A. Fitzpatrick Station in New York showed similar results, i.e., 85 percent reductions in alewife I&E through use of a high frequency sound system. At the Arthur Kill Station, pilot- and full-scale, high frequency sound tests showed comparable results for alewife to Fitzpatrick and Pickering. Impingement of gizzard shad was also three times less than without the system. No deterrence was observed for American shad or bay anchovy using the full-scale system. In contrast, sound provided little or no deterrence for any species at the Roseton Station in New York. Overall, the Agency expects that behavioral systems would be used in conjunction with other technologies to reduce I&E and perhaps targeted towards an individual species (e.g., alewife).

5.5.11 Other Technology Alternatives

The proposed new facility rule does not specify the individual technology (or group of technologies) to be used to minimize I&E to same levels as those achieved with the Track I requirements based, in part, on wet, closed-cycle cooling system. In addition to the above technologies, there are other approaches that may be used on a site-by-site basis. For example:

- Use of variable speed pumps can provide for greater system efficiency and reduced flow requirements (and associated entrainment) by 10-30 percent. EPA Region 4 estimated that use of variable speed pumps at the Canaveral and Indian River Stations in the Indian River estuary would reduce entrainment by 20 percent. Presumably, such pumps would have to be used in conjunction with other technologies. EPA conservatively estimated that facilities complying with the requirements final rule would install variable speed pumps regardless of the baseline cooling system projected for the facility. See Chapter 2 of this document for more information.

- Perforated pipes draw water through perforations or elongated slots in a cylindrical section placed in the waterway. Early designs of this technology were not efficient, velocity distribution was poor, and they were specifically designed to screen out detritus (i.e., not used for fish protection) (ASCE, 1982). Inner sleeves were subsequently added to perforated pipes to equalize the velocities entering the outer perforations. These systems have historically been used at locations requiring small amounts of make-up water. Experience at steam electric plants is very limited (Sharma, 1978). Perforated pipes are used on the intakes for the Amos and Mountaineer Stations along the Ohio River. However, I&E performance data for these facilities are unavailable. In general, EPA projects that perforated pipe system performance should be comparable to wide-mesh wedgewire screens (e.g., at Eddystone Units 1 and 2 and Campbell Unit 3).

- At the Pittsburg Plant in California, impingement survival was studied for continuously rotated screens versus intermittent rotation. Ninety-six-hour survival for young-of-year white perch was 19 to 32 percent for intermittent screen rotation versus 26 to 56 percent for continuous rotation. Striped bass latent survival increased from 26 to 62 percent when continuous rotation was used. Similar studies were also performed at Moss Landing Units 6 and 7, where no increased survival was observed for hardy and very fragile species, however, there was a substantial increase in impingement survival for surfperch and rockfish.

- Facilities may be able to use recycled cooling water to reduce intake flow needs. The Brayton Point Station has a "piggyback" system where the entire intake requirements for Unit 4 can be met by recycled cooling water from Units 1 through 3. The system has been used sporadically since 1993 and reduces the make-up water needs (and thereby entrainment) by 29 percent.

5.6 INTAKE LOCATION

Beyond design alternatives for CWISs, an operator may able to locate CWISs offshore or otherwise in areas that minimize I&E (compared to conventional onshore locations). It is well known that there are certain areas within every waterbody with increased biological productivity, and therefore where the potential for I&E of organisms is higher.

In large lakes and reservoirs, the littoral zone (i.e., shorezone areas where light penetrates to the bottom) of lakes/reservoirs serves as the principal spawning and nursery area for most species of freshwater fish and is considered one of the most productive areas of the waterbody. Fish of this zone typically follow a spawning strategy wherein eggs are deposited in prepared nests, on the bottom, and/or are attached to submerged substrates where they incubate and hatch. As the larvae mature, some species disperse to the open water regions, whereas many others complete their life cycle in the littoral zone. Clearly, the impact potential for intakes located in the littoral zone of lakes and reservoirs is high. The profundal zone of lakes/reservoirs is the deeper, colder area of the waterbody. Rooted plants are absent because of insufficient light, and for the same reason, primary productivity is minimal. A well-oxygenated profundal zone can support benthic macroinvertebrates and cold-water fish; however, most of the fish species seek shallower areas to spawn (either in littoral areas or in adjacent streams/rivers). Use of the deepest open water region of a lake and reservoir (e.g., within the profundal zone) as a source of cooling water typically offers lower I&E impact potential (than use of littoral zone waters).

As with lakes/reservoirs, rivers are managed for numerous benefits, which include sustainable and robust fisheries.

Unlike lakes and reservoirs, the hydrodynamics of rivers typically result in a mixed water column and (overall) unidirectional flow. There are many similarities in the reproductive strategies of shoreline fish populations in rivers and the reproductive strategies of fish within the littoral zone of lakes/reservoirs. Planktonic movement of eggs, larvae, post larvae, and early juvenile organisms along the shorezone are generally limited to relatively short distances. As a result, the shorezone placement of CWISs in rivers may potentially impact local spawning populations of fish. The impact potential associated with entrainment may be diminished if the main source of cooling water is recruited from near the bottom strata of the open water channel region of the river. With such an intake configuration, entrainment of shorezone eggs and larvae, as well as the near surface drift community of ichthyoplankton, is minimized. Impacts could also be minimized by the control of the timing and frequency of withdrawals from rivers. In temperate regions, the number of entrainable/impingeable organisms of rivers increases during spring and summer (when many riverine fishes reproduce). The number of eggs and larvae peak at that time, whereas entrainment potential during the remainder of the year may be minimal.

In estuaries, species distribution and abundance are determined by a number of physical and chemical attributes including: geographic location, estuary origin (or type), salinity, temperature, oxygen, circulation (currents), and substrate. These factors, in conjunction with the degree of vertical and horizontal stratification (mixing) in the estuary, help dictate the spatial distribution and movement of estuarine organisms. However, with local knowledge of these characteristics, the entrainment effects of a CWIS could be minimized by adjusting the intake design to areas (e.g., depths) least likely to impact upon concentrated numbers and species of organisms.

In oceans, nearshore coastal waters are generally the most biologically productive areas. The euphotic zone (zone of photosynthetic available light) typically does not extend beyond the first 100 meters (328 feet) of depth. Therefore, inshore waters are generally more productive due to photosynthetic activity, and due to the input from estuaries and runoff of nutrients from land.

There are limited published data *quantifying* the locational differences in I&E rates at individual power plants. However, some information is available for selected sites. For example,

- For the St. Lucie plant in Florida, EPA Region 4 permitted the use of a once through cooling system instead of closed-cycle cooling by locating the outfall 1,200 offshore (with a velocity cap) in the Atlantic Ocean. This avoided impacts on the biologically sensitive Indian River estuary.

- In *Entrainment of Fish Larvae and Eggs on the Great Lakes, with Special Reference to the D.C. Cook Nuclear Plant, Southeastern Lake Michigan* (1976), researchers noted that larval abundance is greatest within about the 12.2-m (40 ft) contour to shore in Lake Michigan and that the abundance of larvae tends to decrease as one proceeds deeper and farther offshore. This led to the suggestion of locating CWISs in deep waters.

- During biological studies near the Fort Calhoun Power Station along the Missouri River, results of transect studies indicated significantly higher fish larvae densities along the cutting bank of the river, adjacent to the Station's intake structure. Densities were generally were lowest in the middle of the channel.

5.7 SUMMARY

Tables 5-1 and 5-2 summarize I&E performance data for selected, existing facilities. The Agency recognizes that these data are somewhat variable, in part depending on site-specific conditions. This is also because there generally have not been uniform performance standards for specific technologies. However, during the past 30 years, significant experience has been gained in optimizing the design and maintenance of CWIS technologies under various site and environmental conditions. Through this experience and the performance requirements under Track II of the proposed new facility rule, the Agency is confident that technology applicability and performance will continue to be improved.

The Agency has concluded that the data indicate that several technologies, i.e., wide-mesh wedgewire screens and barrier systems, will generally minimize impingement to levels comparable to wet, closed cycle cooling systems. Other technologies, such as modified traveling screens with fish handling and return systems, and fish diversion systems, are likely to be viable at some sites (especially those with hardy species present). In addition, these technologies may be used in groups, e.g., barrier nets and modified screens, depending on site-specific conditions.

Demonstrating that alternative design technologies can achieve comparable entrainment performance to closed-cycle systems is more problematic largely because there are relatively few fully successful examples of full-scale systems being deployed and tested. However, the Agency has determined that fine-mesh traveling screens with fish return systems, fine-mesh wedgewire screens and microfiltration barriers (e.g., gunderbooms) are all promising technologies that could provide a level of protection reasonably consistent with the I&E protection afforded by wet, closed-cycle cooling. In addition, the Agency is also confident that on a site-by-site basis, many facilities will be able to further minimize entrainment (and impingement) by optimizing the location and timing of cooling water withdrawals. Similarly, habitat restoration could also be used, as appropriate as needed, in conjunction with CWIS technologies and/or locational requirements.

Table 5-1: Impingement Performance

Site	Location	Name/Type of Waterbody	Technology	Impingement	Entrainment	Notes
Diablo Canyon/Moss Landing	California	Pacific Ocean	Modified traveling/fish return	75	0	
Brayton Point	Massachusetts	Mt. Hope Bay (Estuary)	Angled screens/fish return	76	0	63% latent
Danskammer	New York	Tidal River (Hudson)	Angled screens/fish return	99	0	84% latent
Monroe	Michigan	River/Great Lake	Fish pump/return (screenwell)	70-80	0	Raisin River trib to L. Erie
Holyoke Canal	Connecticut	Connecticut River Basin	Louvers	85-90	0	Test results
Tracy Fish Collection	California	San Joaquin River	Louvers	63-89	0	
Salem	New Jersey	Tidal River (Delaware)	Ristroph screens	18-98	0	Species specific (no avg.)
Redondo Beach	California	Pacific Ocean	Louvers	96-100	0	Test for San Onofre
San Onofre	California	Pacific Ocean	Louvers	75-96	0	
Dominion Power Surry	Virginia	Estuary (James River)	Modified Fish/fish return	94	0	Includes survival
Barney Davis	Texas	Estuary (coastal lagoon)	Passavant screens (1.5 mm)	86	NA	Entrainment data Not Avail
Kintigh	New York	Great Lake	Modified with fish return	>80	50-97	Except shad 54-65, alewife 15-44
Calvert Cliffs	Maryland	Bay/estuary	Dual flow, cont. rot., return	73	0	Includes survival
Arthur Kill	New York	Estuary	Ristroph screens	79-92	0	
J.H. Campbell	Michigan	Great Lake	Wide mesh wedgewire	99+	0	
Eddystone	Pennsylvania	Estuary (Delaware)	Wide mesh wedgewire	99+	0	
Lovett	New York	Tidal River (Hudson)	Gunderboom	99	82	
J.P. Pulliam	Wisconsin	River/Great Lake	Barrier net	90	0	Only when above 37 degrees C
Ludington Storage	Michigan	Great Lake	Barrier net	96	0	
Chalk Point	Maryland	Bay/Estuary	Barrier net	90+	0	Based on liability reduced 93%
Bowline	New York	Tidal River (Hudson)	Barrier net	91	0	
J.R. Whiting	New York	Great Lake	Barrier net	97-99	0	
D.C. Cook	Michigan	Great Lake	Barrier net	80	0	Estimated by U. of Michigan
Oswego Steam	New York	Great Lake	Velocity cap	78	0	

Table 5-2: Entrainment Performance

Site	Location	Name/Type of Waterbody	Technology	Impingement	Entrainment	Notes
Big Bend	Florida	Tampa Bay	Fine mesh traveling	NA	86-95	66-93% survival
Seminole	Florida	River/Estuary	Fine mesh wedgewire	NA	99	Testing, not full-scale
Logan	New Jersey	River/Estuary	Fine mesh wedgewire	NA	90	19 mgd
TVA (studies)	Various	Fresh Water	Fine mesh traveling	NA	99	lab testing, striped bass larvae only
Lovett	New York	River/Tidal	Gunderboom	99	82	
Brunswick	North Carolina	River/Estuary	Fine mesh traveling	NA	84	used only when less than 84 deg F
Chalk Point	Maryland	Bay/Estuary	Fine mesh wedgewire	NA	80	Testing, not full-scale
Kintigh	New York	Great Lake	Fine mesh traveling	>80	50-97	
Summit	Delaware	Bay/Estuary	Fine mesh wedgewire	NA	90+	"impingement eliminated"

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ATTACHMENT A

CWIS Technology Fact Sheets

Intake Screening Systems	Fact Sheet No. 1: Single-Entry, Single-Exit Vertical Traveling Screens (Conventional Traveling Screens)

DESCRIPTION:

The single-entry, single-exit vertical traveling screens (conventional traveling screens) consist of screen panels mounted on an endless belt; the belt rotates through the water vertically. The screen mechanism consists of the screen, the drive mechanism, and the spray cleaning system. Most of the conventional traveling screens are fitted with 3/8-inch mesh and are designed to screen out and prevent debris from clogging the pump and the condenser tubes. The screen mesh is usually supplied in individual removable panels referred to as " baskets" or "trays".

The screen washing system consists of a line of spray nozzles operating at a relatively high pressure of 80 to 120 pounds per square inch (psi). The screens are usually designed to rotate at a single speed. The screens are rotated either at predetermined intervals or when a predetermined differential pressure is reached across the screens based on the amount of debris in the intake waters.

Because of this intermittent operation of the conventional traveling screens, fish can become impinged against the screens during the extended period of time while the screens are stationary and eventually die. When the screens are rotated the fish are removed from the water and then subjected to a high pressure spray; the fish may fall back into the water and become re-impinged or they may be damaged (EPA, 1976, Pagano et *al*, 1977).

Conventional Traveling Screen (EPA, 1976)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

The conventional traveling screens are the most common screening device presently used at steam electric power plants. Sixty percent of all the facilities use this technology at their intake structure (EEI, 1993).

RESEARCH/OPERATION FINDINGS:

The conventional single-entry single screen is the most common device resulting in impacts from entrainment and impingement (Fritz, 1980).

DESIGN CONSIDERATIONS:

The screens are usually designed structurally to withstand a differential pressure across their face of 4 to 8 feet of water.

The recommended normal maximum water velocity through the screen is about 2.5 feet per second (ft/sec). This recommended velocity is where fish protection is not a factor to consider.

The screens normally travel at one speed (10 to 12 feet per minute) or two speeds (2.5 to 3 feet per minute and 10 to 12 feet per minute). These speeds can be increased to handle heavy debris load.

ADVANTAGES:

Conventional traveling screens are a proven "off-the-shelf" technology that is readily available.

LIMITATIONS:

Impingement and entrainment are both major problems in this unmodified standard screen installation, which is designed for debris removal not fish protection.

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Intake Screening Systems	Fact Sheet No. 2: Modified Vertical Traveling Screens

DESCRIPTION:

Modified vertical traveling screens are conventional traveling screens fitted with a collection "bucket" beneath the screen panel. This intake screening system is also called a bucket screen, Ristroph screen, or a Surry Type screen. The screens are modified to achieve maximum recovery of impinged fish by maintaining them in water while they are lifted to a release point. The buckets run along the entire width of the screen panels and retain water while in upward motion. At the uppermost point of travel, water drains from the bucket but impinged organisms and debris are retained in the screen panel by a deflector plate. Two material removal systems are often provided instead of the usual single high pressure one. The first uses low-pressure spray that gently washes fish into a recovery trough. The second system uses the typical high-pressure spray that blasts debris into a second trough. Typically, an essential feature of this screening device is continuous operation which keeps impingement times relatively short (Richards, 1977; Mussalli, 1977; Pagano et al., 1977; EPA , 1976).

Modified Vertical Traveling Screens (White et al, 1976)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Facilities which have tested the screens include: the Surry Power Station in Virginia (White et al, 1976) (the screens have been in operation since 1974), the Madgett Generating Station in , Wisconsin, the Indian Point Nuclear Generating Station Unit 2 in New York, the Kintigh (formerly Somerset) Generating Station in New Jersey, the Bowline Point Generating Station (King et al, 1977), the Roseton Generating Station in New York, the Danskammer Generating Station in New York (King et al, 1977), the Hanford Generating Plant on the Columbia River in Washington (Page et al, 1975; Fritz, 1980), the Salem Genereating on the Delaware River in New Jersey, and the Monroe Power Plant on the Raisin River in Michigan.

RESEARCH/OPERATION FINDINGS:

Modified traveling screens have been shown to have good potential for alleviating impingement mortality. Some information is available on initial and long-term survival of impinged fish (EPRI, 1999; ASCE, 1982; Fritz, 1980). Specific research and operation findings are listed below:

In 1986, the operator of the Indian Point Station redesigned fish troughs on the Unit 2 intake to enhance survival. Impingement injuries and mortality were reduced from 53 to 9 percent for striped bass, 64 to14 percent for white perch, 80 to 17 percent for Atlantic tomcod, and 47 to 7 percent for pumpkinseed (EPRI, 1999).

The Kintigh Generating Station has modified traveling screens with low pressure sprays and a fish return system. After enhancements to the system in 1989, survivals of generally greater than 80 percent have been observed for rainbow smelt, rock bass, spottail shiner, white bass, white perch, and yellow perch. Gizzard shad survivals have been 54 to 65 percent and alewife survivals have been 15 to 44 percent (EPRI, 1999).

Long-term survival testing was conducted at the Hanford Generating Plant on the Columbia River (Page et al, 1975; Fritz, 1980). In this study, 79 to 95 percent of the impinged and collected Chinook salmon fry survived for over 96 hours.

Impingement data collected during the 1970s from Dominion Power's Surry Station indicated a 93.8 percent survival rate of all fish impinged. Bay anchovies had the lowest survival rate of 83 percent. The facility has modified Ristroph screens with low pressure wash and fish return systems (EPRI 1999).

At the Arthur Kill Station, 2 of 8 screens are modified Ristroph type; the remaining six screens are conventional type. The modified screens have fish collection troughs, low pressure spray washes, fish flap seals, and separate fish collection sluices. 24-hour survival for the unmodified screens averages 15 percent, while the two modified screens have 79 and 92 percent average survival rates (EPRI 1999).

DESIGN CONSIDERATIONS:

The same design considerations as for Fact Sheet No. 1: Conventional Vertical Traveling Screens apply (ASCE, 1982).

ADVANTAGES:

Traveling screens are a proven "off-the-shelf" technology that is readily available. An essential feature of such screens is continuous operation during periods where fish are being impinged compared to conventional traveling screens which operate on an intermittent basis

LIMITATIONS:

The continuous operation can result in undesirable maintenance problems (Mussalli, 1977).

Velocity distribution across the face of the screen is generally very poor.

Latent mortality can be high, especially where fragile species are present.

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Intake Screening Systems	Fact Sheet No. 3: Inclined Single-Entry, Single-Exit Traveling Screens (Angled Screens)

DESCRIPTION:

Inclined traveling screens utilize standard through-flow traveling screens where the screens are set at an angle to the incoming flow as shown in the figure below. Angling the screens improves the fish protection effectiveness of the flush mounted vertical screens since the fish tend to avoid the screen face and move toward the end of the screen line, assisted by a component of the inflow velocity. A fish bypass facility with independently induced flow must be provided. The fish have to be lifted by fish pump, elevator, or conveyor and discharged to a point of safety away from the main water intake (Richards, 1977).

fig : Richards, 4th page 419

Inclined Traveling Screens (Richards, 1977)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Angled screens have been tested/used at the following facilities: the Brayton Point Station Unit 4 in Massachusetts; the San Onofre Station in California; and at power plants on Lake Ontario and the Hudson River (ASCE, 1982; EPRI, 1999).

RESEARCH/OPERATION FINDINGS:

Angled traveling screens with a fish return system have been used on the intake for Brayton Point Unit 4. Studies from 1984 through 1986 that evaluated the angled screens showed a diversion efficiency of 76 percent with latent survival of 63 percent. Much higher results were observed excluding bay anchovy. Survival efficiency for the major taxa exhibited an extremely wide range, from 0.1 percent for bay anchovy to 97 percent for tautog. Generally, the taxa fell into two groups: a hardy group with efficiency greater than 65 percent and a sensitive group with efficiency less than 25 percent (EPRI, 1999).

Southern California Edison at its San Onofre steam power plant had more success with angled louvers than with angled screens. The angled screen was rejected for full-scale use because of the large bypass flow required to yield good guidance efficiencies in the test facility.

DESIGN CONSIDERATIONS:

Many variables influence the performance of angled screens. The following recommended preliminary design criteria were developed in the studies for the Lake Ontario and Hudson River intakes (ASCE, 1982):

Angle of screen to the waterway: 25 degrees

Average velocity of approach in the waterway upstream of the screens: 1 foot per second

Ratio of screen velocity to bypass velocity: 1:1

Minimum width of bypass opening: 6 inches

ADVANTAGES:

The fish are guided instead of being impinged.

The fish remain in water and are not subject to high pressure rinsing.

LIMITATIONS:

Higher cost than the conventional traveling screen

Angled screens need a stable water elevation.

Angled screens require fish handling devices with independently induced flow (Richards, 1977).

REFERENCES:

ASCE. Design of Water Intake Structures for Fish Protection. Task Committee on Fish-Handling Capability of Intake Structures of the Committee on Hydraulic Structures of the Hydraulic Division of the American Society of Civil Engineers, New York, NY. 1982.

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Intake Screening Systems	Fact Sheet No.4: Fine Mesh Screens Mounted on Traveling Screens

DESCRIPTION:

Fine mesh screens are used for screening eggs, larvae, and juvenile fish from cooling water intake systems. The concept of using fine mesh screens for exclusion of larvae relies on gentle impingement on the screen surface or retention of larvae within the screening basket, washing of screen panels or baskets to transfer organisms into a sluiceway, and then sluicing the organisms back to the source waterbody (Sharma, 1978). Fine mesh with openings as small as 0.5 millimeters (mm) has been used depending on the size of the organisms to be protected. Fine mesh screens have been used on conventional traveling screens and single-entry, double-exit screens. The ultimate success of an installation using fine mesh screens is contingent on the application of satisfactory handling and recovery facilities to allow the safe return of impinged organisms to the aquatic environment (Pagano et al, 1977).

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

The Big Bend Power Plant along Tampa Bay area has an intake canal with 0.5-mm mesh Ristroph screens that are used seasonally on the intakes for Units 3 and 4. At the Brunswick Power Plant in North Carolina, fine mesh is used seasonally on two of four screens has shown 84 percent reduction in entrainment compared to the conventional screen systems.

RESEARCH/OPERATION FINDINGS:

During the mid-1980s when the screens were initially installed at Big Bend, their efficiency in reducing impingement and entrainment mortality was highly variable. The operator evaluated different approach velocities and screen rotational speeds. In addition, the operator recognized that frequent maintenance (manual cleaning) was necessary to avoid biofouling. By 1988, system performance had improved greatly. The system's efficiency in screening fish eggs (primarily drums and bay anchovy) exceeded 95 percent with 80 percent latent survival for drum and 93 percent for bay anchovy. For larvae (primarily drums, bay anchovies, blennies, and gobies), screening efficiency was 86 percent with 65 percent latent survival for drum and 66 percent for bay anchovy. Note that latent survival in control samples was also approximately 60 percent (EPRI, 1999).

At the Brunswick Power Plant in North Carolina, fine mesh screen has led to 84 percent reduction in entrainment compared to the conventional screen systems. Similar results were obtained during pilot testing of 1-mm screens at the Chalk Point Generating Station in Maryland. At the Kintigh Generating Station in New Jersey, pilot testing indicated 1-mm screens provided 2 to 35 times reductions in entrainment over conventional 9.5-mm screens (EPRI, 1999).

Tennessee Valley Authority (TVA) pilot-scale studies performed in the 1970s showed reductions in striped bass larvae entrainment up to 99 percent using a 0.5-mm screen and 75 and 70 percent for 0.97-mm and 1.3-mm screens. A full-scale test by TVA at the John Sevier Plant showed less than half as many larvae entrained with a 0.5-mm screen than 1.0 and 2.0-mm screens combined (TVA, 1976).

Preliminary results from a study initiated in 1987 by the Central Hudson and Gas Electric Corporation indicated that the fine mesh screens collect smaller fish compared to conventional screens; mortality for the smaller fish was relatively high, with similar survival between screens for fish in the same length category (EPRI, 1989).

DESIGN CONSIDERATIONS:

Biological effectiveness for the whole cycle, from impingement to survival in the source water body, should be investigated thoroughly prior to implementation of this option. This includes:

The intake velocity should be very low so that if there is any impingement of larvae on the screens, it is gentle enough not to result in damage or mortality.

The wash spray for the screen panels or the baskets should be low-pressure so as not to result in mortality.

The sluiceway should provide smooth flow so that there are no areas of high turbulence; enough flow should be maintained so that the sluiceway is not dry at any time.

The species life stage, size and body shape and the ability of the organisms to withstand impingement should be considered with time and flow velocities.

The type of screen mesh material used is important. For instance, synthetic meshes may be smooth and have a low coefficient of friction, features that might help to minimize abrasion of small organisms. However, they also may be more susceptible to puncture than metallic meshes (Mussalli, 1977).

ADVANTAGES:

There are indications that fine mesh screens reduce entrainment.

LIMITATIONS:

Fine mesh screens may increase the impingement of fish, i.e., they need to be used in conjunction with properly designed and operated fish collection and return systems.

Due to the small screen openings, these screens will clog much faster than those with conventional 3/8-inch mesh. Frequent maintenance is required, especially in marine environments.

REFERENCES:

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Electric Power Research Institute (EPRI). Fish Protection at Cooling Water Intakes: Status Report. 1999.

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Passive Intake Systems	Fact Sheet No. 5: Wedgewire Screens

DESCRIPTION:

Wedgewire screens are designed to reduce entrainment by physical exclusion and by exploiting hydrodynamics. Physical exclusion occurs when the mesh size of the screen is smaller than the organisms susceptible to entrainment. Hydrodynamic exclusion results from maintenance of a low through-slot velocity, which, because of the screen's cylindrical configuration, is quickly dissipated, thereby allowing organisms to escape the flow field (Weisberd et al, 1984). The screens can be fine or wide mesh. The name of these screens arise from the triangular or "wedge" cross section of the wire that makes up the screen. The screen is composed of wedgewire loops welded at the apex of their triangular cross section to supporting axial rods presenting the base of the cross section to the incoming flow (Pagano et al, 1977). A cylindrical wedgewire screen is shown in the figure below. Wedgewire screens are also called profile screens or Johnson screens.

mitre report

Schematic of Cylindrical Wedgewire Screen (Pagano et al, 1977)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Wide mesh wedgewire screens are used at two large power plants, Eddystone and Campbell. Smaller facilities with wedgewire screens include Logan and Cope with fine mesh and Jeffrey with wide mesh (EPRI 1999).

RESEARCH/OPERATION FINDINGS:

In-situ observations have shown that impingement is virtually eliminated when wedgewire screens are used (Hanson, 1977; Weisberg et al, 1984).

At Campbell Unit 3, impingement of gizzard shad, smelt, yellow perch, alewife, and shiner species is significantly lower than Units 1 and 2 that do not have wedgewire screens (EPRI, 1999).

The cooling water intakes for Eddystone Units 1 and 2 were retrofitted with wedgewire screens because over 3 million fish were reportedly impinged over a 20-month period. The wedgewire screens have generally eliminated impingement at Eddystone (EPRI, 1999).

Laboratory studies (Heuer and Tomljanovitch, 1978) and prototype field studies (Lifton, 1979; Delmarva Power and Light, 1982; Weisberg et al, 1983) have shown that fine mesh wedgewire screens reduce entrainment.

One study (Hanson, 1977) found that entrainment of fish eggs (striped bass), ranging in diameter from 1.8 mm to 3.2 mm, could be eliminated with a cylindrical wedgewire screen incorporating 0.5 mm slot openings. However, striped bass larvae, measuring 5.2 mm to 9.2 mm were generally entrained through a 1 mm slot at a level exceeding 75 percent within one minute of release in the test flume.

At the Logan Generating Station in New Jersey, monitoring shows shows 90 percent less entrainment of larvae and eggs through the 1 mm wedgewire screen then conventional screens. In situ testing of1 and 2-mm wedgewire screens was performed in the St. John River for the Seminole Generating Station Units 1 and 2 in Florida in the late 1970s. This testing showed virtually no impingement and 99 and 62 percent reductions in larvae entrainment for the 1-mm and 2-mm screens, respectively, over conventional screen (9.5 mm) systems (EPRI, 1999).

DESIGN CONSIDERATIONS:

To minimize clogging, the screen should be located in an ambient current of at least 1 feet per second (ft/sec).

A uniform velocity distribution along the screen face is required to minimize the entrapment of motile organisms and to minimize the need of debris backflushing.

In northern latitudes, provisions for the prevention of frazil ice formation on the screens must be considered.

Allowance should be provided below the screens for silt accumulation to avoid blockage of the water flow (Mussalli et al, 1980).

ADVANTAGES:

Wedgewire screens have been demonstrated to reduce impingement and entrainment in laboratory and prototype field studies.

LIMITATIONS:

The physical size of the screening device is limiting in most passive systems, thus, requiring the clustering of a number of screening units. Siltation, biofouling and frazil ice also limit areas where passive screens such as wedgewire can be utilized.

Because of these limitations, wedgewire screens may be more suitable for closed-cycle make-up intakes than once-through systems. Closed-cycle systems require less flow and fewer screens than once-through intakes; back-up conventional screens can therefore be used during maintenance work on the wedge-wire screens (Mussalli et al, 1980).

REFERENCES:

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Weisberg, S.B., F. Jacobs, W.H. Burton, and R.N. Ross. Report on Preliminary Studies Using the Wedge Wire Screen Model Intake Facility. Prepared for State of Maryland, Power Plant Siting Program. Prepared by Martin Marietta Environmental Center, Baltimore, MD. 1983.

Weisberg, S.B., W.H. Burton, E.A., Ross, and F. Jacobs. The effects od Screen Slot Size, Screen Diameter, and Through-Slot Velocity on Entrainment of Estuarine Ichthyoplankton Through Wedge-Wire Screens. Martin Marrietta Environmental Studies, Columbia MD. August 1984.

Passive Intake Systems	Fact Sheet No. 6: Perforated Pipes

DESCRIPTION:

Perforated pipes draw water through perforations or slots in a cylindrical section placed in the waterway. The term "perforated" is applied to round perforations and elongated slots as shown in the figure below. The early technology was not efficient: velocity distribution was poor, it served specifically to screen out detritus, and was not used for fish protection (ASCE, 1982). Inner sleeves have been added to perforated pipes to equalize the velocities entering the outer perforations. Water entering a single perforated pipe intake without an internal sleeve will have a wide range of entrance velocities and the highest will be concentrated at the supply pipe end. These systems have been used at locations requiring small amounts of water such as make-up water. However, experience at steam electric plants is very limited (Sharma, 1978).

(Figure ASCE page 79).

Perforations and Slots in Perforated Pipe (ASCE, 1982)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Nine steam electric units in the U.S. use perforated pipes. Each of these units uses closed-cycle cooling systems with relatively low make-up intake flow ranging from 7 to 36 MGD (EEI, 1993).

RESEARCH/OPERATION FINDINGS:

Maintenance of perforated pipe systems requires control of biofouling and removal of debris from clogged screens.

For withdrawal of relatively small quantities of water, up to 50,000 gpm, the perforated pipe inlet with an internal perforated sleeve offers substantial protection for fish. This particular design serves the Washington Public Power Supply System on the Columbia River (Richards, 1977).

No information is available on the fate of the organisms impinged at the face of such screens.

DESIGN CONSIDERATIONS:

The design of these systems is fairly well established for various water intakes (ASCE, 1982).

ADVANTAGES:

The primary advantage is the absence of a confined channel in which fish might become trapped.

LIMITATIONS:

Clogging, frazil ice formation, biofouling and removal of debris limit this technology to small flow withdrawals.

REFERENCES:

American Society of Civil Engineers. Task Committee on Fish-handling of Intake Structures of the Committee of Hydraulic Structures. Design of Water Intake Structures for Fish Protection. ASCE, New York, N.Y. 1982.

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Passive intake Systems	Fact Sheet No. 7: Porous Dikes/Leaky Dams

DESCRIPTION:

Porous dikes, also known as leaky dams or leaky dikes, are filters resembling a breakwater surrounding a cooling water intake. The core of the dike consists of cobble or gravel, which permits free passage of water. The dike acts both as a physical and a behavioral barrier to aquatic organisms and is depicted in the figure below. The filtering mechanism includes a breakwater or some other type of barrier and the filtering core (Fritz, 1980). Tests conducted to date have indicated that the technology is effective in excluding juvenile and adult fish. However, its effectiveness in screening fish eggs and larvae is not established (ASCE, 1982).

Porous Dike (Schrader and Ketschke, 1978)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Two facilities which are both testing facilities and have used the technology are: the Point Beach Nuclear Plant in Wisconsin and the Baily Generating Station in Indiana (EPRI, 1985). The Brayton Point Generating Station in Massachusetts has also tested the technology.

RESEARCH/OPERATION FINDINGS:

Schrader and Ketschke (1978) studied a porous dike system at the Lakeside Plant on Lake Michigan and found that numerous fish penetrated large void spaces, but for most fish accessibility was limited.

The biological effectiveness of screening of fish larvae and the engineering practicability have not been established (ASCE, 1982).

The size of the pores in the dike dictates the degree of maintenance due to biofouling and clogging by debris.

Ice build-up and frazil ice may create problems as evidenced at the Point Beach Nuclear Plant (EPRI, 1985).

DESIGN CONSIDERATIONS:

The presence of currents past the dike is an important factor which may probably increase biological effectiveness.

The size of pores in the dike determines the extent of biofouling and clogging by debris (Sharma, 1978).

Filtering material must be of a size that permits free passage of water but still prevents entrainment and impingement.

ADVANTAGES:

Dikes can be used at marine, fresh water, and estuarine locations.

LIMITATIONS:

The major problem with porous dikes comes from clogging by debris and silt, and from fouling by colonization of fish and plant life.

Backflushing, which is often used by other systems for debris removal, is not feasible at a dike installation.

Predation of organisms screened at these dikes may offset any biological effectiveness (Sharma, 1978).

REFERENCES:

American Society of Civil Engineers. Task Committee on Fish-handling of Intake Structures of the Committee of Hydraulic Structures. Design of Water Intake Structures for Fish Protection. ASCE, New York, N.Y. 1982.

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Sharma, R.K. "A Synthesis of Views Presented at the Workshop". In Larval Exclusion Systems For Power Plant Cooling Water Intakes. San-Diego, California, February 1978, pp 235-237.

Fish Diversion or Avoidance Systems	Fact Sheet No. 8: Louver Systems

DESCRIPTION:

Louver systems are comprised of a series of vertical panels placed at an angle to the direction of the flow (typically 15 to 20 degrees). Each panel is placed at an angle of 90 degrees to the direction of the flow (Hadderingh, 1979). The louver panels provide an abrupt change in both the flow direction and velocity (see figure below). This creates a barrier, which fish can immediately sense and will avoid. Once the change in flow/velocity is sensed by fish, they typically align with the direction of the current and move away laterally from the turbulence. This behavior further guides fish into a current created by the system, which is parallel to the face of the louvers. This current pulls the fish along the line of the louvers until they enter a fish bypass or other fish handling device at the end of the louver line. The louvers may be either fixed or rotated similar to a traveling screen. Flow straighteners are frequently placed behind the louver systems.

These types of barriers have been very successful and have been installed at numerous irrigation intakes, water diversion projects, and steam electric and hydroelectric facilities. It appears that this technology has, in general, become accepted as a viable option to divert juvenile and adult fish.

Top view of a Louver Barrier with Fish By-Pass (Hadderingh, 1979)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Louver barrier devices have been tested and/or are in use at the following facilities: the California Department of Water Resource's Tracy Pumping Plant; the California Department of Fish and Game's Delta Fish Protective Facility in Bryon; the Conte Anadromous Fish Research Center in Massachusetts, and the San Onofre Nuclear Generating Station in

California (EPA, 1976; EPRI, 1985; EPRI, 1999). In addition, three other plants also have louvers at their facilities: the Ruth Falls Power Plant in Nova Scotia, the Nine Mile Point Nuclear Power Station on Lake Erie, and T.W. Sullivan Hydroelectric Plant in Oregon. Louvers have also been tested at the Ontario Hydro Laboratories in Ontario, Canada (Ray et al, 1976).

