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Technical Development Document for the Proposed Section 316(b) Phase II Existing Facilities Rule

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INTRODUCTION

This profile presents data for the electric power generating industry important for understanding the context of the analyses presented in this document. The majority of this profile is excerpted from Chapter A3 of the *Economic and Benefits Analysis for the Proposed Section 316(b) Phase II Existing Facilities Rule* (the "EBA"). For more information on aspects of the industry that may influence the nature and magnitude of economic impacts of the Proposed Section 316(b) Phase II Existing Facilities Rule, see Chapter A3 of the EBA.

The electric power industry is one of the most extensively studied industries. The Energy Information Administration (EIA), among others, publishes a multitude of reports, documents, and studies on an annual basis. This profile is not intended to duplicate those efforts. Rather, this profile compiles, summarizes, and presents those industry data that are important in the context of the proposed Phase II rule. For more information on general concepts, trends, and developments in the electric power industry, the last section of this profile, "References," presents a select list of other publications on the industry.

The remainder of this profile is organized as follows:

- Section 1-1 provides a brief overview of the industry, including descriptions of major industry sectors and types of generating facilities.

- Section 1-2 provides data on industry production and capacity.

- Section 1-3 focuses on the in-scope section 316(b) facilities. This section provides information on the geographical, physical, and cooling water characteristics of the in-scope phase II facilities.

1-1 INDUSTRY OVERVIEW

This section provides a brief overview of the industry, including descriptions of major industry sectors and types of generating facilities.

1-1.1 Industry Sectors

The electricity industry is made up of three major functional service components or sectors: *generation*, *transmission*, and *distribution*. Each of these terms are defined as follows (Beamon, 1998; Joskow, 1997):[1]

- The ***generation*** sector includes the power plants that produce, or "generate," electricity.[2] Electric energy is produced using a specific generating technology, for example, internal combustion engines and turbines. Turbines can be driven by wind, moving water (hydroelectric), or steam from fossil fuel-fired boilers or nuclear reactions. Other methods of power generation include geothermal or photovoltaic (solar) technologies.

[1] Terms highlighted in bold and italic font are defined in the glossary at the end of this chapter.

[2] The terms "plant" and "facility" are used interchangeably throughout this profile and document.

- The ***transmission*** sector can be thought of as the interstate highway system of the business – the large, high-voltage power lines that deliver electricity from power plants to local areas. Electricity transmission involves the "transportation" of electricity from power plants to distribution centers using a complex system. Transmission requires: interconnecting and integrating a number of generating facilities into a stable, synchronized, alternating current (AC) network; scheduling and dispatching all connected plants to balance the demand and supply of electricity in real time; and managing the system for equipment failures, network constraints, and interaction with other transmission networks.

- The ***distribution*** sector can be thought of as the local delivery system – the relatively low-voltage power lines that bring power to homes and businesses. Electricity distribution relies on a system of wires and transformers along streets and underground to provide electricity to residential, commercial, and industrial consumers. The distribution system involves both the provision of the hardware (for example, lines, poles, transformers) and a set of retailing functions, such as metering, billing, and various demand management services.

Of the three industry sectors, only electricity generation uses cooling water and is subject to section 316(b). The remainder of this profile will focus on the generation sector of the industry.

1-1.2 Prime Movers

Electric power plants use a variety of ***prime movers*** to generate electricity. The type of prime mover used at a given plant is determined based on the type of load the plant is designed to serve, the availability of fuels, and energy requirements. Most prime movers use fossil fuels (coal, petroleum, and natural gas) as an energy source and employ some type of turbine to produce electricity. The six most common prime movers are (U.S. DOE, 2000a):

- ***Steam Turbine:*** Steam turbine, or "steam electric" units require a fuel source to boil water and produce steam that drives the turbine. Either the burning of fossil fuels or a nuclear reaction can be used to produce the heat and steam necessary to generate electricity. These units are generally ***baseload*** units that are run continuously to serve the minimum load required by the system. Steam electric units generate the majority of electricity produced at power plants in the U.S.

- ***Gas Combustion Turbine:*** Gas turbine units burn a combination of natural gas and distillate oil in a high pressure chamber to produce hot gases that are passed directly through the turbine. Units with this prime mover are generally less than 100 megawatts in size, less efficient than steam turbines, and used for ***peakload*** operation serving the highest daily, weekly, or seasonal loads. Gas turbine units have quick startup times and can be installed at a variety of site locations, making them ideal for peak, emergency, and reserve-power requirements.

- ***Combined-Cycle Turbine:*** Combined-cycle units utilize both steam and gas turbine prime mover technologies to increase the efficiency of the gas turbine system. After combusting natural gas in gas turbine units, the hot gases from the turbines are transported to a waste-heat recovery steam boiler where water is heated to produce steam for a second steam turbine. The steam may be produced solely by recovery of gas turbine exhaust or with additional fuel input to the steam boiler. Combined-cycle generating units are generally used for ***intermediate loads***.

- ***Internal Combustion Engines:*** Internal combustion engines contain one or more cylinders in which fuel is combusted to drive a generator. These units are generally about 5 megawatts in size, can be installed on short notice, and can begin producing electricity almost instantaneously. Like gas turbines, internal combustion units are generally used only for peak loads.

- ***Water Turbine:*** Units with water turbines, or "hydroelectric units," use either falling water or the force of a natural river current to spin turbines and produce electricity. These units are used for all types of loads.

- ***Other Prime Movers:*** Other methods of power generation include geothermal, solar, wind, and biomass prime movers. The contribution of these prime movers is small relative to total power production in the U.S., but the role of these prime movers may expand in the future because recent legislation includes incentives for their use.

Table 1-1 provides data on the number of existing utility and nonutility power plants by prime mover. This table includes all plants that have at least one non-retired unit and that submitted Forms EIA-860A (Annual Electric Generator Report - Utilities) or EIA-860B (Annual Electric Generator Report - Nonutilities) in 1999.[3] For the purpose of this analysis, plants were classified as "steam turbine" or "combined-cycle" if they have at least one generating unit of that type. Plants that do not have any steam electric units, were classified under the prime mover type that accounts for the largest share of the plant's total electricity generation.

Table 1-1: Number of Existing Plants by Prime Mover, 1999

Prime Mover	Number of Plants
Steam Turbine	1,624
Combined-Cycle	260
Gas Turbine	707
Internal Combustion	887
Hydroelectric	1,713
Other	139
Total	**5,330**

Source: U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

Only prime movers with a steam electric generating cycle use substantial amounts of cooling water (for the condensing of steam exiting the steam turbines). These generators include steam turbines and combined-cycle technologies. As a result, the analysis in support of the proposed Phase II rule focuses on generating plants with a steam electric prime mover. This profile will, therefore, differentiate between steam electric and other prime movers.

[3] At the time of publication of this document, 1999 was the most recent year for which complete EIA data were available for existing utility and nonutility plants. As of March 2002, EIA 860B data were not available for year 2000. As such, this profile is based on 1999 data.

1-2 Domestic Production

This section presents an overview of U.S. generating capacity and electricity generation. Subsection 1-2.1 provides data on capacity, and Subsection 1-2.2 provides data on generation. Subsection 1-2.3 presents an overview of the geographic distribution of generation plants and capacity.

1-2.1 Generating Capacity[4]

The rating of a generating unit is a measure of its ability to produce electricity. Generator ratings are expressed in megawatts (MW). Capacity and capability are the two common measures (U.S. DOE, 2000a):

Nameplate capacity is the full-load continuous output rating of the generating unit under specified conditions, as designated by the manufacturer.

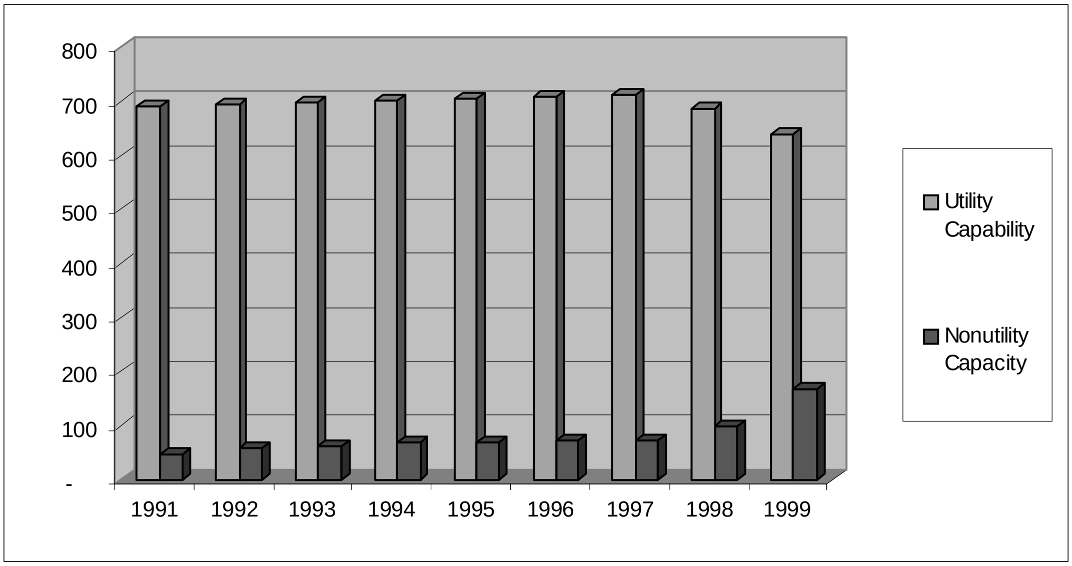
Net capability is the steady hourly output that the generating unit is expected to supply to the system load, as demonstrated by test procedures. The capability of the generating unit in the summer is generally less than in the winter due to high ambient-air and cooling-water temperatures, which cause generating units to be less efficient. The nameplate capacity of a generating unit is generally greater than its net capability.

Figure 1-2 shows the total US generating capacity from 1991 to 1999.[5]

[4] The numbers presented in this section are *capability* for utility facilities and *capacity* for nonutilities. For convenience purposes, this section will refer to both measures as"capacity."

[5] More accurate data were available starting in 1991, therefore, 1991 was selected as the initial year for trends analysis.

Figure 1-2: Generating Capability & Capacity, 1991 to 1999[a]



Source: U.S. DOE, 2000c; U.S. DOE,1996b.

1-2.2 Electricity Generation

Total net electricity generation in the U.S. for 1999 was 3,723 billion kWh. Total net generation has increased by 21 percent over the nine-year period from 1991 to 1999.

Table 1-2 shows the change in net generation between 1991 and 1999 by fuel source for utilities and nonutilities.

> **MEASURES OF GENERATION**
>
> The production of electricity is referred to as generation and is measured in ***kilowatthours (kWh)***. Generation can be measured as:
>
> ***Gross generation:*** The total amount of power produced by an electric power plant.
>
> ***Net generation:*** Power available to the transmission system beyond that needed to operate plant equipment. For example, around 7% of electricity generated by steam electric units is used to operate equipment.
>
> ***Electricity available to consumers:*** Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.
>
> U.S. DOE, 2000a

Table 1-2: Net Generation by Energy Source, 1991 to 1999 (GWh)

Energy Source	Total		
	1991	1999	% Change

Coal	1,591	1,893	19%
Hydropower	286	315	10%
Nuclear	613	734	20%
Petroleum	119	108	-9%
Gas	392	592	51%
Renewables[b]	67	80	19%
Total	**3,067**	**3,723**	**21%**

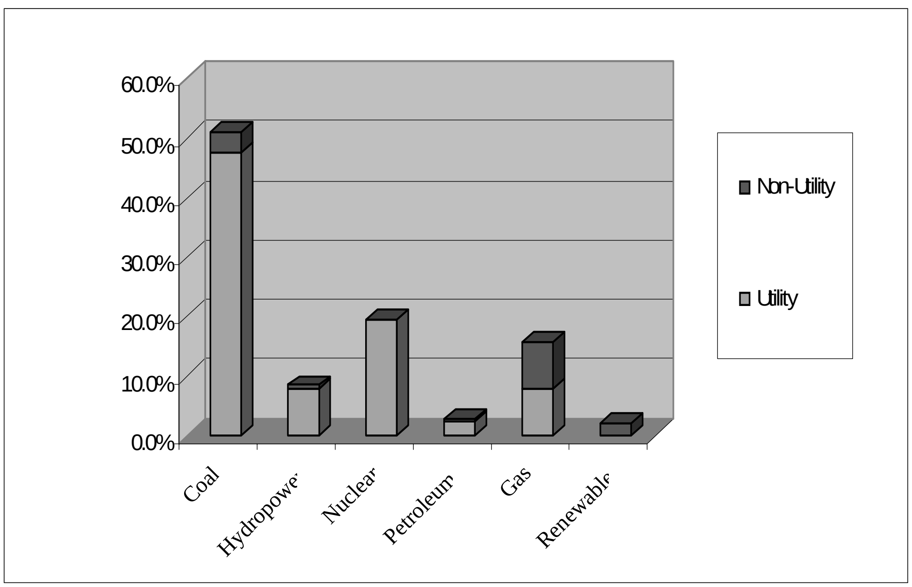
[a] Nonutility generation was converted from gross to net generation based on prime mover-specific conversion factors (U.S. DOE, 2000c). As a result of this conversion, the total net generation estimates differ slightly from EIA published totals by fuel type.

[b] Renewables include solar, wind, wood, biomass, and geothermal energy sources.

Source: U.S. DOE, 2000b;U.S. DOE, 2000c; U.S. DOE, 1995a; U.S. DOE,1995b.

Figure 1-3 shows total net generation for the U.S. by primary fuel source. Electricity generation from coal-fired plants accounts for 47 percent of total 1999 generation. The second largest source of electricity generation is nuclear power plants, accounting for 20 percent of total generation. Another significant source of electricity generation is gas-fired power plants, which account for 16 percent of total generation.

Figure 1-3: Percent of Electricity Generation by Primary Fuel Source, 1999



Source: U.S. DOE,2000b; U.S. DOE,2000c.

Regulatory options cosidered for proposed Phase II rule affect facilities differently based on the fuel sources and prime movers used to generate electricity. As mentioned in Section 1-1.2 above, only prime movers with a steam electric generating cycle use substantial amounts of cooling water.

1-3 Existing Plants with CWIS and NPDES Permits

Section 316(b) of the Clean Water Act applies to a point source facility that uses or proposes to use a cooling water intake structure water that directly withdraws cooling water from a water of the United States. Among power plants, only those facilities employing a steam electric generating technology require cooling water and are therefore of interest to this analysis. Steam electric generating technologies include units with steam electric turbines and combined-cycle units with a steam component.

The following sections describe existing power plants that would be subject to the proposed Phase II rule. The Proposed Section 316(b) Phase II Existing Facilities Rule applies to existing steam electric power generating facilities that meet all of the following conditions:

- They meet the definition of an existing steam electric power generating facility as specified in § 125.93 of this rule;
- They use a cooling water intake structure or structures, or obtain cooling water by any sort of contract or arrangement with an independent supplier who has a cooling water intake structure;
- Their cooling water intake structure(s) withdraw(s) cooling water from waters of the U.S., and at least twenty-five (25) percent of the water withdrawn is used for contact or non-contact cooling purposes;
- They have an NPDES permit or are required to obtain one; and
- They have a design intake flow of 50 MGD or greater.

The proposed Phase II rule also covers substantial additions or modifications to operations undertaken at such facilities. While all facilities that meet these criteria are subject to the regulation, this document focuses on 539 steam electric power generating facilities identified in EPA's 2000 Section 316(b) Industry Survey as being "in-scope" of this proposed rule. These 539 facilities represent 550 facilities nation-wide.[6] The remainder of this chapter will refer to these facilities as "existing section 316(b) plants."

Utilities and nonutilities are discussed in separate subsections because the data sources, definitions, and potential factors influencing the magnitude of impacts are different for the two sectors. Each subsection presents the following information:

- ***Plant size:*** This section discusses the existing section 316(b) facilities by the size of their generation capacity. The size of a plant is important

Water Use by Steam Electric Power Plants

Steam electric generating plants are the single largest industrial users of water in the United States. In 1995:

- steam electric plants withdrew an estimated 190 billion gallons per day, accounting for 39 percent of freshwater use and 47 percent of combined fresh and saline water withdrawals for offstream uses (uses that temporarily or permanently remove water from its source);
- fossil-fuel steam plants accounted for 71 percent of the total water use by the power industry;
- nuclear steam plants and geothermal plants accounted for 29 percent and less than 1 percent, respectively;
- surface water was the source for more than 99 percent of total power industry withdrawals;
- approximately 69 percent of water intake by the power industry was from freshwater sources, 31 percent was from saline sources.

USGS, 1995

6 EPA applied sample weights to the 539 facilities to account for non-sampled facilities and facilities that did not respond to the survey. For more information on EPA's 2000 Section 316(b) Industry Survey, please refer to the Information Collection Request (U.S. EPA 2000).

because it partly determines its need for cooling water.

- ***Geographic distribution:*** This section discusses plants by NERC region. The geographic distribution of facilities is important because a high concentration of facilities with costs under a regulation could lead to impacts on a regional level. Everything else being equal, the higher the share of plants with costs, the higher the likelihood that there may be economic and/or system reliability impacts as a result of the regulation.

- ***Water body and cooling system type:*** This section presents information on the type of water body from which existing section 316(b) facilities draw their cooling water and the type of cooling system they operate. Cooling systems can be either once-through or recirculating systems.[7] Plants with once-through cooling water systems withdraw between 70 and 98 percent more water than those with recirculating systems.

[7] Once-through cooling systems withdraw water from the water body, run the water through condensers, and discharge the water after a single use. Recirculating systems, on the other hand, reuse water withdrawn from the source. These systems take new water into the system only to replenish losses from evaporation or other processes during the cooling process. Recirculating systems use cooling towers or ponds to cool water before passing it through condensers again.