RESEARCH/OPERATION FINDINGS:

Research has shown the following generalizations to be true regarding louver barriers:
1) the fish separation performance of the louver barrier decreases with an increase in the velocity of the flow through the barrier; 2) efficiency increases with fish size (EPA, 1976; Hadderingh, 1979); 3) individual louver misalignment has a beneficial effect on the efficiency of the barrier; 4) the use of center walls provides the fish with a guide wall to swim along thereby improving efficiency (EPA, 1976); and 5) the most effective slat spacing and array angle to flow depends upon the size, species and ability of the fish to be diverted (Ray et al, 1976).

In addition, the following conclusions were drawn during specific studies:

- Testing of louvered intake structures offshore was performed at a New York facility. The louvers were spaced 10 inches apart to minimize clogging. The array was angled at 11.5 percent to the flow. Center walls were provided for fish guidance to the bypass. Test species included alewife and rainbow smelt. The mean efficiency predicted was between 22 and 48 percent (Mussalli 1980).

- During testing at the Delta Facility's intake in Byron California, the design flow was 6,000 cubic feet per second (cfs), the approach velocity was 1.5 to 3.5 feet per second (ft/sec), and the bypass velocities were 1.2 to 1.6 times the approach velocity. Efficiencies were found to drop with an increase in velocity through the louvers. For example, at 1.5 to 2 ft/sec the efficiency was 61 percent for 15 millimeter long fish and 95 percent for 40 millimeter fish. At 3.5 ft/sec, the efficiencies were 35 and 70 percent (Ray et al. 1976).

- The efficiency of a louver device is highly dependent upon the length and swimming performance of a fish. Efficiencies of lower than 80 percent have been seen at facilities where fish were less than 1 to 1.6 inches in length (Mussalli, 1980).

- In the 1990s, an experimental louver bypass system was tested at the USGS' Conte Anadromous Fish Research Center in Massachusetts. This testing showed guidance efficiencies for Connecticut River species of 97 percent for a "wide array" of louvers and 100 percent for a "narrow array" (EPRI, 1999).

- At the Tracy Fish Collection Facility located along the San Joaquin River in California, testing was performed from 1993 and 1995 to determine the guidance efficiency of a system with primary and secondary louvers. The results for green and white sturgeon, American shad, splittail, white catfish, delta smelt, Chinook salmon, and striped bass showed mean diversion efficiencies ranging from 63 (splittail) to 89 percent (white catfish) (EPRI, 1999).

- In 1984 at the San Onofre Station, a total of 196,978 fish entered the louver system with 188,583 returned to the waterbody and 8,395 impinged. In 1985, 407,755 entered the louver system with 306,200 returned and 101,555 impinged. Therefore, the guidance efficiencies in 1984 and 1985 were 96 and 75 percent, respectively. However, 96-hour survival rates for some species, i.e., anchovies and croakers, were 50 percent or less. Louvers were originally considered for use at San Onofre because of 1970s pilot testing at the Redondo Beach Station in California where maximum guidance efficiencies of 96-100 percent were observed. (EPRI, 1999)

- At the Maxwell Irrigation Canal in Oregon, louver spacing was 5.0 cm with a 98 percent efficiency of deflecting immature steelhead and above 90 percent efficiency for the same species with a louver spacing of 10.8 cm.

- At the Ruth Falls Power Plant in Nova Scotia, the results of a five-year evaluation for guiding salmon smelts showed that the optimum spacing was to have wide bar spacing at the widest part of the louver with a gradual reduction in the spacing approaching the bypass. The site used a bypass:approach velocity ratio of 1.0 : 1.5 (Ray et al, 1976).

- Coastal species in California were deflected optimally (Schuler and Larson, 1974 in Ray et al, 1976) with 2.5 cm spacing of the louvers, 20 degree louver array to the direction of flow and approach velocities of 0.6 cm per second.

- At the T.W. Sullivan Hydroelectric Plant along the Williamette River in Oregon, the louver system is estimated to be 92 percent effective in diverting spring Chinook, 82 percent for all Chinook, and 85 percent for steelhead. The system has been optimized to reduce fish injuries such that the average injury occurrence is only 0.44 percent (EPRI, 1999).

DESIGN CONSIDERATIONS:

The most important parameters of the design of louver barriers include the following:

- The angle of the louver vanes in relation to the channel velocity ,
- The spacing between the louvers which is related to the size of the fish,
- Ratio of bypass velocity to channel velocity,

- Shape of guide walls,
- Louver array angles, and
- Approach velocities.

Site-specific modeling may be needed to take into account species-specific considerations and optimize the design efficiency (EPA, 1976; O'Keefe, 1978).

ADVANTAGES:

- Louver designs have been shown to be very effective in diverting fish (EPA, 1976).

LIMITATIONS:

- The costs of installing intakes with louvers may be substantially higher than other technologies due to design costs and the precision required during construction.
- Extensive species-specific field testing may be required.
- The shallow angles required for the efficient design of a louver system require a long line of louvers increasing the cost as compared to other systems (Ray et al, 1976).
- Water level changes must be kept to a minimum to maintain the most efficient flow velocity.
- Fish handling devices are needed to take fish away from the louver barrier.
- Louver barriers may, or may not, require additional screening devices for removing solids from the intake waters. If such devices are required, they may add a substantial cost to the system (EPA, 1976).
- Louvers may not be appropriate for offshore intakes (Mussalli, 1980).

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Fish Diversion or Avoidance Systems	Fact Sheet No. 9: Velocity Cap

DESCRIPTION:

A velocity cap is a device that is placed over vertical inlets at offshore intakes (see figure below). This cover converts vertical flow into horizontal flow at the entrance into the intake. The device works on the premise that fish will avoid rapid changes in horizontal flow. Fish do not exhibit this same avoidance behavior to the vertical flow that occurs without the use of such a device. Velocity caps have been implemented at many offshore intakes and have been successful in decreasing the impingement of fish.

Typical Offshore Coling Water Intake Structure with Velocity Caps (Helrey, 1985; ASCE, 1982)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

The available literature (EPA, 1976; Hanson, 1979; and Pagano et al, 1977) states that velocity caps have been installed at offshore intakes in Southern California, the Great Lakes Region, the Pacific Coast, the Caribbean and overseas; however, exact locations are not specified.

Velocity caps are known to have been installed at the El Segundo, Redondo Beach, and Huntington Beach Steam Electric Stations and the San Onofre Nuclear Generation Station in Southern California (Mussalli, 1980; Pagano et al, 1977; EPRI, 1985).

Model tests have been conducted by a New York State Utility (ASCE, 1982) and several facilities have installed velocity caps in the New York State /Great Lakes Area including the Nine Mile Point Nuclear Station, the Oswego Steam Electric Station, and the Kintigh Generating Station (EPRI, 1985).

Additional known facilities with velocity caps include the Edgewater Generation Station in Wisconsin, the Seabrook Power Plant in New Hampshire, and the Nanticoke Thermal Generating Station in Ontario, Canada (EPRI, 1985).

RESEARCH/OPERATION FINDINGS:

- Horizontal velocities within a range of 0.5 to 1.5 feet per second (ft/sec) did not significantly affect the efficiency of a velocity cap tested at a New York facility; however, this design velocity may be specific to the species present at that site (ASCE, 1982).

- Preliminary decreases in fish entrapment averaging 80 to 90 percent were seen at the El Segundo and Huntington Beach Steam Electric Plants (Mussalli, 1980).

- Performance of the velocity cap may be associated with cap design and the total volumes of water flowing into the cap rather than to the critical velocity threshold of the cap (Mussalli, 1980).

DESIGN CONSIDERATIONS:

- Designs with rims around the cap edge prevent water from sweeping around the edge causing turbulence and high velocities, thereby providing more uniform horizontal flows (EPA, 1976; Mussalli, 1980).

- Site-specific testing should be conducted to determine appropriate velocities to minimize entrainment of particular species in the intake (ASCE, 1982).

- Most structures are sized to achieve a low intake velocity between 0.5 and 1.5 ft/sec to lessen the chances of entrainment (ASCE, 1982).

- Design criteria developed for a model test conducted by Southern California Edison Company used a velocity through the cap of 0.5 to 1.5 ft/sec; the ratio of the dimension of the rim to the height of the intake areas was 1.5 to 1 (ASCE, 1982; Schuler, 1975).

ADVANTAGES:

- Efficiencies of velocity caps on West Coast offshore intakes have exceeded 90 percent (ASCE, 1982).

LIMITATIONS:

- Velocity caps are difficult to inspect due to their location under water (EPA, 1976).
- In some studies, the velocity cap only minimized the entrainment of fish and did not eliminate it. Therefore, additional fish recovery devices are be needed in when using such systems (ASCE,.1982; Mussalli, 1980).
- Velocity caps are ineffective in preventing passage of non-motile organisms and early life stage fish (Mussalli, 1980).

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Fish Diversion or Avoidance Systems	Fact Sheet No. 10: Fish Barrier Nets

DESCRIPTION:

Fish barrier nets are wide mesh nets, which are placed in front of the entrance to an intake structure (see figure below). The size of the mesh needed is a function of the species that are present at a particular site. Fish barrier nets have been used at numerous facilities and lend themselves to intakes where the seasonal migration of fish and other organisms require fish diversion facilities for only specific times of the year.

V-Arrangement of Fish Barrier Net (ASCE, 1982)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

The Bowline Point Generating Station, the J.P. Pulliam Power Plant in Wisconsin, the Ludington Storage Plant in Michigan, and the Nanticoke Thermal Generating Station in Ontario use barrier nets (EPRI, 1999).

Barrier Nets have been tested at the Detroit Edison Monroe Plant on Lake Erie and the Chalk Point Station on the Patuxent River in Maryland (ASCE, 1982; EPRI, 1985). The Chalk Point Station now uses barrier nets seasonally to reduce fish and Blue Crab entry into the intake canal (EPRI, 1985). The Pickering Generation Station in Ontario evaluated rope nets in 1981 illuminated by strobe lights (EPRI, 1985).

RESEARCH/OPERATION FINDINGS:

- At the Bowline Point Generating Station in New York, good results (91 percent impingement reductions) have been realized with a net placed in a V arrangement around the intake structure (ASCE, 1982; EPRI, 1999).

- In 1980, a barrier net was installed at the J.R. Whiting Plant (Michigan) to protect Maumee Bay. Prior to net installation, 17,378,518 fish were impinged on conventional traveling screens. With the net, sampling in 1983 and 84 showed 421,978 fish impinged (97 percent effective), sampling in 1987 showed 82,872 fish impinged (99 percent effective), and sampling in 1991 showed 316,575 fish impinged (98 percent effective) (EPRI, 1999).

- Nets tested with high intake velocities (greater than 1.3 feet per second) at the Monroe Plant have clogged and subsequentially collapsed. This has not occurred at facilities where the velocities are 0.4 to 0.5 feet per second (ASCE, 1982).

- Barrier nets at the Nanticoke Thermal Generating Station in Ontario reduced intake of fish by 50 percent (EPRI, 1985).

- The J.P Pulliam Generating Station in Wisconsin uses dual barrier nets (0.64 centimeters stretch mesh) to permit net rotation for cleaning. Nets are used from April to December or when water temperatures go above 4 degrees Celsius. Impingement has been reduced by as much as 90 percent. Operating costs run about $5,000 per year, and nets are replaced every two years at $2,500 per net (EPRI, 1985).

- The Chalk Point Station in Maryland realized operational costs of $5,000-10,000 per year with the nets being replaced every two years (EPRI, 1985). However, crab impingement has been reduced by 84 percent and overall impingrment liability has been reduced from $2 million to $140,000 (EPRI, 1999).

- The Ludington Storage Plant (Michigan) provides water from Lake Michigan to a number of power plant facilities. The plant has a 2.5-mile long barrier net that has successfully reduced impingement and entrainment. The overall net effectiveness for target species (five salmonids, yellow perch, rainbow smelt, alewife, and chub) has been over 80 percent since 1991 and 96 percent since 1995. The net is deployed from mid-April to mid-October, with storms and icing preventing use during the remainder of the year (EPRI, 1999).

DESIGN CONSIDERATIONS:

- The most important factors to consider in the design of a net barrier are the site-specific velocities and the potential for clogging with debris (ASCE, 1982).

- The size of the mesh must permit effective operations, without excessive clogging. Designs at the Bowline Point Station in New York have 0.15 and 0.2 inch openings in the mesh nets, while the J.P. Pulliam Plant in Wisconsin has 0.25 inch openings (ASCE, 1982).

ADVANTAGES:

- Net barriers, if operating properly, should require very little maintenance.
- Net barriers have relatively little cost associated with them.

LIMITATIONS:

- Net barriers are not effective for the protection of the early life stages of fish or zooplankton (ASCE, 1982).

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Fish Diversion or Avoidance Systems	Fact Sheet No. 11: Aquatic Filter Barrier Systems

DESCRIPTION:

Aquatic filter barrier systems are barriers that employ a filter fabric designed to allow for passage of water into a cooling water intake structure, but exclude aquatic organisms. These systems are designed to be placed some distance from the cooling water intake structure within the source waterbody and act as a filter for the water that enters into the cooling water system. These systems may be floating, flexible, or fixed. Since these systems generally have such a large surface area, the velocities that are maintained at the face of the permeable curtain are very low. One company, Gunderboom, Inc., has a patented full-water-depth filter curtain comprised of polyethylene or polypropylene fabric that is suspended by flotation billets at the surface of the water and anchored to the substrate below. The curtain fabric is manufactured as a matting of minute unwoven fibers with an apparent opening size of 20 microns. The Gunderboom Marine/Aquatic Life Exclusion System (MLES)™ also employs an automated "air burst"™ technology to periodically shake the material and pass air bubbles through the curtain system to clean it of sediment buildup and release any other material back in to the water column.

Gunderboom Marine/Aquatic Life Exclusion System (Gunderboom, Inc., 1999)

TESTING FACILITIES AND/OR FACILITIES USING THE TECHNOLOGY:

Gunderboom MLES ™ have been tested and are currently installed on a seasonal basis at Unit 3 of the Lovett Station in New York. Prototype testing of the Gunderboom system began in 1994 as a means of lowering ichthyoplankton entrainment at Unit 3. This was the first use of the technology at a cooling water intake structure. The Gunderboom tested was a single layer fabric. Material clogging resulted in loss of filtration capacity and boom submergence within 12 hours of deployment. Ichthyoplankton monitoring while the boom was intact indicated an 80 percent reduction in entrainable organisms (Lawler, Matusky, and Skelly Engineers, 1996).

A Gunderboom MLES ™ was effectively deployed at the Lovett Station for 43 days in June and July of 1998 using an Air-Burst cleaning system and newly designed deadweight anchoring system. The cleaning system coupled with a perforated material proved effective at limiting sediment on the boom, however it required an intensive operational schedule (Lawler, Matusky, and Skelly Engineers, 1998).

A 1999 study was performed on the Gunderboom MLES ™ at the Lovett Station in New York to qualitatively determine the characteristics of the fabric with respect to the impingement of ichthyoplankton at various flow regimes. Conclusions were that the viability of striped bass eggs and larvae were not affected (Lawler, Matusky, and Skelly Engineers, 1999).

Ichthyoplankton sampling at Unit 3 (with Gunderboom MLES ™ deployed) and Unit 4 (without Gunderboom) in May through August 2000 showed an overall effectiveness of approximately 80 percent. For juvenile fish, the density at Unit 3 was 58 percent lower. For post yolk-sac larvae, densities were 76 percent lower. For yolk-sac larvae, densities were 87 percent lower (Lawler, Matusky & Skelly Engineers 2000).

RESEARCH/OPERATION FINDINGS:

Extensive testing of the Gunderboom MLES ™ has been performed at the Lovett Station in New York. Anchoring, material, cleaning, and monitoring systems have all been redesigned to meet the site-specific conditions in the waterbody and to optimize the operations of the Gunderboom. Although this technology has been implemented at only one cooling water intake structure, it appears to be a promising technology to reduce impingement and entrainment impacts. It is also being evaluated for use at the Contre Costa Power Plant in California.

DESIGN CONSIDERATIONS:

The most important parameters in the design of a Gunderboom ® Marine/Aquatic Life Exclusion System include the following (Gunderboom, Inc. 1999):

- Size of booms designed for 3-5 gpm per square foot of submerged fabric. Flows greater than 10-12 gallons per minute.
- Flow-through velocity is approximately 0.02 ft/s.
- Performance monitoring and regular maintenance.

ADVANTAGES:

- Can be used in all waterbody types.
- All larger and nearly all other organisms can swim away from the barrier because of low velocities.
- Little damage is caused to fish eggs and larvae if they are drawn up against the fabric.
- Modulized panels may easily be replaced.
- Easily deployed for seasonal use.
- Biofouling not significant.
- Impinged organisms released back into the waterbody.
- Benefits relative to cost appear to be very promising, but remain unproven to date.
- Installation can occur with no or minimal plant shutdown.

LIMITATIONS:

- Currently only a proven technology for this application at one facility.
- Extensive waterbody-specific field testing may be required.
- May not be appropriate for conditions with large fluctuations in ambient flow and heavy currents and wave action.
- High level of maintenance and monitoring required.
- Higher flow facilities may require very large surface areas; could interfere with other waterbody uses.

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Fish Diversion or Avoidance Systems	Fact Sheet No. 12: Sound Barriers

DESCRIPTION:

Sound barriers are non-contact barriers that rely on mechanical or electronic equipment that generates various sound patterns to elicit avoidance responses in fish. Acoustic barriers are used to deter fish from entering industrial water intakes and power plant turbines. Historically, the most widely-used acoustical barrier is a pneumatic air gun or "popper." The pneumatic air gun is a modified seismic device which produces high-amplitude, low-frequency sounds to exclude fish. Closely related devices include "fishdrones" and "fishpulsers" (also called "hammers"). The fishdrone produces a wider range of sound frequencies and amplitudes than the popper. The fishpulser produces a repetitive sharp hammering sound of low-frequency and high-amplitude. Both instruments have ahd limited effectiveness in the field (EPRI, 1995; EPRI, 1989; Hanson, et al., 1977; EPA, 1976; Taft, et al., 1988; ASCE, 1992).

Researchers have generally been unable to demonstrate or apply acoustic barriers as fish deterrents, even though fish studies showed that fish respond to sound, because the response varies as a function of fish species, age, and size as well as environmental factors at specific locations. Fish may also acclimate to the sound patterns used (EPA, 1976; Taft et al., 1988; EPRI, 1995; Ray at al., 1976; Hadderingh, 1979; Hanson et al., 1977; ASCE, 1982).

Since about 1989, the application of highly refined sound generation equipment originally developed for military use (e.g., sonar in submarines) has greatly advanced acoustic barrier technology. Ibis technology has the ability to generate a wide array of frequencies, patterns, and volumes, which are monitored and controlled by computer. Video and computer monitoring provide immediate feedback on the effectiveness of an experimental sound pattern at a given location. In a particular environment, background sounds can be accounted for, target fish species or fish populations can quickly be characterized, and the most effective sound pattern can be selected (Menezes, at al., 1991; Sonalysts, Inc.).

TESTING FACILITIES AND/OR FACILITIES WITH TECHNOLOGY IN USE:

No fishpulsers and pneumatic air guns are currently in use at power plant water intakes.

Research facilities that have completed studies or have on-going testing involving fishpulsers or pneumatic air guns include the Ludington Storage Plant on Lake Michigan; Nova Scotia Power; the Hells Gate Hydroelectric Station on the Black River; the Annapolis Generating Station on the Bay of Fundy; Ontario Hydro's Pickering Nuclear Generating station; the Roseton Generating Station in New York; the Seton Hydroelectric Station in British Columbia; the Surry Power Plant in Virginia; the Indian Point Nuclear Generating Station Unit 3 in New York; and the U.S. Army Corps of Engineers on the Savannah River (EPRI, 1985; EPRI, 1989; EPRI, 1988; and Taft, et al., 1998).

Updated acoustic technology developed by Sonalysts, Inc. has been applied at the James A. Fitzpatrick Nuclear Power Plant in New York on Lake Ontario; the Vernon Hydroelectric plant on the Connecticut River (New England Power Company, 1993; Menezes, et al., 1991; personal communication with Sonalysts, Inc., by SAIC, 1993); and in a quarry in Verplank, New York (Dunning, et al., 1993).

RESEARCH/OPERATION FINDINGS:

Most pre-1976 research was related to fish response to sound rather than on field applications of sound barriers (EPA, 1976; Ray et al., 1976; Uziel, 1980; Hanson, et al., 1977).

Before 1986, no acoustic barriers were deemed reliable for field use. Since 1986, several facilities have tried to use pneumatic poppers with limited successes. Even in combination with light barriers and air bubble barriers, poppers and fishpulsers, were ineffective for most intakes (Taft and Downing, 1988; EPRI, 1985; Patrick, et al., 1988; EPRI, 1989; EPRI, 1988; Taft, et al., 1988; McKinley and Patrick, 1998; Chow, 1981).

A 1991 full-scale 4-month demonstration at the James A. FitzPatrick (JAF) Nuclear Power Plant in New York on Lake Ontario showed that the Sonalysts, Inc. FishStartle System reduced alewife impingement by 97 percent as compared to a control power plant located 1 mile away. (Ross, et al., 1993; Menezes, et al., 1991). JAF experienced a 96 percent reduction compared to fish impingement when the acoustic system was not in use. A 1993 3-month test of the system at JAF was reported to be successful, i.e., 85 percent reduction in alewife impingement. (Menezes, et al., 1991; EPRI, 1999).

In tests at the Pickering Station in Ontario, poppers were found to be effective in reducing alewife impingement and entrainment by 73 percent in 1985 and 76 percent in 1986. No benefits were observed for rainbow smelt and gizzard shad. Sound provided little or no deterrence for any species at the Roseton Generating Station in New York.

During marine construction of Boston's third Harbor Tunnel in 1992, the Sonalysts, Inc. FishStartle System was used to prevent shad, blueback herring, and alewives from entering underwater blasting areas during the fishes' annual spring migration. The portable system was used prior to each blast to temporarily deter fish and allow periods of blastmg as necessary for the construction of the tunnel (personal communication to SAIC from M. Curtin, Sonalysts, Inc., September 17, 1993).

In fall 1992, the Sonalysts, Inc. FishStartle System was tested in a series of experiments conducted at the Vernon Hydroelectric plant on the Connecticut River. Caged juvenile shad were exposed to various acoustical signals to see which signals elicited the strongest reactions. Successful in situ tests involved applying the signals with a transducer system to divert juvenile shad from the forebay to a bypass pipe. Shad exhibited consistent avoidance reactions to the signals and did not show evidence of acclimation to the source (New England Power Company, 1993).

DESIGN CONSIDERATIONS:

Sonalysts Inc.'s FishStartle system uses frequencies between 15 hertz to130 kilohertz at sound pressure levels ranging from 130 to 206+ decibels referenced to one micropascal (dB//uPa). To develop a site-specific FishStartle program, a test program using frequencies in the low frequency portion of the spectrum between 25 and 3300 herz were used. Fish species tested by Sonalysts, Inc. include white perch, striped bass, atlantic tomcod, spottail shiner, and golden shiner (Menezes et al., 1991).

Sonalysts' FishStartle system used fixed programming contained on Erasable Programmable Read Only Memory (EPROM) micro circuitry. For field applications, a system was developed using IBM PC compatible software. Sonalysts' FishStartle system includes a power source, power amplifiers, computer controls and analyzer in a control room, all of which are connected to a noise hydrophone in the water. The system also uses a television monitor and camera controller that is linked to an underwater light and camera to count fish and evaluate their behavior.

One Sonalysts, Inc. system has transducers placed 5 m from the bar rack of the intake.

At the Seton Hydroelectric Station in British Columbia, the distance from the water intake to the fishpulser was 350 m (1150 ft); at Hells Gate, a fishpulser was installed at a distance of 500 feet from the intake.

The pneumatic gun evaluated at the Roseton intake had a 16.4 cubic cm (1.0 cubic inch) chamber connected by a high pressure hose and pipe assembly to an Air Power Supply Model APS-F2-25 air compressor. The pressure used was a line pressure of 20.7 MPa (3000 psi) (EPRI, 1988).

ADVANTAGES:

The pneumatic air gun, hammer, and fishpulser are easily implemented at low costs.

Behavioral barriers do not require physical handling of the fish.

LIMITATIONS:

The pneumatic air gun, hammer, and fishpulser are not considered reliable.

Sophisticated acoustic sound generating system require relatively expensive systems, including cameras, sound generating systems, and control systems. No cost information is available since a permanent system has yet to be installed.

Sound barrier systems require site-specific designs consisting of relatively high technology equipment that must be maintained at the site.

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Chapter 6: Industry Profile: Oil and Gas Extraction Industry

INTRODUCTION

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The oil and gas industry uses non-contact, once-through water to cool crude oil, produced water, power generators, and various other pieces of machinery at oil and gas extraction facilities.[1] EPA did not consider oil and gas extraction facilities in the Phase I 316(b) rulemaking.

The Phase I proposal and its record included no analysis of issues associated with offshore and coastal oil and gas extraction facilities (such as significant space limitations on mobile drilling platforms and ships) that could significantly increase the costs and economic impacts and affect the technical feasibility of complying with the proposed requirements for land-based industrial operations. Additionally, EPA believes it is not appropriate to include these facilities in the Phase II regulations scheduled for proposal in February 2002; the Phase II regulations are intended to address the largest existing facilities in the steam-electric generating industry. During Phase III, EPA will address cooling water intake structures at existing facilities in a variety of industry sectors. Therefore, EPA believes it is most appropriate to defer rulemaking for offshore and coastal oil and gas extraction facilities to Phase III.

This chapter provides a starting point for future discussions with industry and other stakeholders on future Phase III regulatory decisions.

6.1 HISTORIC AND PROJECTED DRILLING ACTIVITIES

The oil and gas extraction industry drills wells both onshore, coastal, and offshore regions for the exploration and development of oil and natural gas. Various engines and brakes are employed which require some type of cooling system. The U.S. oil and gas extraction industry currently produces over 60 billion cubic feet of natural gas and over 9 million barrels of oil per day.[2] There were roughly 1,096 onshore drilling rigs in operation in August 2001.[3] This section focuses on the OCS oil and gas extraction activities as onshore facilities have less demand for cooling water and have more available options for using dry cooling systems. Moreover, OCS facilities are limited in physical space, payload capacity, and operating environments. EPA will further investigate onshore oil and gas extraction facilities for the Phase III rulemaking.

A large majority of the OCS oil and gas extraction occurs in the Gulf of Mexico (GOM). The Federal OCS generally starts three miles from shore and extends out to the outer territorial boundary (about 200 miles).[†] The U.S. Department of Interior's Mineral Management Service (MMS) is the Federal agency responsible for managing OCS mineral resources. The following summary statistics are from the 1999 MMS factbook.[2]

> The OCS accounts for about 27% of the Nation's domestic natural gas production and about 20% of its domestic oil production. On an energy basis (BTU), about 67 percent of the energy currently produced offshore is natural gas.
>
> The OCS contains about 19% of the Nation's proven natural gas reserves and 15% of its proven oil reserves. The OCS is estimated to contain more than 50% of the Nation's remaining undiscovered natural gas and oil resources.
>
> To date, the OCS has produced about 131 trillion cubic feet of natural gas and about 12 billion barrels of oil. The Federal OCS provides the bulk—about 89%—of all U.S. offshore production. Five coastal States—Alaska, Alabama, California, Louisiana and Texas—make up the remaining 11%.

Table 1 presents the number of wells drilled in three areas (GOM, Offshore California, and Coastal Cook Inlet, Alaska) for 1995 through 1997. The table also separates the wells into four categories: shallow water development, shallow water exploratory, deep water development, and deep water exploratory. Exploratory drilling includes those operations drilling wells to determine potential hydrocarbon reserves. Development drilling includes those operations drilling production wells once a hydrocarbon reserve has been discovered and delineated. Although the rigs used in exploratory and development drilling sometimes differ, the drilling process is generally the same for both types of drilling operations.

The water depth in which either exploratory or development drilling occurs may determine the operator's choice of drill rigs and drilling systems. MMS and the drilling industry classify wells as located in either deep water or shallow water, depending on whether drilling is in water depths greater than 1,000 feet or less than 1,000 feet, respectively.

[†]The Federal OCS starts approximately 10 miles from the Florida and Texas shores.

Table 6-1: Number of Wells Drilled Annually, 1995 - 1997, by Geographic Area					
Data Source	**Shallow Water (<1,000 ft)**		**Deep Water (≥ 1,000 ft)**		**Total Wells**
	Development	**Exploration**	**Development**	**Exploration**	
Gulf of Mexico†					
MMS: 1995	557	314	32	52	975
1996	617	348	42	73	1,080
1997	726	403	69	104	1,302
Average Annual	640	355	48	76	1,119
RRC	5	3	NA	NA	8
Total Gulf of Mexico	645	358	48	76	1,127
Offshore California					
MMS: 1995	4	0	15	0	19
1996	15	0	16	0	31
1997	14	0	14	0	28
Average Annual	11	0	15	0	26
Coastal Cook Inlet					
AOGC: 1995	12	0	0	0	12
1996	5	1	0	0	6
1997	5	2	0	0	7
Average Annual	7	1	0	0	8

Source: Ref. 4

† Note: GOM figures do not include wells within State bay and inlet waters (considered "coastal" under 40 CFR 435) and State offshore waters (0-3 miles from shore). In August 2001, there were 1 and 23 drilling rigs in State bay and inlet waters of Texas and Louisiana, respectively. There were also 19 and 112 drilling rigs in State offshore waters (0-3 miles from shore), respectively.[3]

Offshore production in the Gulf of Mexico began in 1949 with a shallow well drilled in shallow water. It took another 25 years until the first deepwater well (1,000 ft. of water) was drilled in 1974. Barriers to deepwater activity include technological difficulties of stabilizing a drilling rig in the open ocean, high financial costs, and natural and manmade barriers to oil and gas activities in the deep waters.

These barriers have been offset in recent years by technological developments (e.g., 3-D seismic data covering large areas of the deepwater Gulf and innovative structure designs) and economic incentives. As a result, deepwater oil and gas activity in the Gulf of Mexico has dramatically increased from 1992 to 1999. In fact, in late 1999, oil production from deepwater wells surpassed that produced from shallow water wells for the first time in the history of oil production in the Gulf of Mexico.[5]

As shown in Table 1, 1,127 wells were drilled in the Gulf of Mexico, on average, from 1995 to 1997, compared to 26 wells in California and 8 wells in Cook Inlet. In the Gulf of Mexico, over the last few years, there has been high growth in the number of wells drilled in deep water, defined as water greater than 1,000 feet deep. For example, in 1995, 84 wells were drilled in deep water, or 8.6 percent of all Gulf of Mexico wells drilled that year. By 1997, that number increased to 173 wells drilled, or over 13 percent of all Gulf of Mexico wells drilled. Nearly all exploration and development activities in the Gulf are taking place in the Western Gulf of Mexico, that is, the regions off the Texas and Louisiana shores.

6.2 OFFSHORE AND COASTAL OIL AND GAS EXTRACTION FACILITIES

There are numerous different types of offshore and coastal oil extraction facilities. Some facilities are fixed for development drilling while other facilities are mobile for both exploration and development drilling. Previous EPA estimates of non-contact cooling water for offshore and coastal oil and gas extraction facilities (OCOGEF) showed a wide range of cooling water demands (294 - 5,208,000 gal/day).[1]

6.2.1 Fixed Oil and Gas Extraction Facilities

Most of these structures use a pipe with passive screens (strainers) to convey cooling water. Non-contact, once-through water is used to cool crude oil, produced water, power generators and various other pieces of machinery (e.g., drawworks brakes). Due to the number of oil and gas extraction facilities in the GOM in relation to other OCS regions, EPA estimated the number of fixed active platforms in the Federal OCS region of the Gulf of Mexico using the MMS Platform Inspection System, Complex/Structure database. These fixed structures are generally used for development drilling. Out of a total of 5,026 structures, EPA identified 2,381 active platforms where drilling is likely to occur (Table 2).

Table 6-2: Identification of Structures in the Gulf of Mexico OCS

Category	Count	Remaining Count
All Structures	5,026	5,026
Abandoned Structures	1,403	3,623
Structures classified as production structures, i.e., with no well slots and production equipment	245	3,378
Structures known not to be in production	688	2,690
Structures with missing information on product type (oil or gas or both)	309	2,381
Structures whose drilled well slots are used solely for injection, disposal, or as a water source	0	2,381

Source: Ref. 5

The Offshore Operators Committee (OOC) and the National Oceans Industries Association (NOIA) also noted in their comments to the May 25, 2001 316(b) Federal Register Notice that a typical platform rig for a Tension Leg Platform[††] will require 10 - 15 MM Btu/hr heat removal for its engines and 3 - 6 MM Btu/hr heat removal for the drawworks brake. The total heat removal (cooling capacity) is 13 - 21 MM Btu/hr. OOC/NOIA also estimated that approximately 200 production facilities have seawater intake requirements that exceed 2 MGD. OOC/NOIA estimate that these facilities have seawater intake requirements ranging from 2 - 10 MGD with one-third or more of the volume needed for cooling water. Other seawater intake requirements include firewater and ballasting. The firewater system on offshore platforms must maintain a positive pressure at all times and therefore requires the

[††] A Tension Leg Platform (TLP) is a fixed production facilities in deepwater environments (> 1,000 ft).

firewater pumps in the deep well casings to run continuously. Ballasting water for floating facilities may not be a continuous flow but is an essential intake to maintain the stability of the facility.

EPA and MMS could only identify one case where the environmental impacts of a fixed OCOGEF CWIS were considered.[6] BP Exploration (Alaska) Inc. (BPXA) plans to locate a vertical intake pipe for a seawater-treatment plant on the south side of Liberty Island, Beaufort Sea, Alaska. The pipe would have an opening 8 feet by 5.67 feet and would be located approximately 7.5 feet below the mean low-water level (Fig. 6-1). The discharge from the continuous flush system consists of the seawater that would be continuously pumped through the process-water system to prevent ice formation and blockage. Recirculation pipes located just inside the opening would help keep large fish, other animals, and debris out of the intake. Two vertically parallel screens (6 inches apart) would be located in the intake pipe above the intake opening. They would have a mesh size of 1 inch by 1/4 inch. Maximum water velocity would be 0.29 feet per second at the first screen and 0.33 feet per second at the second screen. These velocities typically would occur only for a few hours each week while testing the fire-control water system. At other times, the velocities would be considerably lower. Periodically, the screens would be removed, cleaned, and replaced.

MMS states in the Liberty Draft Environmental Impact Statement that the proposed seawater-intake structure will likely harm or kill some young-of-the-year arctic cisco during the summer migration period and some eggs and fry of other species in the immediate vicinity of the intake. However, MMS estimates that less than 1% of the arctic cisco in the Liberty area are likely to be harmed or killed by the intake structure. Further, MMS concludes that: (1) the intake structure is not expected to have a measurable effect on young-of-the-year arctic cisco in the migration corridor; and (2) the intake structure is not expected to have a measurable effect on other fishes populations because of the wide distribution/low density of their eggs and fry.

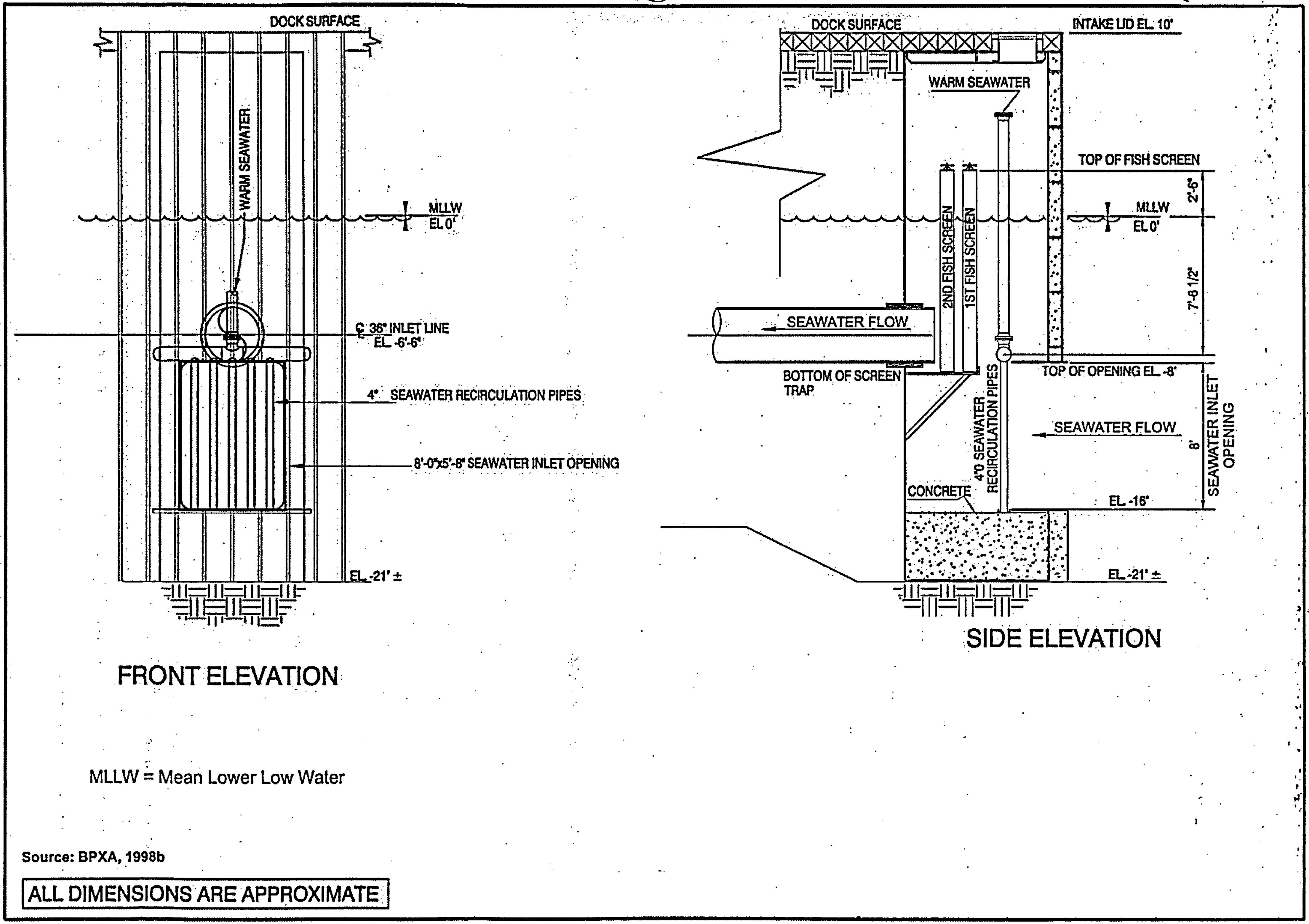

Figure III.D-1 Liberty Development Project: Seawater Intake Detail

6.2.2 Mobile Oil and Gas Extraction Facilities

EPA also estimated the number of mobile offshore drilling units (MODUs) currently in operation. These numbers change in response to market demands. Over the past five years the total number of mobile offshore drilling units (MODUs) operating at one time in areas under U.S. jurisdiction has ranged from less than 100 to more than 200. There are five main types of MODUs operating in areas under U.S. jurisdiction: drillships, semi-submersibles, jack-ups, submersibles and drilling barges. Table 3 gives a brief summary of each MODU. EPA and MMS could not identify any cases where the environmental impacts of a MODU CWIS were considered.

Table 6-3: Description of Mobile Offshore Drilling Units and their CWIS

MODU Type	Water Intake† and Design	Water Depth	No. Currently in GOM	No. Currently Under Construction Over Next Three Years
Drill Ships	16 - 20 MGD Seachest	Greater than 400 ft	5	0.
Semi-submersibles	2 - 15+ MGD Seachest	Greater than 400 ft	37	5
Jack-ups	2 - 10+ MGD Intake Pipe	Less than 400 ft	140	9
Submersibles	< 2 MGD Intake Pipe	Shallow Water (Bays and Inlet Waters)	6	0
Drill Barges	< 2 MGD Intake Pipe	Shallow Water (Bays and Inlet Waters)	20	0

Sources: Ref. 7, Ref. 8, Ref. 9, Ref. 10

† Approximately 80% of the water intake is used for cooling water with the remainder being used for hotel loads, fire water testing, cleaning, and ballast water.[7]

The particular type of MODU selected for operation at a specific location is governed primarily by water depth (which may be controlling), anticipated environmental conditions, and the design (depth, wellbore diameter, and pressure) of the well in relation to the units equipment. In general, deeper water depths or deeper wells demand units with a higher peak power-generation and drawworks brake cooling capacities, and this directly impacts the demand for cooling water.[10]

Drillships and Semi-Submersibles MODUs

Drill ships and semi-submersibles use a "seachest" as a CWIS. In general there are three pipes for each sea chest (these include CWIs and fire pumps). One of the three intake pipes is always set aside for use solely for emergency fire fighting operations. These pipes are usually back on the flush line of the sea chest. The sea chest is a cavity in the hull or pontoon of the MODU and is exposed to the ocean with a passive screen (strainer) often set along the flush line of the sea chest. These passive screens or weirs generally have a maximum opening of 1 inch.[9] There are generally two sea chests for each drill ship or semi-submersible (port and starboard) for redundancy and ship stability considerations. In general, only one seachest is required at any given time for drilling operations.[7]

While engaged in drilling operations most drillships and one-third of semi-submersibles maintain their position over the well by means of "dynamic positioning" thrusters which counter the effects of wind and current. Additional power is required to operate the drilling and associated industrial machinery, which is most often powered electrically from the same diesel generators that supply propulsion power. While the equipment powered by the ship's electrical generating system changes, the total power requirements for drillships are similar to those while in transit. Thus, during drilling operations the total seawater intake on a drillship is approximately the same as while underway. The majority of semi-submersibles are not self- propelled, and thus require the assistance of towing vessels to move from location to location.

Information from the U.S. Coast Guard indicates that when semi-submersibles are drilling their sea chests are 80 to 100 feet below the water surface and are less than 20 feet below water when the pontoons are raised for transit or screen cleaning operations.[7] Drill ships have their sea chests on the bottom of their hulls and are typically 20 to 40 feet below water at all times.

IADC notes that one of the earlier semi-submersible designs still in use is the "victory" class unit.[10] This unit is provided with two seawater-cooling pumps, each with a design capacity of 2.3 MGD with a 300 head. At operating draft the center of the inlet, measuring approximately 4 feet by 6 feet, is located 80 feet below the sea surface and is covered by an inlet screen. In the original design this screen had 3024 holes of 15mm diameter. The approximate inlet velocity is therefore 0.9 feet/sec.

The more recent semi-submersible designs typically have higher installed power to meet the challenges of operating in deeper water, harsher environmental condition, or for propulsion or positioning. IADC notes that a new design, newly-built unit has a seawater intake capacity of 34.8 MGD (including salt water service pumps and ballast pumps) and averages 10.7 MGD of seawater intake of which 7.4 MGD is used for cooling water.

Jack-up MODUs

Jack-up, submersibles, and drill barges use intake pipes for CWIS. These OCOGEF basically use a pipe with a passive screens (strainers) to convey cooling water. Non-contact, once-through water is used to cool crude oil, produced water, power generators and various other pieces of machinery on OCOGEF (e.g., drawworks brakes).

The jack-up is the most numerous type of MODU. These vessels are rarely self- propelled and must be towed from location to location. Once on location, their legs are lowered to the seabed, and the hull is raised (jacked-up) above the sea surface to an elevation that prevents wave impingement with the hull. Although all of these ships do use seawater cooling for some purposes (e.g., desalinators), as with the semi-submersibles a few use air-cooled diesel-electric generators because of the height of the machinery above the sea surface.[9] Seawater is drawn from deep-well or submersible pumps that are lowered far enough below the sea surface to assure that suction is not lost through wave action. Total seawater intake of these ships varies considerably and ranges from less than 2 MGD to more than 10 MGD. Jack-ups are limited to operating in water depths of less than 500 feet, and may rarely operate in water depths of less than 20 feet.

The most widely used of the jack-up unit designs is the Marathon Letourneau 116-C.[10] For these types of jack-ups typically one pump is used during rig operations with a 6" diameter suction at 20 to 50 feet below water level which delivers cooling water intake rates of 1.73 MGD at an inlet velocity of 13.33 ft/sec.[10] Additionally, pre-loading involves the use of two or three pumps in sequence. Pre-loading is not a cooling water procedure, but a ballasting procedure (ballast water is later discharged). Each pump is fitted with its own passive screen (strainer) at the suction point which provides for primary protection against foreign materials entering the system.

In their early configurations, these jack-up MODUs were typically outfitted with either 5 diesel generator units (each rated at about 1,200 horsepower) or three diesel generator units (each rated at about 2,200 horsepower).[10] In subsequent configurations of this design or re-powering of these units, more installed power has generally been provided, as it has in more recent designs. With more installed power, there is a demand for more cooling water. The International Association of Drilling Contractors (IADC) reports that a newly-built jack-up, of a new design, typically requires 3.17 MGD of cooling water for its drawworks brakes and cooling of six diesel generator units, each rated at 1,845 horsepower.[10] In this case, one pump is typically used during rig operations with a 10" diameter suction at 20 to 50 feet below water level, delivering the cooling water at 3.2 MGD.

Submersibles and Drill Barge MODUs

The submersible MODU is used most often in very shallow waters of bays and inlet waters. These MODUs are not self-propelled. Most are powered by air-cooled diesel-electric
generators, but require seawater intake for cooling of other equipment, desalinators, and for other purposes. Total seawater intake varies considerably with most below 2 MGD.

The drilling barge MODU There are approximately 50 drilling barges available for operation in areas under U.S. jurisdiction, although the number currently in operation is less than 20. These ships operate in shallow bays and inlets along the Gulf Coast, and occasionally in shallow offshore areas. Many are powered by air-cooled diesel-electric generators. While they have some water intake for sanitary and some cooling purposes, water intake is generally below 2 MGD.

6.3 316(b) Issues Related to Offshore and Coastal Oil and Gas Extraction Facilities

There are several important 316(b) issues related to OCOGEF CWIS that EPA will be investigating in the Phase III 316(b) rulemaking: (1) Biofouling; (2) Definition of New Source; (3) Potential Costs and Scheduling Impacts. EPA will work with stakeholders to identify other issues for resolution during the Phase III 316(b) rulemaking process.

6.3.1 Biofouling

Industry comments to the 316(b) Phase I proposal assert that operators must maintain a minimum intake velocity of 2 to 5 ft/sec in order to prevent biofouling of the offshore oil and gas extraction facility CWIS. EPA requested documentation from industry regarding the relationship between marine growth (biofouling) and intake velocities.[11] Industry was unable to provide any authoritative information to support the assertion that a minimum intake velocity of 2 to 5 ft/sec is required in order to prevent biofouling of the OCOGEF CWIS. IADC asserts that it is common marine engineering practice to maintain high velocities in the seachest to inhibit attachment of marine biofouling organisms.[10]

The Offshore Operators Committee (OOC) and the National Oceans Industries Association (NOIA) also noted in their comments to the May 25, 2001 316(b) Federal Register Notice that the ASCE "Design of Water Intake Structures for Fish Protection" recommends an approach velocity in the range of 0.5 to 1 ft/s for fish protection and 1 ft/s for debris management but does not address biofouling specifically. OOC/NOIA were unable to find technical papers to support a higher intake velocity. The U.S. Coast Guard and MMS were also unable to provide EPA with any information on velocity requirements or preventative measures regarding marine growth inhibition or has a history of excessive marine growth at the sea chest.

EPA was able to identify some of the major factors affecting marine growth on offshore structures. These factors include temperature, oxygen content, pH, current, turbidity, and light.[12,13] Fouling is particularly troublesome in the more fertile coastal waters, and although it diminishes with distance from the shoreline, it does not disappear in midoceanic and in the abyssal depths.[13] Moreover, operators are required to perform regular inspection and cleaning of these CWIS in accordance with USCG regulations.

Operators are also required by the U.S. Coast Guard to inspect sea chests twice in five years with at least one cleaning to prevent blockages of firewater lines. The requirement to drydock MODUs twice in five years and inspect and clean their sea chests and sea valves are found in U.S. Coast Guard regulations (46 CFR 107.261 and 46 CFR 61.20-5). The U.S. Coast Guard may require the sea chests to be cleaned twice in 5 years at every drydocking if the unit is in an area of high marine growth or has had history of excessive marine growth at the sea chests.

EPA and industry also identified that there are a variety of specialty screens, coatings, or treatments to reduce biofouling. Industry and a technology vendor (Johnson Screens) also identified several technologies currently being used to control biofouling (e.g., air sparing, Ni-Cu alloy materials). Johnson Screens asserted in May 25, 2001 316(b) Federal Register Notice comments to EPA that their copper based material can reduce biofouling in many applications including coastal and offshore drilling facilities in marine environments.

Biocide treatment can also be used to minimize biofouling. IADC reports that one of their members uses Chloropac systems to reduce biofouling (www.elcat.co.uk/chloro_anti_mar.htm). The Liberty Project plans to use chlorine, in the form of calcium hypochlorite, to reduce biofouling. The operator (BPXA) will reduce the total residual chlorine concentration in the discharged cooling water by adding sodium metabisulfate in order to comply with limits of the National Pollution Discharge Elimination System Permit. MMS estimates that the effluent pH will vary slightly from the intake seawater because of the chlorination/dechlorination processes, but this variation is not expected to be more than 0.1 pH units.

In summary, EPA has not yet identified any relationship between the intake velocity and biofouling of a offshore oil and gas extraction facility CWIS. However, EPA will be pursuing this and other matters related to biofouling in the offshore oil and gas industry in the Phase III 316(b) regulation.

6.3.2 Definition of New Source

Industry claimed in comments to the Phase I 316(b) proposal and the May 25, 2001 316(b) Federal Register Notice that existing MODUs could be considered "new sources" when they drill new development wells under 40 CFR 435.11 (exploration facilities are excluded from the definition of new sources). EPA will work with stakeholders to clarify the regulatory status of existing MODUs in the Phase III 316(b) proposal and final rule.

6.3.3 Potential Costs and Scheduling Impacts

Costs to Retrofit for Velocity Standard

EPA did not identify any additional costs to incorporate the 0.5 fps maximum velocity standard into new designs for future (not yet built) OCOGEF CWIS. Retrofit cost for production facilities will vary depending on the type of cooling water intake structure the facility has in place. The U.S. Coast Guard did not have a good estimate of seachest CWIS retrofit costs but did have a general idea of the work requirements for these potential retrofits.[7] The Coast Guard stated that retrofits for drill ships and semi-submersibles that use seachests as the CWI structure could probably be in the millions of dollars (approximately 8-10 million dollars) and require several weeks to months for drydocking operations. Complicating matters is that there are only a few deepwater drydock harbors capable of handling semi-submersibles. MMS did not have any information on costs and issues relating to retrofitting sea chests or other offshore CWIS.

OOC/NOIA estimated costs for retrofitting a larger intake for a floating production system tension leg platform (TLP).[14] Under their costing scenario, it was assumed that the TLP had a seachest intake structure with a pre-existing flange on the exterior of the intake structure which could be used to bolt on a larger diameter intake in order to reduce the intake velocity to below 0.5 ft/s. The estimated cost to retrofit this new intake is $75,000. OOC/NOIA estimates that this same cost can be assumed for retrofiting a deep well pump casing with a larger diameter intake provided the bottom of the casing is not obstructed and the intake structure can be clamped over the casing.

OOC/NOIA further estimates that for TLP's with seachests without a pre-existing flange for an intake structure and for deep well pump casings that are obstructed and prevent the installation of an intake structure, the retrofit costs are estimated to be much higher.[14] OOC/NOIA estimates that if underwater welding or the installation of new pump casing are required, the costs can be as high as $500,000. In these cases, the platform would need to be shut-in for some period of time (1-3 days) to allow for this installation. Included in this estimate is the need to provide for additional stiffening of underwater legs and supports to resist the wave loading forces of the new intake structures. OOC/NOIA estimates that many facilities have multiple deepwell casings or seachests that would require retrofitting.

IADC notes that the feasibility of redesigning seachests to reduce intake velocity would need to be examined on a case-by-case basis.[10] As interior space is typically optimized for the particular machinery installation, IADC further notes that a prerequisite for enlarging any seachest would be repositioning of machinery, piping and electrical systems and that such operations could only be undertaken in a drydock. Seachests on semi-submersible units are not likely located in stress-critical areas, so effective compensation of hull strength is unlikely to be a major concern, unlike a drillship where, depending on the design, it might be difficult to provide effective compensation to hull girder strength for an enlarged seachest

Costs for retro-fitting jack-ups would likely be much less complicated and expensive than semi-submersible and drillship sea chest retro-fits.[7] The U.S. Coast Guard estimates that operators could install a bell or cone intake device on the existing CWIS to reduce CWI velocities. IADC notes that installing passive screens (strainers) with a larger surface area on jack-up CWIS in order to reduce the intake velocity at the face of the screen would add weight and pose handling problems (e.g., require more frequent cleaning).

Costs to Retrofit to Dry Cooling

OOC/NOIA stated in their May 25, 2001 316(b) Federal Register Notice comments that offshore production platforms will typically use direct air cooling or cooling with a closed loop system for cooling requirements where technically feasible. The following items are typically direct air cooled: gas coolers on compressors, lubrication oil coolers on compressors and generators, and hydraulic oil coolers on pumps. These coolers will range from 1 to 35 MM Btu/hr heat removal capacity. Seawater cooling is necessary in many cases because space and weight limitations render air cooling infeasible. This is particularly true for floating production systems which have strict payload limitations.

IADC reports that some jack-up MODUs were converted from sea water cooling systems to closed-loop air cooling systems for engine and drawworks brake cooling.[10] IADC reported the cost of the conversion, completed during a regular shipyard period, was approximately $1.2 million and required a six-month lead-time to obtain the required equipment. The conversion resulted in the loss of deck space associated with the installation of the air-cooling units, and a small loss in variable deck load equal to the additional weight of the air-cooling units and associated piping.

OOC/NOIA provided initial costs to convert from seawater cooling to air cooling with a radiator on a platform rig. In this case, a cantilevered deck was installed onto the side of the pipe rack. The radiator was rated at about 15 MM Btu/hr, and the cost for the installation was about $150,000. The weight of the addition was about 15,000 pounds. The cost of space and payload on an offshore platform is about $5/pound; therefore, the added weight cost about $75,000 bringing the total cost to about $225,000.

EPA agrees with industry that dry cooling systems are most easily installed during planning and construction, but some can be retrofitted with additional costs. IADC believes that it is already difficult to justify such conversions of jack-ups and that it would be far more difficult to justify conversion of drillships or semi-submersibles. EPA will also look at the net gain or loss in the energy efficiency of conversions from wet to dry cooling.

6.3.4 Description of Benefits for Potential 316(b) Controls on Offshore and Coastal Oil and Gas Extraction Facilities

EPA was only able to identify one case where potential impacts to aquatic communities from OCOGEF CWIS were described (MMS Liberty Draft Environmental Impact Statement).[6] MMS estimated that less than 1% of the arctic cisco in the Liberty area are likely to be harmed or killed by the intake structure but that the intake structure is not expected to have a measurable effect on young-of-the-year arctic cisco in the migration corridor or on other fishes populations.

OOC submitted a video tape of three different OCOGEF CWIS as part of their public comments. These CWIS have an intake of 5.9 to 6.3 MGD with a intake velocity of 2.6 to 2.9 ft/s. The intake has a passive screen (strainer) with 1 inch diameter slots. EPA will use this documentation in determining potential impacts on aquatic communities from OCOGEF CWIS.

6.4 Phase III Activities Related to Offshore and Coastal Oil and Gas Extraction Facilities

Numerous researchers and State and Federal regulatory agencies have studied and controlled the discharges from these facilities for decades. The technology-based standards for the discharges from these facilities are located in 40 CFR 435. Conversely, there has been extremely little work done to investigate the environmental impacts or evaluation of the location, design, construction, and capacity characteristics of OCOGEF CWIS that reduce impingement and entrainment of aquatic organisms.

EPA discussions with two main regulatory entities of OCOGEF (i.e., MMS, USCG) identified no regulatory requirements on these OCOGEF CWIS with respect to environmental impacts. MMS generally does not regulate or consider the potential environmental impacts of these OCOGEF CWIS. MMS could only identify one case where the environmental impacts of a OCOGEF CWIS were considered.[6] Moreover, MMS does not collect information on CWI rates, velocities and durations for any OCOGEF CWIS. The U.S. Coast Guard does not investigate potential environmental impacts of MODU CWIS but does require operators to inspect sea chests twice in five years with at least one cleaning to prevent blockages of firewater lines.

EPA will work with industry and other stakeholders to identify all major issues associated with OCOGEF CWIS and potential Phase III 316(b) requirements. EPA will also collect additional data to identify the costs and benefits associated with any regulatory alternative.

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Chart 2-1. Capital Costs of Basic Cooling Towers with Various Building Material (Delta 10 Degrees)

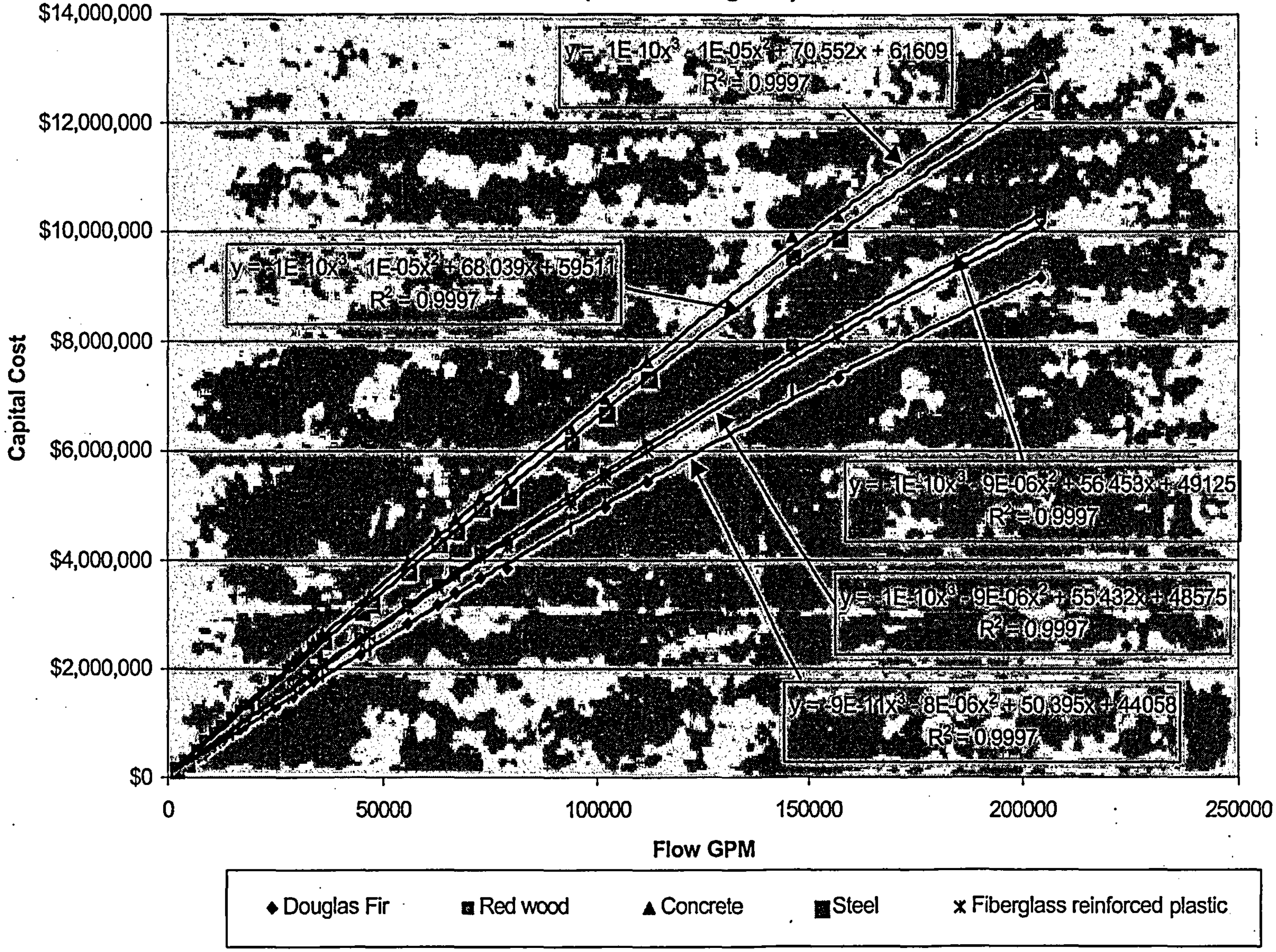


Chart 2-2. Douglas Fir Cooling Tower Capital Costs with Various Features (Delta 10 Degrees)

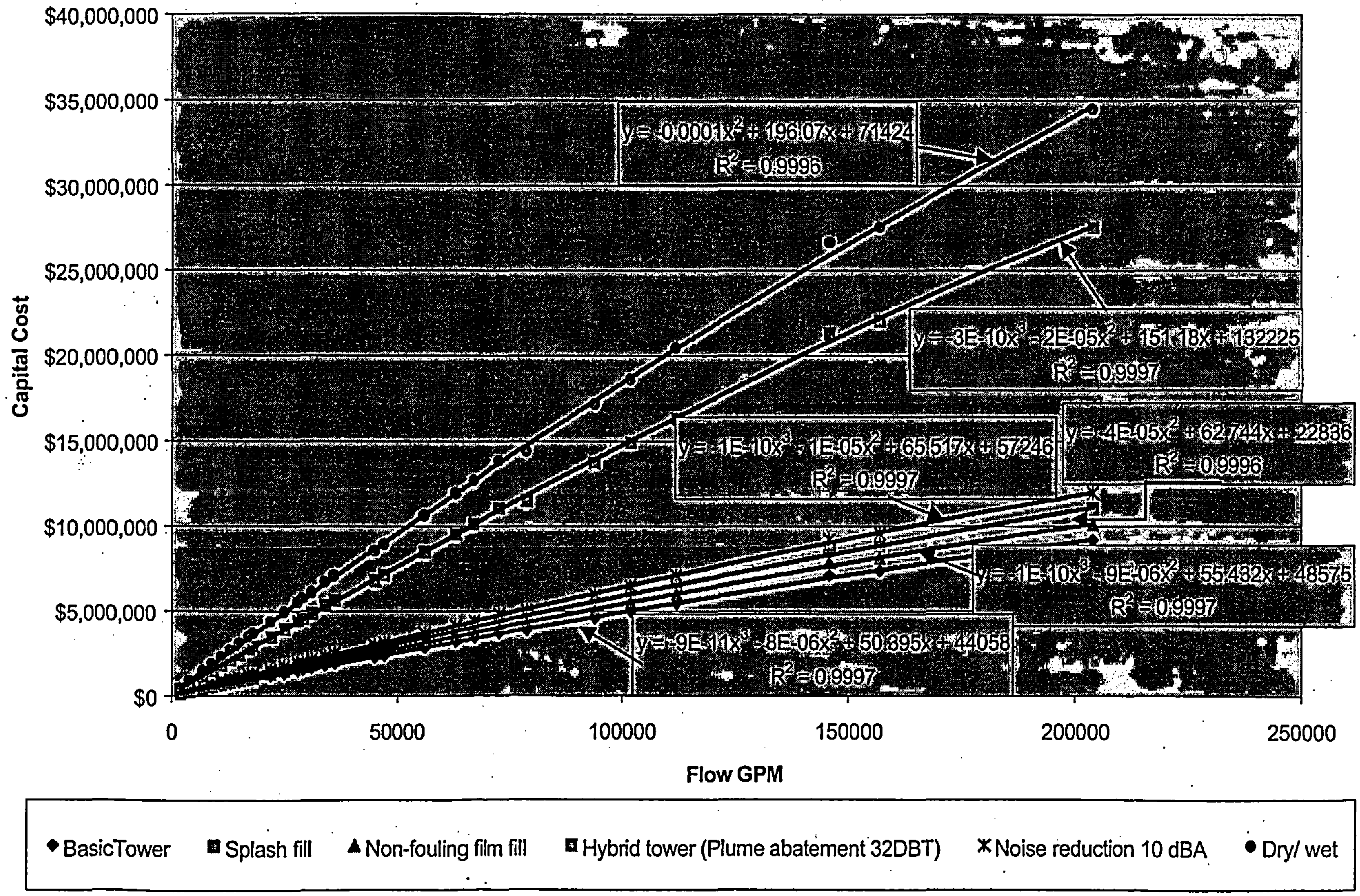


Chart 2-3. Red Wood Cooling Tower Capital Costs with Various Features (Delta 10 Degrees)

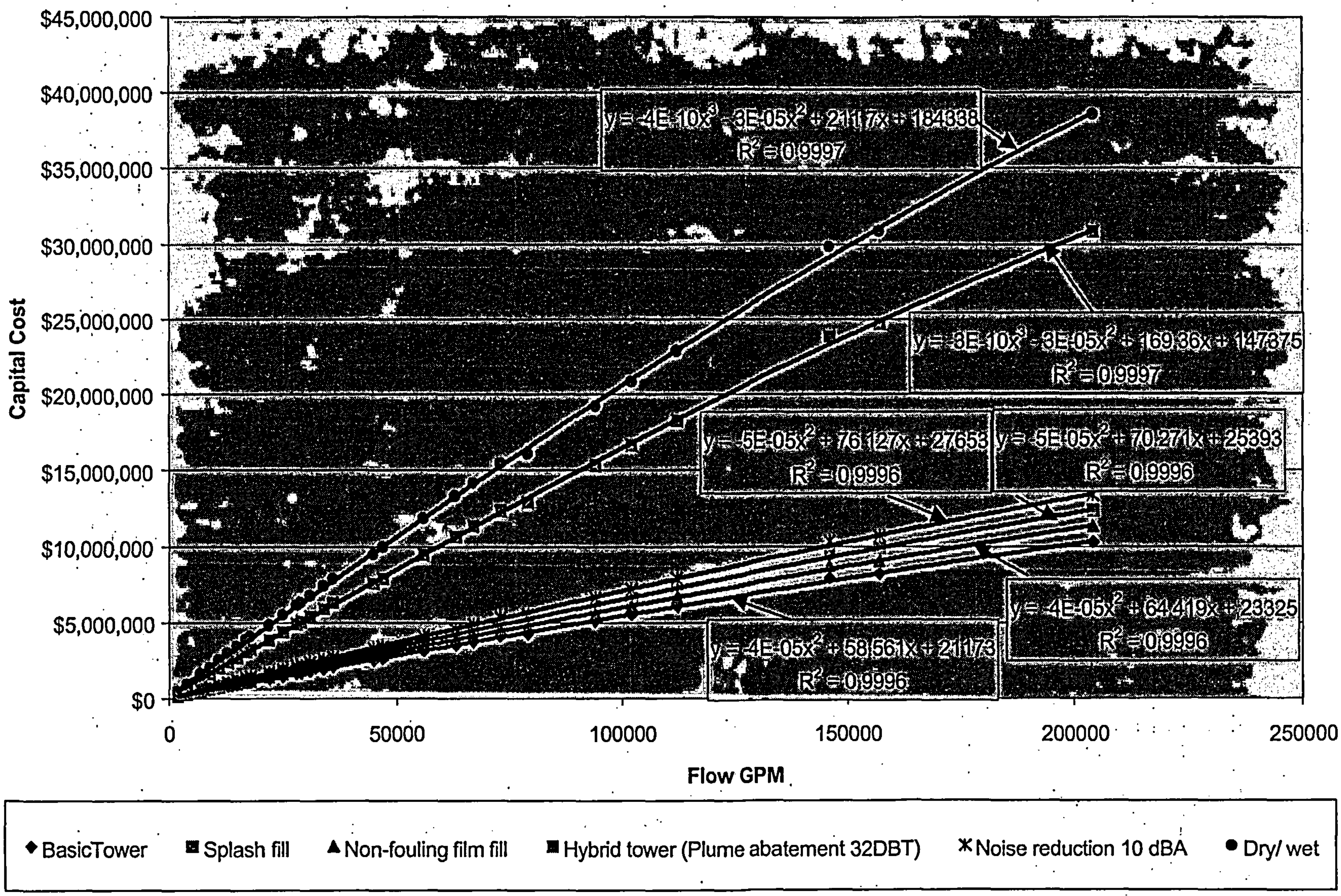


Chart 2-4. Concrete Cooling Tower Capital Costs with Various Features (Delta 10 Degrees)

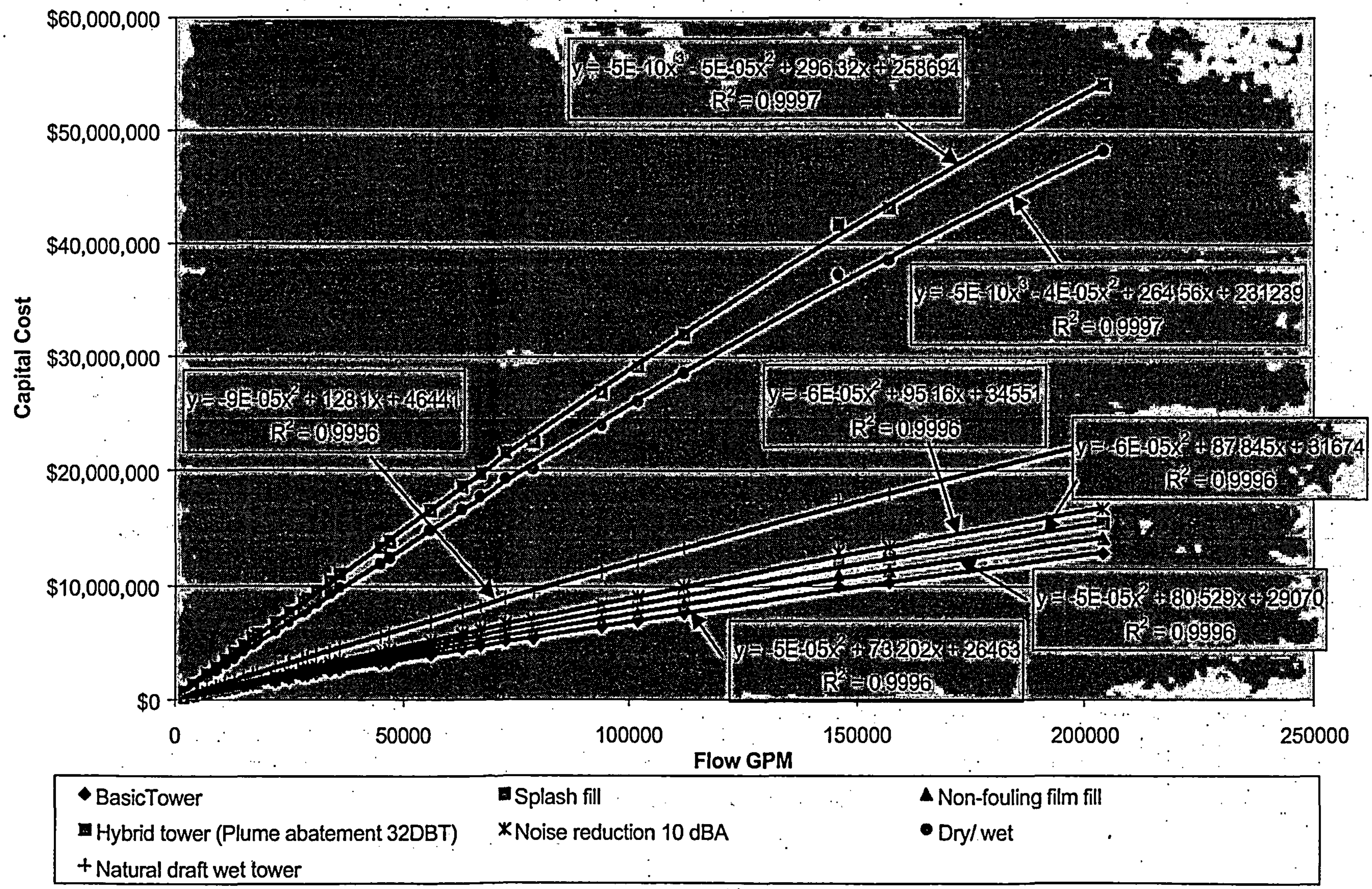


Chart 2-5. Steel Cooling Tower Capital Costs with Various Features (Delta 10 Degrees)