1-3.1 Existing Section 316(b) Utility Plants

EPA identified steam electric prime movers that require cooling water using information from the EIA data collection U.S. DOE, 1999a.[8] These prime movers include:

- Atmospheric Fluidized Bed Combustion (AB)
- Combined-Cycle Steam Turbine with Supplementary Firing (CA)
- Combined Cycle - Total Unit (CC)
- Steam Turbine – Common Header (CH)
- Combined-Cycle – Single Shaft (CS)
- Combined-Cycle Steam Turbine – Waste Heat Boiler Only (CW)
- Steam Turbine – Geothermal (GE)
- Integrated Coal Gasification Combined-Cycle (IG)
- Steam Turbine – Boiling Water Nuclear Reactor (NB)
- Steam Turbine – Graphite Nuclear Reactor (NG)
- Steam Turbine – High Temperature Gas-Cooled Nuclear Reactor (NH)
- Steam Turbine – Pressurized Water Nuclear Reactor (NP)
- Steam Turbine – Solar (SS)
- Steam Turbine – Boiler (ST)

Using this list of steam electric prime movers, and U.S. DOE, 1999a information on the reported operating status of units, EPA identified 862 facilities that have at least one generating unit with a steam electric prime mover. Additional information from the section 316(b) Industry Surveys was used to determine that 416 of the 862 facilities operate a CWIS and hold an NPDES permit. Table 1-4 provides information on the number of utilities, utility plants, and generating units, and the generating capacity in 1999. The table provides information for the industry as a whole, for the steam electric part of the industry, and for the part of the industry potentially affected by the proposed Phase II rule.

Table 1-4: Number of Existing Utilities, Utility Plants, Units, and Capacity, 1999

	Total[a]	Steam Electric[b]		Steam Electric with CWIS and NPDES Permit[c]	
		Number	% of Total	Number	% of Total
Utilities	891	315	35%	148	17%
Plants	3,125	862	28%	416	13%
Units	10,460	2,226	21%	1,220	12%
Nameplate Capacity (MW)	702,624	533,503	76%	344,849	49%

[a] Includes only generating capacity not permanently shut down or sold to nonutilities.
[b] Utilities and plants are listed as steam electric if they have at least one steam electric unit.
[c] The number of plants, units, and capacity was sample weighted to account for survey non-respondents.

[8] U.S. DOE, 1999a (Annual Electric Generator Report) collects data used to create an annual inventory of utilities. The data collected includes: type of prime mover; nameplate rating; energy source; year of initial commercial operation; operating status; cooling water source, and NERC region.

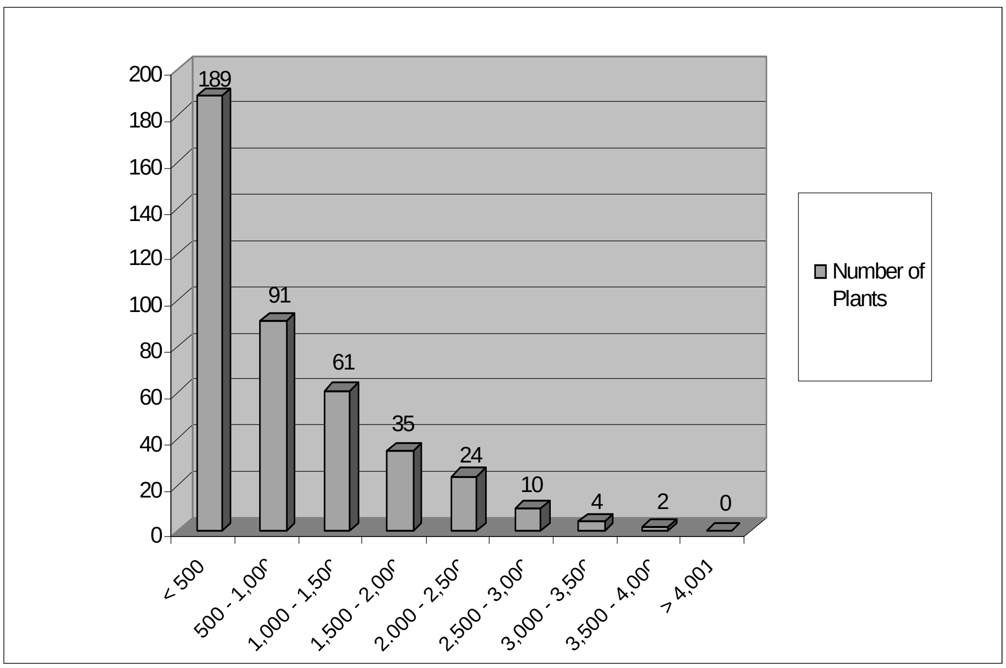
Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

Table 1-4 shows that the while the 862 steam electric plants account for only 28 percent of all plants, these plants account for 76 percent of all capacity. The 416 in-scope plants represent 13 percent of all plants, are owned by 17 percent of all utilities, and account for approximately 49 percent of reported utility generation capacity. The remainder of this section will focus on the 416 utility plants.

a. Plant size

EPA analyzed the utility steam electric facilities with a CWIS and an NPDES permit with respect to their generating capacity. Figure 1-4 presents the distribution of existing utility plants with a CWIS and an NPDES permit by plant size. Of the 416 plants, 189 (45 percent) have a total nameplate capacity of 500 megawatts or less, and 280 (67 percent) have a total capacity of 1,000 megawatts or less.

Figure 1-4: Number of Existing Phase II Facilities by Plant Size (in MW), 1999 [a,b]



[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

b. Geographic distribution

Table 1-5 shows the distribution of existing section 316(b) utility plants by NERC region. The table shows that there are considerable differences between the regions in terms of both the number of existing utility plants with a CWIS and an NPDES permit, and the percentage of all plants that they represent. Excluding Alaska, which only has one utility plant with a CWIS and an NPDES permit, the percentage of existing section 316(b) facilities ranges from two percent in the Western Systems Coordinating Council (WSCC) to 49 percent in the Electric Reliability Council of Texas (ERCOT). The Southeastern Electric Reliability Council (SERC) has the highest absolute number of existing section 316(b) facilities with 94, or 23 percent of all facilities, followed by the East Central Area Reliability Coordination Agreement (ECAR) with 90 facilities, or 22 percent of all facilities.

Table 1-5: Existing Utility Plants by NERC Region, 1999

NERC Region	Total Number of Plants	Plants with CWIS and NPDES Permit[a,b]	
		Number	% of Total
ASCC	168	1	1%
ECAR	301	90	30%
ERCOT	107	52	49%
FRCC	62	29	47%
HI	16	3	19%
MAAC	93	3	3%
MAIN	207	33	16%
MAPP	406	43	11%
NPCC	394	17	4%
SERC	333	94	28%
SPP	262	32	12%
WSCC	773	18	2%
Unknown	3	0	0%
Total	**3,125**	**416**	**13%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: *U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.*

c. Water body and cooling system type

Table 1-6 shows that most of the existing utility plants with a CWIS and an NPDES permit draw water from a freshwater river (204, or 49 percent). The next most frequent water body types are lakes or reservoirs with 138 plants (33 percent) and estuaries or tidal rivers with 47 plants (11 percent). The table also shows that most of these plants, 314 or 75 percent, employ a once-through cooling system. Of the plants that withdraw from an estuary, the most sensitive type of water body, only nine percent use a recirculating system while 85 percent have a once-through system.

Table 1-6: Number of Existing Utility Plants by Water Body Type and Cooling System Type[a]

Water Body Type	Cooling System Type										
	Recirculating		Once-Through		Combination		Other		Unknown		Total [b]
	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	
Estuary/ Tidal River	4	9%	40	85%	1	2%	2	4%	0	0%	**47**
Ocean	0	0%	15	100%	0	0%	0	0%	0	0%	**15**
Lake/ Reservoir	29	21%	103	75%	4	3%	2	1%	0	0%	**138**
Freshwater River	36	18%	149	73%	8	4%	10	5%	1	0%	**204**
Multiple Freshwater	0	0%	6	60%	3	30%	1	10%	0	0%	**10**
Other/ Unknown	1	50%	1	50%	0	0%	0	0%	0	0%	**2**
Total	**70**	**17%**	**314**	**75%**	**16**	**4%**	**15**	**4%**	**1**	**0%**	**416**

[a] The number of plants was sample weighted to account for survey non-respondents.
[b] Numbers may not add up to totals due to independent rounding.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999c.

1-3.2 Existing Section 316(b) Nonutility Plants

EPA identified nonutility steam electric prime movers that require cooling water using information from the EIA data collection Forms EIA-860B[9] and the section 316(b) Industry Survey. These prime movers include:

- Geothermal Binary (GB)
- Steam Turbine – Fluidized Bed Combustion (SF)
- Solar – Photovoltaic (SO)

[9] U.S. DOE, 1998b (Annual Nonutility Electric Generator Report) is the equivalent of U.S. DOE, 1998a for utilities. It is the annual inventory of nonutility plants and collects data on the type of prime mover, nameplate rating, energy source, year of initial commercial operation, and operating status.

- Steam Turbine (ST)

In addition, prime movers that are part of a combined-cycle unit were classified as steam electric.

U.S. DOE, 1998b includes two types of nonutilities: facilities whose primary business activity is the generation of electricity, and manufacturing facilities that operate industrial boilers in addition to their primary manufacturing processes. The discussion of existing section 316(b) nonutilities focuses on those nonutility facilities that generate electricity as their primary line of business.

Using the identified list of steam electric prime movers, and U.S. DOE, 1999b information on the reported operating status of generating units, EPA identified 559 facilities that have at least one generating unit with a steam electric prime mover. Additional information from the section 316(b) Industry Survey determined that 134 of the 559 facilities operate a CWIS and hold an NPDES permit. Table 1-7 provides information on the number of parent entities, nonutility plants, and generating units, and their generating capacity in 1999. The table provides information for the industry as a whole, for the steam electric part of the industry, and for the "section 316(b)" part of the industry.

Table 1-7: Number of Nonutilities, Nonutility Plants, Units, and Capacity, 1999

	Total	Total Steam Electric Nonutilities [a]	Nonutilities with CWIS and NPDES Permit[a,b]	
			Number	% of Steam Electric
Parent Entities	1,509	441	47	11%
Nonutility Plants	2,205	559	134	24%
Nonutility Units	5,958	1,255	343	27%
Nameplate Capacity (MW)	206,500	153,032	107,054	70%

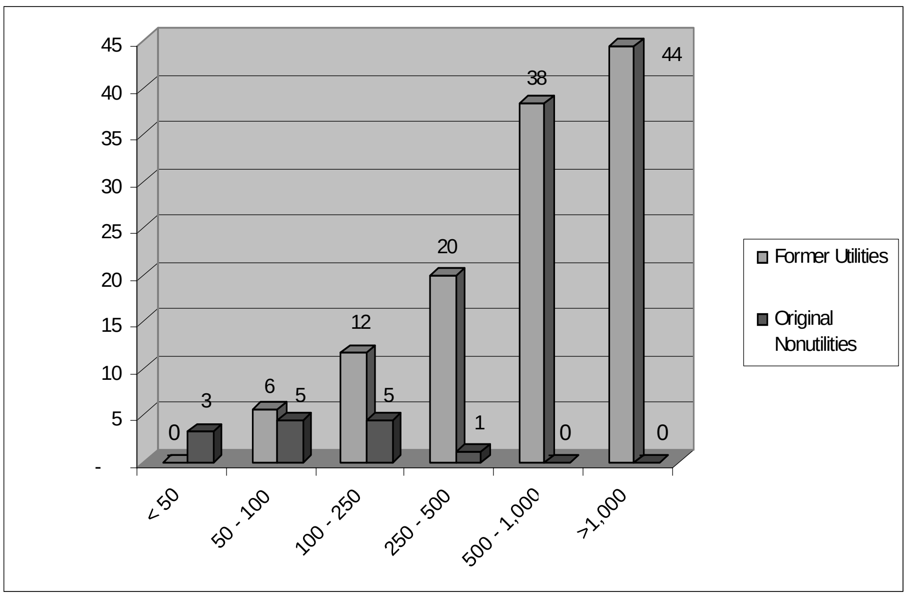
[a] Includes only nonutility plants generating electricity as their primary line of business.
[b] The number of plants, units, and capacity was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

a. Plant size

EPA analyzed the steam electric nonutilities with a CWIS and an NPDES permit with respect to their generating capacity. Figure 1-5 shows that the original nonutility plants are much smaller than the former utility plants. Of the 14 original utility plants, 3 (25 percent) have a total nameplate capacity of 50 MW or less, and 8 (58 percent) have a capacity of 100 MW or less. No original nonutility plant has a capacity of more than 500 MW. In contrast, only 18 (15 percent) former utility plants are smaller than 250 MW while 83 (69 percent) are larger than 500 MW and 44 (37 percent) are larger than 1,000 MW.

Figure 1-5: Number of Existing Nonutility Plants with CWIS and NPDES Permit by Generating Capacity (in MW), 1998[a,b]



[a] Numbers may not add up to totals due to independent rounding.

[a] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

b. Geographic distribution

Table 1-8 shows the distribution of existing section 316(b) nonutility plants by NERC region. The table shows that the Northeast Power Coordinating Council (NPCC) has the highest absolute number of existing section 316(b) nonutility plants with 45 (9 percent) of the 134 plants with a CWIS and an NPDES permit, followed by the Mid-Atlantic Area Council (MAAC) with 41 plants. MAAC also has the largest percentage of plants with a CWIS and an NPDES permit compared to all nonutility plants within the region, at 26 percent.[10]

Table 1-8: Nonutility Plants by NERC Region, 1998

NERC Region	Total Number of Plants	Plants with CWIS & NPDES Permit[a,b]	
		Number	% of Total
ASCC	26	0	0%
ECAR	139	10	7%
ERCOT	75	0	0%
FRCC	57	1	2%
HI	11	0	0%
MAAC	155	41	26%
MAIN	136	18	13%
MAPP	70	1	2%
NPCC	531	45	9%
SERC	279	1	0%
SPP	43	0	0%
WSCC	613	16	3%
Not Available	70	0	0%
Total	**2,205**	**134**	**6%**

[a] Numbers may not add up to totals due to independent rounding.
[b] The number of plants was sample weighted to account for survey non-respondents.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

[10] The total number of plants includes industrial boilers while the number of plants with a CWIS and an NPDES permit does not. Therefore, the percentages are likely higher than presented.

c. Water body and cooling system type

Table 1-9 shows the distribution of existing section 316(b) nonutility plants by type of water body and cooling system. The table shows that a majority of plants with a CWIS and an NPDES permit draw water from either a freshwater river, or an estuary or tidal river.

The table also shows that most of the nonutilities employ a once-through system: 114 out of 133 nonutility plants. Of the plants that withdraw from an estuary/tidal river, the most sensitive type of waterbody, only two use a recirculating system, while 56 operate a once-through system.

Table 1-9: Number of Nonutility Plants by Water Body Type and Cooling System Type[a]

Water Body Type	Cooling System Type								
	Recirculating		Once-Through		Combination		Other		Total [b]
	No.	% of Total	No.	% of Total	No.	% of Total	No.	% of Total	
Estuary/ Tidal River	2	3%	56	95%	1	2%	0	0%	59
Ocean	0	0%	9	100%	0	0%	0	0%	9
Lake/ Reservoir	2	17%	9	74%	1	9%	0	0%	12
Freshwater River	13	25%	39	75%	0	0%	1	2%	52
Other/ Unknown	0	0%	1	100%	0	0%	0	0%	1
Total	**17**	**13%**	**114**	**86%**	**2**	**2%**	**1**	**1%**	**133**

[a] The number of plants was sample weighted to account for survey non-respondents.
[b] Numbers may not add up to totals due to independent rounding.

Source: U.S. EPA, 2000; U.S. DOE, 1999a; U.S. DOE, 1999b; U.S. DOE, 1999c.

1-3.3 Cooling Water Intake Structure Data

A primary source of information used to prepare the analyses of this document is the 316(b) survey. The 316(b) survey was a two phase process. The results from the second phase of this process -- the distribution of questionnaires to utility and nonutility power producers -- is of specific interest to the analyses in this document. The results from following questionnaires are of interest to this proposed rule: (1) Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures -Traditional Steam Electric Utilities, (2) Short Technical Industry Questionnaire: Phase II Cooling Water Intake Structures - Traditional Steam Electric Utilities, (3) Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures - Steam Electric Nonutility Power Producers, and (4) Short Technical Industry Questionnaire: Phase II Cooling Water Intake Structures - Steam Electric Nonutility Power Producers. For the purposes of this document, the results of the detailed industry questionnaires for both utilities and nonutilities are addressed as simply the detailed questionnaire (the "DQ") results. Similarly, this document refers to the results from the short technical industry questionnaire for both utilities and nonutilities as simply the short technical questionnaire (the "STQ") results. Specific details about the questions may be found in EPA's Information Collection Request (DCN 3-3084-R2 in Docket W-00-03) and in the questionnaires (see DCN 3-0030 and 3-0031 in Docket W-00-03 and Docket for today's proposal); these documents are also available on EPA's web site (http://www.epa.gov/waterscience/316b/question/).

All utilities and a sample of nonutility facilities (those identified as in-scope by the results of a screener questionnaire) were sent either a STQ or a DQ. A total of 878 utility facilities and 343 nonutility facilities received one of the two questionnaires. EPA selected a random sample of these eligible facilities to receive a DQ. The sample included 282 utility facilities and 181 nonutility facilities. Those facilities not selected to receive a DQ were sent a STQ. More detail is provided in a report, Statistical Summary for Cooling Water Intakes Structures Surveys (See DCN 3-3077 in Docket W-00-03). Of the 282 utility facilities and 181 nonutility facilities receiving a DQ, the Agency determined that 225 of the respondents would fall within the scope of this rule. Of the STQ respondents, the Agency found that 314 would be in-scope.

The Agency compiled facility level, cooling system, and intake structure data for the 225 in-scope Detailed Questionnaire (DQ) respondents and, to the extent possible, for the 314 Short Technical Questionnaire (STQ) respondents. The Agency then used this tabulation of data to make determinations on the types of cooling systems and intake structures in-place at the in-scope facilities. The Agency utilized questions about intake systems common to both the DQ and STQ in order to make determinations about costing decisions that hinged on the intake structures in-place. Other pieces of information from the STQ provided insight into the types of intake structures in-place at the STQ facilities, when compared to more detailed information for the DQ respondents.

Using both the DQ and STQ responses, the Agency studied the intake structure characteristics for all 539 facilities and/or the 225 DQ facilities. The Agency focused on questions about intake screen structure types common to both the DQ and STQ. The Agency then examined the DQ respondents within the context of these questions to discern patterns and statistics for use in making decisions relating to costing of the proposed option based on intake systems currently in-place for both the DQ and STQ facilities. Tables 1-10 through 1-19 summarize this data analysis. For discussion and descriptions of the types of cooling water intake technologies presented in the tables, see Chapter 3 of this document.