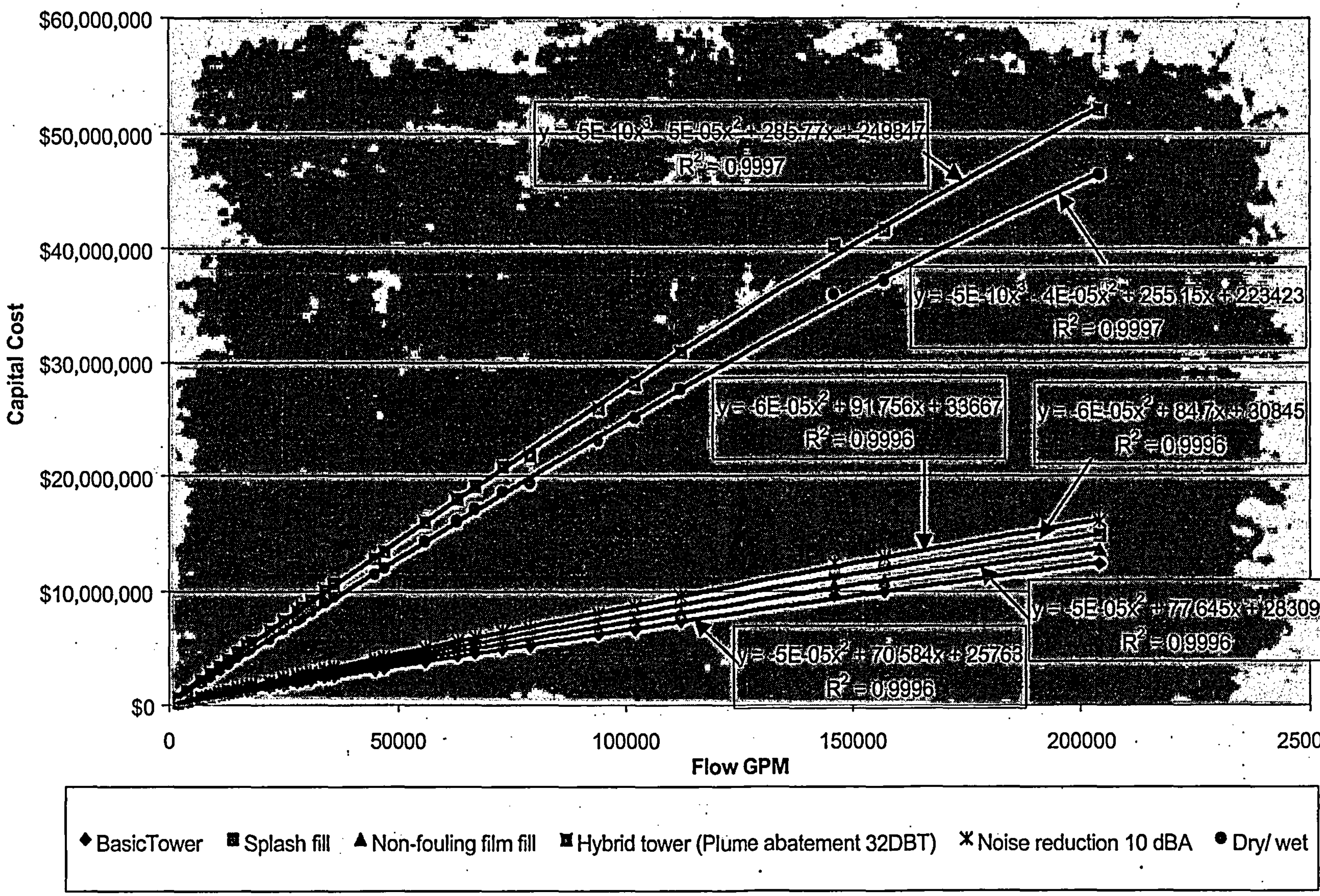


Chart 2-6. Fiberglass Cooling Tower Capital Costs with Various Features (Delta 10 Degrees)

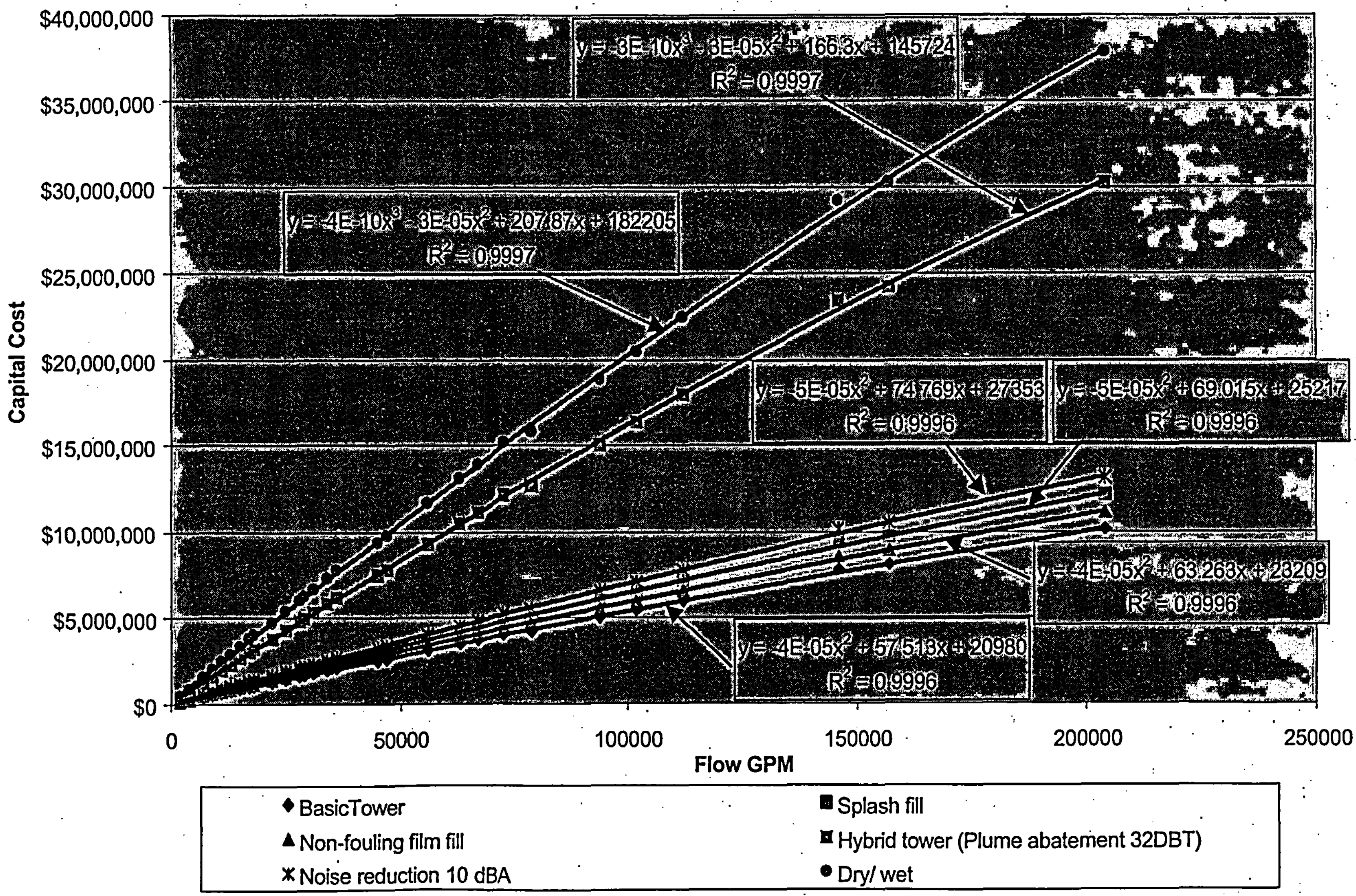


Chart 2-7. Actual Capital Costs for Wet Cooling Tower Projects and Comparable Costs from EPA Cost Curves

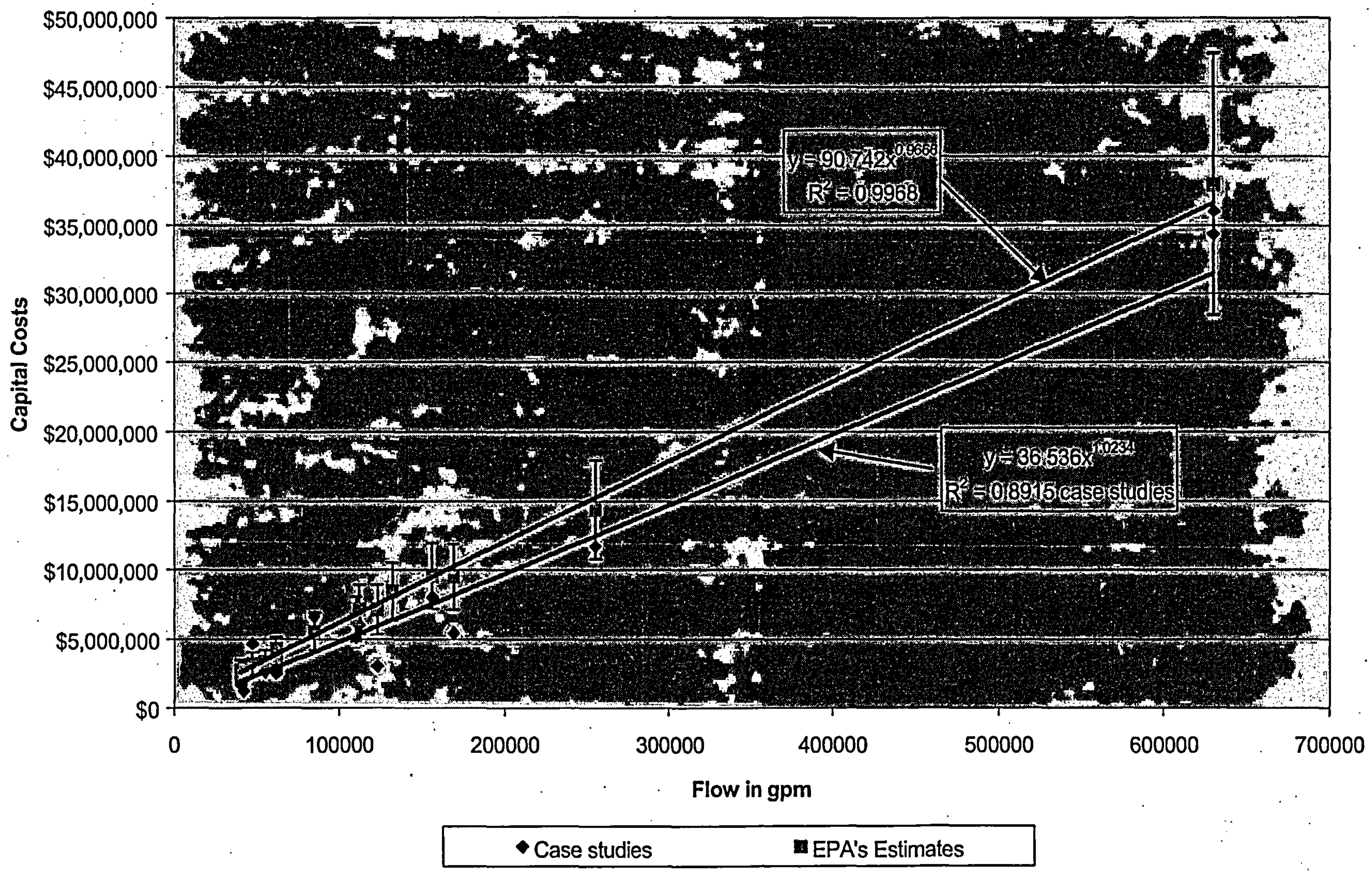


Chart 2-8. O&M Redwood Tower Annual Costs - 1st Scenario

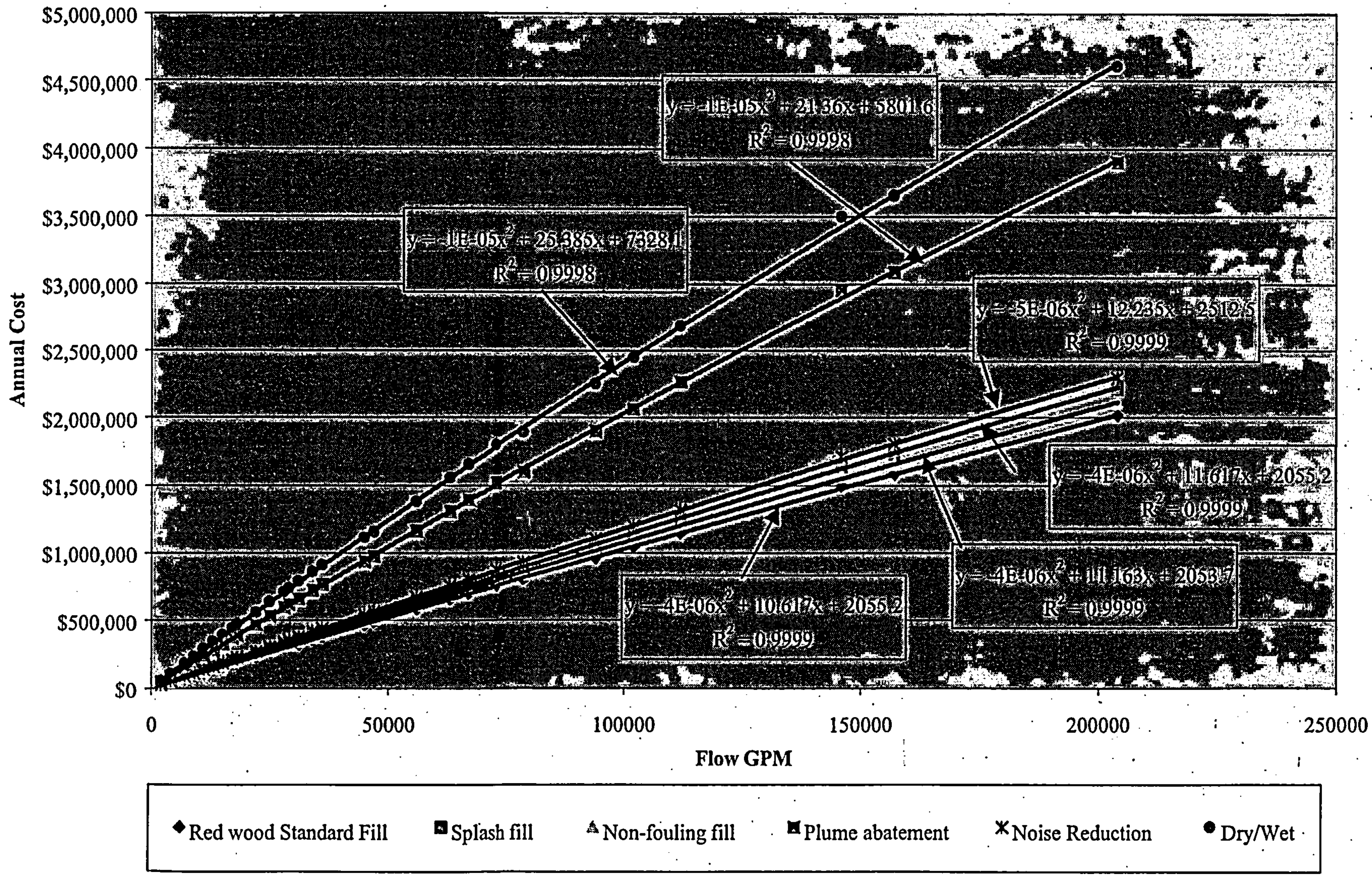


Chart 2-9. O&M Concrete Tower Annual Costs - 1st Scenario

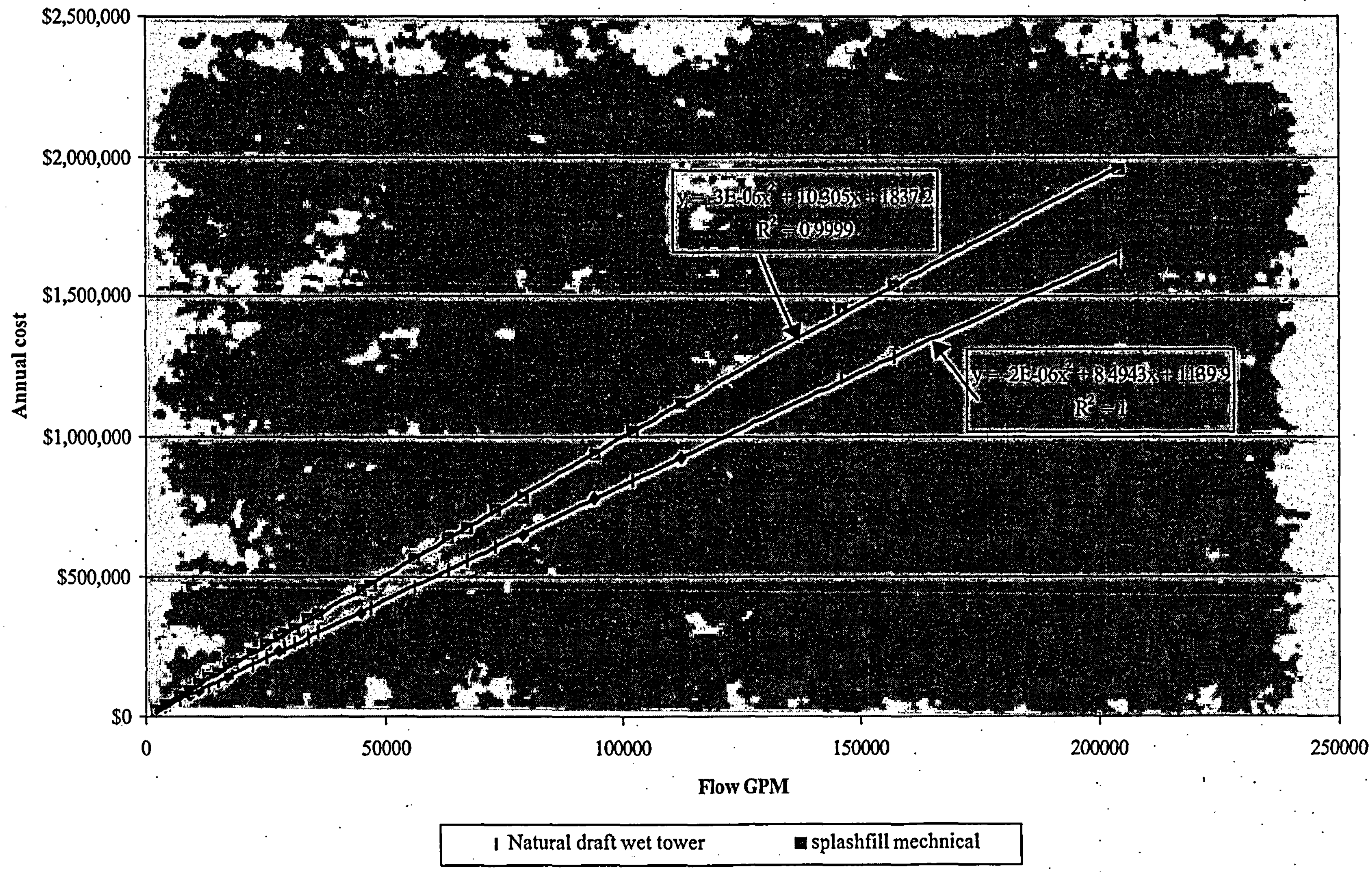


Chart 2-10. Variable Speed Pump Capital Cost

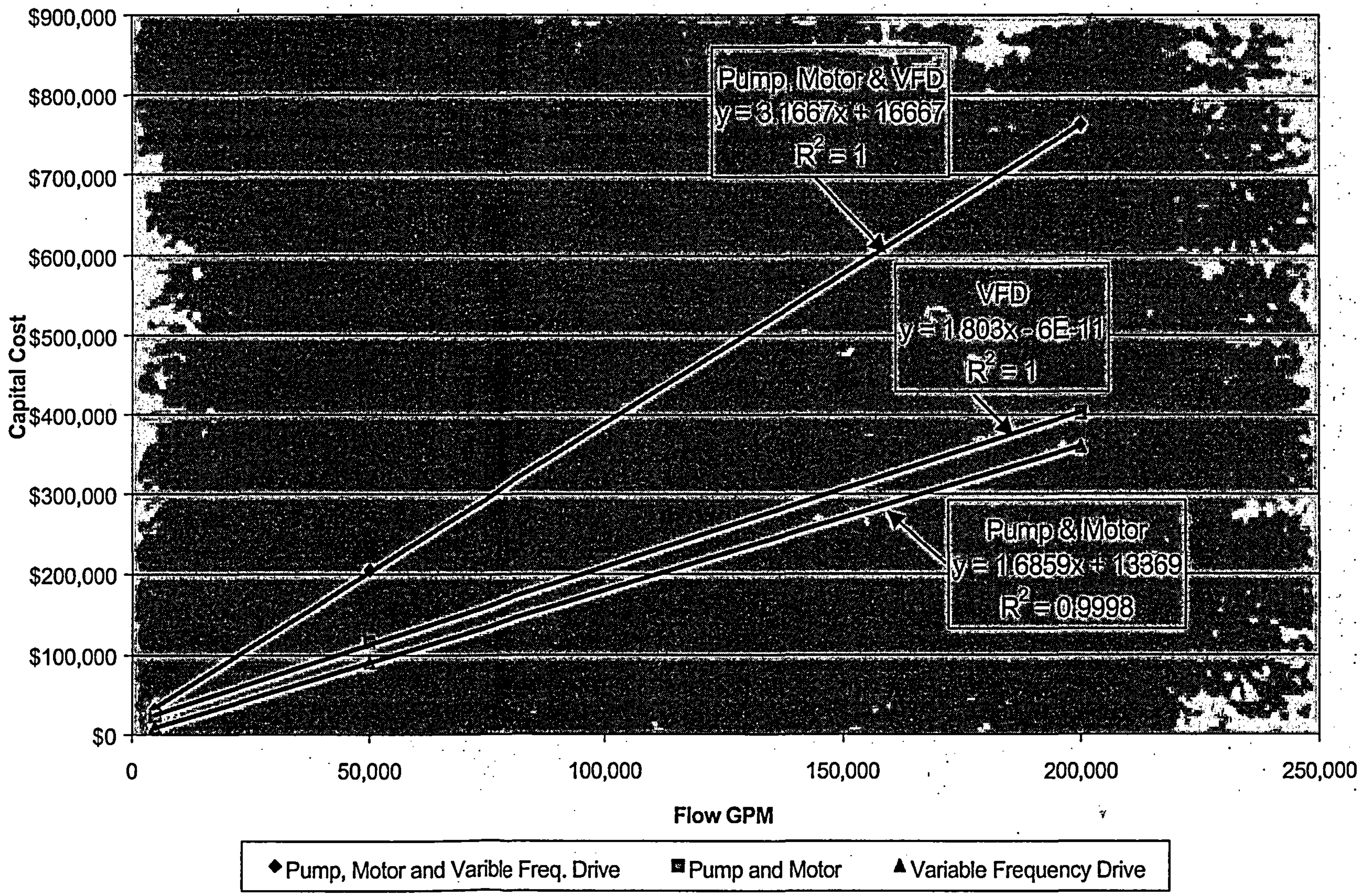


Chart 2-11. Municipal Water Use Costs

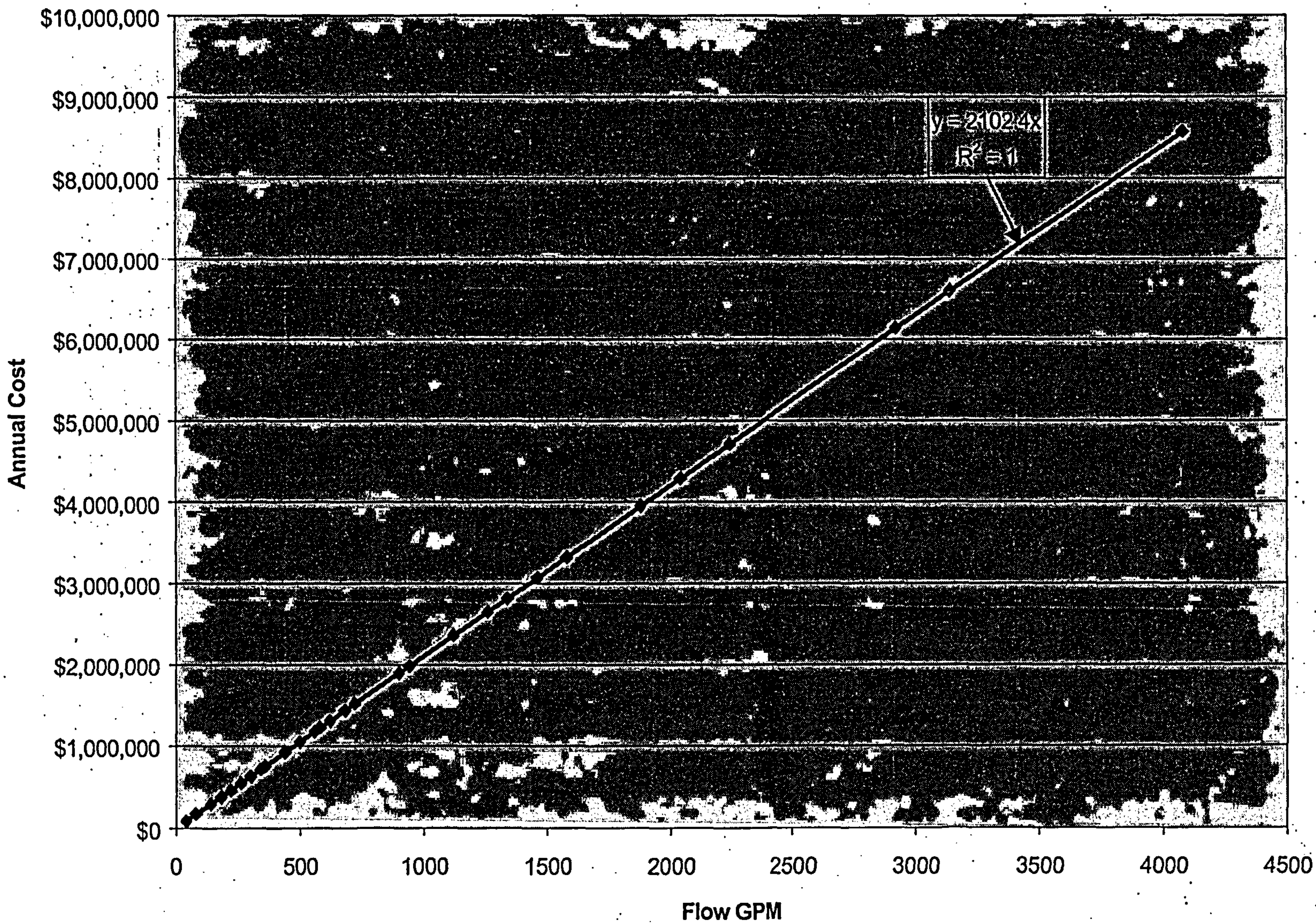


Chart 2-12. Gray Water Use Costs

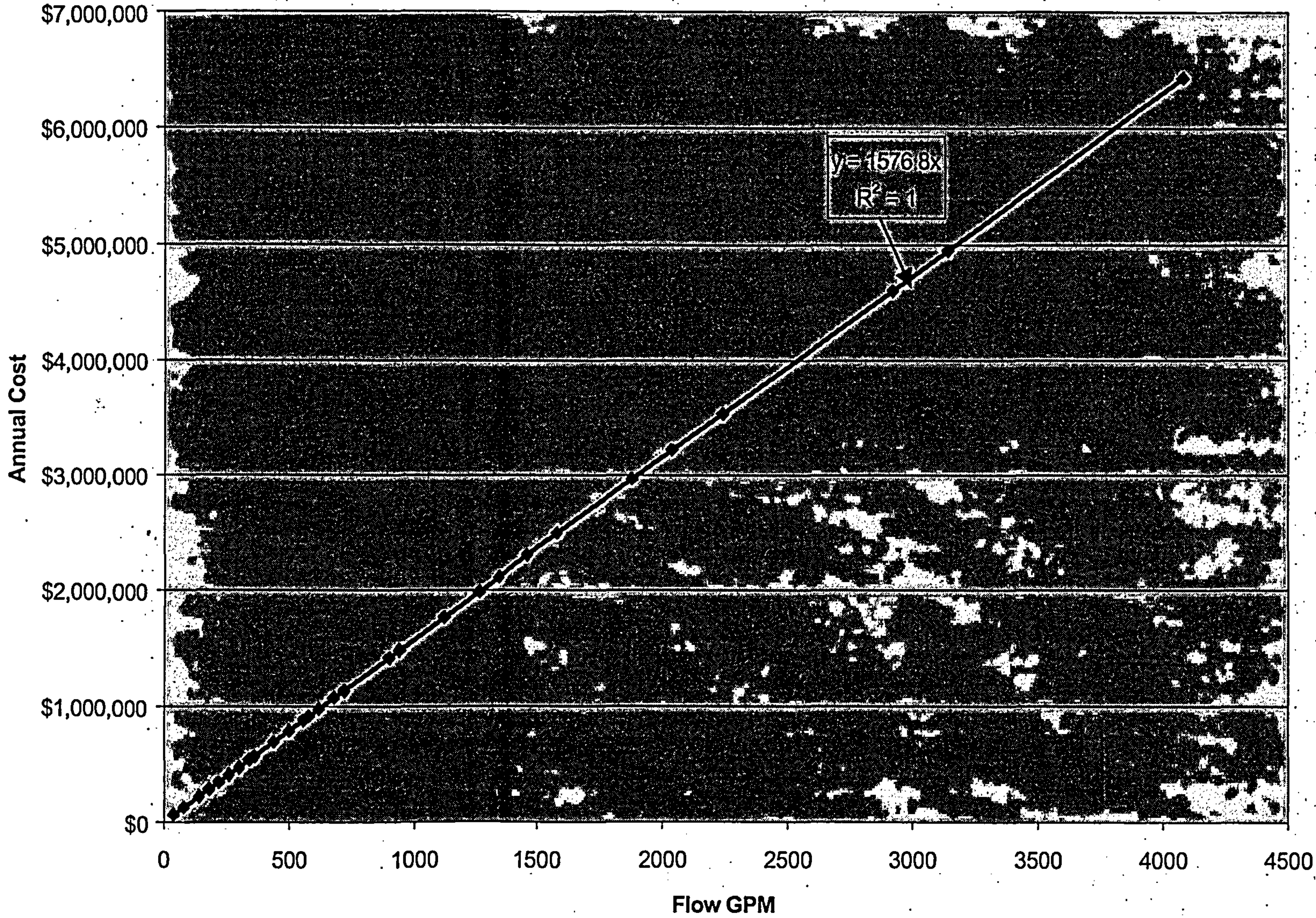


Chart 2-13. Capital Costs of Passive Screens Based on Well Depth

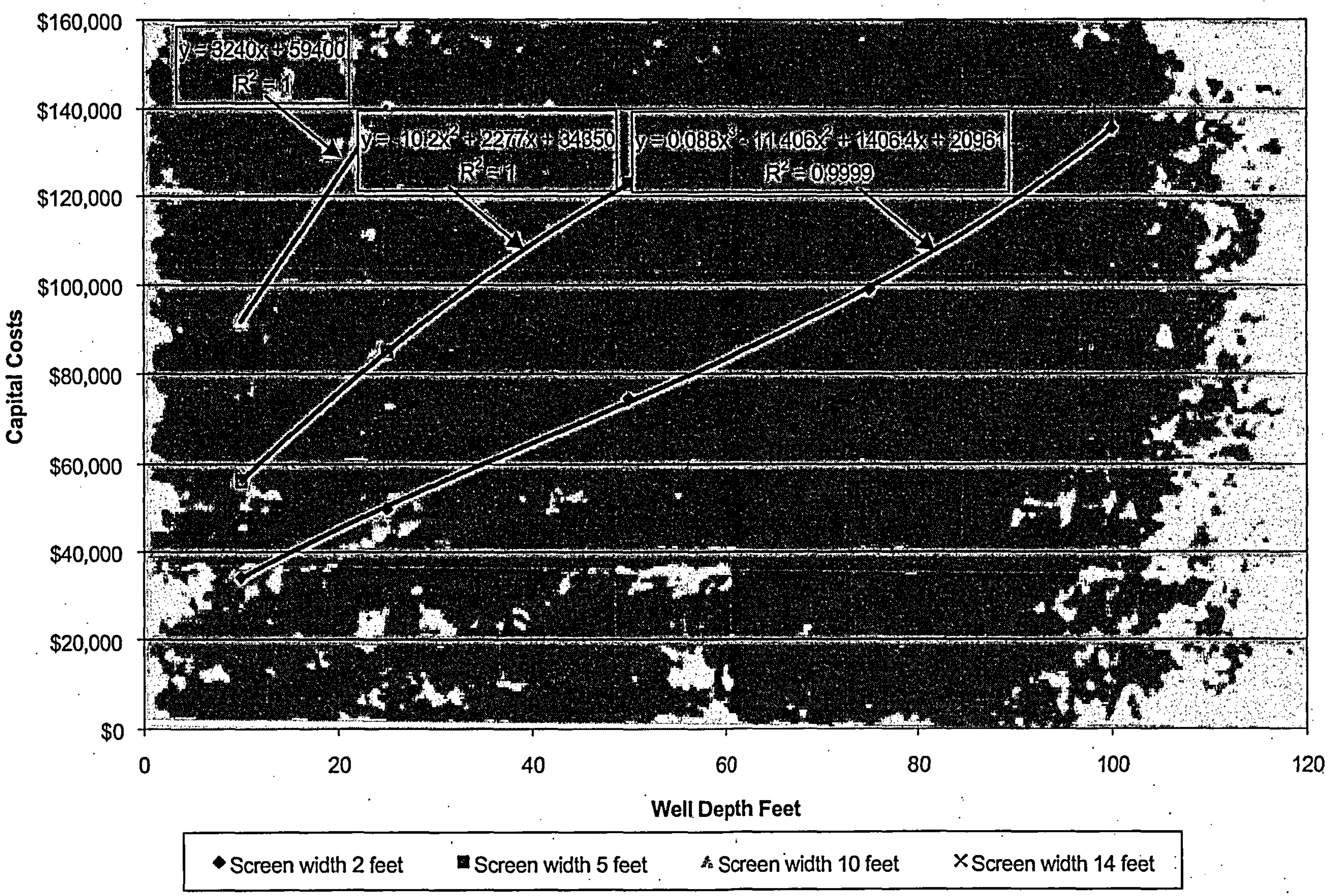


Chart 2-14. Capital Costs of Passive Screens - Flow Velocity 0.5 ft/sec

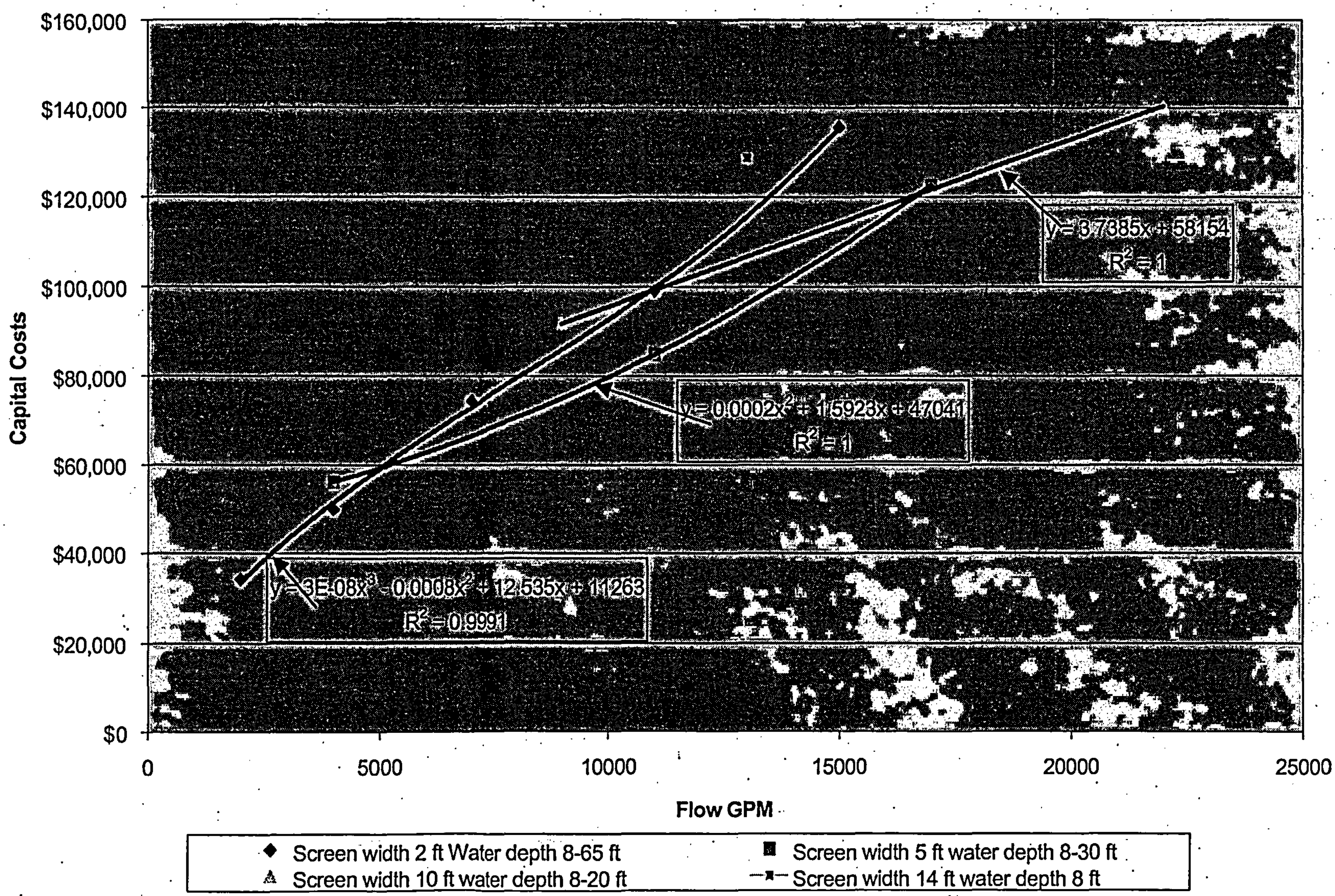
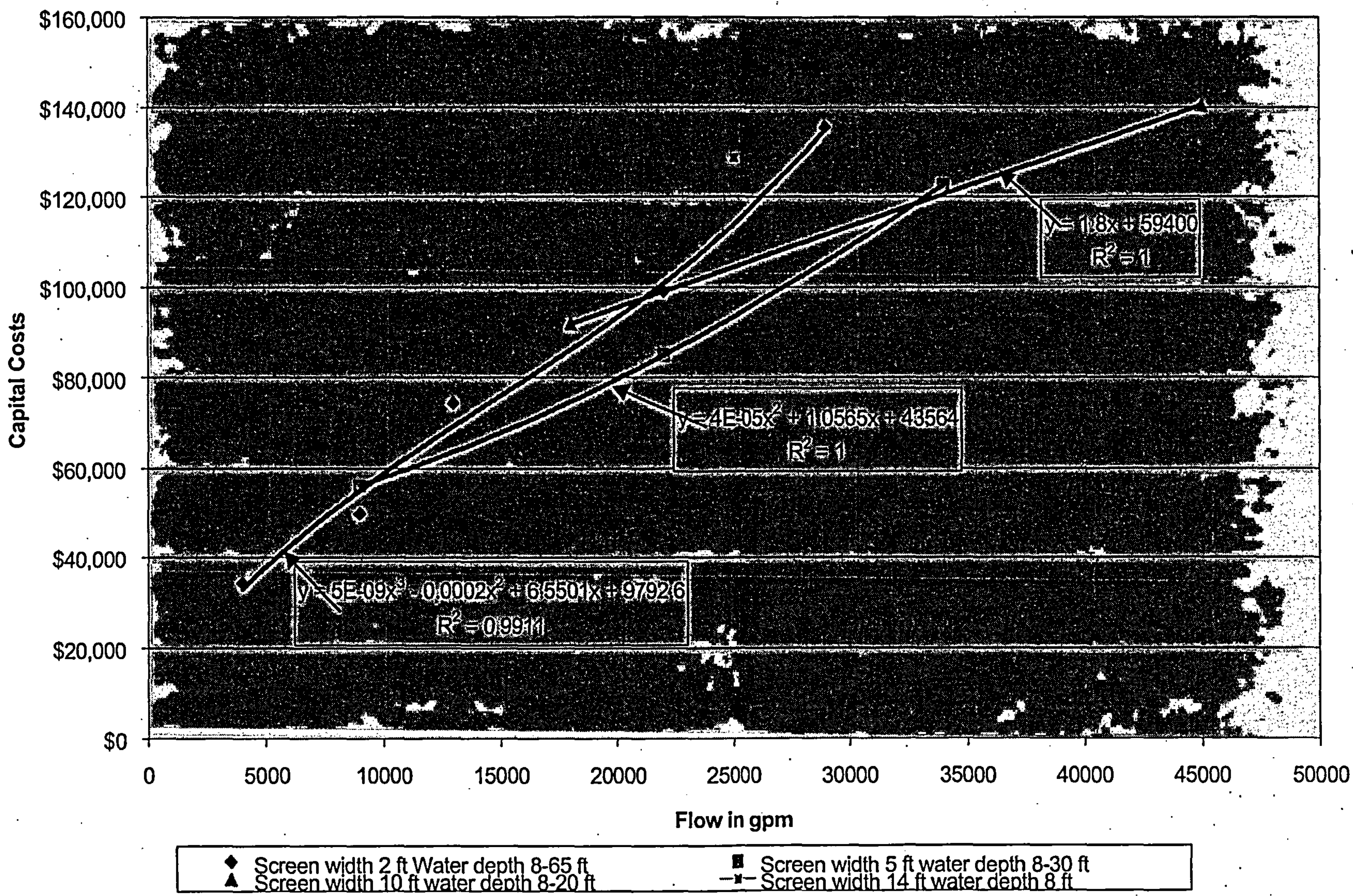


Chart 2-15. Capital Costs of Passive Screens - Flow Velocity 1 ft/sec



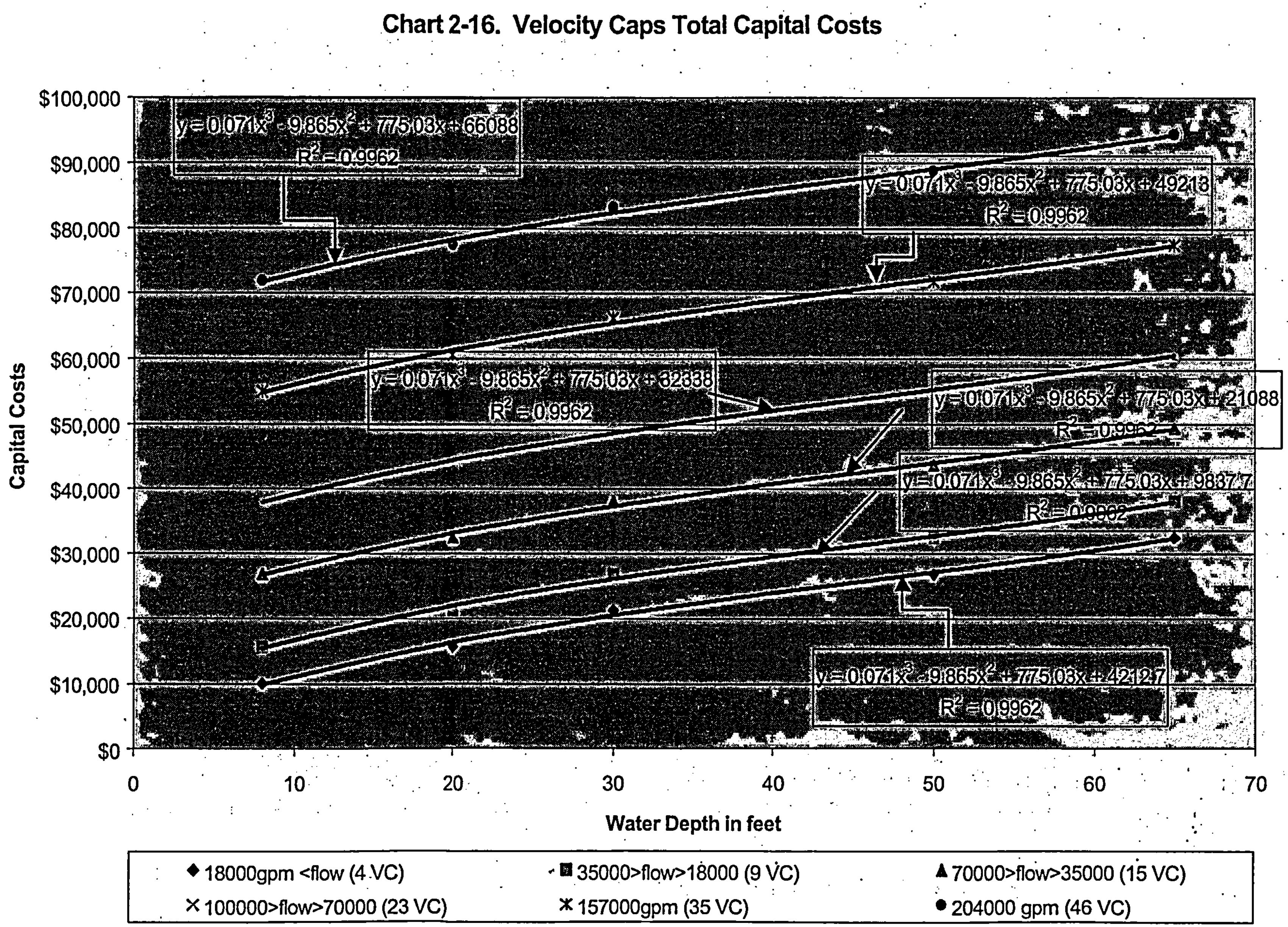
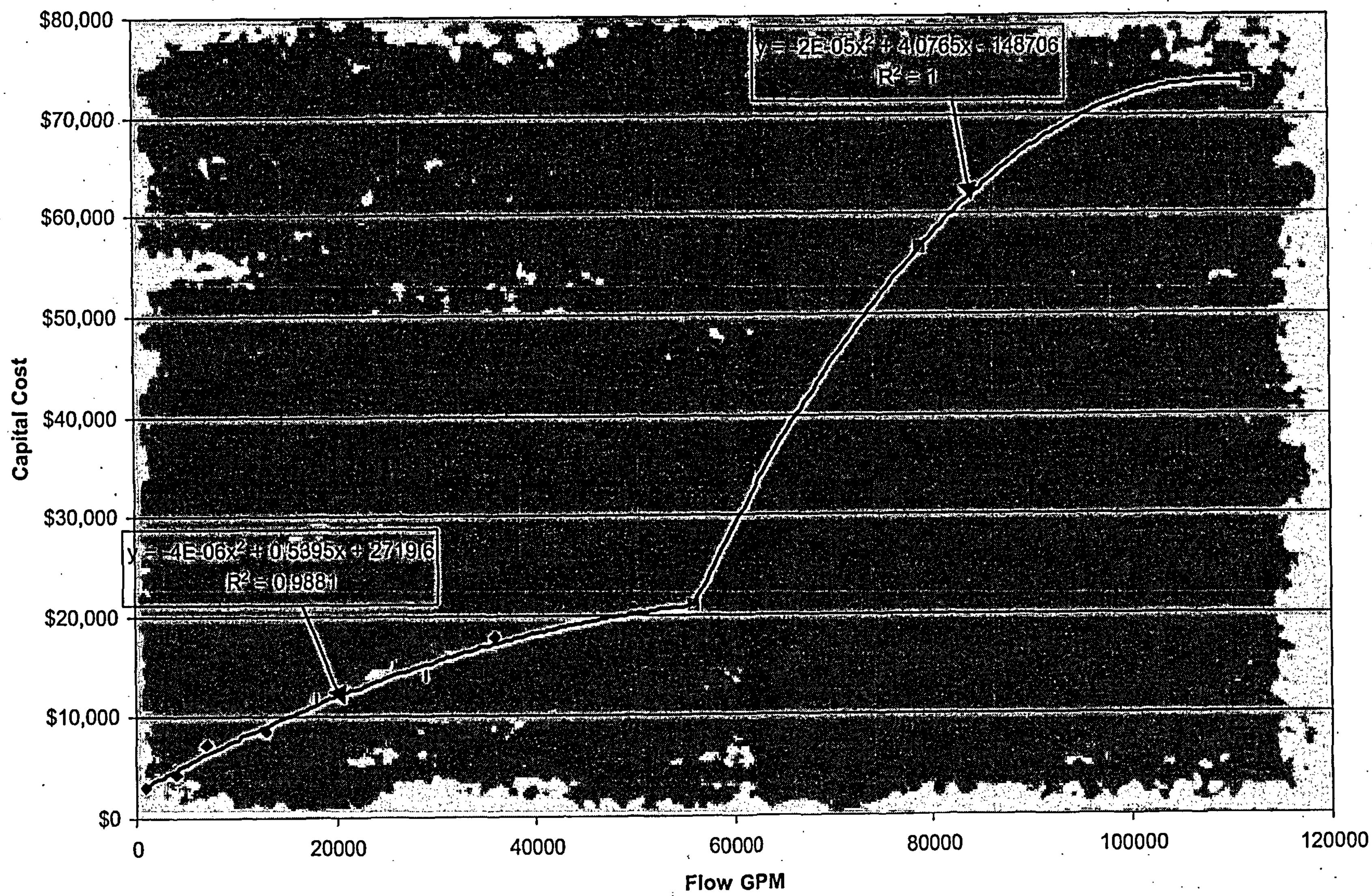


Chart 2-16. Velocity Caps Total Capital Costs
$y = 0.071x^3 - 9.865x^2 + 775.03x + 66088$
$R^2 = 0.9962$
$y = 0.071x^3 - 9.865x^2 + 775.03x + 49218$
$R^2 = 0.9962$
$y = 0.071x^3 - 9.865x^2 + 775.03x + 32338$
$R^2 = 0.9962$
$y = 0.071x^3 - 9.865x^2 + 775.03x + 21088$
$R^2 = 0.9962$
$y = 0.071x^3 - 9.865x^2 + 775.03x + 9837.7$
$R^2 = 0.9962$
$y = 0.071x^3 - 9.865x^2 + 775.03x + 4212.7$
$R^2 = 0.9962$
Capital Costs
$100,000
$90,000
$80,000
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$0
0
10
20
30
40
50
60
70
Water Depth in feet
18000gpm <flow (4 VC)
35000>flow>18000 (9 VC)
70000>flow>35000 (15 VC)
100000>flow>70000 (23 VC)
157000gpm (35 VC)
204000 gpm (46 VC)

Chart 2-17. Concrete Fittings for Intake Flow Velocity Reduction



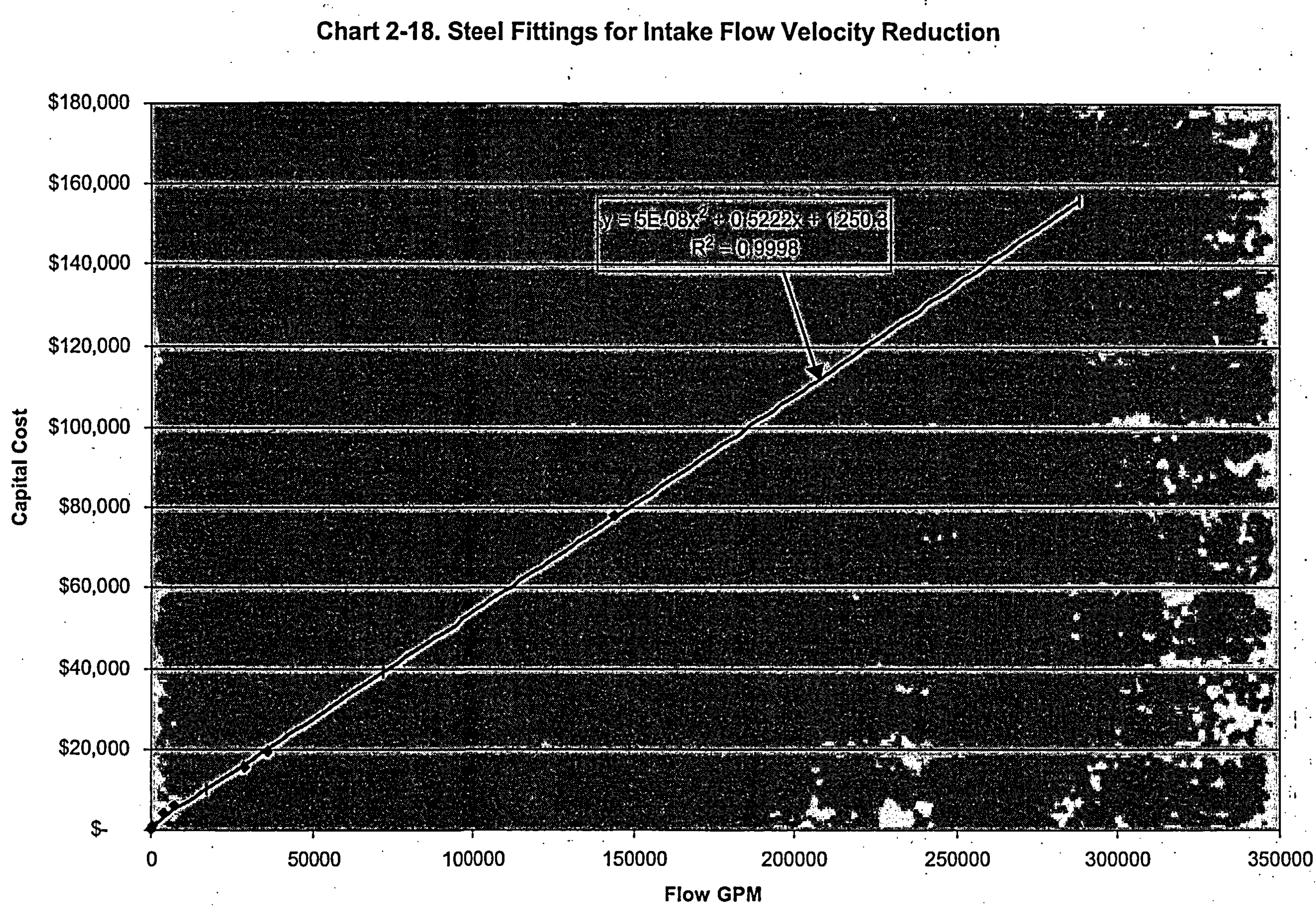


Chart 2-18. Steel Fittings for Intake Flow Velocity Reduction
$180,000
$160,000
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$-
Capital Cost
y = 5E-08x² + 0.5222x + 1250.3
R² = 0.9998
0
50000
100000
150000
200000
250000
300000
350000
Flow GPM

Chart 2-19. Travel Screens Capital Cost Without Fish Handling Features
Flow Velocity 0.5ft/sec

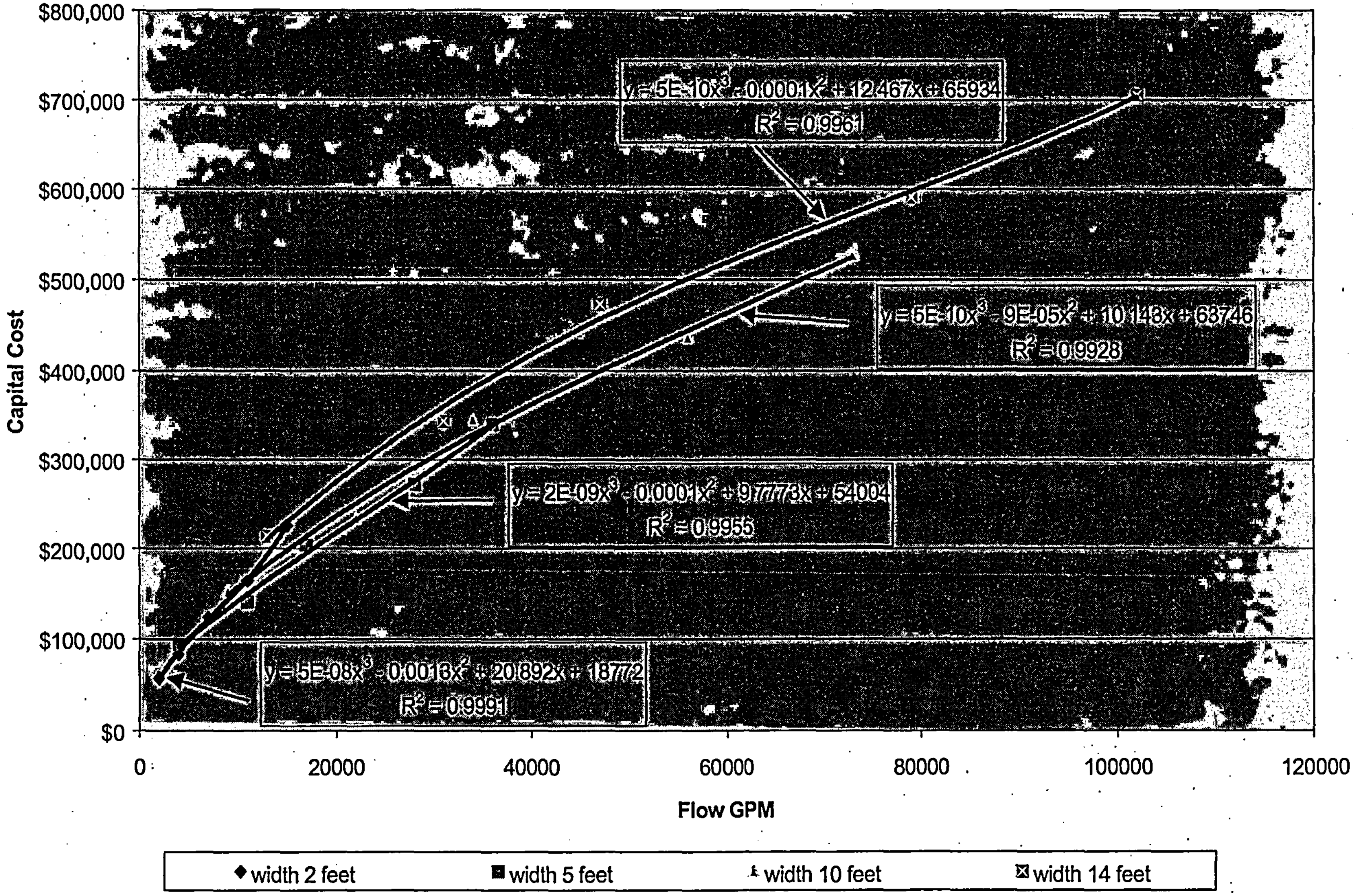


Chart 2-20. Travel Screens Capital Cost With Fish Handling Features
Flow Velocity 0.5ft/sec

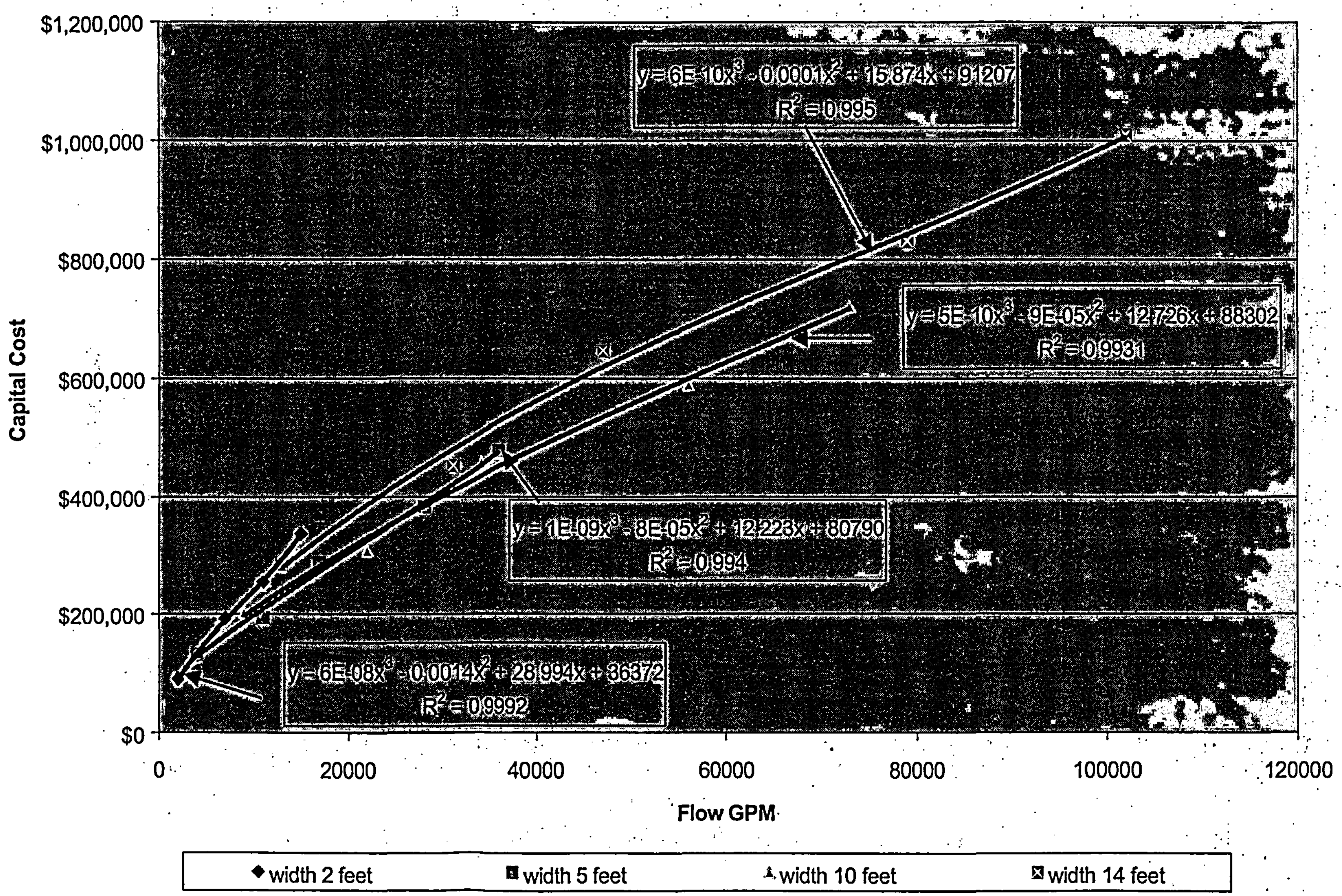
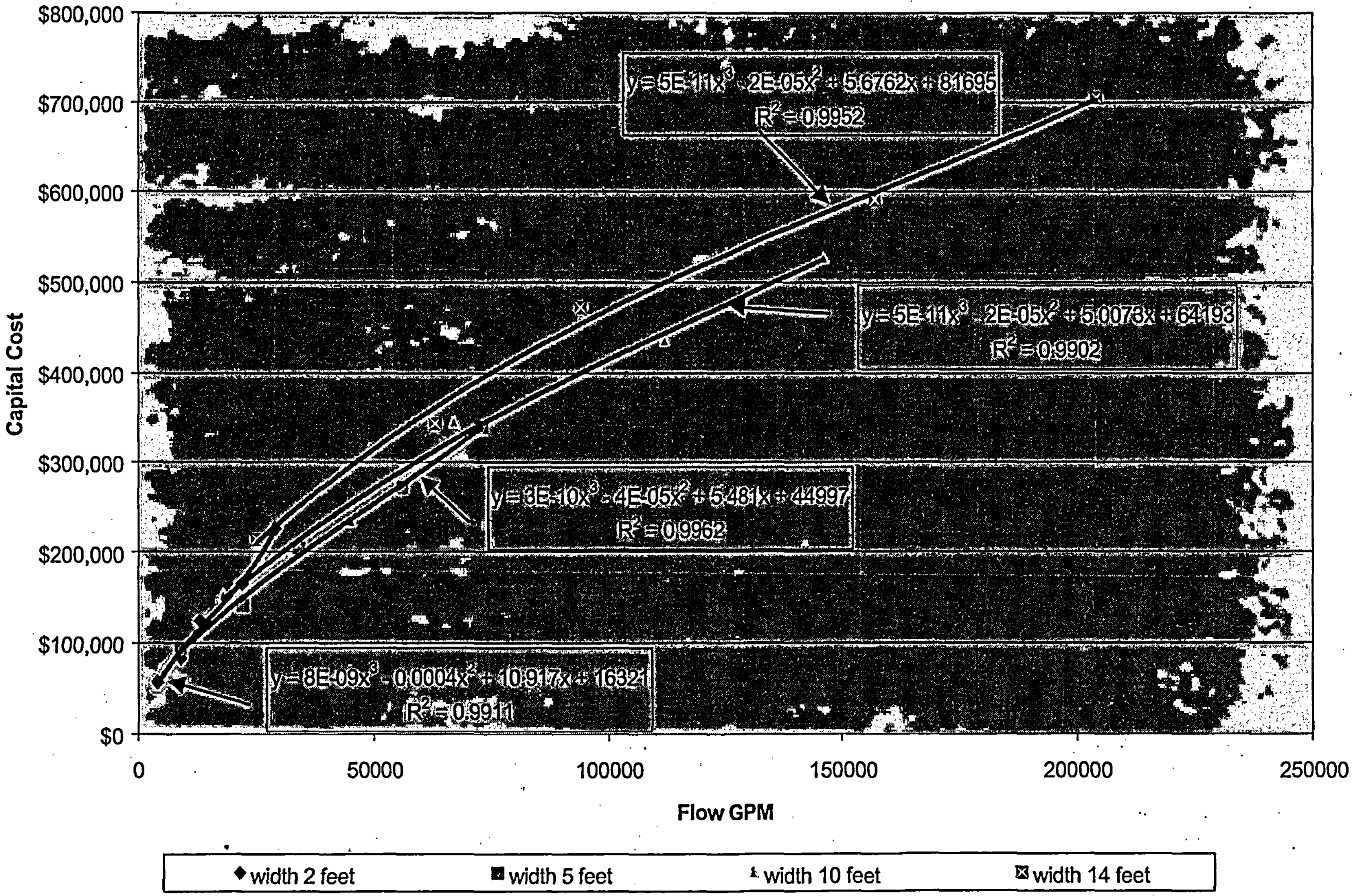


Chart 2-21. Travel Screens Capital Cost Without Fish Handling Features
Flow Velocity 1 ft/sec



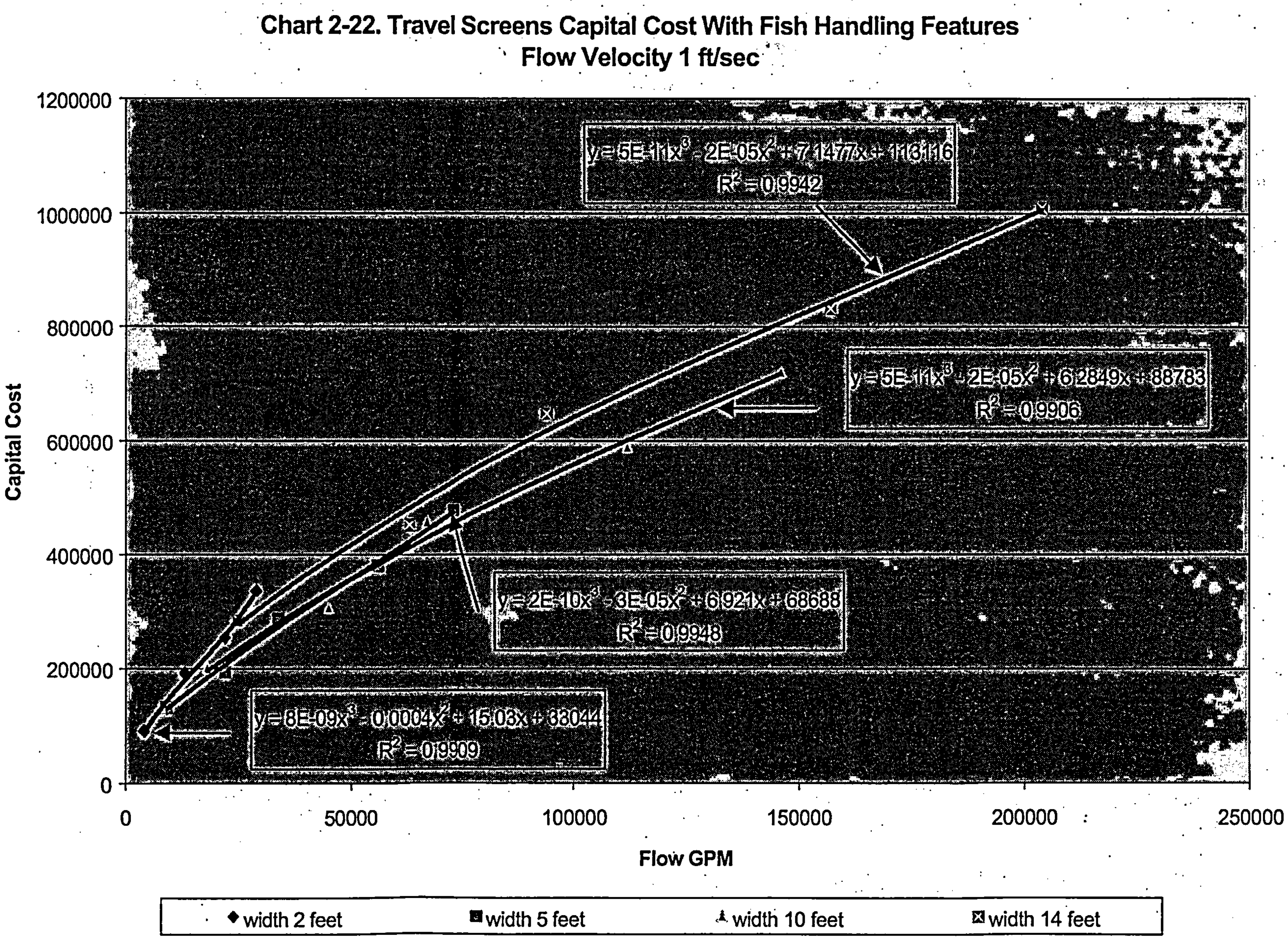


Chart 2-22. Travel Screens Capital Cost With Fish Handling Features
Flow Velocity 1 ft/sec
y = 5E-11x3 - 2E-05x2 + 7.1477x + 113116
R2 = 0.9942
y = 5E-11x3 - 2E-05x2 + 6.2849x + 88783
R2 = 0.9906
y = 2E-10x3 - 3E-05x2 + 6.921x + 68688
R2 = 0.9948
y = 8E-09x3 - 0.0004x2 + 15.03x + 38044
R2 = 0.9909
Capital Cost
Flow GPM
0
200000
400000
600000
800000
1000000
1200000
50000
100000
150000
200000
250000
width 2 feet
width 5 feet
width 10 feet
width 14 feet

Chart 2-23. Fish Spray Pumps Capital Costs

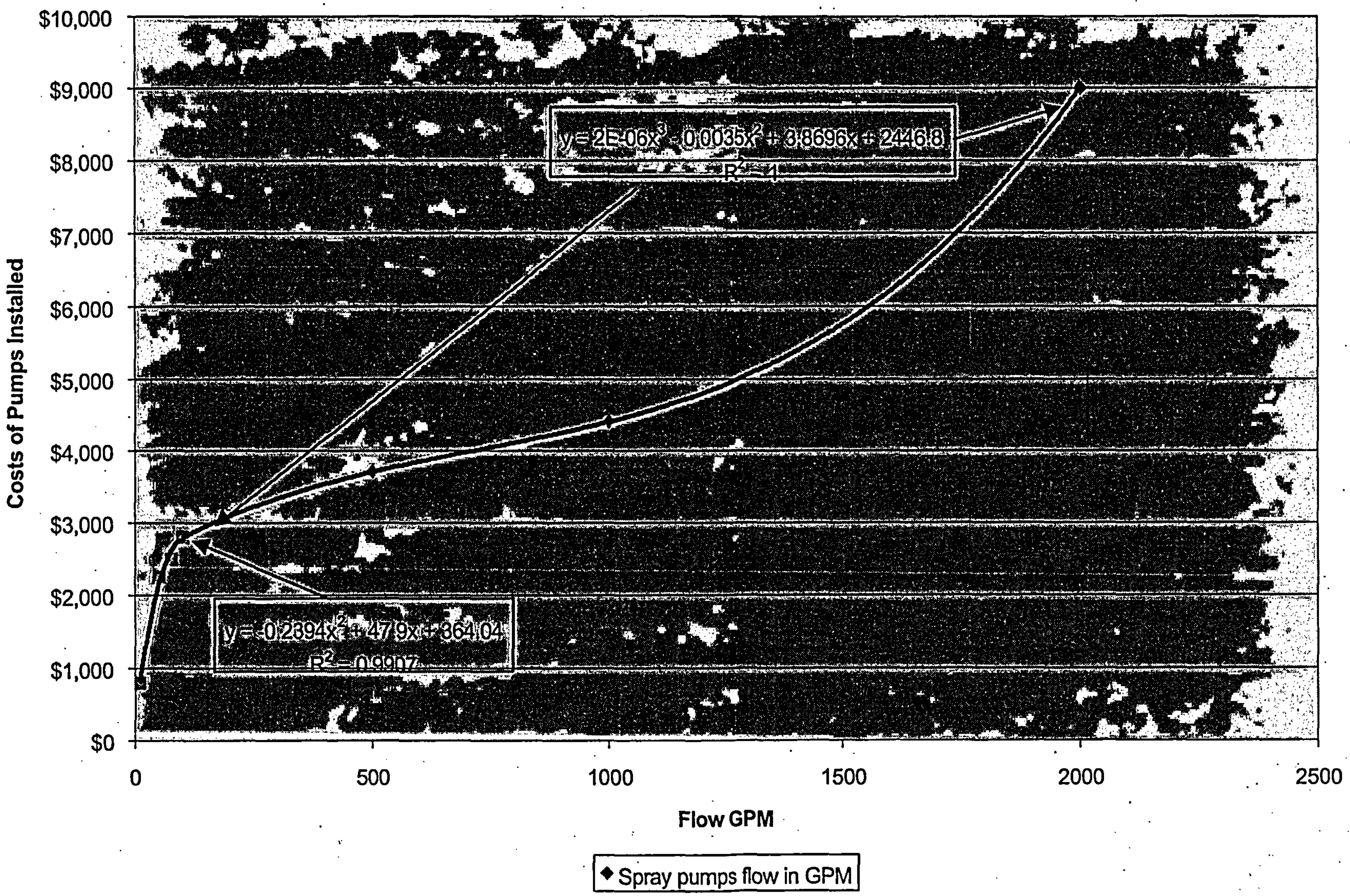


Chart 2-24. O&M Cost for Traveling Screens Without Fish Handling Features Flow Velocity 0.5ft/sec