Table 1-10 presents information for the in-scope, DQ respondents relating to the general configuration of their cooling water intake system, water body from which they withdraw cooling water, and cooling system type. The table also shows that the median intake velocity for all in-scope, DQ intakes is 1.5 feet per second. Of interest is the fact that of all in-scope DQ respondents, 89 percent of the intakes operate traveling screens and 25 percent report some form of impingement or entrainment reducing configuration.

Table 1-10 Statistics for all Detailed Questionnaire, In-scope Facilities

Percent	Cooling Water Intake Technology
22	cooling tower (recirculating or helper)
36	intake canal or channel
10	embayment/bay/cove
30	submerged shoreline intake
38	surface shoreline intake
14	submerged offshore intake
95	trash racks
97	intake screen
25	impingement / entrainment technology
5	passive intake
6	fish diversion or avoidance
32	fish handling and/or return
89	traveling screens
Percent	Cooling System Type
76	once-through
12	recirculating cooling
11	combination cooling
1	other cooling type
Percent	Intake Velocity (median intake velocity = 1.5 ft/sec)
14	velocity < or = 0.5 fps
Percent	Waterbody Type
22	Estuary/Tidal River
5	Ocean
49	Freshwater Stream/River
19	Lake/Reservoir
5	Great Lake

Table 1-11 shows similar information as in Table 1-10, however, the data is specific to the in-scope respondents to the DQ that reported impingement/ entrainment technologies. The cooling water intake technology information in the first portion of Table 1-11 resembles that of Table 1-10. However, the percentage of intakes with fish handling / fish return technologies is considerably higher for those reporting impingement / entrainment technologies compared to all in-scope DQ intakes. The distribution of cooling system types are similar for Tables 1-10 and 1-11, as is the median velocity.

Table 1-11 Statistics for DQ Intakes with Impingement / Entrainment Technologies

Percent	Cooling Water Intake Technology
22	cooling tower (recirculating or helper)
34	intake canal or channel
7	embayment/bay/cove
34	submerged shoreline intake
37	surface shoreline intake
5	submerged offshore intake
94	trash racks
98	intake screen
8	passive intake
2	fish diversion or avoidance
59	fish handling and/or return
Percent	**Cooling System Type**
80	once-through
14	recirculating cooling
5	combination cooling
1	other cooling type
Percent	**Intake Velocity (median intake velocity = 1.4 ft/sec)**
18	velocity < or = 0.5 fps
Percent	**Waterbody Type**
41	Estuary/Tidal River
4	Ocean
35	Freshwater Stream/River
19	Lake/Reservoir
2	Great Lake

Table 1-12 presents the number and capacity of the intakes for the in-scope DQ respondents. Key statistics, in the Agency's view, are the number of intakes per facility (less than two), the distribution of the number of intakes at in-scope DQ respondent facilities (64 percent with only one intake and only 11 percent of facilities with three or more intakes), and the average percent of intake flow used for cooling (86 percent).

Table 1-12. Number and Capacity of Intakes for In-Scope Detailed Questionnaire Facilities

Characteristic	Value
median design capacity per intake (gpd) for all intakes	219,000,000
median design capacity per facility (gpd) for all facilities	374,000,000
median capacity per intake (gpd) for facilities at or below median facility flow	100,800,000
median capacity per intake (gpd) for facilities above median facility flow	408,400,000
average number of intakes per facility for all facilities	1.6
Facilities with only 1 intake	64 %
Facilities with 2 or more intakes	36 %
Facilities with 3 or more intakes	11 %
Facilities at or below median facility flow with 2 or more intakes	26 %
Facilities above median facility flow with 2 or more intakes	46 %
Facilities at or below median facility flow with 3 or more intakes	4 %
Facilities above median facility flow with 3 or more intakes	17 %
Facilities at or below median facility flow with 4 or more intakes	1 %
Facilities above median facility flow with 4 or more intakes	8 %
Facilities with four or more intakes	4 %
Average number of intakes per facility at or below median facility flow	1.3
Average number of intakes per facility above median facility flow	1.8
Average percent of intake used for cooling per intake (all facilities)	86 %
Average percent of intake used for cooling for facilities at or below median flow	86 %
Average percent of intake used for cooling for facilities above median facility flow	87 %

Table 1-13 gives a breakdown of the type of fish handling / return systems at in-scope DQ facilities. Table 1-14 presents the same information, but only for the in-scope DQ respondents that reported both fish handling / fish return systems and impingement/ entrainment reducing configurations. Clearly, the most prevalent form of fish handling / return system is the conveyance system. See Chapter 3 of this document for descriptions of the types of fish handling / return systems.

Table 1-13. Statistics for DQ Facilities Reporting Fish Handling/Return Systems

Percent	Characteristic
8	fish pump
94	fish conveyance system
4	fish elevator/lift baskets
3	fish bypass
1	fish holding tank
3	other handling/return system
10	more than one of the above

Table 1-14. Statistics for Facilities Reporting Fish Handling / Returns AND Impingement / Entrainment Systems in Detailed Quetionnaire

Percent	Characteristic
14	fish pump
86	fish conveyance system
8	fish elevator/lift baskets
6	fish bypass
2	fish holding tank
6	other handling/return system
18	more than one of the above

Table 1-15 presents information for the in-scope DQ respondents that reported shoreline intakes (either surface or submerged intakes). Interestingly, the median surface water depth for surface and submerged shoreline intakes is very similar (approximately 18 feet). The percentage of in-scope DQ respondents with shoreline intakes is split, roughly equally, between submerged and surface configurations. The majority (77 percent) of all shoreline intakes are flush with the shore and only 8 percent protrude offshore.

Table 1-15. Statistics for Detailed Questionnaire Shoreline Intakes

characteristic	value
median surface water depth for both submerged and surface intakes (ft)	18
median surface water depth for surface intakes (ft)	17
median surface water depth for submerged intakes (ft)	18
median distance from top of intake to surface for all shoreline intakes (ft)	9
median distance from intake bottom to surface for all shoreline intakes (ft)	18
Percent of all shoreline intakes submerged	45
Percent of all shoreline intakes surface	55
Percent of all shoreline intakes flush with shore	77
Percent of all shoreline intakes recessed	15
Percent of all shoreline intakes protruding offshore	8
Percent of all shoreline intakes with skimmer/curtain/baffle wall	45

Tables 1-16 and 1-17 present basic information from the in-scope DQ respondents on the percent of fine-mesh screens and passive intakes in-place at these facilities. In addition, Table 1-16 includes the Agency's projection of the total number of fine-mesh screens at STQ respondents (note: the STQ did not collect information of sufficient detail to distinguish fine-mesh from coarse-mesh screens).

Table 1-16. Statistics for Fine Mesh Screens

Characteristic	Value
Detailed Questionnaire Intakes with Fine Mesh in-place	1.3 %
Detailed Questionniare Estuarine Intakes with Fine Mesh in-place	4.3%
Projected Number of Short Technical Questionnaire Intakes with Fine Mesh in-place	6

Table 1-17. Statistics for Passive Intake

Percent	Characteristic
5.4	Percent of All Intakes reported as Passive Intakes
5.3	Percent of Estuarine Intakes reported as Passive

Table 1-18 presents detailed information from the in-scope DQ respondents with offshore intakes. The percentage of impingement / entrainment technologies on offshore intakes is very low (2 percent). The median distance from shore is 450 feet and the median surface water depth is 30 feet at the intake. As expected, ocean intakes show the highest percentage of offshore configurations.

Table 1-18. Statistics for Intakes Reported as Offshore in the Detailed Questionnaire

Characteristic	Value
all DQ intakes Offshore	10
% of intakes reporting I/E Offshore	2
Median distance to shore for Offshore intakes (feet)	450
Median surface water depth at Offshore intake (feet)	30
Percent of estuarine intakes Offshore	5
Percent of ocean intakes Offshore	41
Percent of lake / Reservoir intakes Offshore	16
Percent of freshwater stream / river intakes Offshore	11
Percent of Great Lake intakes Offshore	35

Table 1-19 presents information for in-scope DQ intakes reporting canal or channel configurations. The median canal/channel length from mouth to pumps is 1000 feet. The cross-sectional water level ranges from 470 ft (median of reported low-water levels) to 620 ft (median of reported mean-water levels).

Table 1-19. Statistics for DQ Intakes Reporting Canal/Channel

Characteristic	Value
Median Length Canal Mouth to Pumps (ft)	1000
Median Intake X-Section-Low Water (ft)	472
Median Intake X-Section-Mean Water (ft)	617
Median Distance curtain/baffle from canal mouth (ft)	650
Median intake bay depth (ft)	17
Percent of canal/channel intakes with submerged shoreline Intakes	9 %
Percent of canal/channel intakes with surface shoreline intakes	19 %
Percent of canal/channel intakes with flush intakes	20 %
Percent of canal/channel intakes with recessed intakes	6 %
Percent of canal/channel intakes with protruding intakes	2 %

Glossary

Baseload: A baseload generating unit is normally used to satisfy all or part of the minimum or base load of the system and, as a consequence, produces electricity at an essentially constant rate and runs continuously. Baseload units are generally the newest, largest, and most efficient of the three types of units. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Combined-Cycle Turbine: 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 heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Distribution: The portion of an electric system that is dedicated to delivering electric energy to an end user.

Electricity Available to Consumers: Power available for sale to customers. Approximately 8 to 9 percent of net generation is lost during the transmission and distribution process.

Energy Policy Act (EPACT): In 1992 the EPACT removed constraints on ownership of electric generation facilities and encouraged increased competition on the wholesale electric power business.

Gas Combustion Turbine: A gas turbine typically consisting of an axial-flow air compressor and one or more combustion chambers, where liquid or gaseous fuel is burned and the hot gases are passed to the turbine. The hot gases expand to drive the generator and are then used to run the compressor.

Generation: The process of producing electric energy by transforming other forms of energy. Generation is also the amount of electric energy produced, expressed in watthours (Wh).

Gross Generation: The total amount of electric energy produced by the generating units at a generating station or stations, measured at the generator terminals.

Intermediate load: Intermediate-load generating units meet system requirements that are greater than baseload but less than peakload. Intermediate-load units are used during the transition between baseload and peak load requirements. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Internal Combustion Engine: An internal combustion engine has one or more cylinders in which the process of combustion takes place, converting energy released from the rapid burning of a fuel-air mixture into mechanical energy. Diesel or gas-fired engines are the principal fuel types used in these generators.

Kilowatthours (kWh): One thousand ***watthours (Wh)***.

Nameplate Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Net Capacity: The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer, exclusive of station use, and unspecified conditions for a given time interval.

Net Generation: ***Gross generation*** minus plant use from all plants owned by the same utility.

Nonutility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Nonutility power producers include qualifying cogenerators, qualifying small power producers, and other nonutility generators (including independent power producers) without a designated franchised service area that do not file forms listed in the Code of Federal Regulations, Title 18, Part 141. (http://www.eia.doe.gov/emeu/iea/glossary.html)

Other Prime Movers: Methods of power generation other than ***steam turbine***, ***combined-cycle***, ***gas combustion turbine***, ***internal combustion engine***, and ***water turbine***. Other prime movers include: geothermal, solar, wind, and biomass.

Peakload: A peakload generating unit, normally the least efficient of the three unit types, is used to meet requirements during the periods of greatest, or peak, load on the system. (http://www.eia.doe.gov/cneaf/electricity/page/prim2/chapter2.html)

Power Marketers: Business entities engaged in buying, selling, and marketing electricity. Power marketers do not usually own generating or transmission facilities. Power marketers, as opposed to brokers, take ownership of the electricity and are involved in interstate trade. These entities file with the Federal Energy Regulatory Commission for status as a power marketer. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Power Brokers: An entity that arranges the sale and purchase of electric energy, transmission, and other services between buyers and sellers, but does not take title to any of the power sold. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Prime Movers: The engine, turbine, water wheel or similar machine that drives an electric generator. Also, for reporting purposes, a device that directly converts energy to electricity, e.g., photovoltaic, solar, and fuel cell(s).

Public Utility Regulatory Policies Act (PURPA): In 1978 PURPA opened up competition in the electricity generation market by creating a class of nonutility electricity-generating companies referred to as “qualifying facilities.”

Reliability: Electric system reliability has two components: adequacy and security. Adequacy is the ability of the electric system to supply customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. (http://www.eia.doe.gov/cneaf/electricity/epav1/glossary.html)

Steam Turbine: A generating unit in which the prime mover is a steam turbine. The turbines convert thermal energy (steam or hot water) produced by generators or boilers to mechanical energy or shaft torque. This mechanical energy is used to power electric generators, including combined-cycle electric generating units, that convert the mechanical energy to electricity.

Transmission: The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act (PURPA) are not considered electric utilities. (http://www.eia.doe.gov/emeu/iea/glossary.html)

Water Turbine: A unit in which the turbine generator is driven by falling water.

Watt: The electrical unit of power. The rate of energy transfer equivalent to 1 ampere flowing under the pressure of 1 volt at unity power factor.(Does not appear in text)

Watthour (Wh): An electrical energy unit of measure equal to 1 watt of power supplied to, or take from, an electric circuit steadily for 1 hour. (Does not appear in text)

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Chapter 2: Costing Methodology for Model Plants

INTRODUCTION

This chapter presents the methodologies used by the Agency to develop cost estimates at the model plant level for the proposed rule and regulatory options considered. The Agency costs for 539 model plants and these were then used in the economic analysis to scale to the total universe of in-scope facilities. For the model-plant specific projected compliance costs of the proposed rule, see Appendix A of this document. Under the proposed rule, facilities have the option of conducting a cost test against the compliance costs developed by the Agency for support of the regulatory requirements of the rule. The costs presented in Appendix A, and developed based on the methodology presented in this chapter, would form the basis of the "significantly greater" cost test in the proposed rule.

The term model plant is used frequently throughout this document. The Agency notes that model plants are not actual existing facilities. Model Plants are statistical representations of existing facilities (or fractions of existing facilities). Therefore, the cost estimates developed for the rule should not be considered to reflect those exactly of a particular existing facility. However, in the Agency's view, the national estimates of benefits, compliance costs, and economic impacts are representative of those expected from the industry as a whole.

2.1 COOLING WATER INTAKE STRUCTURE COSTS

EPA developed distinct sets of intake structure and conduit system costs for existing source model plants expected to (1) upgrade screen systems only, (2) upgrade cooling systems and intake structures, and (3) upgrade cooling systems only.

For those plants projected to incur costs of cooling water intake structure upgrades (but not flow-reducing cooling system conversions), the Agency estimates that intake fanning/expansion would be necessary for the majority of plants projected to install entrainment reducing fine-mesh screens. Therefore, the Agency developed capital costs for these scenarios that incorporate the costs of expanding/fanning or adding an additional bay to an existing intake structure in order to upgrade to fine-mesh screens. Because fine-mesh screens have reduced open cross-sectional area when compared to coarse-mesh screens, the Agency considers the intake expansion/fanning costs to be appropriate in these cases. Even though there is not a set of velocity-based requirements for this proposal, the Agency projects that the model plants expected to upgrade their intake screens from coarse to fine-mesh would reduce their through-screen velocity from the median facility value of 1.5 feet/second to 1.0 feet/second as a result of this technology change. In part, in the Agency's view, the reduced velocity would adopted for the operational requirements of the screens and to balance the impingement reduction benefits of lower velocities with the physical constraints of velocity reduction for existing intake structures. The Agency utilized costs developed for fine-mesh screens with a through-screen velocity of 1.0 feet/second to size the intake for the full design, once-through intake flow. The operation and maintenance (O&M) costs of these screens are calculated based on the same principle. These capital and O&M costs for fine-mesh screens were developed for the New Facility 316(b) rule and are utilized for existing facilities with some modifications. The Agency applies a capital cost construction inflation factor (in addition to a "retrofit" factor discussed in section

2.6) to account for the expansion/fanning of the intake structure, but does not estimate further O&M costs for this one-time activity. Those plants that additionally would install fish handling/return systems to the upgraded screens incur capital and operation and maintenance costs developed based on the size of the larger size screens. See Sections 2.1.1 and 2.1.2 for the development of the cost estimates for capital and O&M costs for fine-mesh screens.

The Agency developed existing facility construction factors (used in addition to "retrofit" factors discussed in Section 2.6) based on the average ratio of intake modification construction costs to costs derived from CWIS equations developed for New Facility projects. Thus the differences reflect differences in construction costs for nuclear and non-nuclear and differences in CWIS installation capital costs. Table 2-1 presents the construction factors for a variety of compliance technologies used as the basis for the costs estimated for this proposal and regulatory options.

Table 2-1 CWIS Technology Flow Sizing and Construction Factors for Existing Facilities

Compliance Cooling System Type	Plant Type	Flow Used to size Cooling Water Intake Technology	Compliance Cooling Water Intake Technology	Construction Factor for Scenario
Non-Cooling Tower	Non-nuclear	100% of Once-through Baseline Design Intake	Fish Handling	None
Non-Cooling Tower	Non-nuclear	100% of Once-through Baseline Design Intake	Fine Mesh Screens	30%*
Non-Cooling Tower	Non-nuclear	100% of Once-through Baseline Design Intake	Fine Mesh Screens w/ Fish Handling	15%*
Non-Cooling Tower	Nuclear	100% of Once-through Baseline Design Intake	Fish Handling	None
Non-Cooling Tower	Nuclear	100% of Once-through Baseline Design Intake	Fine Mesh Screens	65%*
Non-Cooling Tower	Nuclear	100% of Once-through Baseline Design Intake	Fine Mesh Screens w/ Fish Handling	30%*

* Existing facility construction factors based on average ratio of intake modification construction costs to costs derived from CWIS equations developed for New Facility projects. Thus the differences reflect differences in construction costs for nuclear and non-nuclear and differences in CWIS installation capital costs.

** For cooling sizing of cooling towers and appropriate flow for determining the costs of retrofitted cooling water systems, see Section 2.2.

Intake modification construction costs are based on the following general framework:

- An increase in screen area of 50% due to conversion from coarse-mesh to fine-mesh.
- Screen size increase will involve demolition of one side of intake and extension in that direction.
- Installation/removal of sheet piling.
- Concrete demolition of one column and one side (cost doubled for nuclear*).

- Excavation (cost doubled for nuclear*).
- Additional concrete foundation.
- Additional concrete side and back wall.
- Additional concrete column.

* EPA doubled costs to account for concerns that use of blasting and high-impact equipment may be limited at nuclear facilities.