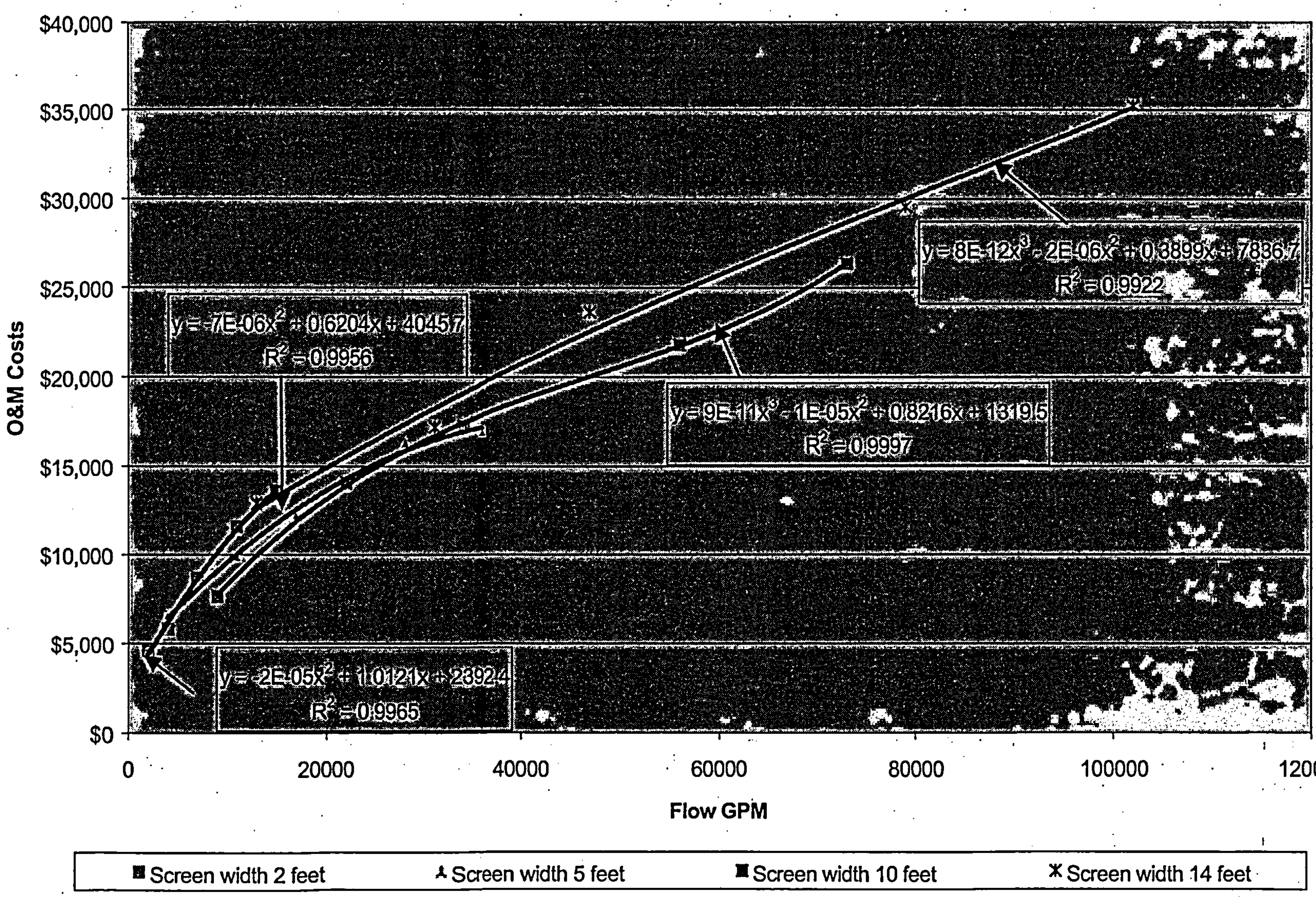


Chart 2-25. O&M Cost for Traveling Screens With Fish Handling Features
Flow Velocity 0.5ft/sec

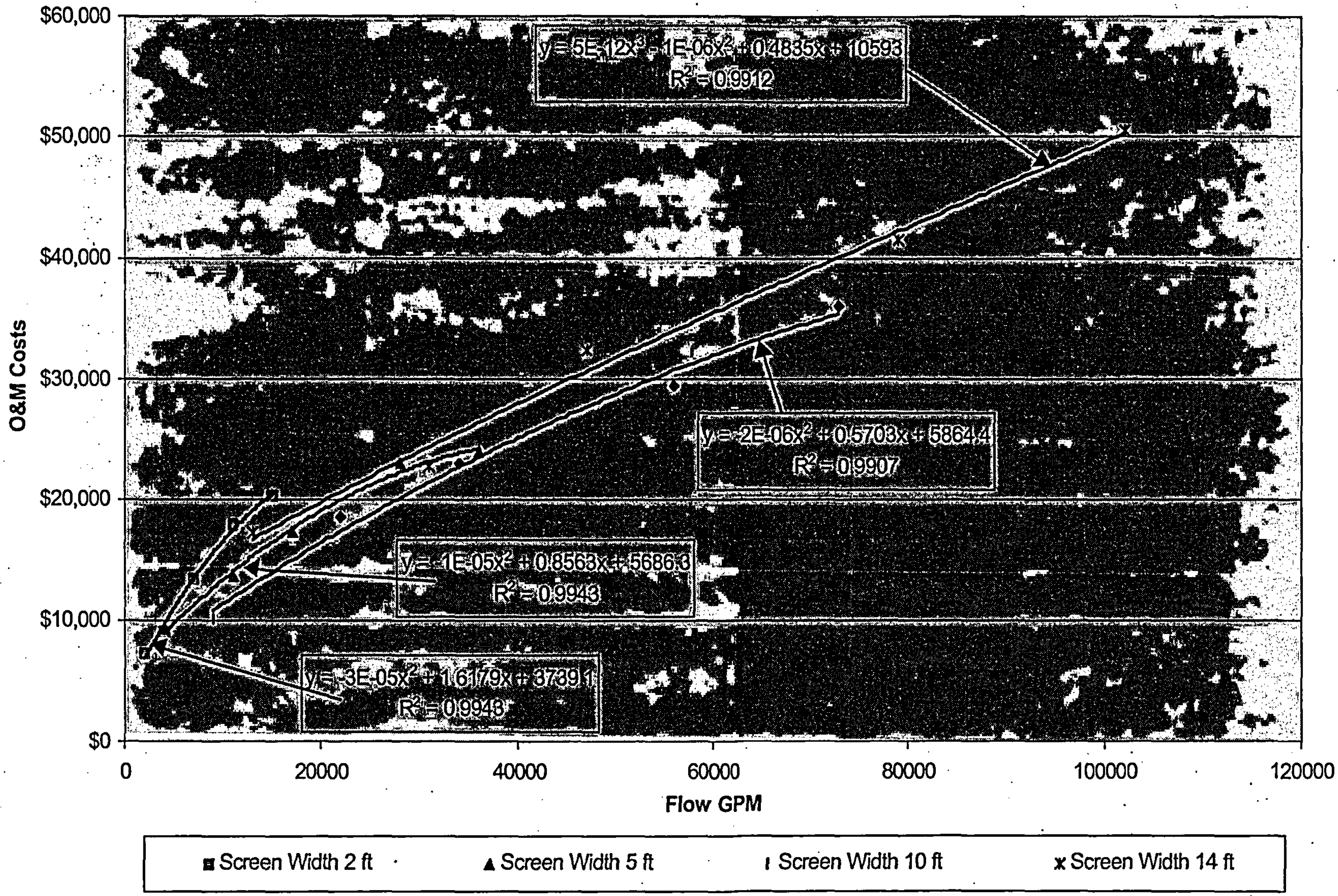


**Chart 2-26. O&M Cost for Traveling Screens Without Fish Handling Features
Flow Velocity 1 ft/sec**

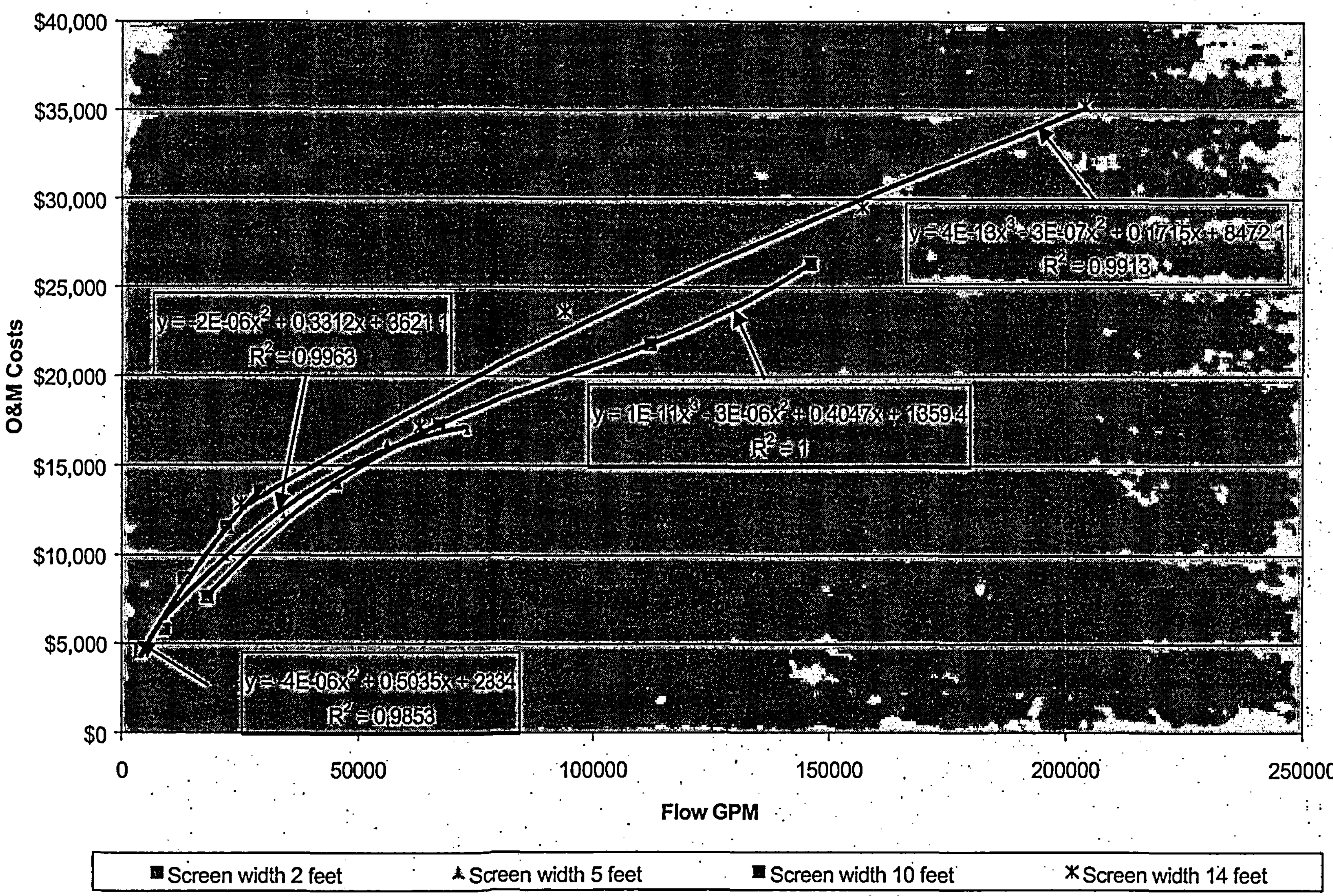


Chart 2-27. O&M Cost for Traveling Screens With Fish Handling Features
Flow Velocity 1 ft/sec

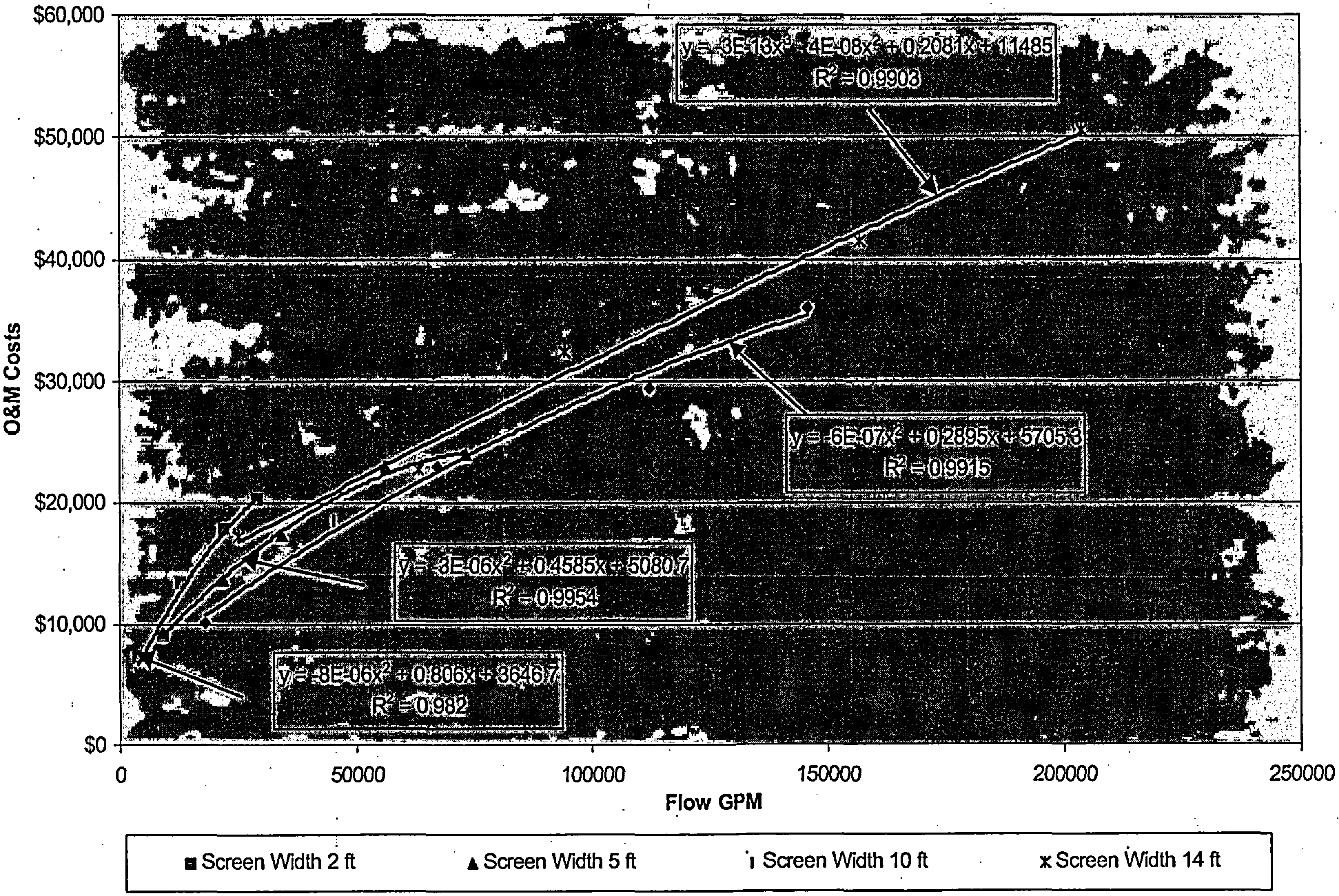


Chart 2-28. Capital Cost of Fish Handling Equipment Screen Flow Velocity 0.5 ft/sec

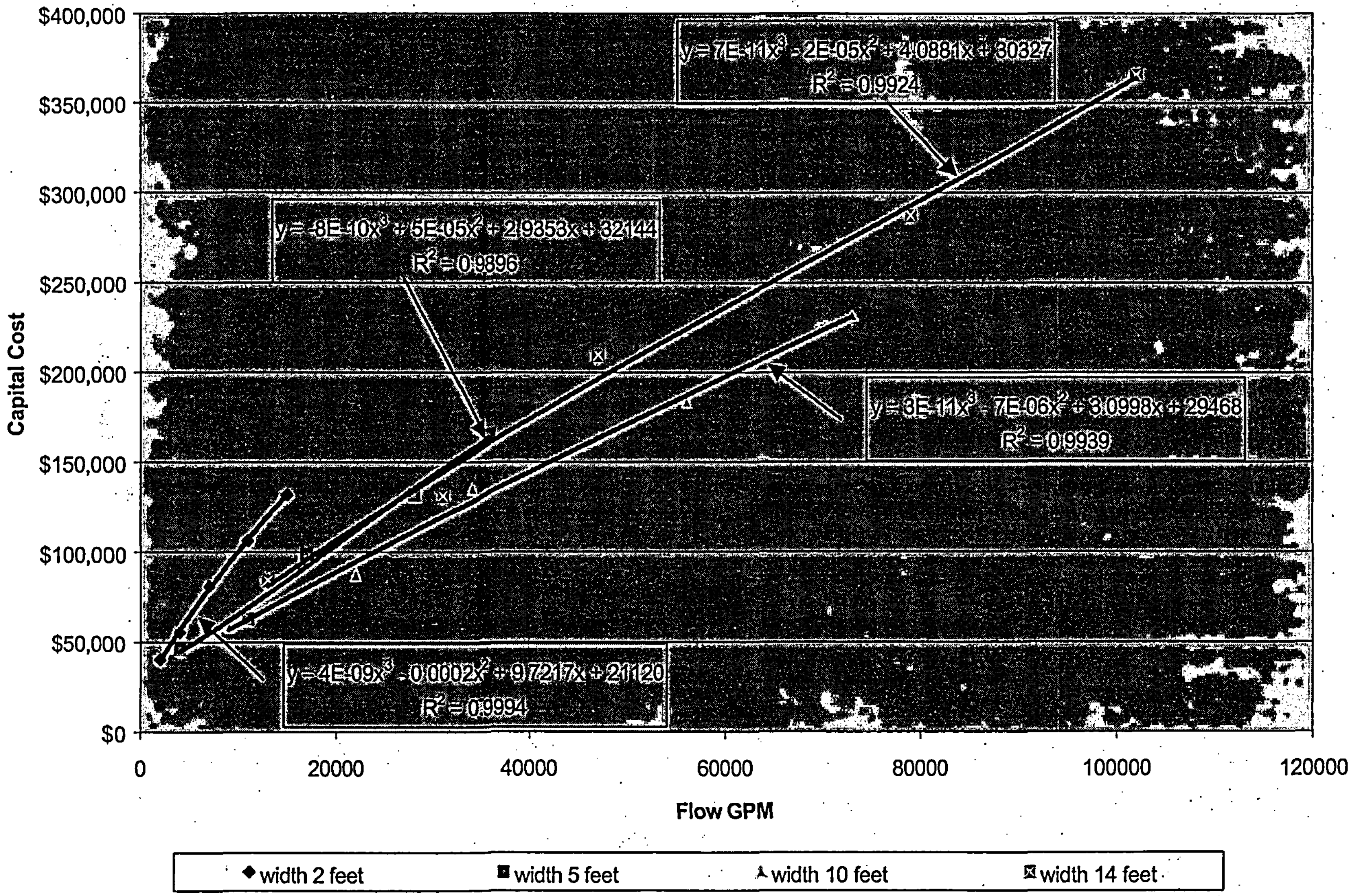


Chart 2-29. O&M Cost for Fish Handling Features
Flow Velocity 0.5ft/sec

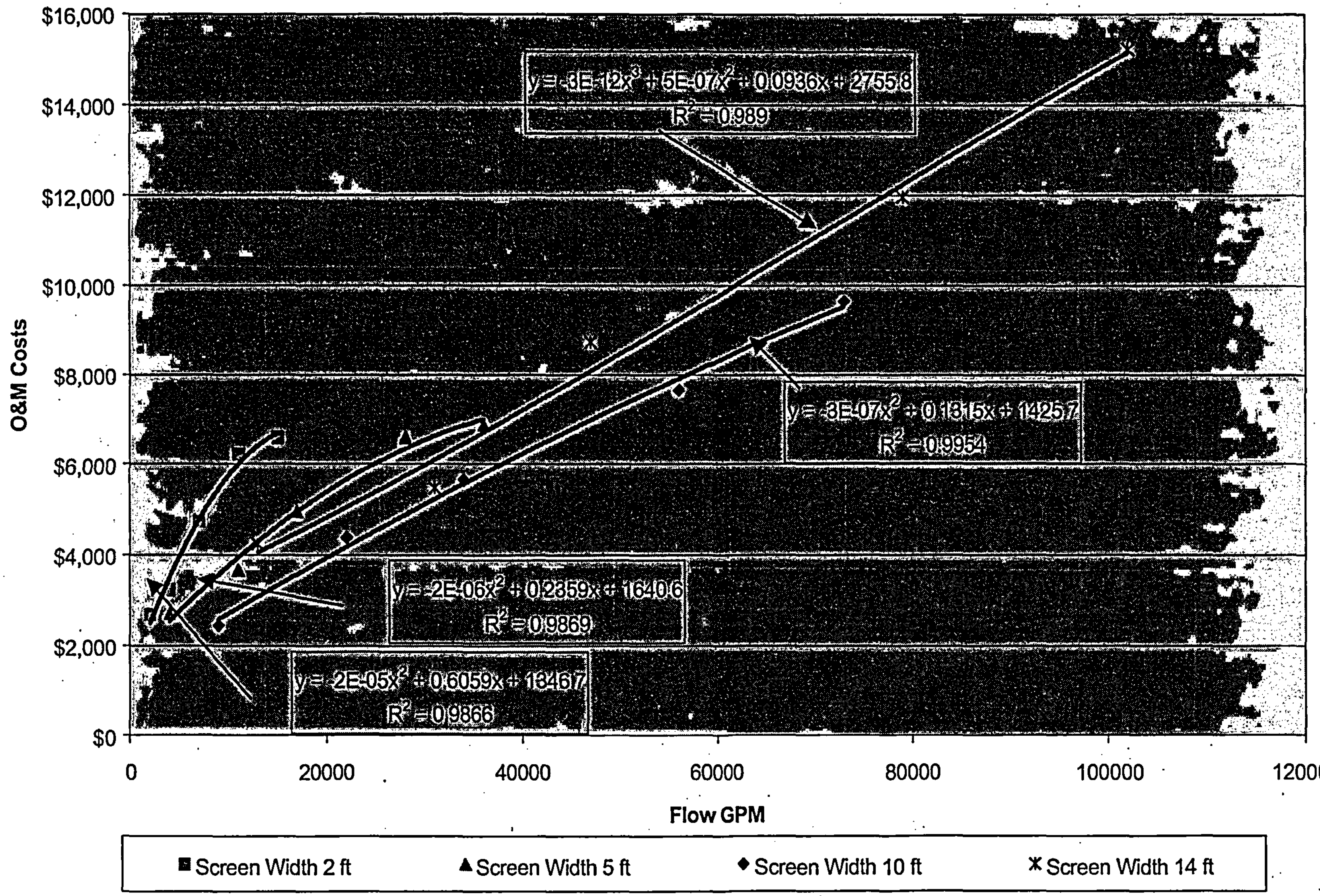
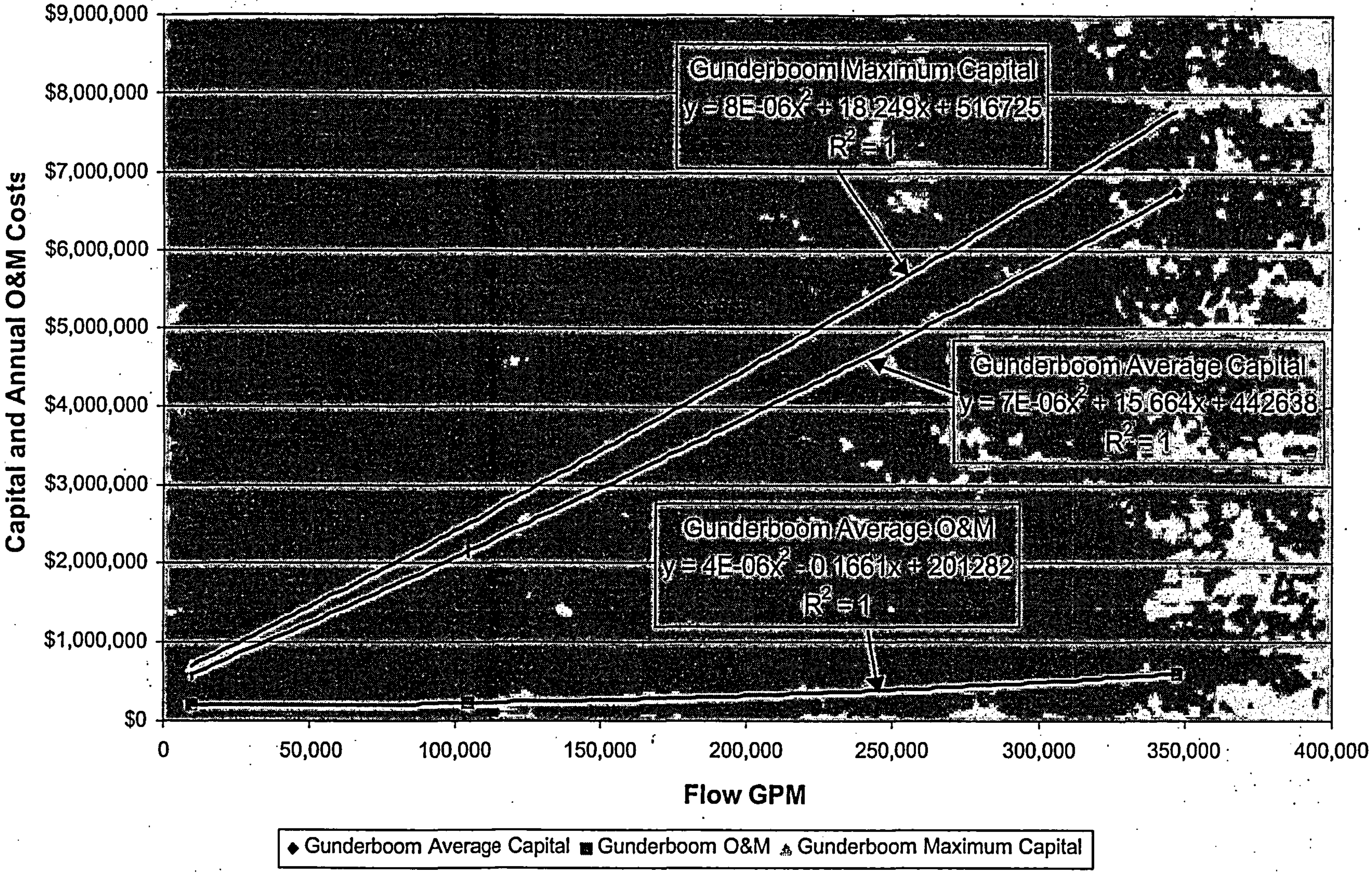


Chart 2-30. Gunderboom Capital and O&M Costs For Simple Floating Structure



SRC-REPORT. 12/23/11

(NRC NUREG-1087 1985)

NUREG-1087

V-002

Final Environmental Statement

related to the operation of Vogtle Electric Generating Plant, Units 1 and 2

Docket Nos. 50-424 and 50-425

Georgia Power Company, et al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

March 1985

V-388

USGS 2004

Water Resources Data–Georgia, 2003

Volume 1: Continuous water-level, streamflow, water-quality data, and periodic water-quality data, Water Year 2003

Compilers: S. Jack Alhadeff, Brian E. McCallum, and Mark N. Landers
Authors: Andrew C. Hickey, John F. Kerestes, and Brian E. McCallum

U.S. GEOLOGICAL SURVEY

Water-Data Report GA-03-1

Prepared in cooperation with the
State of Georgia and other agencies

Atlanta, Georgia
2004

This document in its entirety is stored in the electronic file.

Westinghouse 2003

V-008

AP1000 Siting Guide: Site Information for an Early Site Permit Application

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1 INTRODUCTION

Part of the EPRI Early Site Permit Demonstration Program was the development of a guide for site selection criteria and procedures. "Siting Guide: Site Selection and Evaluation Criteria for an Early Site Permit Application" has been issued to serve as a roadmap and tool for applicants to use in developing detailed siting plans for their specific region of the country.

This AP1000 document (APP-0000-X1-001) can be used in conjunction with the EPRI Siting Guide: Site Selection and Evaluation Criteria for an Early Site Permit Application for evaluating the siting of an AP1000 to a potential site. It also has sufficient information to support the plant/site interface portions of a Combined License application.

1.1 Background

In November 1990, the Nuclear Power Oversight Committee (NPOC) prepared a strategic plan for building new nuclear power facilities. An essential element in the strategy (Building Block 5) consisted of initiating a project to obtain Nuclear Regulatory Commission (NRC) approval through newly issued 10 CFR Part 52 (Early Site Permits; Standard Design Certifications and Combined Licenses for Nuclear Power Reactors). The plan was designed to be implemented either through attainment of an early site permit (ESP) or through the submission of, and NRC approval of, a combined construction and operating license (COL) application for a design certified ALWR under the NRC standardization rule. In 1990 Sandia National Laboratory issued a Request for Quotation to test the ESP process in a demonstration program. In early 1991, the Joint Contractors were formed and selected by the DOE through SNL to implement the Early Site Permit Demonstration Program. The Joint Contractors were assisted by the Electric Power Research Institute (EPRI) and the Nuclear Management and Resources Council (NUMARC) and developed a phased approach to the preparation, review, and application to NRC for acceptance of an early site permit. An output of this effort was the EPRI Siting Guide.

1.2 Purpose and Goals

The EPRI Siting Guide has been designed to be responsive to 10 CFR 52, 10 CFR 100, and related regulations and guidance, and form a framework or roadmap for an applicant to use in developing a detailed siting plan for a specific region of the country. The purpose and scope of this AP1000 siting information document (APP-0000-X1-001) is to provide specific AP1000 information relating directly to the Siting Guide. It is based upon providing information for a single AP1000. If siting a twin unit, values should be doubled except for the acreage required. To determine the amount of land area required for a twin station a site specific plot plan should be developed.

1.3 Report Structure

This section provides an overview of the balance of the report. Section 2.0 presents AP1000 design information in the same order and format as criteria are presented in Section 3 of the EPRI Siting Guide. The discussion of the bases for criteria and the use of design information is contained in the Siting Guide and not repeated here. Note that all data in this AP1000 document is reference in that the data is controlled in some other AP1000 design document. Section 3 of this AP1000 Siting Guide contains detailed site interface information not addressed in the EPRI Siting Guide. Section 4 contains other information identified as Plant Parameter Envelopes that are not covered in the balance of this document. Section 5 is an addition to the information presented in the EPRI siting Guide. The section contains a listing of the site related Combined License (COL) information items identified in the AP1000 Design Control Document. These COL information items are not necessarily required for an Early Site Permit, but they are required to be part of a COL for an AP1000. As such, this information will ultimately be required by NRC and should be considered in the planning for site licensing activities.

2
DETAILED DISCUSSION OF AP1000 SITING INFORMATION

This section provides detailed AP1000 siting information for each siting criterion of the EPRI Siting Guide. This information is presented so that it can be applied to an ESP or COL application anywhere in the continental United States. Accordingly, some "customization" of utility functions may be appropriate for specific regions; and some information may not be applicable for some siting applications.

Each applicant should also conduct a review of the materials in this document; the state siting, emergency planning, and environmental regulations applicable to the region of interest; and the physical characteristics of the region of interest.

Plant Parameters Envelopes (PPEs) define the envelope of the AP1000/site interface conditions that, if not satisfied by the site, may preclude locating AP1000 on the selected site. An ESP or COL applicant can utilize PPEs to represent a bound on whether an AP1000 can be considered for the site without further analysis and justification to NRC.

2.1 Health and Safety Criteria

2.1.1 Accident Cause-Related Criteria

2.1.1.1 Geology/Seismology

Current NRC regulations identify three geologic, seismologic, and soil parameters that must be evaluated to determine the suitability of prospective sites. First, the Safe Shutdown Earthquake (SSE) must be determined to establish a vibratory ground motion design basis, and detailed information regarding capable tectonic structures and sources are needed to determine the SSE. Second, the occurrence of, or potential for, surface faulting or deformation must be identified and evaluated to permit evaluation of site conditions with respect to standard facility designs. Third, other geologic conditions (e.g., geologic hazards and soil characteristics) that could affect the safety of a facility must also be evaluated.

The following site parameter criteria are intended to provide applicants with specific values included in the AP1000 Design Certification for use in ESP and COL application. The criteria discussed in the following geology/seismology sections provide a set of conditions within which an AP1000 can be sited without additional licensing.

2.1.1.1.1 Vibratory Ground Motion

See Section 4, Table Item 1.5.

2.1.1.1.2 Capable Tectonic Structures or Sources

The AP1000 Design Certification provides for no fault displacement potential within the investigative area.

2.1.1.1.3 Surface Faulting and Deformation

With regard to surface faulting and deformation, no absolute exclusionary criteria have been identified for AP1000 other than the fault displacement criteria addressed in 2.1.1.1.2.

2.1.1.1.4 Geologic Hazards

With regard to geologic hazards, no absolute exclusionary criteria have been identified for AP1000. Therefore, geologic hazards should be addressed as an avoidance criterion. The following geologic and related man-made conditions should be avoided in locating a facility:

- Areas of active (and dormant) volcanic activity;
- Subsidence areas caused by withdrawal of subsurface fluids such as oil or groundwater, including areas which may be effected by future withdrawals;
- Potential unstable slope areas, including areas demonstrating paleolandslide characteristics;
- Areas of potential collapse (e.g., karstic areas in limestone, salt, or other soluble formations);
- Mined areas, such as near-surface coal mined-out areas, as well as areas where resources are present and may be exploited in the future;
- Areas subject to seismic and other induced water waves and floods.

2.1.1.1.5 Soil Stability

With regard to soil stability, the AP1000 structural design is based on the AP600 design. AP600 has an average allowable static soil bearing capacity requirement of 8000 pounds per square inch or greater and a shear wave velocity requirement of 1000 ft/sec or greater. The current AP1000 Design Certification is based upon a rock foundation with the average allowable soil bearing capacity to be greater than or equal to 8400 lb/ft^2 over the footprint of the nuclear island at its excavation depth. The shear wave velocity shall be greater than or equal to 3500 ft/sec based upon low-strain, best-estimate soil properties over the footprint of the nuclear island at its excavation depth. There are no constraints on soils surrounding the nuclear island. No liquefaction potential is assumed. We expect to expand the licensed soil stability requirements for AP1000 to be at least those of AP600 at the time of Combined License application or before.

2.1.1.2 Cooling System Requirements

Since AP1000 is a passive nuclear plant, it requires no safety-related heat sink to reach safe shutdown other than the water contained in its passive cooling system tank located atop the reactor building. Thus a safety-related ultimate heat sink system similar to traditional nuclear plants is not required. The ultimate heat sink for a passive plant is air, which is motivated by natural convection over the containment vessel.

The AP1000 has two nonsafety-related systems for discharging waste heat from the plant. These are a conventional circulating water system to remove the waste heat related to power production and a smaller service water system. The service water system in AP1000 has its own cooling tower, which is separate from the circulating water system. The circulating water system pump discharge lines connect to a common header which connects to the inlet water boxes of the condenser as well as supplies cooling water to the Turbine Cooling System (TCS) and condenser vacuum pump seal water heat exchangers.

AP1000 circulating water requirements can vary greatly depending on site specific conditions and limitations. The AP1000 requires no more or no less circulating water than any other similarly sized nuclear plant. Essentially the plant needs to reject approximately 2/3 of 3415 MWt or about 2270 MWt. If the plant uses a cooling tower, site ambient air temperature and humidity conditions, and the design rise across the cooling tower / condenser are needed to estimate the required flow rate. (A very rough estimate is that the required flow rate is somewhere between 450,000 gpm to 850,000 gpm). The AP1000 design used as a reference for Design Certification assumes a circulating water system with a cooling tower, a flow rate of 600,000 gpm, and a 25.2 °F range.

Make-up for a circulating water system that utilizes a cooling tower can be estimated to be up to 4% of the circulating water flow rate.

The service water system consists of two 100-percent-capacity service water pumps, automatic backwash strainers, a two-cell cooling tower with a divided basin, and associated piping, valves, controls, and instrumentation.

The service water pumps, located in the turbine building, take suction from piping which connects to the basin of the service water cooling tower. Service water is pumped through strainers to the component cooling water heat exchangers for removal of heat. Heated service water from the heat exchangers then returns through piping to a mechanical draft cooling tower where the system heat is rejected to the atmosphere. Cool water, collected in the tower basin, flows through fixed screens to the pump suction piping for recirculation through the system.

NOMINAL SERVICE WATER FLOWS AND HEAT LOADS AT DIFFERENT OPERATING MODES

	Component Cooling Water Pumps and Heat Exchangers	SWS Pumps and Cooling Tower Cells (Number Normally is Service)	Flow (gpm)	Heat Transferred (Btu/hr)
Normal Operation (Full Load)	1	1	8,000	$83x10^6$
Cooldown	2	2	16,000	$296x10^6$ ($148x10^6$ per cell)
Refueling (Full Core Offload)	2	2	16,000	$74x10^6$
Plant Startup	2	2	16,000	$96x10^6$
Minimum to Support Shutdown Cooling and Spent Fuel Cooling	2	2	14,400	$240x10^6$ ($120x10^6$ per cell)

A small portion of the service water flow is normally diverted to the circulating water system (CWS) basin. This blowdown is used to control levels of solids concentration in the SWS. [An alternate blowdown flow path is provided to the waste water system (WWS) for times when the CWS is not operating.] This design affords a single blowdown interface from the CWS to the site.

Make-up for the service water cooling tower is estimated to be 80 gpm nominally. Potable water and sanitary drain requirements can be estimated based on the assumption that there may be up to 300 operating personnel required for the first single unit and up to 420 operating personnel required for the first twin unit. The AP1000 design for these systems is based upon 1000 persons on site and 100 gallons/day/person.

2.1.1.2.1 Cooling Water Supply

PPE Section	Requirement	AP1000 Value
2.7.15	Makeup Flow Rate (Closed Cycle Systems)	See Section 4, Table Item 2.7.15
2.7.16 2.8.15 2.10.11	Maximum Consumption of Raw Water (Closed Cycle System)	See Section 4, Table Items 2.7.16, 2.8.15 and 2.10.11

PPE Section	Requirement	AP1000 Value
2.7.17 2.8.16 2.10.12	Monthly Average Consumption of Raw Water (Closed Cycle Systems)	See Section 4, Table Items 2.7.17, 2.8.16 and 2.10.12
2.9.2	Cooling Water Flow Rate (Cooling Tower)	See Section 4, Table Item 2.9.2

2.1.1.2.2 Ambient Temperature Requirements

PPE Section	Requirement	AP1000 Value
2.1.1	Normal Maximum Ambient Temperature with 1% Exceedance	See Section 4, Table Item 2.1.1
2.1.2	Normal Maximum Wet Bulb Temperature with 1% Exceedance	See Section 4, Table Item 2.1.2
2.1.3	Normal Minimum Ambient Temperature with 1% Exceedance	See Section 4, Table Item 2.1.3
2.1.5	Maximum Safety Ambient Temperature with 0% Exceedance	See Section 4, Table Item 2.1.5
2.1.6	Maximum Safety Wet Bulb Temperature with 0% Exceedance	See Section 4, Table Item 2.1.6
2.1.7	Minimum Safety Ambient Temperature with 0% Exceedance	See Section 4, Table Item 2.1.7
2.7.3 2.8.2	Approach Temperature	See Section 4, Table Items 2.7.3 and 2.8.2

2.1.1.3 Flooding

The maximum flood level assumed for AP1000 is the plant design grade elevation. The standard grid coordinate system for AP1000 labels plant grade as plant elevation 100 ft. Structural analyses have assumed grade to be at 100 ft. Actual grade will be a few inches lower to prevent surface water from entering doorways.

Adverse effects of flooding due to high water or ice effects do not have to be considered for site-specific non-safety-related structures and water sources outside the scope of the certified AP1000 design. Flooding of intake structures, cooling canals, or reservoirs or channel diversions would not prevent safe operation of the plant.

2.1.1.4 Nearby Hazardous Land Uses

AP1000 has no specific requirements or restrictions on nearby land use over and above those generally imposed by NRC for plants of this type. There are design provisions for detection of aerosols that may be toxic to the main control room staff and there are combined license applicant action items requiring identification of nearby hazardous land use.

2.1.1.5 Extreme Weather Conditions

See Section 4, Table Item 1.

2.1.1.5.1 Winds

The design wind is specified as a basic wind speed of 145 mph with an annual probability of occurrence of 0.02 based on the most severe location identified in American Society of Civil Engineers," Minimum Design Loads for Buildings and Other Structures," ASCE 7-98. This wind speed is the 3 second gust speed at 33 feet above the ground in open terrain (ASCE 7-98, exposure C). This basic wind speed of 145 mph is the 3 second gust speed that has become the basis of wind design codes since 1995. It corresponds to the 110 mph fastest mile wind used as the basis for the AP600 design in accordance with the 1988 edition of ASCE 7-98. Higher winds with a probability of occurrence of 0.01 are used in the design of seismic Category I structures by using an importance factor of 1.15.

2.1.1.5.2 Precipitation

There are no additional AP1000 requirements or restrictions.

2.1.2 Accident Effects-Related

2.1.2.1 Population

There are no additional or specific AP1000 requirements or restrictions related to population concentration or distribution. See Section 4, Table Item 9.6.6.

2.1.2.2 Emergency Planning

There are no additional or specific AP1000 requirements or restrictions related to emergency planning.

2.1.2.3 Atmospheric Dispersion

See Section 4, Table Item 9.1.

2.1.3 Operational Effects-Related

2.1.3.1 Surface Water – Radionuclide Pathway

See Section 4, Table Item 10.1.

There are no additional or specific AP1000 requirements or restrictions related to radionuclide pathways.

2.1.3.1.1 Dilution Capacity

There are no additional or specific AP1000 requirements or restrictions related to dilution capacity.

2.1.3.1.2 Baseline Loadings

There are no additional or specific AP1000 requirements or restrictions related to baseline loadings.

2.1.3.1.3 Proximity to Consumptive Users

There are no additional or specific AP1000 requirements or restrictions related to proximity of consumptive users.

2.1.3.2 Groundwater Radionuclide Pathway

There are no additional or specific AP1000 requirements or restrictions related to the groundwater radionuclide pathway.

2.1.3.3 Air Radionuclide Pathway

There are no additional or specific AP1000 requirements or restrictions related to air radionuclide pathway.

2.1.3.3.1 Topographic Effects

There are no additional or specific AP1000 requirements or restrictions related to the site topography as it relates to air radionuclide pathway.

2.1.3.3.2 Atmospheric Dispersion

See Section 4, Table Item 9.2.

2.1.3.4 Air-Food Ingestion Pathway

There are no additional or specific AP1000 requirements or restrictions related to the air-food ingestion pathway.

2.1.3.5 Surface Water – Food Radionuclide Pathway

There are no additional or specific AP1000 requirements or restrictions related to the use of irrigation waters in downstream areas is a potential pathway for radionuclides.

2.1.3.6 Transportation Safety

There are no additional or specific AP1000 requirements or restrictions related to potential impacts from facility operations on transportation safety that could occur as a result of increased hazards such as fog and ice from the operation of cooling systems (e.g., cooling towers and cooling reservoirs).

2.2 Environmental Criteria

2.2.1 Construction-Related Effects on Aquatic Ecology

2.2.1.1 Disruption of Important Species/Habitats

There are no additional or specific AP1000 requirements or restrictions related to the disruption of important species or habitats.

2.2.1.2 Bottom Sediment Disruption Effects

There are no additional or specific AP1000 requirements or restrictions related to bottom sediment disruption effects. The nature and extent of construction and cooling water related disruption is site specific.

2.2.1.2.1 Contamination

There are no additional or specific AP1000 requirements or restrictions related to contamination.

2.2.1.2.2 Grain Size

There are no additional or specific AP1000 requirements or restrictions related to grain size.

2.2.2 Construction-Related Effects on Terrestrial Ecology

2.2.2.1 Disruption of Important Species/Habitats and Wetlands

There are no additional or specific AP1000 requirements or restrictions related to construction-related effects on terrestrial ecology.

2.2.2.1.1 Important Species/Habitats

There are no additional or specific AP1000 requirements or restrictions related to construction-related effects on important species or their habitats.

2.2.2.1.2 Groundcover/Habitat

There are no additional or specific AP1000 requirements or restrictions related to construction related effects on groundcover.

2.2.2.1.3 Wetlands

There are no additional or specific AP1000 requirements or restrictions related to construction-related effects on wetlands.

2.2.2.2 Dewatering Effects on Adjacent Wetlands

During construction, dewatering is required for AP1000 to the depth of 40 feet below the working grade elevation for the excavation of the Nuclear Island. The footprint of this excavation is an irregular rectangle about 260 feet by 160 feet. In addition, dewatering will be required for the site specific circulating water system. At a minimum this excavation will include the condenser waterbox sump under the turbine building, the circulating water pipe trench and the pump house or cooling tower sump. After plant completion, dewatering is not required.

2.2.2.2.1 Depth to Water Table

See Section 4, Table Item 1.8.2.

2.2.2.2.2 Proximal Wetlands

There are no additional or specific AP1000 requirements or restrictions related to the proximity of wetlands.

2.2.3 Operational-Related Effects on Aquatic Ecology

2.2.3.1 Thermal Discharge Effects

2.2.3.1.1 Migratory Species Effects

There are no additional or specific AP1000 requirements or restrictions related to potential effects on migratory species water and land use during construction.

2.2.3.1.2 Disruption of Important Species/Habitats

There are no additional or specific AP1000 requirements or restrictions related to the disruption of important species or their habitats during plant operation.

2.2.3.1.3 Water Quality

Most of the values presented below for AP1000 are estimates for use in preliminary site investigations. AP1000 is designed to be adaptable to a variety of cooling water sources. Details of blowdown rates, constituents and concentrations will be site specific. They are a function of the type of cooling (cooling tower or once through), the inlet water quality and the cycles of concentration. Once-through discharge temperature and temperature rise will most likely be dictated by inlet temperature, inlet flow rate and local environmental regulations. The values presented should envelop most sites in the United States. They are as follows:

PPE Section	Requirement	AP1000 Value
2.7.4 2.8.3 2.10.2	Blowdown Constituents and Concentrations	See " Blowdown Constituents and Concentrations" table directly below this table
2.7.5 2.10.3	Blowdown Flow Rate (Mechanical Draft & Pond)	See Section 4, Table Items 2.7.5 and 2.10.3
2.8.4	Blowdown Flow Rate (Natural Draft)	See Section 4, Table Item 2.8.4
2.7.6 2.8.5 2.10.4	Blowdown Temperature (Closed Cycle)	See Section 4, Table Items 2.7.6, 2.8.5 and 2.10.4
2.7.9 2.8.8 2.10.7	Cycles of Concentration (Closed Cycle)	See Section 4, Table Items 2.7.9, 2.8.8 and 2.10.7
2.9.1	Cooling Water Discharge Temp (Once-	See Section 4, Table Item 2.9.1

PPE Section	Requirement	AP1000 Value
	through)	
2.9.3	Cooling Water Temperature Rise (Once-through)	See Section 4, Table Item 2.9.3
2.9.5	Heat Rejection Rate (Once-through)	See Section 4, Table Item 2.9.5

Blowdown Constituents and Concentrations

Constituent	Concentration (ppm)[1]		
	River Source	Well/Treated Water	Envelope
Chlorine demand	10.1	--	10.1
Free available chlorine	0.5	--	0.5
Chromium	--	--	--
Copper	--	6	6
Iron	0.9	3.5	3.5
Zinc	--	0.6	0.6
Phosphate	--	7.2	7.2
Sulfate	599	3,500	3,500
Oil and grease	--	--	--
Total dissolved solids	--	17,000(1)	17,000(1)
Total suspended solids	49.5	150	150
BOD, 5-day	--	--	--

(1) Assumed cycles of concentration equals 4

These parameters define the thermal and water quality impacts that cooling system blowdown effluents will have on the receiving water body for the various cooling system configurations.

2.2.3.2 Entrainment/Impingement Effects

2.2.3.2.1 Entrainable Organisms

There are no additional or specific AP1000 requirements or restrictions related to entrainable organisms.

2.2.3.3 Dredging/Disposal Effects

2.2.3.3.1 Upstream Contamination Sources

There are no additional or specific AP1000 requirements or restrictions related to potential upstream contamination sources.

2.2.3.3.2 Sedimentation Rates

There are no additional or specific AP1000 requirements or restrictions related to sedimentation rates.

2.2.4 Operational-Related Effects on Terrestrial Ecology

2.2.4.1 Drift Effects on Surrounding Areas

2.2.4.1.1 Important Species Habitat Areas

There are no additional or specific AP1000 requirements or restrictions related to the plants operational drift effects on important species habitat areas.

2.2.4.1.2 Source Water Suitability

There are no additional or specific AP1000 requirements or restrictions related to the drift effects of site source water including evaporation rate and concentrations of dissolved solids.

2.3 Socioeconomics Criteria

The siting, construction and operation of a nuclear power station can place stresses on the local labor supply, transportation facilities, and community services. An evaluation of suitability of nuclear power station sites should include an assessment of impacts of construction and operation, including transmission and transportation corridors, and potential problems relating to community services (e.g., schools, police and fire protection, water and sewage, and health facilities).

Incompatible land uses, referred to as "nearby hazardous land uses," are discussed in Section 3.1.1.4. The following sections discuss the socioeconomic and environmental justice criteria associated with construction and operation of a nuclear power facility.

2.3.1 Socioeconomic - Construction Related Effects

See Section 4, Table Item 29.4.

There are no additional or specific AP1000 requirements or restrictions related to construction workforce or other construction related socioeconomic effects.

2.3.2 Socioeconomics – Operation

The operation of a single AP1000 requires a labor force of about 300 skilled workers (including security personnel and an allowance for attrition) for the first plant and about 200 each for follow plants. If twins are paced on one site the first twin requires about 420 skilled workers (including security personnel and an allowance for attrition) and follow twins require about 320.

2.3.3 Environmental Justice

There are no additional or specific AP1000 requirements or restrictions related to environmental justice

2.3.4 Land Use

There are no additional or specific AP1000 requirements or restrictions related to land use. Land uses that are incompatible with nuclear power facilities because of the hazards they pose to safe operation are categorized as "nearby hazardous land uses;" these are discussed in Section 2.1.1.4.

2.4 Engineering and Cost-Related Criteria

This section addresses those criteria that are cost-sensitive. Consideration of these criteria allows important site-related cost differentials to be considered in the site selection process. Because of the amount of detailed design work incorporated into the AP1000 design, cost estimates for it should be considered relatively reliable. This is due to the amount of reusable design created for AP600 and the resulting detailed bill of material developed during the design phase.

Cost estimates specified in these criteria should be developed in constant-year dollars, taking into account timing of each expense and a consistent discount rate. For example, a "present value" for operational costs such as water pumping and transmission losses should be developed so these costs can be directly compared with construction costs. All costs should be discounted to a single year.

2.4.1 Health and Safety Related Criteria

A number of these issues are also addressed in Section 3.1 and from a site suitability perspective, it may be helpful to revisit these evaluations as part of the development of the Engineering and Cost-Related criteria. Correlation with the health and safety utility functions may be helpful in evaluating cost.

2.4.1.1 Water Supply

There are no additional or specific AP1000 requirements or restrictions related to the cost of water supply. The analysis in this section addresses the costs associated with supplying the facility water requirements, in light of future, competitive, non-facility consumption rates.

2.4.1.2 Pumping Distance

There are no additional or specific AP1000 requirements or restrictions related to the cost of constructing pumping stations and infrastructure developments necessary to transport water from the source to the site.

2.4.1.3 Flooding

Flooding was initially treated in Section 2.1.1.3. The site storm drain system should be adequate to remove expected precipitation without flooding. There are no additional or specific AP1000 requirements or restrictions related to the cost of flooding protection.

2.4.1.4 Vibratory Ground Motion

For the AP1000, site cost increments that are a function of Peak Ground Acceleration do not exist as a result of standardization. There may a cost associated with site soil preparation for foundations of non-safety-related buildings or construction load paths.

2.4.1.5 Soil Stability

Soil stability was initially treated in Section 2.1.1.1.4 from the standpoint of soil properties and their relationship to the suitability of foundation conditions. For this criterion, the applicant should estimate the cost of site-specific foundation design features and associated construction requirements that might arise from soil conditions (e.g., slope stability).

2.4.1.6 Industrial Site Remediation

The purpose of this criterion is to capture costs associated with any environmental cleanup activities, that may be required at industrial sites before they can be developed for a nuclear power facility. There are no additional or specific AP1000 requirements or restrictions related to the cost of remediation.

2.4.2 Transportation or Transmission-Related Criteria

AP1000 has been designed to allow shipment by rail. It is preferable to ship larger units (assembled from the rail shippable units) by barge. An access and transportation plan will be required for each site to optimize the balance between offsite fabrication, shipping and onsite assembly. See Section 4, Table Item 29.1.

2.4.2.1 Railroad Access

See 2.4.2 above. An adequate railroad spur is recommended, but not required.

2.4.2.2 Highway Access

There are no additional or specific AP1000 requirements or restrictions related to highway access.

2.4.2.3 Barge Access

See 2.4.2 above. Adequate barge and load handling facilities will be required if barge delivery is appropriate for the site in question.

2.4.2.4 Transmission Cost and Market Price Differentials

2.4.2.4.1 Transmission Construction

AP1000 has no requirement for redundant connections to transmission grids. There are no additional or specific AP1000 requirements or restrictions related to transmission.

2.4.2.4.2 Electricity Market Price Differentials

There are no additional or specific AP1000 requirements or restrictions related to electricity market price differentials.

2.4.3 Criteria Related to Land Use and Site Preparation

2.4.3.1 Topography

The standard AP1000 design is based upon a relatively level site. Site plot plans for a variety of circulating water supply options are shown on AP1000 drawings APP-0000-X2-010 through APP-0000-X2-022. The standard AP1000 plot plans showing construction laydown, access and assembly areas are AP1000 drawings APP-0000-X2-810 through APP-0000-X2-822. The costs associated with any topographic features that would translate into site-specific differences in site preparation costs. For example, extensive cutting and filling, grading, and blasting could be factors that differentiate among sites.

2.4.3.2 Land Rights

There are no additional or specific AP1000 requirements or restrictions related to land rights.

2.4.3.3 Labor Rates

A significant portion of AP1000 can be fabricated in a shop or shipyard. This reduces the expected amount of site labor for a plant of this type and size. The impact of this construction approach may require negotiations with impacted labor unions both at the site and at the fabrication factories.

3
ADDITIONAL DETAIL SITE INTERFACES

3.1 Security Criteria

The AP1000 Design Certification is based upon the existence of an adequate site boundary security system. There are no additional or specific AP1000 requirements or restrictions related to land rights.

3.2 Grounding and Lightning Criteria

The AP1000 Design Certification is based upon the existence of an adequate station grounding system and a connection between it and the lightning protection system. There are no additional or specific AP1000 requirements or restrictions.

3.3 Raw Water Criteria

The AP1000 raw water treatment system will be based upon an adequate supply of surface water, clear well water or municipal water.

3.4 Detail Site Interface Dimensions

These AP1000 documents define detailed site interface dimensions.

AP1000 Document Number	Document Title
APP-0000-X2-010	AP1000 Single Unit Site Plot Plan Plant with Pumphouse
APP-0000-X2-011	AP1000 Single Unit Site Plot Plan Plant with Cooling Tower
APP-0000-X2-020	AP1000 Twin Unit Site Plot Plan with Separate Pumphouses
APP-0000-X2-021	AP1000 Twin Unit Site Plot Plan with Common Pumphouse
APP-0000-X2-022	AP1000 Twin Unit Site Plot Plan with Cooling Tower
APP-0000-X2-810	AP1000 Single Unit Construction Plot Plan Plant with Pumphouse

APP-0000-X2-811	AP1000 Single Unit Construction Plot Plan Plant with Cooling Tower
APP-0000-X2-820	AP1000 Twin Unit Construction Plot Plan with Separate Pumphouses
APP-0000-X2-821	AP1000 Twin Unit Construction Plot Plan with Common Pumphouse
APP-0000-X2-822	AP1000 Twin Unit Construction Plot Plan with Cooling Towers
APP-0000-X4-901	AP1000 Plant Grid Coordinates & Column Line Identification View A-A
APP-0000-X4-902	AP1000 Plant Grid Coordinates & Column Line Identification Views B-B
APP-0000-X4-903	AP1000 Plant Grid Coordinates & Column Line Identification Views C-C
APP-0030-X4-001	AP1000 Plant Grid Coordinates & Column Line Identification Plan
APP-0031-X4-001	Yard Arrangement Fuel Tank Storage/Transfer Facility
APP-0031-X4-002	Plant Grid Coordinates for Fuel Tank Storage/Transfer Facility Plan
APP-0035-X4-001	Yard Arrangement CWS Cooling Tower
APP-00350-X4-001	Yard Arrangement CWS Cooling Tower Area
APP-0036-X4-001	Yard Arrangement Hydrogen Storage Tank Area
APP-00360-X4-001	Yard Arrangement Hydrogen Storage Tank Area
APP-0070-X4-001	AP1000 Plant Grid Coordinates & Roof Plan

3.5 Detail Fuel and Waste Shipping Information

3.5.1 Information on Annual Fuel Requirements

3.5.1.1 Standard Technical Configuration

Reactor Power	3400 MW_t
Plant Power	1117 – 1150 MW_e
Number of Plants per Unit	1

3.5.1.2 Expected Fuel Loading

Initial Core Fuel Loading	84.5 MTU

Annual Average Fuel Loading 24.4 MTU

3.5.1.3 Average Fuel Enrichment (initial load)

Region 1	2.35 weight % U-235
Region 2	3.40 weight % U-235
Region 3	4.45 weight % U-235

3.5.1.4 Fuel Form

Total mass	1730 lb/assembly
Uranium mass	0.5383 MTU/assembly
Volume (FA envelope)	13404.3 in^3
Outside Dimensions	8.426x8.426x188.8 in
Number of Assemblies (Initial)	157
Number of Assemblies (Reload)	68 on 18 month cycle

3.5.1.5 Fuel Materials

Fuel	211,588 lb UO_2
Structure and Cladding	43,105 lb Zircaloy or ZIRLO™
	270 lb Alloy 718 (top & bottom Grids for 157 assemblies)

3.5.1.6 Expected Typical Transport Truck

3.5.1.7 Fresh Fuel Transport Containers

Capacity	2 assemblies per container
Shipping	6 containers per truck

3.5.1.8 Fuel reload data:

Cycle Length	18 months - 520 EFPD @ 3400 MWT
Capacity Factor	95% including refueling outage
Reload fuel requirement	68 Fuel Assemblies
Average Enrichment	4.51 w/o U235

3.5.1.9 Spent fuel data:

At 5 years decay, the average spent fuel assembly curie content:

Actinides	8.506E+04 curies
Fission Products	4.450E+05 curies
Total	5.301E+05 curies

3.5.1.10 Spent fuel data:

At 5 years decay, the average spent fuel assembly curie content:

Actinides	8.506E+04 curies
Fission Products	4.450E+05 curies
Total	5.301E+05 curies

3.5.1.11 Spent Fuel Shipping Information

Quantity of spent fuel (MTU):

Truck Cask	To be provided later
Rail Car Cask	To be provided later

3.2.1.12 Average Fuel Burnup

Expected	21000 MWD/MTU (3400 MWt x 520 efpd / 84.5 MTU)
Design	60000 MWD/MTU

3.2.1.13 Estimate of Decay Heat in watts per MTU after 5 years of decay

While we use ORIGEN, we have not used it for decay heat calculation for AP1000. We therefore have estimated decay heat based on ANS 1979 standards, with 0 sigma margin, at five years to be 1.127E-4 watts/watt. With core power of 3400 MW and core loading of 84.5 MTU, the estimated specific decay heat for AP1000 is 4530 watts/MTU.

3.5.1.14 Estimates of spent fuel inventories and radioactivity

ORIGEN results for spent fuel inventories and radioactivity are addressed by AP1000 document APP-SSAR-GS2-496. This is based on one burned AP1000 assembly, decayed to 5 years. (Note that ORIGEN was run assuming a core loading of 83.6 MTU.) The 5 year decay data is in the last column (as label indicates). Also note that the inventory units are total Curies (based on 532337.6 grams for an assembly).

3.5.1 Information on Expected Low Level Waste Production

3.5.2.1 LLW Production

Volume	1964 cubic feet per year (average, as shipped)
Activity	1830 curies per year (average, as shipped)

3.5.2.2 LLW from Decommissioning

No AP1000 specific estimate has been made. Information from Sizewell indicates 6200 cubic meters of LLW from decommissioning. The AP1000 value should be significantly less (maybe half) considering the design differences.

4

OTHER PLANT PARAMETER ENVELOPES

Structure, System, Component			(Value)
1.	<u>Structures</u>		
	1.1	Foundation Embedment	39' 6" to bottom of Basemat from Plant Grade
	1.2	Height	234' 0"
	1.4	Precipitation (for Roof Design)	
		1.4.1 Maximum Rainfall Rate	19.4 in/hr (6.3 in/5 min)
		1.4.2 Snow Load	75 lbs/sq ft on ground with exposure factor of 1.0 and importance factor of 1.2 (safety) and 1.0 (non-safety)
	1.5	Safe Shutdown Earthquake (SSE)	
		1.5.1 Design Response Spectra	modified Regulatory Guide 1.60
		1.5.2 Peak Ground Acceleration	0.30g at base of foundation or at grade
		1.5.3 Time History	Envelope SSE Resp Spectra
		1.5.4 Fault Displacement Potential	None
	1.8	Site Water Level (Allowable)	
		1.8.1 Maximum Flood (or Tsunami)	Plant grade or plant elevation 100 feet. See Section 2.1.1.3
		1.8.2 Maximum Ground Water	Less than 98 feet with plant grade defined at 100 feet.
	1.9	Soil Properties Design Bases	
		1.9.1 Liquefaction	None. See Section 2.1.1.1.5
		1.9.2 Minimum Bearing Capacity (Static)	Greater than or equal to 8,000 pounds per square foot over the footprint of the nuclear island at its excavation depth. See Section 2.1.1.1.5
		1.9.3 Minimum Shear Wave Velocity	Greater than or equal to 1000 ft/sec based on low strain best estimate soil properties. See Section 2.1.1.1.5
	1.11	Tornado (Design Bases)	
		1.11.1 Maximum Pressure Drop	2.0 PSID
		1.11.2 Maximum Rotational Speed	240 MPH
		1.11.3 Maximum Translational Speed	60 MPH
		1.11.4 Maximum Wind Speed	300 MPH

Structure, System, Component			(Value)
	1.11.5	Missile Spectra	A 4000 pound automobile at 105 mph horizontal and 74 mph vertical, a 275 pound 8 inch shell at 105 mph horizontal and 74 mph vertical, and a 1 inch diameter steel ball at 105 mph horizontal and 105 mph vertical.
	1.11.6	Radius of Maximum Rotational Speed	150 ft
	1.11.7	Rate of Pressure Drop	1.2 psi/sec
1.12	Wind		
	1.12.1	Basic Wind Speed	145 MPH. See Section 2.1.1.5.1
	1.12.2	Importance Factors	See Section 2.1.1.5.1
2.	<u>Normal Plant Heat Sink</u>		*Also see discussion in Section 2.1.1.2*
2.1	Ambient Air Requirements		
	2.1.1	Normal Shutdown Max Ambient Temp (1% Exceedance)	100 °F db/77 °F wb coincident
	2.1.2	Normal Shutdown Max Wet Bulb Temp (1% Exceedance)	80 °F wb non-coincident
	2.1.3	Normal Shutdown Min Ambient Temp (1% Exceedance)	-10 °F
	2.1.5	Rx Thermal Power Max Ambient Temp (0% Exceedance)	115 °F db/80 °F wb coincident
	2.1.6	Rx Thermal Power Max Wet Bulb Temp (0% Exceedance)	81 °F wb non-coincident
	2.1.7	Rx Thermal Power Min Ambient Temp (0% Exceedance)	-40 °F
2.2	Blowdown Pond Acreage		24 hr blowdown
2.3	Condenser/Heat Exchanger Duty		7.54E9 Btu/hr
2.6	Maximum Inlet Temp Condenser/Heat Exchanger		91 °F
2.7	Mech Draft Cooling Towers		Also see discussion in Section 2.1.1.2
	2.7.1	Acreage	25 acres
	2.7.3	Approach Temperature	10 °F
	2.7.4	Blowdown Constituents and Concentrations	See Section 2.2.3.1.3
	2.7.5	Blowdown Flow Rate (Circ and Service Water)	6000 (24,500 max) gpm
	2.7.6	Blowdown Temperature (Circ and Service Water)	100 °F
	2.7.7	Cooling Tower Temperature Range	25.2 °F
	2.7.8	Cooling Water Flow Rate	600,000 gpm (nominal)
	2.7.9	Cycles of Concentration	4

Structure, System, Component			(Value)
	2.7.10	Evaporation Rate (Circulating and Service Water)	15,000 gpm
	2.7.12	Heat Rejection Rate	7.54E9 Btu/hr
	2.7.13	Height	60 ft
	2.7.15	Makeup Flow Rate (Circulating and Service Water)	21,000 gpm
	2.7.16	Maximum Consumption of Raw Water (Circulating and Service Water)	30,000 gpm
	2.7.17	Monthly Average Consumption of Raw Water (Circulating and Service Water)	21,000 gpm
	2.7.18	Noise	55 dba at 1000 ft
	2.7.22	Stored Water Volume	7,000,000 gal
2.8		Natural Draft Cooling Towers	Also see discussion in Section 2.1.1.2
	2.8.1	Acreage	2.3 acres without basin
	2.8.2	Approach Temperature	10 °F
	2.8.3	Blowdown Constituents and Concentrations	See Section 2.2.3.1.3
	2.8.4	Blowdown Flow Rate (Circ and Service Water)	6,000 (24,500 max) gpm
	2.8.5	Blowdown Temperature (Circ and Service Water)	100 °F
	2.8.6	Cooling Tower Temperature Range	25.2 °F
	2.8.7	Cooling Water Flow Rate	600,000 gpm
	2.8.8	Cycles of Concentration	4
	2.8.9	Evaporation Rate (Circulating and Service Water)	15,000 gpm
	2.8.11	Heat Rejection Rate	7.54E9 Btu/hr
	2.8.12	Height	500 ft
	2.8.14	Makeup Flow Rate (Circulating and Service Water)	21,000 gpm
	2.8.15	Maximum Consumption of Raw Water (Circulating and Service Water)	30,000 gpm
	2.8.16	Monthly Average Consumption of Raw Water (Circulating and Service Water)	21,000 gpm
	2.8.17	Noise	55 dba at 1000 ft
	2.8.20	Stored Water Volume	5,500,000 gal

Structure, System, Component			(Value)
2.9	Once-Through Cooling		Also see discussion in Section 2.1.1.2
	2.9.1	Cooling Water Discharge Temperature	88 °F
	2.9.2	Cooling Water Flow Rate	850,000 gpm
	2.9.3	Cooling Water Temperature Rise	18 °F
	2.9.4	Evaporation Rate	14,500 gpm
	2.9.5	Heat Rejection Rate	7.76E9 Btu/hr. See Sections 2.1.1.2.
2.10	Ponds		Also see discussion in Section 2.1.1.2
	2.10.1	Acreage	Site Specific
	2.10.2	Blowdown Constituents and Concentrations	See Section 2.2.3.1.3
	2.10.3	Blowdown Flow Rate	Site Specific
	2.10.4	Blowdown Temperature	Site Specific
	2.10.5	Cooling Pond Temperature Range	Site Specific
	2.10.6	Cooling Water Flow Rate	Site Specific
	2.10.7	Cycles of Concentration	Site Specific
	2.10.8	Evaporation Rate	Site Specific
	2.10.9	Heat Rejection Rate	7.54E9 Btu/hr
	2.10.10	Makeup Flow Rate	Site Specific
	2.10.11	Maximum Consumption of Raw Water	Site Specific
	2.10.12	Monthly Average Consumption of Raw Water	Site Specific
	2.10.13	Stored Water Volume	Site Specific
3.	Ultimate Heat Sink		None. See Section 2.1.1.2
4.	Containment Heat Removal System (Post-Accident)		
4.1	Ambient Air Requirements		
	4.1.1	Maximum Ambient Air Temperature (0% Exceedance)	115 °F db/80 °F wb
	4.1.2	Minimum Ambient Temperature (0% Exceedance)	-40 °F
5.	Potable Water/Sanitary Waste System		
5.2	Discharge to Site Water Bodies		
	5.2.1	Flow Rate	30,000 gal/day normal (single unit) 42,000 gal/day normal (twin unit) 100,000 gal/day (max)
5.4	Raw Water Requirements		
	5.4.1	Maximum Use	100,000 gal/day
	5.4.2	Monthly Average Use	30,000 gal/day normal (single unit) 42,000 gal/day normal (twin unit)

Structure, System, Component			(Value)
6.	Demineralized Water System		
	6.2	Discharge to Site Water Bodies	25 expected (70 max) gpm
		6.2.1 Flow Rate	
	6.4	Raw Water Requirements	
		6.4.1 Maximum Use	200 gpm
		6.4.2 Monthly Average Use	75 gpm
7.	Fire Protection System		
	7.1	Raw Water Requirements	
		7.1.1 Maximum Use	625 gpm
		7.1.2 Monthly Average Use	225,000 gal/mo (5 gpm)
		7.1.4 Stored Water Volume	775,000 gallons
8.	Miscellaneous Drain		
	8.2	Discharge to Site Water Bodies	
		8.2.1 Flow Rate	25 (50) gpm
9.	Unit Vent/Airborne Effluent Release Point		
	9.1	Atmospheric Dispersion (CHI/Q) (Accident)	
		9.1.1 0.5 mile, 0-2 hr	0.61E-3 sec/m^3
		9.1.2 2 mile, 0-8 hr	1.35E-4 sec/m^3
		9.1.5 2 mile, 8-24 hour	1.0E-4 sec/m^3
		9.1.3 2 mile, 1-4 day	5.4E-5 sec/m^3
		9.1.4 2 mile, 4-30 day	2.2E-5 sec/m^3
	9.2	Atmospheric Dispersion (CHI/Q) (Annual Average)	Site Boundary 2.0E-5 sec/m^3
	9.3	Containment Leakage Rate	0.5%/day (+35 scfh/ms line BWR only)
	9.5	Dose Consequences	
		9.5.1 Normal	10CFR20, 10CFR50 APP I
		9.5.2 Post-Accident	10CFR -20, -50 APP I, -100
		9.5.3 Severe Accidents	25 rem wb in 24 hr @ 0.5 mi <1E-6/rx-yr
	9.6	Release Point	
		9.6.1 Configuration (Horiz vs Vert)	Vertical
		9.6.3 Elevation (Normal)	160'
		9.6.4 Elevation (Post Accident)	Ground Level
		9.6.6 Minimum Distance to Site Boundary	0.5 mile
		9.6.7 Temperature	50-120 °F (estimate)
		9.6.8 Volumetric Flow Rate	171, 500 SCFM (Norm)
	9.7	Source Term	
		9.7.1 Gaseous (Normal)	See Table 4
		9.7.2 Gaseous (Post-Accident)	See Chap 15 Tables - Reg Guide 1.70
		9.7.4 Tritium	350 ci/yr

Structure, System, Component	(Value)
10. Liquid Radwaste System	
10.1 Dose Consequences	
10.1.1 Normal	10 CFR 50, Appendix I 10 CFR 20
10.1.2 Post-Accident	10 CFR 20 10 CFR 100
10.2 Release Point	
10.2.1 Flow Rate	1.4 gpm average
10.3 Source Term	
10.3.1 Liquid	0.26 ci/yr, see Table 5
10.3.2 Tritium	1010 ci/yr
11. Gaseous Radwaste System	
12. Solid Radwaste System	
12.1 Acreage	
12.1.1 Low Level Radwaste Storage	2 years @ expected generation rate 1 year @ maximum generation rate
12.2 Solid Radwaste	
12.2.1 Activity	*1830 ci/yr*
12.2.2 Principal Radionuclides	See Table 1
12.2.3 Volume	1964 cu ft/yr avg expected shipped
13. Reactor Coolant System	
14. RCS Cleanup System	
15. CVCS Letdown Subsystem	
16. CVCS Purification Subsystem	
17. CVCS Shim/Bleed Subsystem	
18. Spent Fuel Storage	
18.3 Spent Fuel Dry Storage	
18.3.1 Acreage	15 acres
18.3.2 Minimum Distance to Nearest Residence	3500 ft
18.3.3 Minimum Distance to Power Block	1500-2200 ft
18.3.4 Storage Capacity	60 years dry storage
19. Steam Generator Blowdown System	
20. Standby-Gas Treatment System	
21. Auxiliary Boiler System	
21.1 Exhaust Elevation	150 ft above plant grade
21.2 Flue Gas Effluents	*See Table 2*
21.3 Fuel	
21.3.2 Type	No. 2
21.4 Heat Input Rate (Btu/hr)	156,000,000 Btu/hr
22. Condensate Cleanup System	

Structure, System, Component			(Value)
23.	Gas Storage System		
24.	Heating, Ventilation and Air Conditioning System		
24.1	Ambient Air Requirements		
	24.1.2	Non-safety HVAC max ambient temp (1% Exceedance)	100 °F db/77 °F wb coincident
	24.1.3	Non-safety HVAC min ambient temp (1% Exceedance)	-10 °F
	24.1.4	Safety HVAC max ambient temp (0% Exceedance)	115 °F db/80 °F wb coincident
	24.1.5	Safety HVAC min ambient temp (0% Exceedance)	-40 °F
	24.1.6	Vent System max ambient temp (5% Exceedance)	95 °F dry bulb/77 °F coincident wet bulb
		(1% Exceedance)	100 °F db/77 °F wb coincident
	24.1.7	Vent System min ambient temp (5% Exceedance)	-5 °F
		(1% Exceedance)	-10 °F
25.	Onsite/Offsite Electrical Power System		
25.1	Acreage		
	25.1.1	Switchyard	12 acres
25.3	Duty Cycles		35 peak-to-peak per day
26.	Standby Power System		
26.1	Diesel Capacity (kW)		2 x 4000 kW
26.2	Diesel Exhaust Elevation		50 ft
26.3	Diesel Flue Gas Effluents		See Table 3
26.4	Diesel Fuel		
	26.4.1	Resupply Time	7 days
	26.4.2	Type	No. 2 Oil Per ASTM D 975
26.5	Diesel Noise		55 dba at 1000 ft
26.6	Gas-Turbine Capacity (kW)		None
26.7	Gas-Turbine Exhaust Elevation		None
26.8	Gas-Turbine Flue Gas Effluents		None
26.9	Gas-Turbine Fuel		None
	26.9.2	Type	
26.10	Gas-Turbine Noise		None
27.	Severe Accident Features		
28.	Plant Characteristics		
28.1	Access Routes		
	28.1.3	Heavy Haul Routes	4 acres
	28.1.5	Spent Fuel Cask Weight	100 tons
28.2	Acreage		27 acres

Structure, System, Component			(Value)
	28.4	Megawatts - Thermal	3415 MWt
	28.5	Plant Design Life	60 years
	28.6	Plant Population	
		28.6.1 Operation	About 300. See Section 2.3.2
		28.6.2 Refueling	*1000 people*
	28.9	Station Capacity Factor	93%
29.	Construction		
	29.1	Access Routes	
		29.1.1 Construction Module Dimensions	
		Shipping Dimensions (ft)	
		Reactor Vessel	22 (Dia) x 34 (L)
		Steam Generator	20 (Dia) x 80 (L)
		Turbine Rotor	18 (Dia) x 29 (L)
		Generator Stator	18 (Dia) x 40 (L)
		Modules by Rail	12(H) x 12(W) x 80(L)
		Modules by Barge	90(H) x 82(W) x 93(L) or
			130(Dia) x 51(H)
		29.1.2 Heaviest Construction Shipment	
		Heaviest Shipment Weight	
		Reactor Vessel	652,000 lbs
		Steam Generator	1,464,000 lbs
		Turbine Rotor	350,000 lbs
		Generator Stator	1,020,000 lbs
		Modules by Rail	160,000 lbs.
		Modules by Barge	1,900,000 lbs.
	29.2	Acreage	
		29.2.1 Laydown Area	10 acres
		29.2.2 Temporary Construction Facilities	2.36 acres
	29.3	*Construction*	
		29.3.6 Noise	76-101 db @ 50 ft
	29.4	Plant Population	
		29.4.1 Construction	1200 monthly maximum
	29.5	Site Preparation Duration	18 months with construction and test of 4 to 5 years

Table 1 Principal Radionuclides in Solid Radwaste[1]

Radionuclide	PWR (Ci/yr)
Fe-55	311.488
Fe-59	--
Co-60	287.256
Mn-54	22.428
Cr-51	0.29151
C0-58	62.289
Ni-63	316.386
H-3	1.6057
C-14	0.285
Nb-95	0.3233
Ag-110m	0.04604
Zr-95	0.07163
Ba-140	0.08725
Pu-241	0.114027
La-140	0.04011
Other	29.982
Total (rounded to nearest hundred)	1100

Notes:
(1) See PPE Section 12.2.2

Table 2 Yearly Emissions Auxiliary Boilers[1]

Pollutant Discharged[2]	AP600 Quantity (lbs)
Particulates	17,250
Sulfur oxides	51,750
Carbon monoxide	-
Hydrocarbons	50,100
Nitrogen oxides	

Notes:
(1) See PPE Section 21.2.
(2) Emissions are based on 30 days/year operation for each of the generators.