Modification construction costs were then increased by the following cost factors:

Item	Factor
Mobilization/Demobilization	3 %
Engineering	10 %
Site Work	5 %
Electrical	10 %
Controls	3 %
Contingency	10 %
Allowance	5 %

For those model plants projected to only incur costs of installing fish handling/return systems to existing screens, the Agency developed costs by estimating the size of coarse mesh, 1.5 feet/sec screens. The through-screen velocity of 1.5 feet/sec is the median velocity for all 316b survey respondents. The Agency determined that use of this metric to size the fish handling/return systems was appropriate for the variety of plants projected to incur their capital and operation and maintenance costs as a result of this proposal. The capital cost estimates used here for installation of the fish handling/return systems to existing screens were those developed for new facilities, with an additional inflation (or "retrofit") factor to account for the issues discussed in Section 2.6 below. Section 2.1.1 presents the cost estimates developed for new facilities for fish handling/return systems.

For the those plants projected to incur costs of cooling system conversions and entrainment-reducing fine-mesh screens, the Agency considered the existing intake structures to be of a size too large for a realistic screen retrofit. Therefore, in these cases, the Agency estimated that one-half of the intake bay(s) would be blocked/closed and the retrofitted fine-mesh intake screens would apply to only one-half of the size of the original intake. The Agency considers this a reasonable approach to estimating realistic scenarios where the average plant (as demonstrated in Table 1-12) utilizes multiple intake bays. In the Agency's view, the plant, when presented an equal opportunity option, would utilize the potential cost savings option of installing the fine-mesh screens on only the maximum intake area necessary. For those plants also projected to incur costs of the addition of fish handling/return systems, the Agency estimates the system size based on this concept of closure/blockage of one-half of the existing intake. The operation and maintenance costs are also developed using this size of an intake. Therefore, for the case of each of these retrofit activities, the installed capital costs and operation and maintenance costs of the intake screens and fish handling/return systems are approximately one-half of those for a full size screen replacement.

For those model plants converting their cooling systems from once-through to recirculating systems but not incurring costs of entrainment-reducing intake screens, the existing intake structures are considered to be operational without significant modification (as was the case in the example of the conversions discussed in Chapter 4). In turn, the plants would incur no additional operation and maintenance costs.

The Agency notes that in addition to the intake structure capital costs described above, the capital costs are inflated by the "retrofit" capital cost factor of 30 percent described in section 2.6, below. Therefore, the Agency views the retrofit capital costs developed for upgrading intake screens and structures to be appropriate for existing model plants.

2.1.1 Capital and O&M Costs of Intake Structures and Conduit Systems

Installation of traveling screens with fish baskets for New Facilities

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 2-2. 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 2-3. 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 2-4 and 2-5. Table 2-4 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 2-4. 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 2-5. 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 for New Facilities 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 2-6 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 2-7 presents the estimated costs of site preparation for four sizes of screen widths and various well depths.

Table 2-6. Estimated Installation (Site Preparation) Costs for Traveling Water Screens Installed at a 10-foot Well Depth (1999 Dollars)

Screen Width (ft)	Clearing and Grabbing (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 2-7. 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 2-7. 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).

Table 2-8. 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 2-9 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 2-9. 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 for New Facilities

The installation costs in Table 2-9 were added to the equipment costs in Tables 2-4 and 2-5 to derive total equipment and installation costs for traveling screens with and without fish handling features. These estimated costs are presented in Tables 2-10 and 2-11. 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 2-12 and 2-13 for flow velocities of 1.0 fps and 0.5 fps, respectively.

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

Table 2-10. Estimated Total Capital Costs for Traveling Screens Without Fish Handling Features (Equipment and Installation)[1] (1999 Dollars)

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 2-11. 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 2-12 and 2-13 present equations that can be used to estimate costs for traveling screens at 0.5 fps and 1.0 fps, respectively. See the Appendix B for cost curves and equations.

Table 2-12. Capital Cost Equations for Traveling Screens for Velocity of 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	$y = 6E{-}08x^3 - 0.0014x^2 + 28.994x + 36372$	$R^2 = 0.9992$	$y = 5E{-}08x^3 - 0.0013x^2 + 20.892x + 18772$	$R^2 = 0.9991$
5	$y = 1E{-}09x^3 - 8E{-}05x^2 + 12.223x + 80790$	$R^2 = 0.994$	$y = 2E{-}09x^3 - 0.0001x^2 + 9.7773x + 54004$	$R^2 = 0.9995$
10	$y = 5E{-}10x^3 - 9E{-}05x^2 + 12.726x + 88302$	$R^2 = 0.9931$	$y = 5E{-}03x^3 - 9E{-}05x^2 + 10.143x + 63746$	$R^2 = 0.9928$
14	$y = 6E{-}10x^3 - 0.0001x^2 + 15.874x + 91207$	$R^2 = 0.995$	$y = 5E{-}10x^3 - 0.0001x^2 + 12.467x + 65934$	$R^2 = 0.9961$

1) x is the flow in gpm y is the capital cost in dollars.

Table 2-13. Capital Cost Equations for Traveling Screens for Velocity of 1 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	$y = 8E\text{-}09x^3 - 0.0004x^2 + 15.03x + 33044$	$R^2 = 0.9909$	$y = 8E\text{-}09x^3 - 0.0004x^2 + 10.917x + 16321$	$R^2 = 0.9911$
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 2-4 and 2-5, 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 2-14 and 2-15 for flow velocities of 1.0 fps and 0.5 fps, respectively.

Table 2-14. Estimated Annual O&M Costs for Traveling Water Screens Without Fish Handling Features (Carbon Steel - Standard Design)[1] (1999 Dollars)

Well Depth (ft)	Screen Panel Width (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 2-15. 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 2-16: Annual O&M Cost Equations for Traveling Screens Velocity 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	$y = -3E\text{-}05x^2 + 1.6179x + 3739.1$	$R^2 = 0.9943$	$y = -2E\text{-}05x^2 + 1.0121x + 2392.4$	$R^2 = 0.9965$
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 2-17. Annual O&M Cost Equations for Traveling Screens Velocity 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	$y = -8E\text{-}06x^2 + 0.806x + 3646.7$	$R^2 = 0.982$	$y = -4E\text{-}06x^2 + 0.5035x + 2334$	$R^2 = 0.9853$
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 2-17 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 2-4), plus a 20 percent add-on for upgrading existing equipment (mainly to convert traveling screens from intermittent operation to continuous operation).[1] 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 2-18. 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.

[1]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.

Installation of Fish Handling Features to Existing Traveling Screens

As stated earlier, the basic equipment cost of fish handling features (presented in Table 2-18) 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 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 2-8) for a traveling screen (based on BPJ). Table 2-19 shows total estimated costs (equipment and installation) for adding fish handling equipment to an existing traveling screen.

Table 2-19. 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 Appendix B for cost curves and equations.

Other CWIS Technologies

Fine mesh traveling screens and traveling screens with fish handling are but two means by which facilities may comply with the impingement and/or entrainment reduction requirements of the proposed rule. The Agency based its cost estimates on the technologies outlined here, in part due to their prevalence, their applicability to the primary types of intake structures at existing facilities within the scope of the rule, and for their conservative costs (that is, fine mesh traveling screens tend to have higher costs, in the Agencies estimation than other similar technologies). As such, the Agency notes that there are many ways by which facilities may comply with the requirements of this rule and that the costs will be comparable to those developed here and presented in Appendix A. In that regard, the Agency has prepared cost estimates for other comparable screening systems to those presented here and gave the majority of this information in the Technical Development Document for the Final Regulations Addressing Cooling Water Intake Structures for New Facilities (EPA-821-R-01-036), hereinafter referred to as the New Facility TDD. The Agency refers the reader to the New Facility TDD for information on the development of cost for other technologies that facilities may consider for meeting the proposed impingement and entrainment requirements. In addition, Appendix B of this document contains additional cost curves for technologies the Agency analyzed for the development of this rule and the New Facility rule. In addition, Chapter 3 presents a detailed analysis of the types and performance of technologies that facilities may use to comply with the proposed existing facility rule.

2.2 Outline of Cooling System Conversion Costing Methodology

Under certain regulatory options considered (those described in Chapter 4.3), existing facilities are projected to install recirculating wet cooling systems. The Agency developed a methodology for estimating the costs of converting model-facility cooling systems from once-through to recirculating operation in the effort of reproducing the costs and engineering characteristics of the example cooling system conversion cases presented in Chapter 4. The methodology for estimating costs of these cooling system conversions is based on the principles observed in the empirical cases and in historical proposals for cooling system conversions (see Chapter 4 for more discussion). The commonalities and/or principles are as follows:

- recirculating systems can be connected to the existing condensers and operated successfully under a variety of conditions (but not all);
- condenser flows generally do not change due to the conversions;
- significant portions of the condenser conduit systems can be used for the recirculating tower systems;
- existing cooling water pumps generally would be replaced with new circulating water pumps or booster pumps would be installed to increase pumping energy of the circulating system;
- the existing intake structures can be used for supplying make-up water to the recirculating towers (though demolition and replacement of the intake pumps may be necessary);
- pumping distances from tower systems to condensers can be significant, but existing piping runs can, in some cases, be utilized to reduce the amount of new circulating piping installed;
- tower structures can be constructed on-site before connection to the existing conduit system; and
- modification and branching of circulating piping is necessary for connecting the recirculating system to the existing conduits and for providing make-up water to the towers.

Based on these principles, the Agency developed cost estimates for cooling system conversions utilizing those developed for new, “greenfield” facilities and inflated these costs by a “retrofit” factor to account for activities outside the scope of the “greenfield” cost estimates. See sections 2.1 and 2.2 for the cost estimates for “greenfield” cooling tower systems and intake structures. See section 2.6 for a discussion of the “retrofit” factor.

Condenser Refurbishments for Cooling System Conversions

The Agency includes costs for condenser refurbishments at a subset of facilities expected to comply with flow reduction requirements in the regulatory options considered. The Agency projects premature condenser refurbishments, in part, to alleviate potential condenser tube failures, such as that experienced at the Palisades plant. The Agency researched the materials of construction of surface condensers for the model plants under certain regulatory options and for the example cases described in Chapter 4. The Agency also consulted with condenser manufacturing representatives for advice on probable causes for condenser failures due to cooling system conversions, motivations for condenser replacements or refurbishments, useful lives of condensers, and appropriate tube materials for recirculating cooling systems for a variety of water types. Of the four example cases in Chapter 4, only the Palisades plant experienced condenser failure potentially related to the cooling system conversion. Plant personnel were not able to confirm the condenser tube material at the time of the failure, nor were they able to positively confirm the cause of the failure as relating to the recirculating system. Hence, the Agency could not isolate the specific cause of the Palisades failure and, therefore, relied on additional information to determine which plants would likely replace condensers in order to upgrade the cooling system under certain regulatory options. The Agency learned from condenser vendors that plants would elect to upgrade condenser tube materials to increase the efficiency of the recirculating cooling system. In addition, based on the circumstantial evidence that the Palisades failure happened, at least in part, due to the chemical addition necessary for the recirculating system and the fact that many of the plants projected to upgrade their cooling systems under certain regulatory options utilize brackish or saline cooling water, the Agency judged that the material of the tubes would need to withstand corrosive effects of chemical addition and increased salt content of the cooling water (due to concentration in a recirculating system). Hence, the Agency concluded that meeting a baseline standard of condenser tube material would determine which model plants would most likely upgrade condenser tube materials. See section 3.2.4 for further information on condenser refurbishments.

Condenser Flows for Cooling System Conversions

Based on the example cases of cooling system conversions in Chapter 4, the Agency determined that condenser flows would not change as a result of cooling system upgrades. The cooling water flow through these tube bundles would be the same as for the once-through systems due to the fact that each of the example cases utilized the original, once-through designed, cooling water flow. In addition to the empirical example cases, the Agency researched condenser flow to MW ratios to determine if cooling system type influenced the flow rate to capacity ratio. Published condenser flows and generating capacity data from the Nuclear Regulatory Commission (DCN 4-2521)) for all nuclear units in the US demonstrates that recirculating cooling systems have lower condenser flow to MW ratios than once-through systems, regardless of age or other characteristics. After considering this information, EPA chose a conservative approach and used the design cooling water intake flow of the baseline once-through system intake to estimate the size of the recirculating cooling tower and associated conduit system for its model facilities. EPA notes that design flows are significantly higher than operating flows in some cases. As such, the approach of the Agency is additionally conservative, in that facilities considering cooling system conversions could optimize the design of the circulating flow levels appropriate for the facilities operating flows if sufficient unused design intake capacity exists.

Reuse of Existing Intake Structures for Supplying Make-up Water to Cooling Towers

As demonstrated by the example cases in Chapter 4, conversions from once-through to recirculating cooling systems do not require construction of new intake structures to provide make-up water to the cooling tower systems. Installation of a fully recirculating cooling system reduces intake flow by upwards of approximately 92 percent as compared to a once-through system. In turn the intake structure designed for a once-through cooling system is oversized for moving flows reduced to this level. For the case of the Palisades plant, the original intake structure withdrew water from a submerged offshore intake. The plant continued to utilize this intake structure (a velocity cap) and the associated submerged piping system (3300 ft) after the conversion. A branch from the onshore portion of the original intake conduit system provided make-up flow to the cooling tower via a separate pump system. The Agency includes capital costs for the conduit system required to bring make-up water to the cooling tower and basin. See Example 1 of this chapter for a discussion of the makeup and blowdown piping associated with the Agency's cooling system conversion estimates. The Agency includes these costs to account for conversion cases in which significant distances may exist between intake locations and cooling tower sites. The Agency notes, as described in Example 1, that these piping capital costs are further inflated by the "retrofit" factor to account for construction techniques and situations outside the scope of a typical "greenfield" cost estimate. In turn, the Agency views the inclusion of these cost estimates as conservative and appropriate for cooling system conversions.

Cooling Tower Construction and Conduit Connections

The actual process of adjoining the cooling tower system to the existing condenser conduit system is reported to have not disrupted service significantly for two of the example cases presented in Chapter 4. However, for the Palisades plant, Consumers Energy report that the outage lasted approximately 10 months for connection and start-up of the cooling tower system (see Chapter 4). The Agency estimates for the flow-reduction regulatory options considered that the typical process of adjoining the recirculating system to the existing condenser unit and the refurbishment of the existing condenser (when necessary) would last approximately two months. Because the Agency analyzed flexible compliance dates (extended over a five-year compliance period), the Agency estimated that plants under the flow-reduction regulatory options could plan the cooling system conversion to coincide with periodic scheduled outages, as was the case for the example cases. For the case of nuclear units, these outages can coincide with periodic inspections (ISIs) and refueling. For the case of fossil-fuel and combined-cycle units, the conversion can be planned to coincide with periodic maintenance. Even though ISIs for nuclear units last typically 2 to 4 months, which would extend equal to or beyond the time required to connect the converted system, the Agency estimates for all model plants one month of interrupted service due to the cooling system conversion. For further information see Chapter 4 of this document and the EBA.

Connections of circulating systems to existing once-through conduits, in the Agency's view, would occur through either demolition and/or removal of the connecting piping and/or through branching (and plugging) of the existing conduit system outside the condenser buildings. The Agency estimates that the primary activities fall within the scope of types of construction projects accounted for by the "retrofit" capital cost inflation factor (see Section 2.6 below). Note that the Agency applies the "retrofit" factor to each capital cost outlay for the entire project. Therefore, the branching/connection of the cooling system conduit system could be accounted for in the inflation of a variety of cost components.

2.2.1 Capital Costs of Wet Towers

As described in section 2.2, above, in order to develop cooling system conversion costs for existing facilities, the Agency modified the capital cost estimates for wet cooling tower systems that it developed for new, "greenfield" facilities in the 316b Phase I Rule for New Facilities by applying a "retrofit" factor. The description of the Agency's cost estimates for cooling tower systems at new facilities is presented below:

For cooling towers, EPA developed cost estimates for use at a range of different total recirculating flow volumes. The cost for flow reduction technologies depends on many factors, including site-specific conditions. The Agency determined that 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.

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.

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. Relative capital and operation cost estimates for various types of cooling towers are estimated in literature (Mirsky et al. (1992), Mirsky and Bauthier (1997), and Mirsky (2000))[2].

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.

Capital Cost of Cooling Towers (New Facility Cost Development)

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 an approach of 10 degrees and $50/gpm for an approach of 5 degrees.[3] This

[2] In developing cost estimates for hybrid-wet/dry cooling towers included in Charts 2-1 through 2-6 of the attachments to this chapter, the Agency computed the capital costs of the hybrid tower unit according to the factors referenced here. The Agency then applied an inflation factor to account for the auxiliary components of installation of a cooling tower system. However, this may overstate the costs of hybrid towers in comparison to wet (only) systems, for the fact that hybrid and wet (only) towers would have roughly identical installation costs (see Appendix C of this document for a discussion of the installation costs of hybrid towers and Chapter 6 for a discussion of the relative costs of plume abatement (that is, hybrid towers) versus wet (only) cooling towers).

[3] The approach 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

cost is for a "small" tower (flow less than 10,000 gpm) and equipment associated with the "basic" tower, and does not include installation. Important auxiliary 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.

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).[4] 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 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.

Capital costs for the recirculating wet tower include costs for all installation components, such as site preparation and clearing, support foundation, electrical wiring and controls, basin and sump, cicrulating piping, blowdown water treatment system, and recirculating pump and housing costs. Wet tower costs are based on cost data for redwood towers with splash fill and an approach of 10 ^{o}F taken from Chart 2-3 in the attachments to this chapter. This tower equation does not include make-up and blowdown piping, intake pumps, intake structure and screening technologies.

In order to account for the important auxiliary costs of installing the cooling tower system, the Agency obtained estimates from industry representatives for installation costs as an inflation percentage of the installed cooling tower unit costs. The factor that EPA obtained is 80 percent, which experienced industry representatives described as the average installation inflation factor. The Agency used this factor to inflate the rule of thumb described above for 10

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.

[4] 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.

degree F approach towers (from approximately \$30 / gpm to \$54 / gpm for the total project cost of a small douglas fir tower and from \$25 / gpm to \$ 45 / gpm for large fir towers). The Agency chose the median design approach of 10 degrees F based on empirical data from recently installed cooling towers at a variety of geographic locations and plant sizes (See Attachment C to Chapter 5). Applying the factors provided in literature for converting from douglas fir material to other types of cooling towers, the Agency derived capital cost equations for basic cooling towers of douglas fir, redwood, concrete, steel, and fiberglass reinforced plastic. For example, using the Agency's methodology for new facilities, the installed cost of a basic 205,000 gpm fiberglass tower would be expressed as follows: \$25 * 1.8 * 110 / 100 * 205,000 = \$10,147,500 (in 1999 \$). To accommodate the relatively standard application of splash fill the Agency additionally multiplied by the factor for splash fill from the literature tower factors. For example, using the new facility methodology for the installation of a 205,000 gpm redwood tower with splash fill would be expressed as follows: \$25 * 1.8 * 120 / 100 * 112 / 100 * 205,000 = \$12,398,400 (in 1999 \$). The Agency developed a series of these calculations for each type of tower using the literature factors and fitted curves to the results. These curve fits are presented in Appendix B of this document as Figures 2-1 through 2-6. The Agency determined that the median cost material was redwood, which is just slightly more expensive than fiberglass reinforced plastic. The Agency learned from cooling tower vendors that fiberglass has become relatively standard for new facility installations, and therefore chose to use the median costs of the redwood because they slightly exceeded those of fiberglass. As such, the Agency primarily developed installed cooling tower costs for the new facility rule using the equation for redwood towers with splash fill. The equation for an installed redwood mechanical-draft cooling tower unit with 10 degree F design approach and splash fill is as follows:

y = -5E-5 x^2 + 70.721 x + 25393 , (in 1999 \$)
where x = flow in gallons per minute, valid up to 225,000 gpm.

For existing facility estimates of cooling tower conversions at non-nuclear facilities, this equation is the starting point for assessing the conversion project costs. In addition to the retrofit factor described in Section 2.6 below, the Agency also added additional makeup and discharge piping capital costs according to the methodology presented in Example 2, which demonstrates how the Agency estimated cooling tower conversion costs for certain regulatory options considered for this proposal.

Similarly, the Agency developed the following equation for the installation capital costs of mechanical-draft concrete cooling tower systems with splash fill:

y = -6E-5 x^2 + 87.845 x + 31674 , (in 1999 \$)
where x = flow in gallons per minute, valid up to 225,000 gpm.

This equation was used as the starting point for assessing cooling tower conversion project capital costs for nuclear facilities for certain regulatory options of this proposed rule. See Example 2 for a demonstration of the incorporation of regional cost factors, the retrofit factor, and makeup and discharge piping costs with the above capital cost equation.

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 in the attachments to this chapter compares actual, total 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 approaches different than the 10 °F used for EPA's cost curves.

For the existing facility regulatory options based on flow reduction, the Agency first compared the validity of the redwood cost curve against empirical turn key costs from cooling tower projects at existing facilities. The Agency obtained four sets of total installed cooling tower costs for helper towers and expansions at existing facilities. The Agency attempted to discern if construction costs at existing facilities were inherently different from its empirically verified cost equations for new facilities. The results of this analysis showed that the median $ per gpm predictions of the redwood equation were nearly identical to those of the four existing facility projects (DCN 4522). However, the Agency determined that additional inflation of the new facility costs was necessary to compensate for the probable additional costs that would be associated with cooling system conversions. In turn, the Agency estimated a retrofit factor of 20 percent additional installed capital cost would be necessary for an average retrofit project.

As described in Chapter 4, the Agency obtained two empirical, total project costs for cooling tower conversion projects. The Agency calculated estimated project costs based on the methodology presented in Example 2 below and determined that for the case of the Palisades conversion that the Agency's methodology was very accurate. For the case of Pittsburg Unit 7, the Agency methodology for assessing conversion costs at non-nuclear plants may have understated total project capital costs (as reported by Pittsburg) by approximately 18 percent. In part, the Agency estimates that exclusion of makeup water pumps may have contributed to the difference (see Example 2). For more information on the on the cooling system example cases see Chapter 4 .

2.2.2 Operation and Maintenance Costs of Wet Towers

The Agency estimates that operation and maintenance costs of wet cooling tower systems for conversion projects would be the same as those developed for new, "greenfield" facilities during the 316b Phase I Rule for New Facilities. The Agency notes that recirculating pumping costs included in these operation and maintenance costs should be deducted from annual costs of cooling system conversion projects. In EPA's view, this methodology presents a realistic estimate of the actual operation and maintenance costs of cooling tower conversion projects.

Even though the Agency did not include capital costs for make-up water pumps for the cooling system conversions (see Example 2, below), the Agency includes operation and maintenance costs for delivering make-up water to the cooling towers.

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.

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 based the estimate 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.

- 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. The O&M equations are shown in Charts 2-8 and 2-9 for redwood and concrete towers with various features. The following equations present the O&M costs for 10 degree F design approach redwood and concrete towers with splash fill:

$y = -4E\text{-}6\ x^2 + 11.617\ x + 2055.2$, (in 1999 $ for with Splash Fill)
where x = flow in gallons per minute, valid up to 225,000 gpm.

$y = -3E\text{-}6\ x^2 + 10.305\ x + 1837.2$, (in 1999 $ for Concrete with Splash Fill)
where x = flow in gallons per minute, valid up to 225,000 gpm.

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 of cooling tower systems.

2.2.3 Operation and Maintenance Costs of Baseline, Once-Through Systems

The Agency also utilizes estimates of operation and maintenance costs of once-through cooling based on a similar methodology to the costs developed for the 316b Phase I Rule for New Facilities. However, the Agency has concluded that the price of electricity used to estimate once-through system pumping costs plus ancillary operational and maintenance costs of operating the existing intake structure and other process activities is not appropriate in the context of existing facility O&M costs. The electricity price used by the Agency to reflect only the dedicated operational pumping costs of the once-through system is a realistic $0.03/kWh. Therefore, when subtracted from the overall cooling tower operation and maintenance estimates, the once-through pumping costs would approximately represent the original pumping costs of the reused cooling water pump. If the Agency had not subtracted this element from the recurring annual costs of the cooling system conversion, the pumping costs, as compared to the baseline operating costs of the once-through system, would be miscounted. See Example 2 for a demonstration of the Agency's estimates of once-through O&M costs.

2.2.4 Capital Costs of Surface Condenser Refurbishments

As described in section 2.2, above, the Agency projects premature condenser refurbishments for a portion of the plants expected to incur costs of cooling tower conversions under certain regulatory options considered for this proposal. The Agency concluded that meeting a baseline standard of condenser tube material would determine which model plants would most likely upgrade condenser tube materials. In part, the Agency based this methodology based on a reference developing cost estimates for modular condenser tube replacements (Burns and

Tsou, 2001). The Agency judged that the minimum standard material would be copper-nickel alloy (of any mixture) for brackish water and stainless steel (of any type) for saline water. The Agency then consulted the 1994 UDI database (Power Statistics Unit Design Data File Part B) – the only data source the Agency is aware of with condenser tube material statistics – to determine the condenser tube material for the plants. For the units at each plant with condenser tube materials of a quality judged below that of the minimum standards mentioned above, the Agency estimates that the plant would refurbish the condenser (thereby changing out the condenser tubes) as a result of the cooling system conversion. The Agency projected that tube material for the upgrades would be stainless steel for all model plants receiving upgrade refurbishments. At some plants, EPA projects that only a portion of design intake flow serves units that would require condenser refurbishment or replacement.

As noted in the discussion above, condenser manufacturing representatives advised the Agency that plants would be motivated to upgrade condenser materials to maximize the energy efficiency of the recirculating cooling system. By upgrading the condensers for those plants utilizing less than the adjudged minimum standard (copper-nickel alloy for brackish waters and stainless steel for saline waters), the Agency determines that the turbine energy penalties derived for new, "greenfield" plants would be more applicable to the upgraded recirculating cooling systems at existing plants. See Chapter 5 of this document for the Agency's energy penalty analysis. In addition, the Agency determines that by accounting for condenser upgrades for those model plants with materials below the minimum standard that it has addressed potential condenser failures due to cooling system upgrades. See Table 2-20 for statistics on condenser materials at recirculating cooling facilities (compiled from the 1994 UDI database for all generating units in the database with cooling towers in-place).

Table 2-20. Condenser Tubes for Units with Cooling Tower (from all Units in 1994 UDI database)

Percent of Cooling Tower Units with Condenser Material	
17%	Titanium
3%	Stainless Steel (any type)
27%	Brass or Admir. Brass
35%	Copper-Nickel Alloy (any type)
12%	AL6X
2%	Others
5%	Unknown

The Agency contacted condenser vendors to obtain cost estimates for refurbishing of existing condensers and for full condenser replacements. The Agency developed cost estimates (on a flow basis) for several types of condenser tube materials – copper-nickel alloy, stainless steel, and titanium. The capital cost estimates for condenser refurbishing were lower than those for full replacements, and the Agency determined that, given equal opportunity, facilities would make the economical decision to refurbish existing condensers rather than replace the waterboxes and the tube bundles. The condenser refurbishing costs developed by the Agency account for the tube materials, full labor, overhead, and potential bracing of the shell due to buoyancy changes (related to changes in tube material and, hence, densities). See Example 2 below for the condenser tube replacement and upgrade capital cost equations.

Power plants will refurbish or replace condensers on a periodic basis. Condenser vendors estimated the average useful life of condenser tubes as 20 years. In order to determine remaining useful life of the condensers at the 59 model plants, the Agency calculated a condenser replacement/refurbishing schedule based on the 20-year useful life estimate and the age of the generating units at the plants. The average useful life remaining for a condenser at the 59 model plants is approximately 9-1/2 years (in 2001). The Agency rounded this to 10 years and used this figure to represent lost operating years as a result of premature condenser refurbishments. The Agency estimates the baseline condenser material for any plant upgrading a condenser would be copper-nickel alloy. Therefore, plants upgrading condensers in order to install recirculating cooling would incur the costs of the full condenser refurbishment/upgrade to stainless steel, less the 10 years of useful life already expended, on average, in a condenser made of a lesser material (e.g., copper-nickel alloy). The economic analysis then uses these capital cost estimates in the calculation of net annualized costs. See the EBA. As explained in the EBA, the full capital cost value of the replacement is reduced to represent lost operating years of the existing condenser.

2.3 Recurring Annual Costs of Post-Compliance Monitoring

Existing facilities that fall within the scope of this proposed rule would be required to perform biological monitoring of impingement and entrainment, and visual or remote inspections of the cooling water intake structure and any additional technologies, on an on-going basis. Additional ambient water quality monitoring may also be required of facilities depending on the specifications of their NPDES permits. Facilities would be expected to analyze the results from their monitoring efforts and provide these results in an annual status report to the permitting authority. In addition, facilities would be required to maintain records of all submitted documents, supporting materials, and monitoring results for at least three years. (Note that the Director may require that records be kept for a longer period to coincide with the life of the NPDES permit.)

EPA expects that facility managers, biologists, biological technicians, statisticians, and clerical staff will devote time toward gathering, preparing, submitting and maintaining records of the post-compliance monitoring information that is required by the proposed rule. To develop representative profiles of each employee's relative contribution, EPA assumed burden estimates that reflect the staffing and expertise typically found in power generating plants. In doing this, EPA considered the time and qualifications necessary to complete a variety of tasks: collecting, preparing, and analyzing samples; enumerating organisms; performing statistical analyses; performing visual or remote inspections of installed technologies; compiling and submitting yearly status reports; and maintaining records of monitoring results. For each activity burden assumption, EPA selected time estimates to reflect the expected effort necessary to carry out these activities under normal conditions and reasonable labor efficiency.

The costs to the respondent facilities associated with these time commitments can be estimated by multiplying the time spent in each labor category by an appropriately loaded hourly wage rate. All base wage rates used for facility labor categories were derived from the Bureau of Labor Statistics (BLS) Occupational Handbook 2002-2003 (BLS, 2002). Additional detail on the development of cost estimates for annual post-compliance monitoring can be found in the Draft Information Collection Request for Cooling Water Intake Structures Phase II Existing Facilities Proposed Rule.

EPA estimated the annual cost of post-compliance monitoring to be approximately $62,650 for freshwater facilities (i.e., facilities withdrawing cooling water from freshwater rivers and streams; or lakes and reservoirs), and approximately $78,300 for marine facilities (i.e., facilities withdrawing cooling water from estuaries and tidal rivers; or oceans) and Great Lakes facilities.

2.4 One-Time Costs for Track II Demonstration Studies

Under the proposed rule, all facilities would submit a comprehensive demonstration study to characterize the source water baseline in the vicinity of the intake, characterize the operation of the intake, and confirm that the technology(ies), operational measures and restoration measures proposed and/or implemented at the intake meet the applicable performance standards. EPA developed burden and cost estimates for the comprehensive demonstration study in a manner similar to that described in section 1.4 above (i.e., by building up the estimated burdens and corresponding costs associated with the various activities being performed).

The burden estimates include: developing a proposal for collecting information to support the study; developing a description of the proposed and/or implemented technologies, operational measures and restoration measures to be evaluated and their efficacies; performing biological sampling; assessing the source waterbody; estimating the magnitude of impingement mortality and entrainment; calculating the reduction in impingement mortality and entrainment that would be achieved by the technologies and operational measures selected; demonstrating that the location, design, construction and capacity of the intake reflects the best technology available for minimizing adverse environmental impact (BTA); and reporting the results. The burden also includes developing a verification monitoring plan to verify the full-scale performance of the proposed or implemented technologies and operational measures. In addition, the burden includes performing a site-specific evaluation of the suitability of the technology(ies) and/or operational measures based on representative studies and/or site-specific technology prototype studies.

The costs to the respondent facilities associated with these time commitments can be estimated by multiplying the time spent in each labor category by an appropriately loaded hourly wage rate. Additional detail on the development of cost estimates for annual post-compliance monitoring can be found in the Draft Information Collection Request for Cooling Water Intake Structures Phase II Existing Facilities Proposed Rule.

EPA estimated the one-time costs for comprehensive demonstration studies to be approximately $827,000 for facilities withdrawing cooling water from freshwater rivers and streams, $739,000 for facilities withdrawing cooling water from lakes, $864,000 for facilities withdrawing cooling water from the Great Lakes, and $1,015,000 for facilities withdrawing cooling water from estuaries/tidal rivers or oceans.

2.5 Regional Cost Factors

As described in sections 2.1 and 2.2 above, the Agency developed technology-specific cost estimates for construction projects at new, "greenfield" projects on a national average basis. However, the capital construction costs can vary significantly for different locations within the United States. Therefore, to account for these regional variations, EPA adjusted the capital cost estimates for the existing model plants using state-specific cost factors, which ranged from 0.739 for South Carolina to 1.245 for Alaska. The applicable state cost factors were multiplied by the facility model cost estimates to obtain the facility location-specific capital costs used in the impact analysis.

The Agency derived the state-specific capital cost factors shown in Table 2-21 below from the "location cost factor database" in RS Means Cost Works 2001. The Agency used the weighted-average factor category for total costs (including material and installation). The RS Means database provides cost factors (by 3-digit Zip code) for numerous locations within each state. The Agency selected the median of the cost factors for all locations reported within each state as the state-specific capital cost factor.

Table 2-21. State-Specific Capital Cost Factors

State	State Code	Median Weighted Cost Factor	State	State Code	Median Weighted Cost Factor
Alaska	AK	1.245	North Carolina	NC	0.752
Alabama	AL	0.81	North Dakota	ND	0.827
Arkansas	AR	0.7815	Nebraska	NE	0.828

State	State Code	Median Weighted Cost Factor	State	State Code	Median Weighted Cost Factor
Arizona	AZ	0.864	New Hampshire	NH	0.913
California	CA	1.081	New Jersey	NJ	1.099
Colorado	CO	0.915	New Mexico	NM	0.912
Connecticut	CT	1.052	Nevada	NV	0.997
DC	DC	0.948	New York	NY	1.0235
Delaware	DE	1.009	Ohio	OH	0.955
Florida	FL	0.832	Oklahoma	OK	0.82
Georgia	GA	0.812	Oregon	OR	1.059
Hawaii	HI	1.225	Pennsylvania	PA	0.9765
Iowa	IA	0.886	Rhode Island	RI	1.039
Idaho	ID	0.932	South Carolina	SC	0.7385
Illinois	IL	0.994	South Dakota	SD	0.789
Indiana	IN	0.922	Tennessee	TN	0.803
Kansas	KS	0.84	Texas	TX	0.797
Kentucky	KY	0.847	Utah	UT	0.8975
Louisiana	LA	0.819	Virginia	VA	0.822
Massachusetts	MA	1.064	Vermont	VT	0.743
Maryland	MD	0.89	Washington	WA	1.028
Maine	ME	0.829	Wisconsin	WI	0.97
Michigan	MI	0.966	West Virginia	WV	0.943
Minnesota	MN	1.046	Wyoming	WY	0.787
Missouri	MO	0.925			
Mississippi	MS	0.7425	Minimum	SC	0.739
Montana	MT	0.954	Maximum	AK	1.245

2.6 Retrofit Cost Factor

In order to account for capital cost expenditures specific to construction at existing power plants, the Agency applies a capital cost inflation factor to the cost estimates described in sections 2.1 and 2.2 above. This capital cost inflation factor, referred to hereinafter as a "retrofit factor" accounts for activities outside the scope of the costs estimates described in sections 1.2 and 1.3. These activities relate to the "retrofit," or upgrade, of existing cooling water and intake structure systems. The Agency generally developed the cost estimates summarized in sections 2.1 through 2.2 specifically for construction projects at new, "greenfield" projects (with the exception of those for surface condenser refurbishing, which the Agency developed to inherently include retrofit activities). These projects and, therefore, the costs equations described in sections 2.1 and 2.2 generally do not include retrofit activities such as (but not limited to) branching or diversion of cooling water delivery systems, reinforcement of retrofitted conduit system connections, partial or full demolition of conduit systems and/or intake structures, additional excavation activities, temporary delays in construction schedules, expedited construction schedules, potential small land acquisitions, hiring of additional (beyond those typical for the "greenfield" cost estimates) equipment and personnel for subsurface construction, administrative and construction related safety precautions, and potential additional cooling water (recirculating or make-up) delivery needs.

The Agency estimates that a capital cost inflation factor of 20 or 30 percent applied to the costs developed for new, "greenfield" projects accounts for the retrofit activities described above. The retrofit activities represented by the factor do not relate to uncertainty of the construction project, and therefore are not considered "contingencies." Rather, the retrofit activities are site-specific, may vary between sites, but on average, in the Agency's view, will approach 20 percent for activity necessary to convert cooling systems and approach 30 percent for upgrading of cooling water intake structures and screens.