Table 3 Yearly Emissions From Diesel Generators (DG)[1]

Pollutant Discharged[2]	Two 4000 kW Standby DGs Quantity[2] (lbs)	Two 35 kW Ancillary DGs Quantity[2] (lbs)
Particulates	<800	<10
Sulfur Oxides	<2,500	<5
Carbon Monoxide	<1,000	<30
Hydrocarbons	<600	<11
Nitrogen oxides	<12,000	<140

Notes:
(1) See PPE Section 26.3.
(2) Emissions are based on 4 hrs/month operation for each of the generators.

Table 4
EXPECTED ANNUAL AVERAGE RELEASE OF AIRBORNE RADIONUCLIDES AS DETERMINED BY THE PWR-GALE CODE, REVISION 1 (RELEASE RATES IN Ci/yr)

Noble Gases[1]	Waste Gas System	Building/Area Ventilation: Cont.	Building/Area Ventilation: Auxiliary Building	Building/Area Ventilation: Turbine Building	Condenser Air Removal System	Total
Kr-85m	0.	3.0E+01	4.0E+00	0.	2.0E+00	3.6E+01
Kr-85	1.65E+02	2.4E+03	2.9E+01	0.	1.4E+01	4.1E+03
Kr-87	0.	9.0E+00	4.0E+00	0.	2.0E+00	1.5E+01
Kr-88	0.	3.4E+01	8.0E+00	0.	4.0E+00	4.6E+01
Xe-131m	1.42E+02	1.6E+03	2.3E+01	0.	1.1E+01	1.8E+03
Xe-133m	0.	8.5E+01	2.0E+00	0.	0.	8.7E+01
Xe-133	3.0E+01	4.5E+03	7.6E+01	0.	3.6E+01	4.6E+03
Xe-135m	0.	2.0E+00	3.0E+00	0.	2.0E+00	7.0E+00
Xe-135	0.	3.0E+02	2.3E+01	0.	1.1E+01	3.3E+02
Xe-138	0.	1.0E+00.	3.0E+00	0.	2.0E+00	6.0E+00
					Total	1.1E+04
Additionally:						
H-3 released via gaseous pathway						350
C-14 released via gaseous pathway						7.3
Ar-41 released via containment vent						34
Iodines[1]	**Fuel Handling Area[2]**	**Building/Area Ventilation: Cont.**	**Building/Area Ventilation: Auxiliary Building**	**Building/Area Ventilation: Turbine Building**	**Condenser Air Removal System**	**Total**
I-131	4.5E-03	2.3E-03	1.1E-01	0.	0.	1.2E-01
I-133	1.6E-02	5.5E-03	3.8E-01	2.0E-04	0.	4.0E-01
Radionuclide[1]	**Waste Gas System**	**Building/Area Ventilation: Cont.**	**Building/Area Ventilation: Auxiliary Building**	**Building/Area Ventilation: Fuel Handling Area[2]**		**Total**
Cr-51	1.4E-05	9.2E-05	3.2E-04	1.8E-04		6.1E-04
Mn-54	2.1E-06	5.3E-05	7.8E-05	3.0E-04		4.3E-04

Co-57	0.	8.2E-06	0.	0.	8.2E-06
Co-58	8.7E-06	2.5E-04	1.9E-03	2.1E-02	2.3E-02
C0-60	1.4E-05	2.6E-05	5.1E-04	8.2E-03	8.7E-03
Fe-59	1.8E-06	2.7E-05	5.0E-05	0.	7.9E-05
Sr-89	4.4E-05	1.3E-04	7.5E-04	2.1E-03	3.0E-03
Sr-90	1.7E-05	5.2E-05	2.9E-04	8.0E-04	1.2E-03
Zr-95	4.8E-06	0.	1.0E-03	3.6E-06	1.0E-03
Nb-95	3.7E-06	1.8E-05	3.0E-05	2.4E-03	2.5E-03
Ru-103	3.2E-06	1.6E-05	2.3E-05	3.8E-05	8.0E-05
Ru-106	2.7E-06	0.	6.0E-06	6.9E-05	7.8E-05
Sb-125	0.	0.	3.9E-06	5.7E-05	6.1E-05
Cs-134	3.3E-05	2.5E-05	5.4E-04	1.7E-03	2.3E-03
Cs-136	5.3E-06	3.2E-05	4.8E-05	0.	8.5E-05
Cs-137	7.7E-05	5.5E-05	7.2E-04	2.7E-03	3.6E-03
Ba-140	2.3E-05	0.	4.0E-04	0.	4.2E-04
Ce-141	2.2E-06	1.3E-05	2.6E-05	4.4E-07	4.2E-05

Notes:

1. The appearance of 0. in the table indicates less than 1.0 Ci/yr for noble gas or less than 0.0001 Ci/yr for iodine. For particulates, release is not observed and assumed less than 1 percent of the total particulate releases.
2. The fuel handling area is within the auxiliary building but is considered separately.

Table 5 RELEASES TO DISCHARGE CANAL (CI/YR) CALCULATED BY GALE CODE					
Nuclide	**Shim Bleed**	**Misc. Wastes**	**Turbine Building**	**Combined Releases**	**Total Releases**(1)
Corrosion and Activation Products					
Na-24	0.00053	0.0(2)	0.00008	0.00061	0.00163
Cr-51	0.00068	0.0	0.0	0.00070	0.00185
Mn-54	0.00048	0.0	0.0	0.00049	0.00130
Fe-55	0.00037	0.0	0.0	0.00037	0.00100
Fe-59	0.00008	0.0	0.0	0.00008	0.00020
Co-58	0.00125	0.0	0.00001	0.00126	0.00336
Co-60	0.00016	0.0	0.0	0.00017	0.00044
Zn-65	0.00015	0.0	0.0	0.00015	0.00041
W-187	0.00004	0.0	0.0	0.00005	0.00013
Np-239	0.00008	0.0	0.0	0.00009	0.00024
Fission Products					
Br-84	0.00001	0.0	0.0	0.00001	0.00002
Rb-88	0.00010	0.0	0.0	0.00010	0.00027
Sr-89	0.00004	0.0	0.0	0.00004	0.00010
Sr-90	0.0	0.0	0.0	0.0	0.00001
Sr-91	0.00001	0.0	0.0	0.00001	0.00002
Y-91m	0.0	0.0	0.0	0.00001	0.00001
Y-93	0.00003	0.0	0.0	0.00002	0.00009
Zr-95	0.00010	0.0	0.0	0.00005	0.00023
Nb-95	0.00009	0.0	0.0	0.00005	0.00021
Mo-99	0.00028	0.0	0.00001	0.00013	0.00057
Tc-99m	0.00027	0.0	0.00001	0.00013	0.00055
Ru-103	0.00183	0.00001	0.00002	0.00185	0.00493
Rh-103m	0.00183	0.00001	0.00002	0.00185	0.00493
Ru-106	0.02729	0.00011	0.00021	0.02761	0.07352
Rh-106	0.02729	0.00011	0.00021	0.02761	0.07352
Ag-110m	0.00039	0.0	0.0	0.00039	0.00105
Ag-110	0.00005	0.0	0.0	0.00005	0.00014
Te-129m	0.00004	0.0	0.0	0.00005	0.00012
Te-129	0.00006	0.0	0.0	0.00006	0.00015
Te-131m	0.00003	0.0	0.0	0.00003	0.00009
Te-131	0.00001	0.0	0.0	0.00001	0.00003
I-131	0.00512	0.00004	0.00015	0.00531	0.01413
Te-132	0.00009	0.0	0.0	0.00009	0.00024
I-132	0.00054	0.00001	0.00007	0.00062	0.00164
I-133	0.00211	0.00003	0.00038	0.00252	0.00670
I-134	0.00030	0.0	0.0	0.00031	0.00081
Cs-134	0.00370	0.00001	0.00002	0.00373	0.00993
I-135	0.00144	0.00002	0.00041	0.00187	0.00497

Table 5
RELEASES TO DISCHARGE CANAL (CI/YR) CALCULATED BY GALE CODE

Nuclide	Shim Bleed	Misc. Wastes	Turbine Building	Combined Releases	Total Releases[1]
Cs-136	0.00023	0.0	0.0	0.00024	0.00063
Cs-137	0.00496	0.00001	0.00003	0.00500	0.01332
Ba-137m	0.00464	0.00001	0.00002	0.00468	0.01245
Ba-140	0.00203	0.00001	0.00003	0.00207	0.00552
La-140	0.00272	0.00002	0.00005	0.00279	0.00743
Ce-141	0.00003	0.0	0.0	0.00004	0.00009
Ce-143	0.00006	0.0	0.00001	0.00007	0.00019
Pr-143	0.00005	0.0	0.0	0.00005	0.00013
Ce-144	0.00117	0.0	0.00001	0.00119	0.00316
Pr-144	0.00117	0.0	0.00001	0.00119	0.00316
All others	0.00001	0.0	0.0	0.00001	0.00002
Total (except tritium)	0.09398	0.00043	0.00182	0.09623	0.25623
Tritium release		1010 curies per year			

Notes:
1. The release totals include an adjustment of 0.16 Ci/yr added by PWR-GALE code to account for anticipated operational occurrences such as operator errors that result in unplanned releases.
2. An entry of 0.0 indicates that the value is less than 10-5 Ci/yr.

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SITE RELATED COMBINED LICENSE INFORMATION ITEMS

This section provides a listing of the Combined License (COL) information items identified in the AP1000 Design Control Document (DCD) that are site related. The AP1000 DCD (APP-GW-GL-700) includes identification of information items which must be provided to NRC during a COL application process. In addition to the site related items listed below there are items are related to additional detail in the plant design and to the COL applicant's organization information. It is important for a COL applicant to plan for the submittal of required site related COL information items and include planning for data acquisition in the Early Site Permit process. The following information items and their referenced DCD sections are site related and should be acknowledged during Early Site permit planning.

Item Number	Subject	DCD Subsection
2.1-1	Geography and Demography Combined License applicants referencing the AP1000 certified design will provide site-specific information related to site location and description, exclusion area authority and control, and population distribution. Site Information – Site-specific information on the site and its location will include political subdivisions, natural and man-made features, population, highways, railways, waterways, and other significant features of the area. Exclusion Area – Site-specific information on the exclusion area will include the size of the area and the exclusion area authority and control. Activity that may be permitted within the exclusion area will be included in the discussion. Population Distribution – Site-specific information will be included on population distribution.	2.1.1
2.2-1	Identification of Site-specific Potential Hazards Combined License applicants referencing the AP1000 certified design will provide site-specific information related to the identification of potential hazards within the site vicinity, including an evaluation of potential accidents and verify that the frequency of site-specific potential hazards is consistent with the criteria outlined in Section 2.2. The site-specific information will provide a review of aircraft hazards, information on nearby transportation routes, and information on potential industrial and military hazards.	2.2.1

2.3-1	**Regional Climatology**	2.3.6.1

Combined License applicants referencing the AP1000 certified designwill address site-specific information related to regionalclimatology.

2.3-2	**Local Meteorology**	2.3.6.2

Combined License applicants referencing the AP1000 certified design will address site-specific local meteorology information.

2.3-3	**Onsite Meteorological Measurements Program**	2.3.6.3

Combined License applicants referencing the AP1000 certified design will address the site-specific onsite meteorological measurements program.

2.3-4	**Short-Term Diffusion Estimates**	2.3.6.4

Combined License applicants referencing the AP1000 certified design will address the site-specific X/Q values specified in subsection 2.3.4. For a site selected that exceeds the boundingX/Q values, the Combined License applicant will address how the radiological consequences associated with the controlling design basis accident continue to meet the dose reference values given in 10CFR Part 50.34 and control room operator dose limits given in General Design Criteria 19 using site-specific X/Q values. The Combined License applicant should consider topographical characteristics in the vicinity of the site for restrictions of horizontal and/or vertical plume spread, channeling or other changes in airflow trajectories, and other unusual conditions affecting atmospheric transport and diffusion between the source and receptors. No further action is required for sites within the bounds of the site parameters for atmospheric dispersion.

2.3-5	**Long-Term Diffusion Estimates**	2.3.6.5

Combined License applicants referencing the AP1000 certified design will address long-term diffusion estimates andX/Q values specified in subsection 2.3.5. The Combined License applicant should consider topographical characteristics in the vicinity of the site for restrictions of horizontal and/or vertical plume spread, channeling or other changes in airflow trajectories, and other unusual conditions affecting atmospheric transport and diffusion between the source and receptors. No further action is required for sites within the bounds of the site parameter for atmospheric dispersion.

2.4-1	**Hydrological Description**	2.4.1.1

Combined License applicants referencing the AP1000 certified designwill describe major hydrologic features on or in the vicinity of the site including critical elevations of the nuclear island and access routes to the plant.

2.4-2	**Floods**	2.4.1.2

Combined License applicants referencing the AP1000 certified designwill address the following site-specific information on historical flooding and potential flooding factors, including the effects of local intense precipitation.

- Probable Maximum Flood on Stream and Rivers – Site-specific information that will be used to determine the design basis flooding at the site. This information will include the probable maximum flood on streams and rivers.

- Dam Failures – Site-specific information on potential dam failures.
- Probable Maximum Surge and Seiche Flooding – Site-specific information on probable maximum surge and seiche flooding.
- Probable Maximum Tsunami Loading – Site-specific information on probable maximum tsunami loading.
- Flood Protection Requirements – Site-specific information on flood protection requirements or verification that flood protection is not required to meet the site parameter for flood level.

No further action is required for sites within the bounds of the site parameter for flood level.

2.4-3 Cooling Water Supply 2.4.1.3

Combined License applicants will address the water supply sources to provide makeup water to the service water system cooling tower.

2.4-4 Groundwater 2.4.1.4

Combined License applicants referencing the AP1000 certified design will address site-specific information on groundwater. No further action is required for sites within the bounds of the site parameter for ground water.

2.4-5 Site Effects of Accidental Release of Liquid Effluents in Ground and Surface Water 2.4.1.5

Combined License applicants referencing the AP1000 certified design will address site-specific information on the ability of the ground and surface water to disperse, dilute, or concentrate accidental releases of liquid effluents. Effects of these releases on existing and known future use of surface water resources will also be addressed.

2.4-6 Flood Protection Emergency Operation Procedures 2.4.1.6

Combined License applicants referencing the AP1000 certified design will address any flood protection emergency procedures required to meet the site parameter for flood level.

2.5-1 Basic Geologic and Seismic Information 2.5.1

Combined License applicants referencing the AP1000 certified design will address the following site-specific geologic and seismic information:

- Regional and site physiography
- Geomorphology
- Stratigraphy
- Lithology

- Structural geology
- Tectonics

Seismicity

2.5-2 Site Seismic and Tectonic Characteristic Information 2.5.2.1

Combined License applicants referencing the AP1000 certified design will address the following site-specific information related to seismic and tectonic characteristics of the site and region:

Correlation of earthquake activity with geologic structure or tectonic provinces

Maximum earthquake potential

Seismic wave transmission characteristics of the site

Safe shutdown earthquake (SSE) ground response spectra

The Combined License applicant must demonstrate that the proposed site meets the following requirements:

The free field peak ground acceleration at the foundation level is less than or equal to a 0.30g safe shutdown earthquake.

The site design response spectra at the foundation level in the free-field are less than or equal to those given in Figures 3.7.1-1 and 3.7.1-2.

2.5-3 Surface Faulting 2.5.3

Combined License applicants referencing the AP1000 certified designwill address surface and subsurface geological and geophysical information including the potential for surface or near-surface faulting affecting the site.

2.5-4 Site and Structures 2.5.4.6.1

Site and Structures – Site-specific information regarding the underlying site conditions and geologic features will be addressed. This information will include site topographical features, as well as the locations of seismic Category I structures.

2.5-5 Properties of Underlying Materials 2.5.4.6.2

The Combined License applicant will establish the properties of the foundation soils to be within the range considered for design of the nuclear island basemat.

Properties of Underlying Materials – A determination of the static and dynamic engineering properties of foundation soils and rocks in the site area will be addressed. This information will include a discussion of the type, quantity, extent, and purpose of field explorations, as well as logs of borings and test pits. Results of field plate load tests, field permeability tests, and other special field tests (e.g., bore-hole extensometer or pressuremeter tests) will also be provided. Results of geophysical surveys will be presented in tables and profiles. Data will be provided pertaining to site-specific soil layers (including theirthicknesses, densities, moduli, and Poisson's ratios) between the basemat and the underlying rock stratum. Plot plans and profiles of site explorations will be provided.

Laboratory Investigations of Underlying Materials – Information about the number and type of laboratory tests and the location of samples used to investigate underlying materials will be provided. Discussion of the results of laboratory tests on disturbed and undisturbed soil and rock samples obtained from field investigations will be provided.

2.5-6 Excavation and Backfill 2.5.4.6.3

Excavation and Backfill – Information concerning the extent (horizontal and vertical) of seismic Category I excavations, fills, and slopes, if any will be addressed. The sources, quantities, and static and dynamic engineering properties of borrow materials will be described in the site-specific application. The compaction requirements, results of field compaction tests, and fill material properties (such as moisture content, density, permeability, compressibility, and gradation) will also be provided. Information will be *provided concerning the specific soil retention system, for example, the soil* nailing system, including the length and size of the soil nails, which is based on actual soil conditions and applied construction surcharge loads. Information will also be provided on the waterproofing system along the vertical face and the mudmat.

2.5-7 Ground Water Conditions 2.5.4.6.4

Ground Water Conditions – Groundwater conditions will be described relative to the foundation stability of the safety-related structures at the site. The soil properties of the various layers under possible groundwater conditions during the life of the plant will be compared to the range of values assumed in the standard design in Table2-1 of the DCD.

2.5-8 Response of Soil and Rock to Dynamic Loading 2.5.4.6.5

Response of Soil and Rock to Dynamic Loading – The Combined License applicant will establish the dynamic characteristics of the soil and rock to be used in the soil structure interaction analyses and the foundation design for soil sites. *For rock sites the dynamic characteristics will be compared to the* assumptions made in the standard design regarding the variation of shear wave velocity and material damping.

2.5-9 Liquifaction Potential 2.5.4.6.6

Liquefaction Potential – Soils under and around seismic Category I structures will be evaluated for liquefaction potential for the site specific SSE ground motion. This should include justification of the selection of the soil properties, as well as the magnitude, duration, and number of excitation cycles of the earthquake used in the liquefaction potential evaluation (e.g., laboratory tests, field tests, and published data). Liquefaction potential will also be evaluated to address seismic margin.

2.5-10 Bearing Capacity 2.5.4.6.7

Bearing Capacity – The Combined License applicant will verify that the site-specific soil static bearing capacity is equal to or greater than the value documented in Table2-1 of the DCD. The Combined License applicant will verify that the dynamic site-specific bearing capacity is equal or greater than the seismic bearing demand.

2.5-11 Earth Pressures 2.5.4.6.8

Earth Pressures – The Combined License applicant will describe the design for *static and dynamic lateral earth pressures and hydrostatic groundwater* pressures acting on plant safety-related facilities using soil parameters as evaluated in previous subsections.

2.5-12	Static and Dynamic Stability of Facilities	2.5.4.6.10
	Static and Dynamic Stability of Facilities – Soil characteristics affecting the stability of the nuclear island will be addressed including foundation rebound, settlement, and differential settlement.	
2.5-14	Stability of Slopes	2.5.5
	Combined License applicants referencing the AP1000 design will address site-specific information about the static and dynamic stability of soil and rock slopes, the failure of which could adversely affect the nuclear island.	
2.5-15	Embankments and Dams	2.5.6
	Combined License applicants referencing the AP1000 design will address site-specific information about the static and dynamic stability of embankments and dams, the failure of which could adversely affect the nuclear island.	
3.3-1	Wind and Tornado Site Interface Criteria	3.3.3
	Combined License applicants referencing the AP1000 certified design will address site interface criteria for wind and tornado.	
3.4-1	Site-Specific Flooding Hazards Protective Measures	3.4.3
	The Combined License applicant will demonstrate that the site satisfies the interface requirements as described in Section 2.4 of the DCD. If these criteria cannot be satisfied because of site-specific flooding hazards, the Combined License applicant may propose protective measures as discussed in Section 2.4 of the DCD.	
3.5-1	External Missile Protection Requirements	3.5.4
	The Combined License applicant will demonstrate that the site satisfies the interface requirements provided in Section 2.2 of the DCD. This requires an evaluation for those external events that produce missiles that are more energetic than the tornado missiles postulated for design of the AP1000, or additional analyses of the AP1000 capability to handle the specific hazard.	
3.7-1	Seismic Analysis of Dams	3.7.5.1
	Combined License applicants referencing the AP1000 certified design will evaluate dams whose failure could affect the site interface flood level specified in subsection 2.4.1.2 of the DCD. The evaluation of the safety of existing and new dams will use the site-specific safe shutdown earthquake.	
6.4-1	Local Toxic Gas Service and Monitoring	6.4.7
	Combined License applicants referencing the AP1000 certified design are responsible for the amount and location of possible sources of toxic chemicals in or near the plant and for seismic Category I Class 1E toxic gas monitoring, as required. Regulatory Guides 1.78 and 1.95 address control room protection for toxic chemicals, and for evaluating offsite toxic releases (including the potential for toxic releases beyond 72 hours) in accordance with the guidelines of Regulatory Guides 1.78 and 1.95 in order to meet the requirements of TMI	

Action Plan Item III.D.3.4 and GDC 19.

Combined License applicants referencing the AP1000 certified design are responsible for verifying that procedures and training for control room habitability are consistent with the intent of Generic Issue 83 (see Section 1.9 of the DCD).

8.2-1	**Offsite Electrical Power**	8.2.5

Combined License applicants referencing the AP1000 certified design will address the design of the ac power transmission system and its testing and inspection plan.

8.2-2	**Plant/Site Technical Interfaces**	8.2.5

The Combined License applicant will address the technical interfaces for this nonsafety-related system listed in Table 1.8-1 and subsection 8.2.2. These technical interfaces include those for ac power requirements from offsite and the analysis of the offsite transmission system and the setting of protective devices.

8.3-1	**Onsite (Grounding and Lightning) Electrical Power**	8.3.3

Combined License applicants referencing the AP1000 certified design will address the design of grounding and lightning protection.
The Combined License applicant will establish plant procedures as required *for:*

- Clearing ground fault on the Class1E dc system
- Checking sulfated battery plates or other anomalous conditions through periodic inspections
- Battery maintenance and surveillance (for battery surveillance requirements, refer to DCD Chapter 16, Section 3.8)
- Periodic testing of penetration protective devices

Diesel generator operation, inspection, and maintenance in accordance with manufacturers' recommendations.

9.5-2	**Fire Protection Analysis Information on Adjacent Structures**	9.5.1.8

The Combined License applicant will address qualification requirements for individuals responsible for development of the fire protection program, training of firefighting personnel, administrative procedures and controls governing the fire protection program during plant operation, and fire protection system maintenance.

The Combined License applicant will provide site-specific fire protection analysis information for the yard area, the administration building, and for other outlying buildings consistent with Appendix 9A of the DCD.

The Combined License applicant will address BTP CMEB 9.5-1 issues identified in Table 9.5.1-1 of the DCD by the acronym "WA."

The Combined License applicant will address updating the list of NFPA exceptions after design certification, if necessary.

The Combined License applicant will provide an analysis that demonstrates that operator actions which minimize the probability of the potential for spurious ADS actuation as a result of a fire can be accomplished within 30 minutes following detection of the fire.

9.5-9	**Cathodic Protection of External Tanks**	9.5.4.7

Combined License applicants referencing the AP1000 certified design will address the site-specific need for cathodic protection in accordance with NACE Standard RP-01-69 for external metal surfaces of metal tanks in contact with the ground.

Combined License applicants referencing the AP1000 certified design will address site-specific factors in the fuel oil storage tank installation specification to reduce the effects of sun heat input into the stored fuel, the diesel fuel specifications grade and the fuel properties consistent with manufacturers' recommendations, and will address measures to protect against fuel degradation by a program of fuel sampling and testing.

10.4-1	**Circulating Water Supply**	10.4.12.1

The Combined License applicant will address the final configuration of the plant circulating water system including piping design pressure, the cooling tower or other site-specific heat sink.

As applicable, the Combined License applicant will address the acceptable Langelier or Stability Index range, the specific chemical selected for use in the CWS water chemistry control, pH adjuster, corrosion inhibitor, scale inhibitor, dispersant, algicide and biocide applications reflecting potential variations in site water chemistry and in micro macro biological lifeforms. A biocide such as sodium hypochlorite is recommended. Toxic gases such as chlorine are not recommended. The impact of toxic gases on the main control room compatibility is addressed in Section 6.4 of the DCD.

10.4-3	**Potable Water Biocide**	10.4.12.3

The Combined License applicant will address the specific biocide. A biocide such as sodium hypochlorite is recommended. Toxic gases such as chlorine are not recommended. The impact of toxic gases on the main control room compatibility is addressed in Section 6.4 of the DCD.

11.2-1	**Liquid Radwaste Processing by Mobile Equipment**	11.2.5.1

The Combined License applicant will discuss how any mobile or temporary equipment used for storing or processing liquid radwaste conforms to Regulatory Guide 1.143. For example, this includes discussion of equipment containing radioactive liquid radwaste in the nonseismic Radwaste Building.

11.2-2	**Cost Benefit Analysis of Population Doses (Liquid)**	11.2.5.2

The analysis performed to determine offsite dose due to liquid effluents is based upon the AP1000 generic site parameters included in Chapter 1 and Tables 11.2-5 and 11.2-6 of the DCD. The Combined License applicant will provide a site specific cost-benefit analysis to address the requirements of 10 CFR 50, Appendix I, regarding population doses due to liquid effluents.

11.2-4	**Dilution and Control of Boric Acid Discharge**	11.2.5.4

The Combined License applicant will determine the rate of discharge and the required dilution to maintain acceptable concentrations. Refer to Section 11.5 of the DCD for a discussion of the program to control releases.

The Combined License applicant will discuss the planned discharge flow rate for borated wastes and controls for limiting the boric acid concentration in the circulating water system blowdown.

11.3-1	**Cost Benefit Analysis of Population Doses (Gas)** The analysis performed to determine offsite dose due to gaseous effluents is based upon the AP1000 generic site parameters included in Chapter 1 and Tables 11.3-1, 11.3-2 and 11.3-4 of the DCD. The Combined License applicant will provide a site specific cost-benefit analysis to demonstrate compliance with 10 CFR 50, Appendix I, regarding population doses due to gaseous effluents.	11.3.5.1
11.5-2	**Effluent Monitoring and Sampling** The Combined License applicant will develop an offsite dose calculation manual that contains the methodology and parameters used for calculation of offsite doses resulting from gaseous and liquid effluents. The Combined License applicant will address operational setpoints for the radiation monitors and address programs for monitoring and controlling the release of radioactive material to the environment, which eliminates the potential for unmonitored and uncontrolled release. The offsite dose calculation manual will include planned discharge flow rates. The Combined License applicant is responsible for the site-specific and program aspects of the process and effluent monitoring and sampling per ANSI N13.1 and Regulatory Guides 1.21 and 4.15.	11.5.7
11.5-3	**10 CFR 50, Appendix I** The Combined License applicant is responsible for addressing the 10 CFR 50, Appendix I guidelines for maximally exposed offsite individual doses and population doses via liquid and gaseous effluents.	11.5.7
13.3-2	**Activation of Emergency Operations Facility** Combined License applicants referencing the AP1000 certified design will address emergency planning including post-72 hour actions and its communication interface. Combined License applicants referencing the AP1000 certified design will address the activation of the emergency operations facility consistent with current operating practice and NUREG-0654/FEMA-REP-1 except for a loss of offsite power and loss of all onsite AC power. For this initiating condition, the Combined License applicant shall immediately activate the emergency operations facility rather than bringing it to a standby status. To initially and continuously assess the course of an accident for emergency response purposes, Combined License applicants referencing the AP1000 certified design will address the capability for promptly obtaining and analyzing grab samples of reactor coolant and containment atmosphere and sump in accordance with the guidance of Item II.B.3 of NUREG-0737.	13.3.1
13.6-1	**Security Plans, Organization and Testing** Combined License applicants referencing the AP1000 certified design will address site-specific information related to the security, contingency, and guard training plans. Those plans will include descriptions of the tests planned to show operational status, maintenance of the plant security system, the security organization, communication, and response requirements. The Combined License applicant will develop the comprehensive physical security program which includes the security plan, contingency plan, and guard training plan. Each COL applicant will describe in its physical security plan how the requirements of 10 CFR Part 26 will be met. At least 60 days before loading fuel, the Combined License applicant will confirm that the security systems and programs described in its physical security plan, safeguards contingency plan, and training and qualification plan have achieved operational status and are available for the staff's inspection. Operational status means that	13.6.13.1

the security systems and programs are functioning. The determination that operational status has been achieved will be based on tests conducted under realistic operating conditions of sufficient duration to demonstrate that:

the equipment is properly operating;

procedures have been developed, approved, and implemented; and

personnel responsibility for security operations and maintenance have been appropriately trained and have demonstrated their capability to perform their assigned duties and responsibilities.

13.6-3 Site-Specific Security System 13.6.13.3

Combined License applicants referencing the AP1000 certified design will address site-specific information related to the maintenance and testing of the plant security system including the intrusion detection and assessment system, the access control features specified in subsections 13.6.6, 13.6.7.2, and 13.6.7.3 of the DCD, and the vehicle barrier system. The Combined License applicant will address in its safeguards plans how the physical protection system will provide the protection stated in subsection 13.6.3.2 of the DCD.

14.4-5 Testing Interface Requirements 14.4.5

The combined license applicant is responsible for testing that may be required of structures and systems which are outside the scope of this design certification. Test Specifications and acceptance criteria are provided by the responsible design organizations as identified in subsection 14.2.3. The interfacing systems to be considered for testing are taken from Table1.8-1 and include as a minimum, the following:

- storm drains
- site specific seismic sensors
- offsite ac power systems
- circulating water heat sink
- raw and sanitary water systems
- individual equipment associated with the fire brigade
- portable personnel monitors and radiation survey instruments
- equipment associated with the physical security plan

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AP1000 DOCUMENT NO.	REVISION NO.		ASSIGNED TO
APP-0000-X1-001	3	Page 1 of 51	W- Winters

ALTERNATE DOCUMENT NUMBER: WORK BREAKDOWN #: 0000

ORIGINATING ORGANIZATION: Westinghouse Electric Co., LLC

TITLE: **AP1000 Siting Guide: Site Information for an Early Site Permit**

ATTACHMENTS:	DCP #/REV. INCORPORATED IN THIS DOCUMENT REVISION: Class 3 change to correct values in Items 2 of Section 4 and to add spent fuel information to Section 3.
CALCULATION/ANALYSIS REFERENCE:	

ELECTRONIC FILENAME	ELECTRONIC FILE FORMAT	ELECTRONIC FILE DESCRIPTION
APP-0000-X1-R3.doc	Word	

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B. Alfieri	for - Linda S. Kish 4/24/03	
REVIEWERS	SIGNATURE/DATE	
INDEPENDENT VERIFIER	SIGNATURE/DATE	VERIFICATION METHOD
D. Hutchings	D F Hutchings 4/24/03	
AP1000 RESPONSIBLE MANAGER	SIGNATURE*	APPROVAL DATE
J. W. Winters	[signature]	4/24/03

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