2.7 Examples of Model Plant Cost Estimates

Example 1: Impingement and Entrainment Upgrade for Once-through Intake

Source Water: Freshwater
Steam Plant Type: Nuclear
Baseline Cooling System: Once-through
Baseline Intake Type: Trash Racks and Coarse-Mesh Screens
Baseline Design Intake Capacity: 600 million gallons per day (416,667 gpm)
Compliance Intake Type: Fine-mesh Travelling Screens with Fish Handling/Returns
Regional Capital Cost Factor: 1.00

Cooling Water Intake Technology Retrofitted Capital Cost:

- Utilized intake technology capital cost curves derived for New Facility Rule.
- Multiplied by additional retrofit cost equal to 30% of installed costs.
- Multiplied by regional capital cost factor.
- Utilized flow for sizing and construction factors as follows:

Table EX-1 CWIS Technology Retrofit Flow Sizing and Construction Factors

Compliance Cooling System Type	Plant Type	Flow Used to size Cooling Water Intake Technology	Compliance Cooling Water Intake Technology	Construction Factor for Scenario
Cooling Tower **	All	50% of Once-through, Baseline Design Intake	All	None
Non-Cooling Tower	Non-nuclear	100% of Once-through Baseline Design Intake	Fish Handling	None
Non-Cooling Tower	Non-nuclear	100% of Once-through Baseline Design Intake	Fine Mesh Screens	30%*
Non-Cooling Tower	Non-nuclear	100% of Once-through Baseline Design Intake	Fine Mesh Screens w/ Fish Handling	15%*
Non-Cooling Tower	Nuclear	100% of Once-through Baseline Design Intake	Fish Handling	None

Table EX-1 CWIS Technology Retrofit Flow Sizing and Construction Factors

Compliance Cooling System Type	Plant Type	Flow Used to size Cooling Water Intake Technology	Compliance Cooling Water Intake Technology	Construction Factor for Scenario
Non-Cooling Tower	Nuclear	100% of Once-through Baseline Design Intake	Fine Mesh Screens	65%*
Non-Cooling Tower	Nuclear	100% of Once-through Baseline Design Intake	Fine Mesh Screens w/ Fish Handling	30%*

* Existing facility construction factors based on average ratio of intake modification construction costs to costs derived from CWIS equations developed for New Facility projects. Thus the differences reflect differences in construction costs for nuclear and non-nuclear and differences in CWIS installation capital costs.

** For cooling sizing of cooling towers and appropriate flow for determining the costs of retrofitted cooling water systems, see Section 2.2.

Intake modification construction costs are based on the following general framework:

- An increase in screen area of 50% due to conversion from coarse-mesh to fine-mesh.
- Screen size increase will involve demolition of one side of intake and extension in that direction.
- Installation/removal of sheet piling.
- Concrete demolition of one column and one side (cost doubled for nuclear*).
- Excavation (cost doubled for nuclear*).
- Additional concrete foundation.
- Additional concrete side and back wall.
- Additional concrete column.

* EPA doubled costs to account for concerns that use of blasting and high-impact equipment may be limited at nuclear facilities.

Modification construction costs were then increased by the following cost factors:

Item	Factor
Mobilization/Demobilization	3 %
Engineering	10 %
Site Work	5 %
Electrical	10 %
Controls	3 %
Contingency	10 %
Allowance	5 %

Fine-mesh travelling screens with fish handling/return capital cost equation:

$(5\text{ E-}11 * x^3 - 2\text{ E-}5 * x^2 + 7.1477 * x + 113116) * (1.05*1.30)$ * regional factor * construction factor

where x = appropriate flow for sizing

Total Capital Cost of Intake Structure Technology Modification for this example: $5,742,300 (addition of fine-mesh travelling screens with fish handling/return to the existing intake).

Total Capital Cost of Intake Upgrade: $5,742,300.

Cooling Water Intake Technology O&M Costs:

Based on outreach with industry representatives, EPA estimated annual O&M cost as a percentage of total capital cost (that is, those costs developed for new facility projects, not including retrofit factors). 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. The screen O&M costs are based on the size of the screen, which are based on the initial sizing flow. For this example, the Agency uses the sizing flow of full, baseline once-through flow.

O&M Equation for Fine-mesh Travelling Screens with Fish Handling/Return:
$-3\text{ E-}13 * x^3 - 4\text{ E-}8 * x^2 + 0.2081 * x + 11485$

Cooling Water Intake Technology O&M Costs for This Example: $69,548

Total Annual O&M Costs for this Example: $69,548

EXAMPLE 2: COOLING SYSTEM CONVERSION

Source Water: Estuary / Tidal River
Steam Plant Type: Fossil
Baseline Cooling System: Once-through
Baseline Intake Type: Trash Racks and Coarse-Mesh Screens
Baseline Design Intake Capacity: 600 million gallons per day (416,667 gpm)
Converted Cooling System: Mechanical-Draft Wet Cooling Towers
Compliance Intake Type: Fine-mesh Travelling Screens with Fish Handling/Returns
Reduced Intake Capacity: 33,333 gpm (416,667 gpm * 0.08)
Regional Capital Cost Factor: 1.08

Recirculating Wet Cooling Tower Cost Development:

Cooling Tower Material of Construction: Redwood
Number of Cooling Tower Units: 2
Cooling Flow for Each Tower Unit: 208,334 gpm

Basic Redwood Tower with Splash Fill Capital Cost Equation:

$$n * (-5\text{E-}5 * x^2 + 70.271 * x + 25393) * \text{regional factor},$$

where x = cooling flow per unit
n = number of cooling units

Items included in the installed tower capital cost equation:

- Wet tower, furnished & erected
  - includes internal tower piping, risers, and valves
  - includes splash fill
  - includes fans and motors
  - includes electrical service and housing
- Site preparation, clearing, grading
- Excavation for basins and piping
- Circulating water piping, valves, and fittings to and from condenser
- Access roads
- Full circulating pumps and housing
- Installed concrete basins, sumps, and footings
- Electrical wiring, controls, and transformers
- Blowdown-water treatment facility
- Acceptance testing
- Installation

Factors included in the installed tower capital cost equation (i.e., these factors inflate the direct capital costs):

- Construction management, mobilization and demobilization
- Design engineering and architectural fees
- Contractor overhead and profit
- Turnkey Fee
- Contingencies

Additional Cooling Tower Retrofit Scaling Factor: 20 percent.
Regional Capital Cost Factor: 1.08

Total Capital Cost of Installed Cooling Tower (2 unit tower system): $44,550,000 (new facility project cost) + $8,910,000 (retrofit cost factor) = <u>$53,550,000</u>

<u>Intake and Discharge Piping Modification Capital Costs:</u>

Pipe modification costs are based on the following assumptions:[5]

- Piping material and installation cost is $12 per in-diameter per ft-length.

[5] The Agency excluded makeup water pump costs from its derived equations for cooling system conversions. In doing so, the Agency attempted to compensate for the situations where existing pumps can be reused in the converted recirculating system, as was the case for the Jefferies Steam Plant conversion (see Chapter 4 for futher discussion of cooling tower conversion example cases). However, the Agency recognized that the probability of existing circulating water pumps being reused for retrofitted tower systems was low. Therefore, because the Agency was able to confirm the reuse of existing intake structures for three of the example cases, the Agency considered the cost of the makeup pump to offset the possible savings of pump reuse such as the Jefferies plant to be appropriate. The Agency estimates that the installed cost of intake pumps, such as for the model plant cost example above, would be a very small fraction of the total cost of the installed cooling tower system (less than 0.25 percent). For the final rule's analyses, the Agency will consider the costs of new intake pumps at a portion, or all cooling system conversions.

- Additional retrofit cost equal to 30% of material and installation.
- Note: EPA inadvertently excluded excavation, backfill, and other civil costs from the intake piping modifications. This could represent a significant cost increase. The Agency intends to rectify this error for the final rule's analysis.
- Additional cost factors as follows:

Item	Factor
Mobilization/Demobilization	3%
Engineering	10%
Site Work	5%
Controls	3%
Contingency	10%
Allowance	5 %

- Pipe characteristics as follows:

Table EX-2 Pipe Characteristics for Intake Piping Modifications for Cooling Conversions

Compliance Intake Flow (gpm)	Pipe Diameter (in)	Pipe Velocity (fps)	Pipe Length (ft)
1,000	8	6.4	2,000
5,000	16	8.0	2,000
10,000	20	10	2,000
50,000	42	12	3,000
100,000	60	11	4,000
350,000	60 (3 pipes)	13	4,000

Cost equation (incorporating retrofit factor and all other factors) derived is as follows:

(-0.00002*Flow^2 + 48.801*Flow + 350292) * regional factor

Total Capital Cost of Intake/Discharge Piping Modification for this example: <u>$1,955,000</u>

<u>Cooling Water Intake Technology Retrofit Capital Cost:</u>

- Utilized intake technology capital cost curves derived for New Facility Rule.
- Multiplied by additional retrofit cost equal to 30% of installed costs.
- Multiplied by regional capital cost factor.
- Utilized flow for sizing and construction factors as described in Table EX-1 above:

Fine-mesh travelling screens with fish handling/return capital cost equation:

(5 E-11 * x^3 – 2 E-5 * x^2 + 7.1477 * x + 113116) * (1.05*1.30) * regional factor * construction factor
where x = appropriate flow for sizing (which is 50 % of baseline, once-through flow for this example)

Total Capital Cost of Intake Structure Technology Modification for this example: $1,748,800 (this includes addition of fine mesh travelling screens with fish handling/return to the existing intake).

Total Capital Cost of Cooling System Conversion and Intake Upgrade: $57,414,400.

Condenser Upgrade Capital Costs:

EPA estimates that some condensers would require upgrades premature to the end of their useful lives due to the cooling system conversion. For this example case, the condenser baseline tube material is Copper/Nickel Alloy. The Agency determined that the tubes would be upgraded to 304 Stainless Steel for a cooling tower using brackish cooling water. This upgrade would occur when the existing condenser had 10 years of useful life remaining. Therefore, EPA developed cost estimates for the tube upgrade and the tube replacement.

The Capital Cost equation for CuNi replacement is as follows:

Number of Cooling Tower Units * (18.046 * Unit Cooling Flow – 13134) * Regional Factor.

- Accounts for cost of materials
- Accounts for vibration/stability analysis
- Accounts for labor, overhead, etc.
- EPA utilizes a 1.58 factor for safety at nuclear plants
- Replacement tubing includes non-corroding internal tubing liner
- Does not include an additional retrofit or allowance, due to the fact that the cost estimates forming the basis of the curves were for actual tube replacement projects.

Capital Cost of Existing Material Condenser Tube Replacement: $8,029,400

Capital Cost of Condenser Tube Upgrade: $8,774,600

The economic analysis calculates the net capital cost to the facility for the premature replacement of the condenser tube sheets. The analysis accounts for the upgraded material and deducts the useful life of the replacement. See the Economic and Benefits Analysis for more information.

Operation and Maintenance Costs of Baseline Intake Pumping (once-through):

- Pumping head estimated at 50 ft for all systems.
- Pump and motor efficiency estimated at 70 percent.
- Annual hours of operation estimated at 7860 (i.e., 90 percent of 8760).
- Energy cost estimated at $0.03/KWh. This value is set near the average wholesale cost of electricity. To be conservative, this estimation of the unit energy cost is intended to account for the pumping electricity costs and does not account for such O&M costs as pump maintenance.

  Baseline Intake Pumping Annual Cost Equation: - (50 * Flow * 8.33 * 0.746 * 7860 * 0.03) / (33,000 * 0.7)

  Baseline Intake Annual Pumping Cost in this Example: $1,321,500

Wet Cooling Tower Operation and Maintenance:

- Includes periodic equipment replacement and maintenance costs (i.e., 10^{th} and 20^{th} year overhauls).

- Includes pumping and fanning O&M requirements.
- Includes blowdown-water treatment and disposal.
- Accounts for increase in equipment replacement costs as tower useful life diminishes.
- Includes chemical addition.
- Does not include turbine efficiency penalty, which is factored into the economic analysis through lost revenue.

Redwood Wet Tower O&M Equation: $n * (-4E\text{-}6 * x^2 + 11.617 * x + 2055.2)$
Where x = cooling flow per unit
n = number of cooling units

Wet Cooling Tower O&M Cost Estimate for this Example: <u>$4,497,300</u>

<u>Intake Pumping O&M Costs:</u>

Developed in a manner very similar to the once-through, baseline intake pumping costs. However, the compliance intake flow is used in place of the baseline, once-through flow.

Wet Tower Compliance Intake Pumping O&M Cost Estimate for this Example: <u>$105,700</u>

<u>Cooling Water Intake Technology O&M Costs:</u>

Based on outreach with industry representatives, EPA estimated annual O&M cost as a percentage of total capital cost (that is, those costs developed for new facility projects, not including retrofit factors). 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. The screen O&M costs are based on the size of the screen, which are based on the initial sizing flow. For this example, the Agency uses the sizing flow of ½ of the baseline once-through flow.

O&M Equation for Fine-mesh Travelling Screens with Fish Handling/Return:
$-3E\text{-}13 * x^3 - 4E\text{-}8 * x^2 + 0.2081 * x + 11485$

Cooling Water Intake Technology O&M Costs for This Example: <u>$50,390</u>

Total Annual O&M Costs for this Example: <u>$3,331,900</u>

2.9 Repowering Facilities and Model Plant Costs

Under this proposed rule certain forms of repowering could be undertaken by an existing power generating facility that uses a cooling water intake structure and it would remain subject to regulation as a Phase II existing facility. For example, the following scenarios would be existing facilities under the proposed rule:

- An existing power generating facility undergoes a modification of its process short of total replacement of the process and concurrently increases the design capacity of its existing cooling water intake structures;

- An existing power generating facility builds a new process for purposes of the same industrial operation and concurrently increases the design capacity of its existing cooling water intake structures;

- An existing power generating facility completely rebuilds its process but uses the existing cooling water intake structure with no increase in design capacity.

Thus, in most situations, repowering an existing power generating facility would be addressed under this proposed rule.

As discussed in Section III.B of the preamble, the section 316(b) Survey acquired technological and economic information from facilities for the years 1998 and 1999. With this information, the Agency established a subset of facilities potentially subject to this rule. Since 1999, some existing facilities have proposed and/or enacted changes to their facilities in the form of repowering that could potentially affect the applicability of this proposal or a facility's compliance costs. The Agency therefore conducted research into repowering facilities for the section 316(b) existing facility rule and any information available on proposed changes to their cooling water intake structures. The Agency used two separate databases to assemble available information for the repowering facilities: RDI's NEWGen Database, November 2001 version and the Section 316(b) Survey.

In January 2000, EPA conducted a survey of the technological and economic characteristics of 961 steam-electric generating plants. Only the detailed questionnaire, filled out by 283 utility plants and 50 nonutility plants, contains information on planned changes to the facilities' cooling systems (Part 2, Section E). Of the respondents to the detailed questionnaire, only six facilities (three utility plants and three nonutility plants) indicated that their future plans would lead to changes in the operation of their cooling water intake structures

The NEWGen database is a compilation of detailed information on new electric generating capacity proposed over the next several years. The database differentiates between proposed capacity at new (greenfield) facilities and additions/modifications to existing facilities. To identify repowering facilities of interest, the Agency screened the 1,530 facilities in the NEWGen database with respect to the following criteria: facility status, country, and steam electric additions. The Agency then identified 124 NEWGen facilities as potential repowering facilities.

Because the NEWGen database provides more information on repowering than the section 316(b) survey, the Agency used it as the starting point for the analysis of repowering facilities. Of the 124 NEWGen facilities identified as repowering facilities, 85 responded to the section 316(b) survey. Of these 85 facilities, 65 are in-scope and 20 are out of scope of this proposal. For each of the 65 in scope facilities, the NEWGen database provided an estimation of the type and extent of the capacity additions. The Agency found that 36 of the 65 facilities would be combined-cycle facilities after the repowering changes. Of these, 34 facilities are projected to decrease their cooling water intake after repowering (through the conversion from a simple steam cycle to a combined-cycle plant). The other 31 facilities within the scope of the rule would increase their cooling water intake. The Agency examined the characteristics of these facilities projected to undergo repowering and determined the waterbody type from which they withdraw cooling water. The results of this analysis are presented in Table 2-22.

Table 2-22 - In-scope Existing Facilities Projected to Enact Repowering Changes

Waterbody Type	Repowering Facilities Projected to Increase Cooling Water Withdrawals	Repowering Facilities Projected to Decrease or Maintain Cooling Water Withdrawals
Ocean	N/A	N/A
Estuary/Tidal River	3	17
Freshwater River/Stream	14	10
Freshwater Lake/Reservoir	10	1
Great Lake	0	1

Of the 65 in scope facilities identified as repowering facilities in the NEWGen database, 24 received the detailed questionnaire, which requested information about planned cooling water intake structures and changes to capacity. Nineteen of these 24 facilities are utilities and the remaining five are nonutilities. The Agency analyzed the section 316(b) detailed questionnaire data for these 24 facilities to identify facilities that indicated planned modifications to their cooling systems which will change the capacity of intake water collected for the plant and the estimated cost to comply with today's proposal. Four such facilities were identified, two utilities and two nonutilities. Both utilities responded that the planned modifications will decrease their cooling water intake capacity and that they do not have any planned cooling water intake structures that will directly withdraw cooling water from surface water. The two nonutilities, on the other hand, indicated that the planned modifications will increase their cooling water intake capacity and that they do have planned cooling water intake structures that will directly withdraw cooling water from surface water.

Using the NEWGen and section 316(b) detailed questionnaire information on repowering facilities, the Agency examined the extent to which planned and/or enacted repowering changes would effect cooling water withdrawals and, therefore, the potential costs of compliance with this proposal. Because the Agency developed a cost estimating methodology that primarily utilizes design intake flow as the independent variable, the Agency examined the extent to which compliance costs would change if the repowering data summarized above were incorporated into the cost analysis of this rule. The Agency determined that projected compliance costs for facilities withdrawing from estuaries could be lower after incorporating the repowering changes. The primary reason for this is the fact that the majority of estuary repowering facilities would change from a steam cycle to a combined-cycle, thereby maintaining or decreasing their cooling water withdrawals (note that a combined-cycle facility generally will withdraw one-third of the cooling water of a comparably sized full-steam facility). Therefore, the portion of compliance costs for regulatory options that included flow reduction requirements or technologies could significantly decrease if the Agency incorporated repowering changes into the analysis. As shown in Table 2-22 the majority of facilities projected to increase cooling water withdrawals due to the repowering changes use freshwater sources. In turn, the compliance costs for these facilities would increase if the Agency incorporated repowering for this proposal.

2.9 Capacity Utilization Rate Cut-off

The Agency is proposing standards for reducing impingement mortality but not entrainment when a facility operates at a capacity utilization rate of less than 15 percent over the course of several years (see § 125.94 (b)(2) of the proposed rule). Capacity utilization rate means the ratio between the average annual net generation of the facility (in MWh) and the total net capability of the facility (in MW) multiplied by the number of available hours during a year. The average annual generation is to be measured over a five year period (if available) of representative operating conditions. Incorporation of capacity utilization into the level of control was found to be the most economically practicable given these facilities' reduced operating levels. Fifteen percent capacity utilization corresponds to facility operation for roughly 55 days in a year (that is, less than two months). The Agency refers to this differentiation between facilities based on their operating time as a capacity utilization cut-off. Facilities operating at capacity utilization rates of less than 15 percent are generally facilities of significant age, including the oldest facilities within the scope of the rule. Frequently, entities will refer to these facilities as peaker plants, though the definition extends to a broader range of facilities. These peaker plants are less efficient and more costly to operate than other facilities. Therefore, operating companies generally utilize them only when demand is highest and, therefore, economic conditions are favorable. Because these facilities operate only a fraction of the time compared to other facilities, such as base-load plants, the peaking plants achieve sizable flow reductions over their maximum design annual intake flows. The lower the intake flow at a site, the lesser the potential for entraining of organisms. Therefore, the concept of an entrainment reduction requirement for such facilities does not appear necessary. Additionally, the plants typically operate during two specific periods: the extreme winter and the extreme summer demand periods. Each of these periods can, in some cases, coincide with periods of abundant aquatic concentrations and/or sensitive spawning events. However, it is generally accepted that peak winter and summer periods will not be the most crucial for aquatic organism communities on a national basis.

Based on an analysis of data collected through the detailed industry questionnaire and the short technical questionnaire, EPA believes that today's proposed rule would apply to 539 existing steam electric power generating facilities. Of these, 53 facilities operate at less than 15 percent capacity utilization and would potentially only comply with impingement controls, with 34 of these estimated to actually require such controls. (The remaining 19 facilities have existing impingement controls).

Of the facilities exceeding the capacity utilization cut-off, the median and average capacity utilization is 50 percent. As a general rule, steam plants operate cyclically between 100 percent load and standby. In turn, the intake flow rate of a typical steam plant cycles between flows approaching the full design rate and standby (that is, near-zero intake flow). Facilities operating with an average capacity utilization of 50 percent would generally withdraw more than three times as much water over the course of time than a facility with a capacity utilization of less than 15. Therefore, the capacity utilization cut-off coincides with an approximate flow reduction, and hence entrainment reduction, of roughly 70 percent as compared to the average facility above the cut-off. This level of reduction is within the range of performance standards for entrainment reduction. Were the Agency to establish the cut-off at less than 20 percent capacity utilization, an additional 18 facilities would be subject to the reduced requirements and the comparable flow reduction would be roughly 60 percent. The operating period would extend to approximately 75 days (that is, 2.5 months) for the hypothetical 20 percent cut-off. Were the Agency to establish the cut-off at less than 25 percent capacity, 108 of the 539 facilities would be subject to the reduced standards, and the comparable entrainment reduction would be roughly 54 percent. For a hypothetical 25 percent capacity utilization cut-off, the operating period would extend to approximately three months.

The median age of generating units with capacity utilization factors less than 15 percent is 48 years in 2002. The median age of generating units with capacity utilization factors of less than 25 percent and equal to or greater than 15 percent is 43 years. The age of generating units shows a continued trend upwards as capacity utilization rate increases. This trend agrees with the theory that existing peaking plants generally are aged facilities only dispatched when economic conditions are favorable and/or demand is highest.

The Agency examined the cooling water use of all plants for trends associated with or related to capacity utilization. As the analysis of unit age described above shows, most plants with low capacity utilization rates are very old. These plants generally utilize once-through cooling systems. For some plants, not all generating units may be available or capable of operating during extended periods, and the plant may staggered operation of generating units may be employed. However, as discussed above, the Agency believes that these aged units generally operate at or near peak capacity when they are dispatched. Therefore, the intake pumps will operate at near design intake capacity when functioning. Because a peaker plant will only operate for limited times during the year, its overall use of water (that is, the average annual intake) would be significantly below its design maximum intake rate. The Agency calculated a ratio of actual annual intake (for 1998) to maximum-design annual intake for the plants within the scope of this rule and compared this to capacity utilization. Though the data shows a significant degree of scatter, the Agency concludes that the data plotted in Figure 2-1 (actual-to-design intake ratio versus capacity utilization rate for all model plants within scope of this proposed rule) shows that generally, the lower the capacity utilization of a plant, the lower the intake flow as a percent of the maximum design intake capability.

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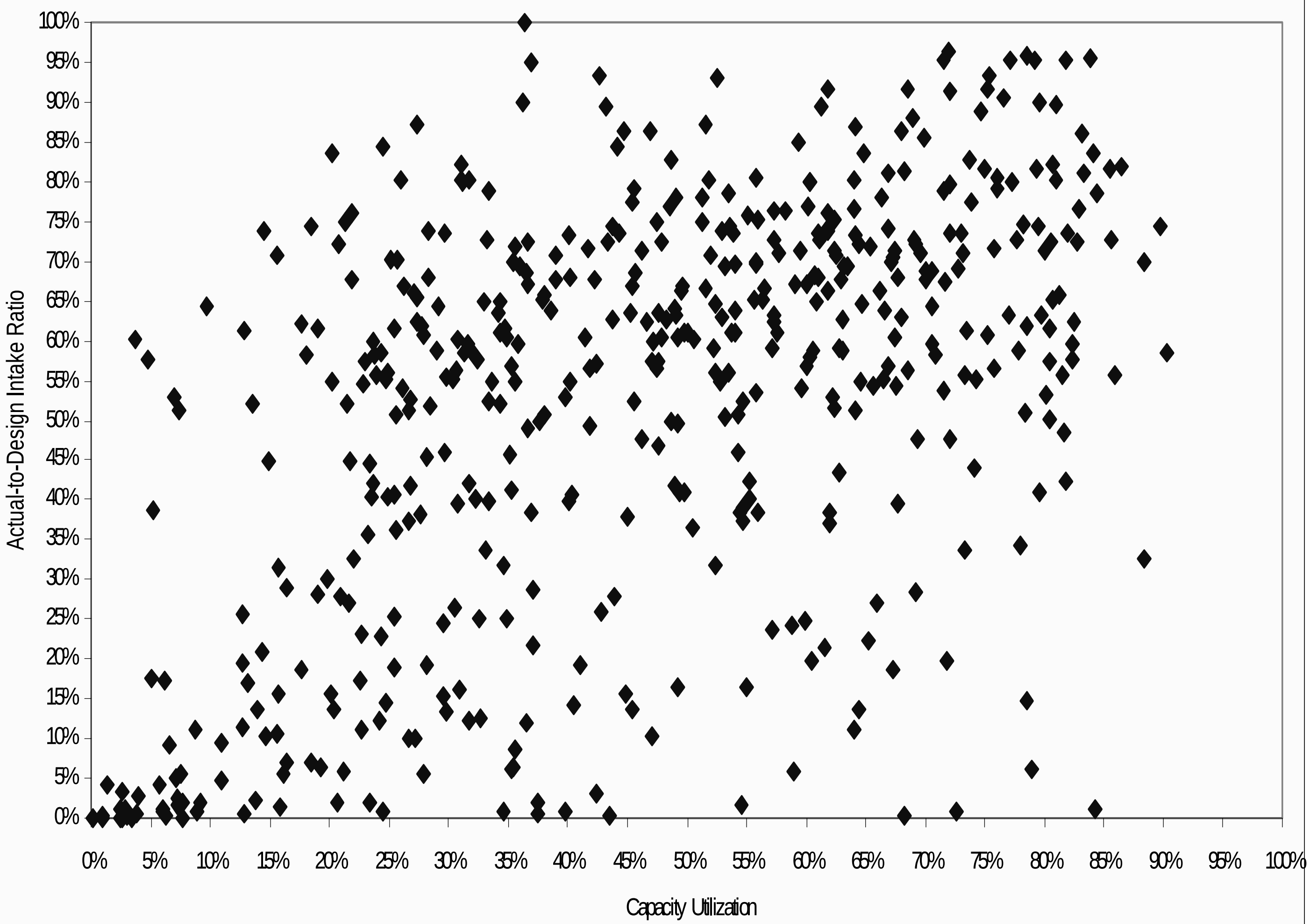
Figure 2-1. Actual-to-Design Intake versus Capacity Utilization for All Model Plants



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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List of Cost Curves and Equations in Appendix B

Chart 2-10. Variable Speed Pump Capital Cost

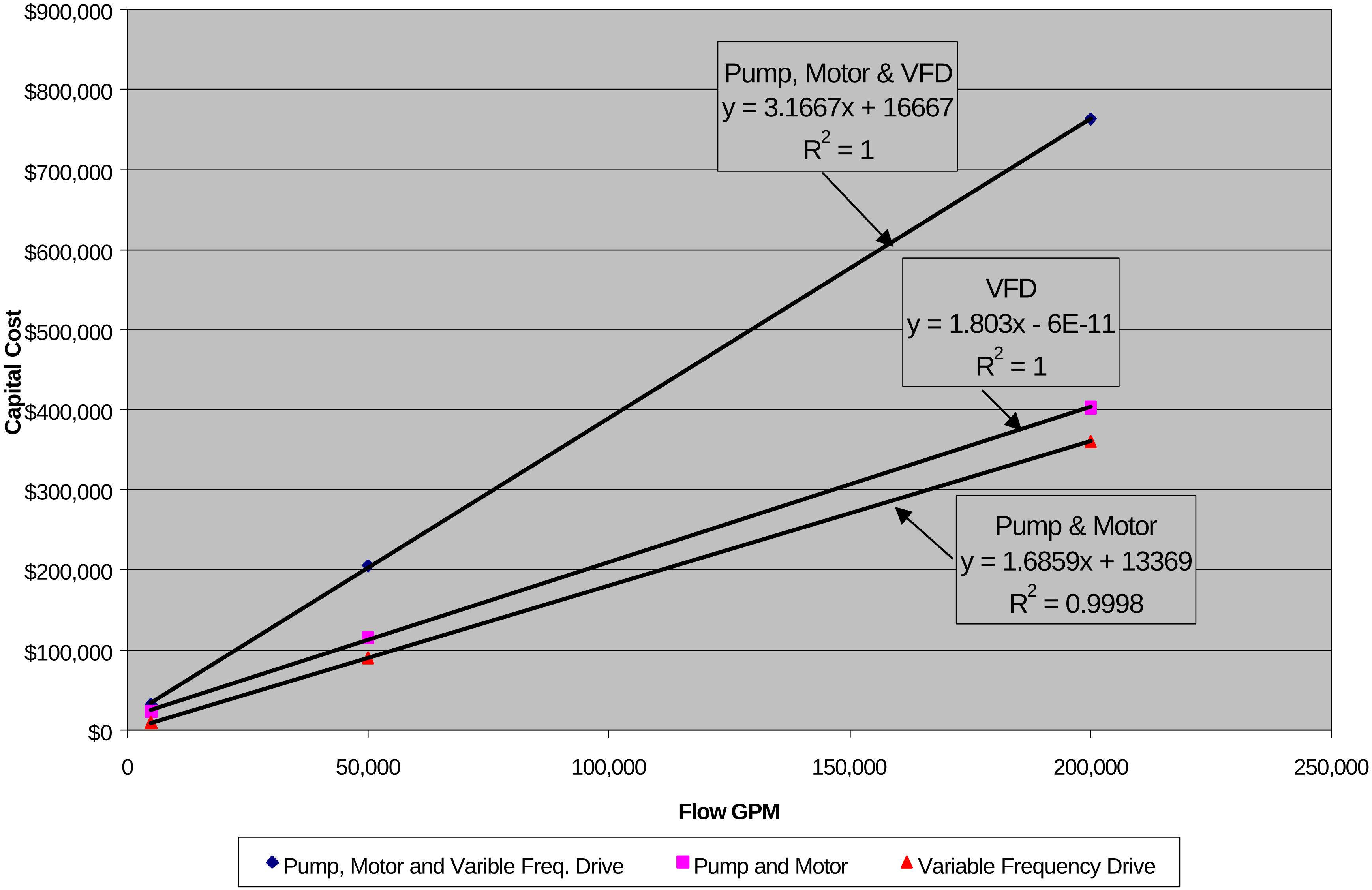


Chart 2-11. Municipal Water Use Costs

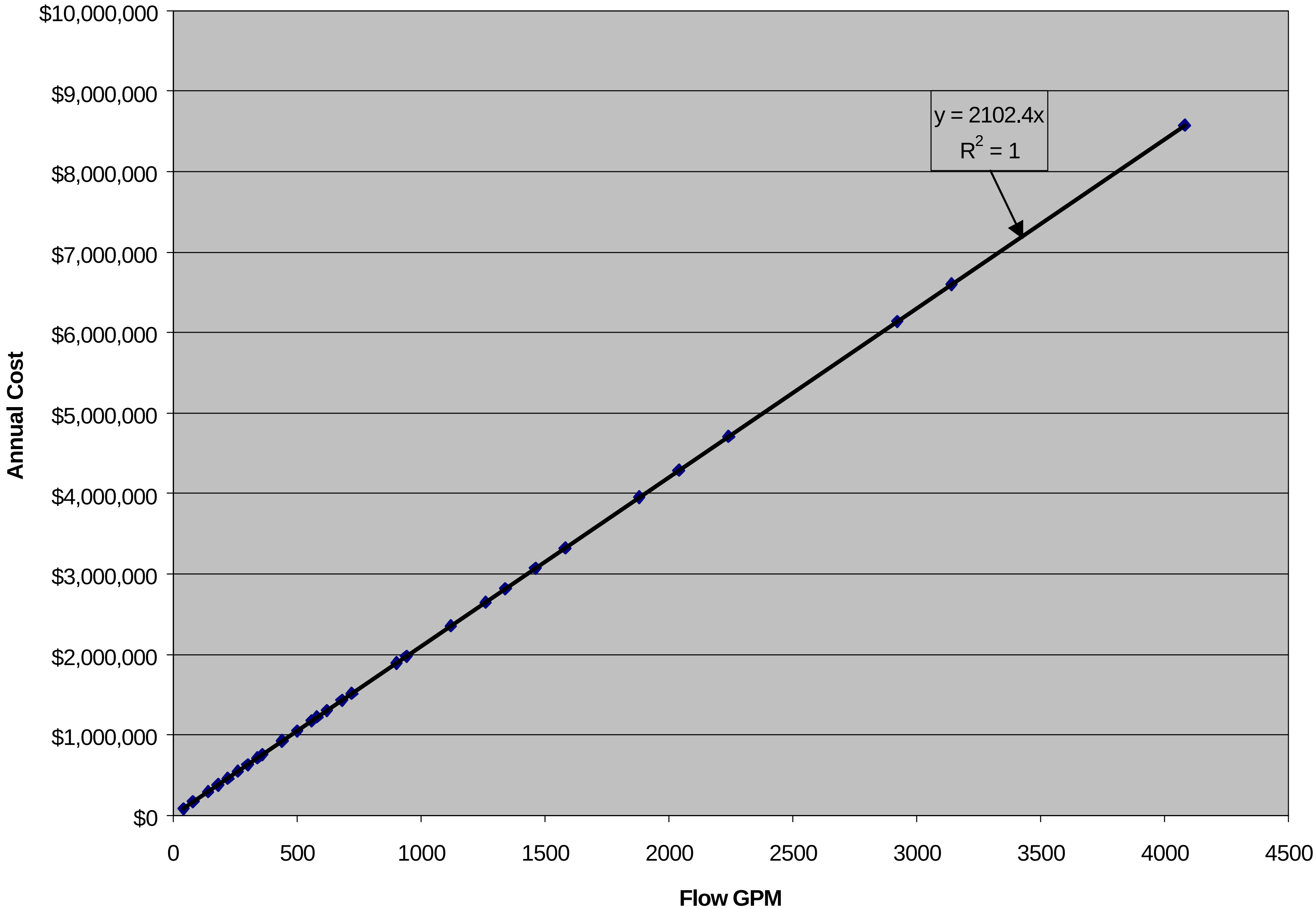


Chart 2-12. Gray Water Use Costs

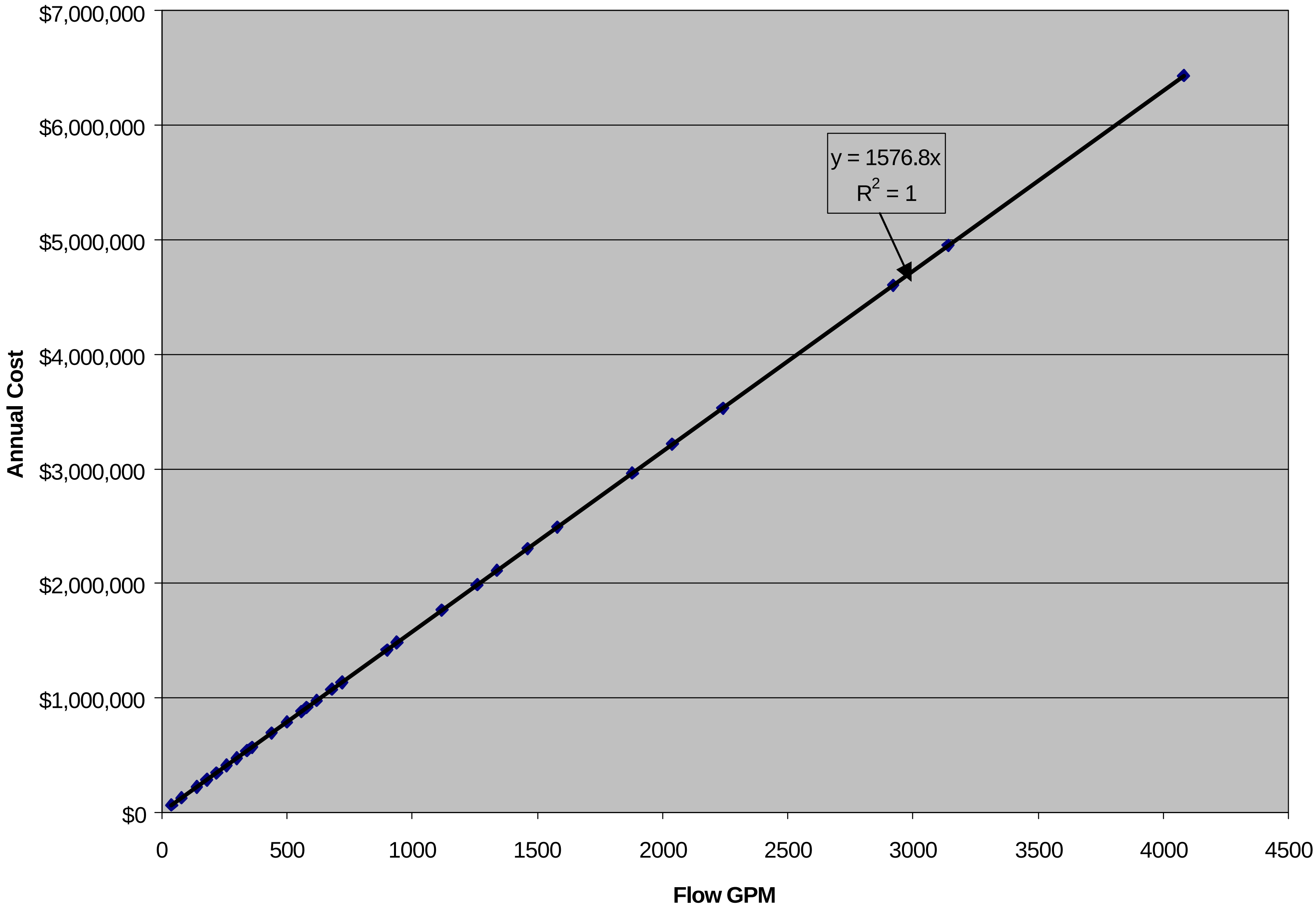


Chart 2-13. Capital Costs of Passive Screens Based on Well Depth

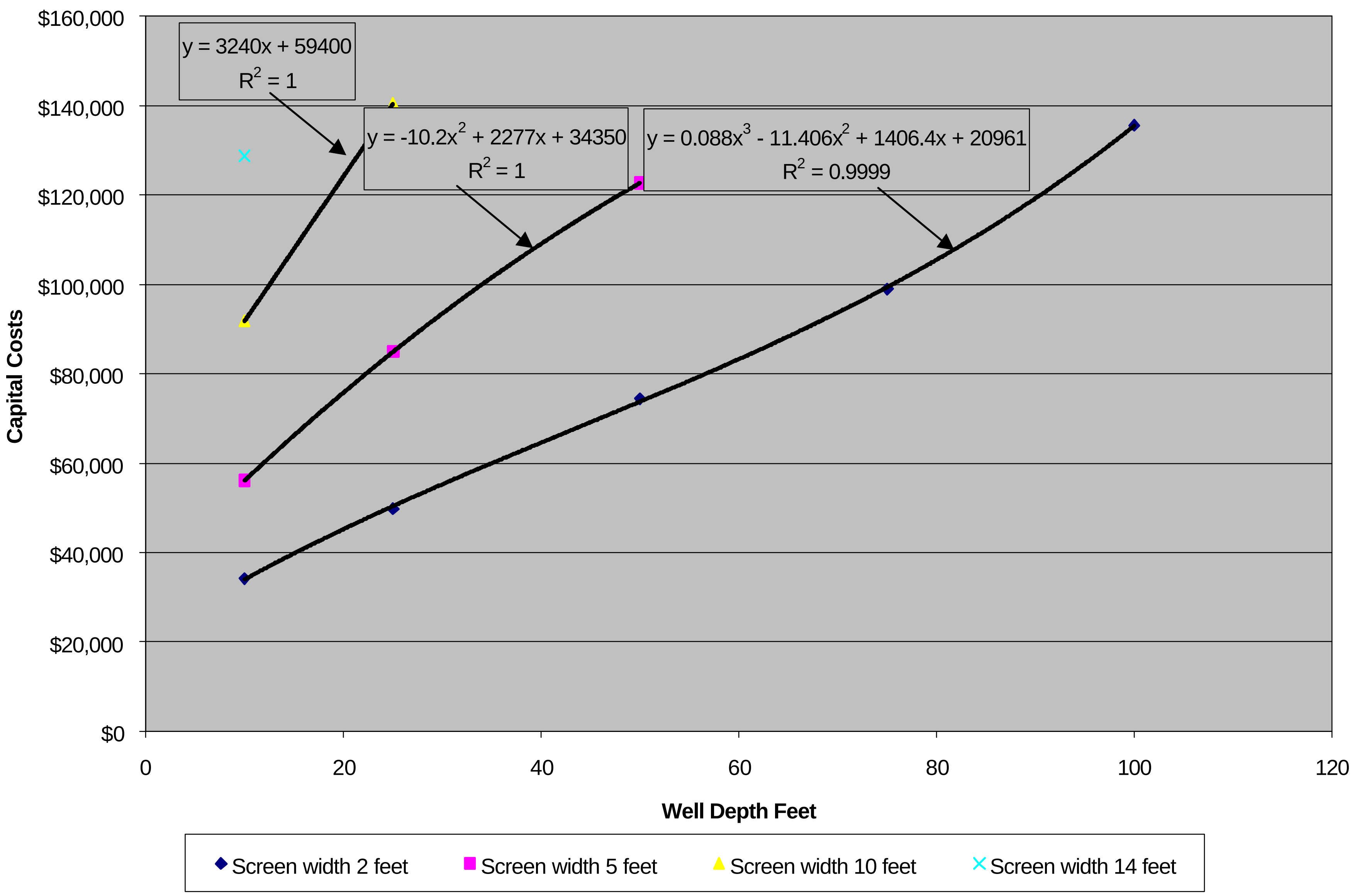
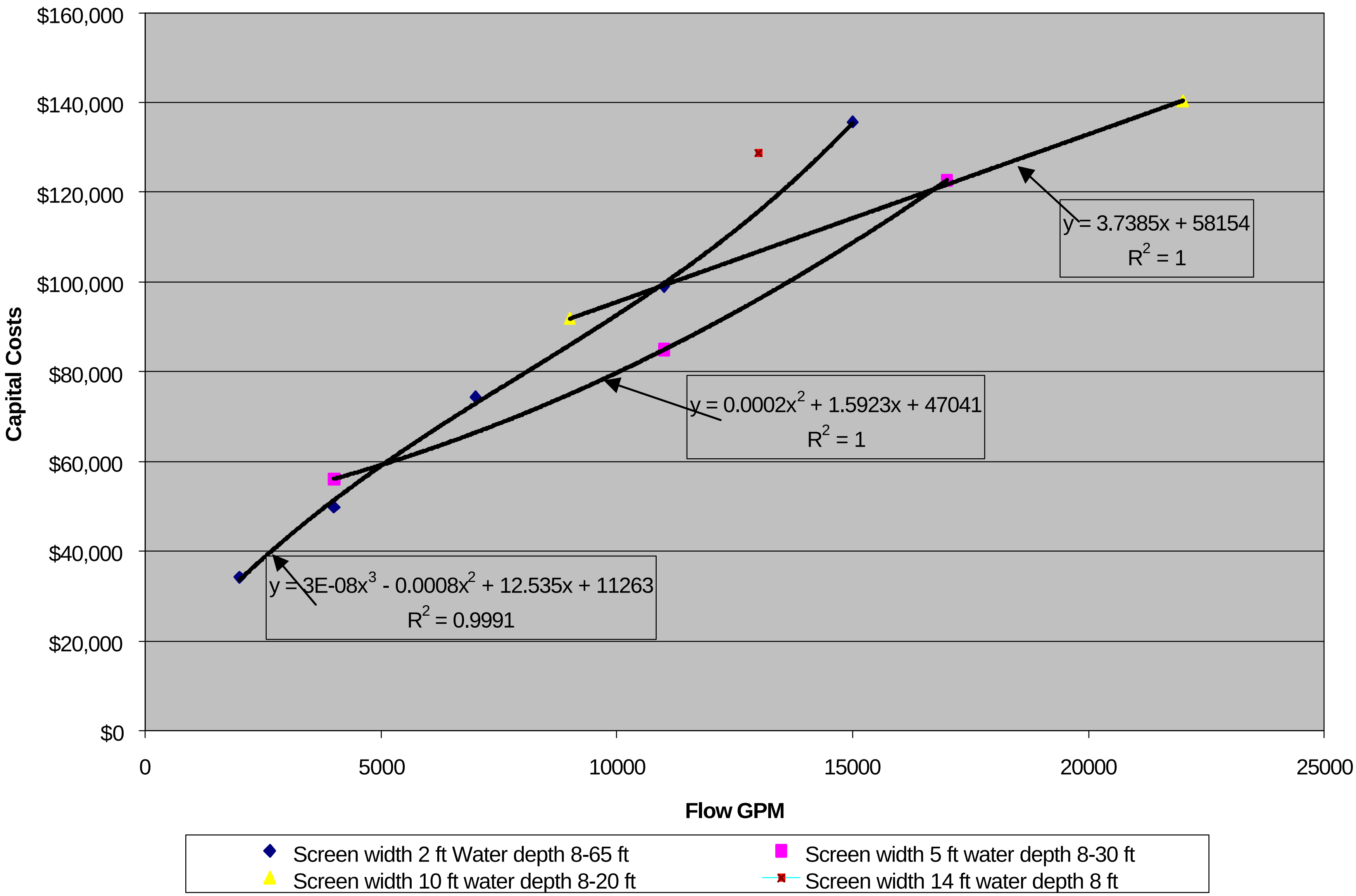


Chart 2-14. Capital Costs of Passive Screens - Flow Velocity 0.5 ft/sec



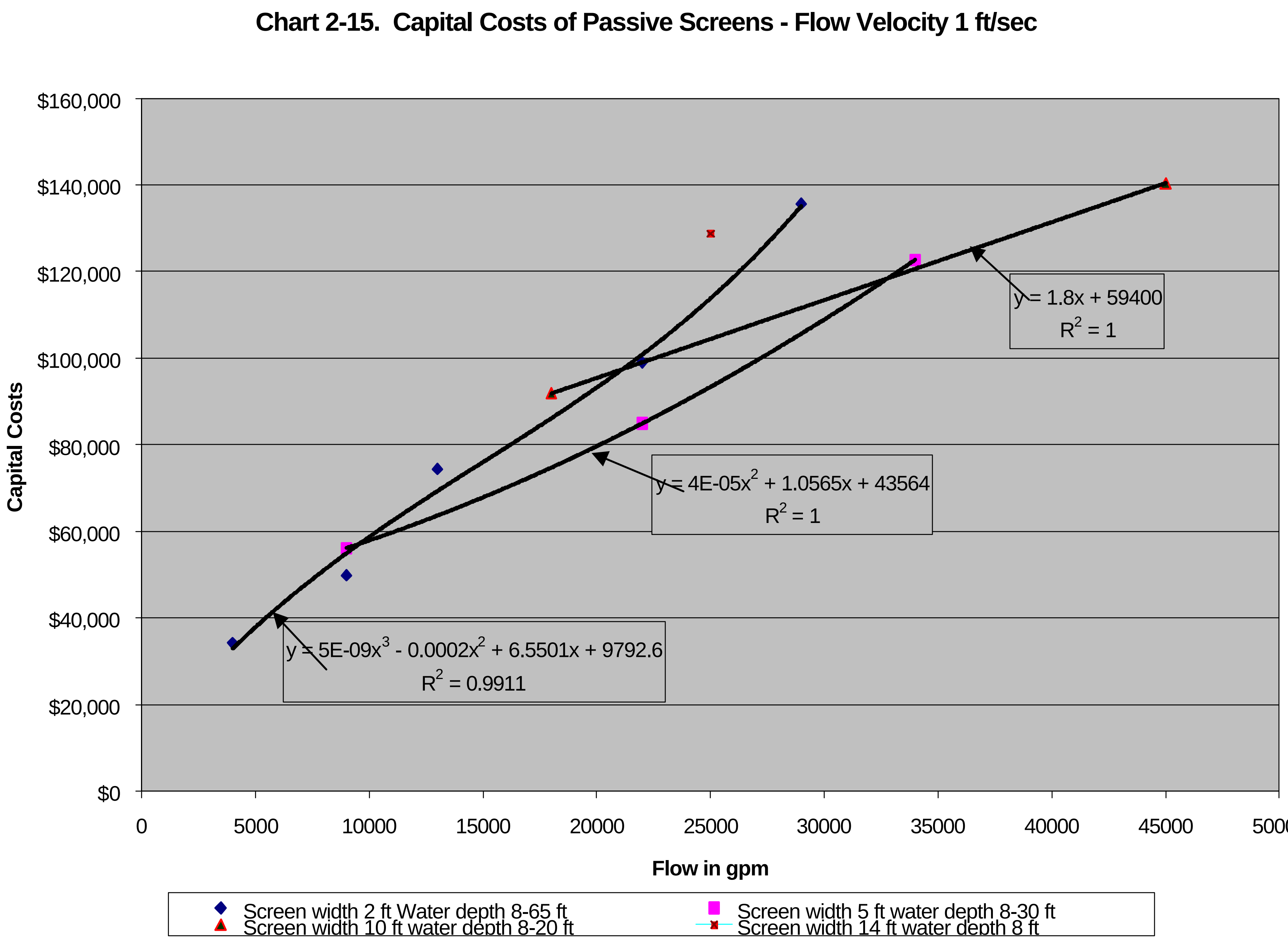


Chart 2-15. Capital Costs of Passive Screens - Flow Velocity 1 ft/sec
$160,000
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$0
Capital Costs
0
5000
10000
15000
20000
25000
30000
35000
40000
45000
50000
Flow in gpm
y = 1.8x + 59400
R2 = 1
y = 4E-05x2 + 1.0565x + 43564
R2 = 1
y = 5E-09x3 - 0.0002x2 + 6.5501x + 9792.6
R2 = 0.9911
Screen width 2 ft Water depth 8-65 ft
Screen width 5 ft water depth 8-30 ft
Screen width 10 ft water depth 8-20 ft
Screen width 14 ft water depth 8 ft

Chart 2-16. Velocity Caps Total Capital Costs

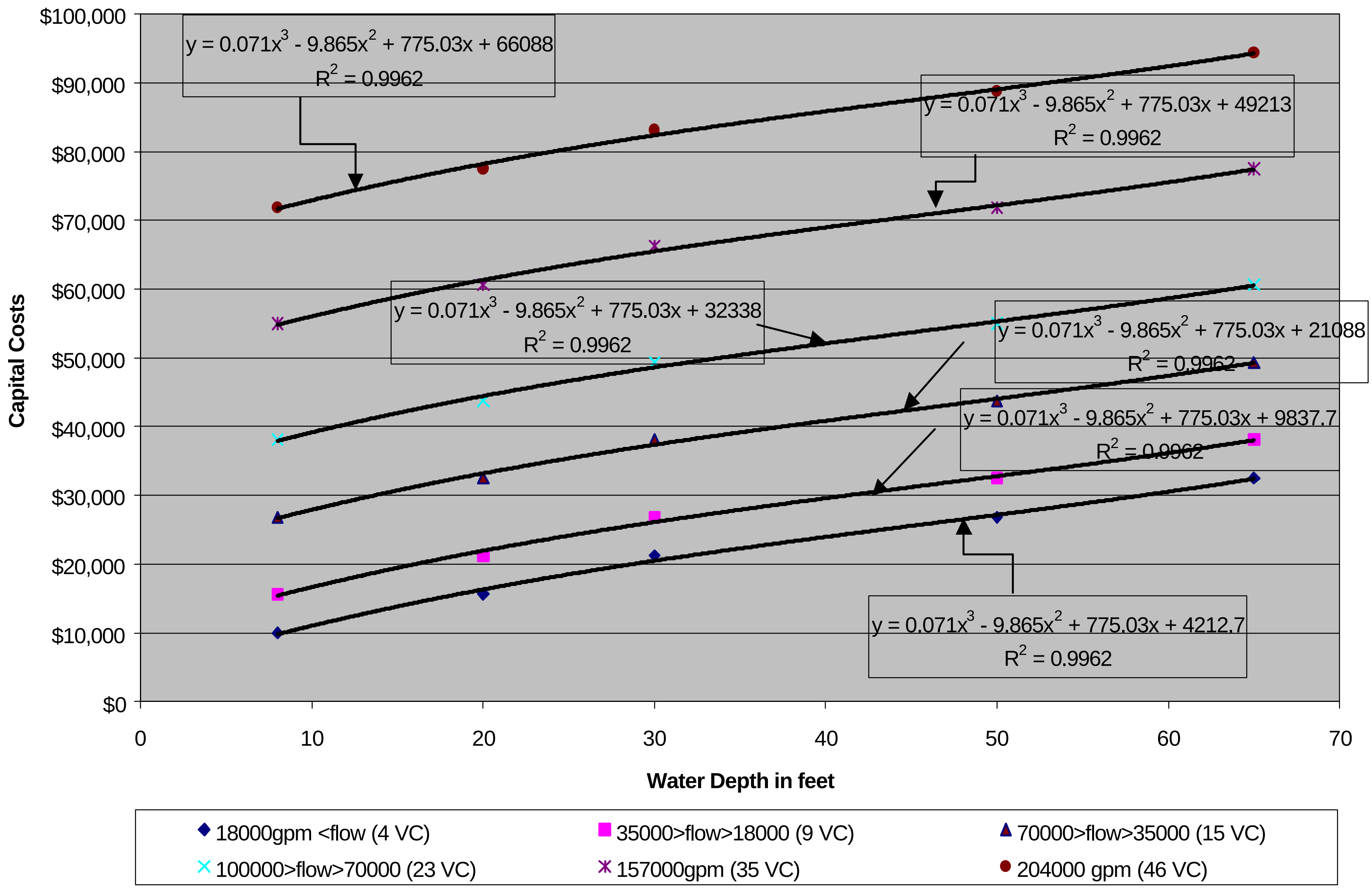
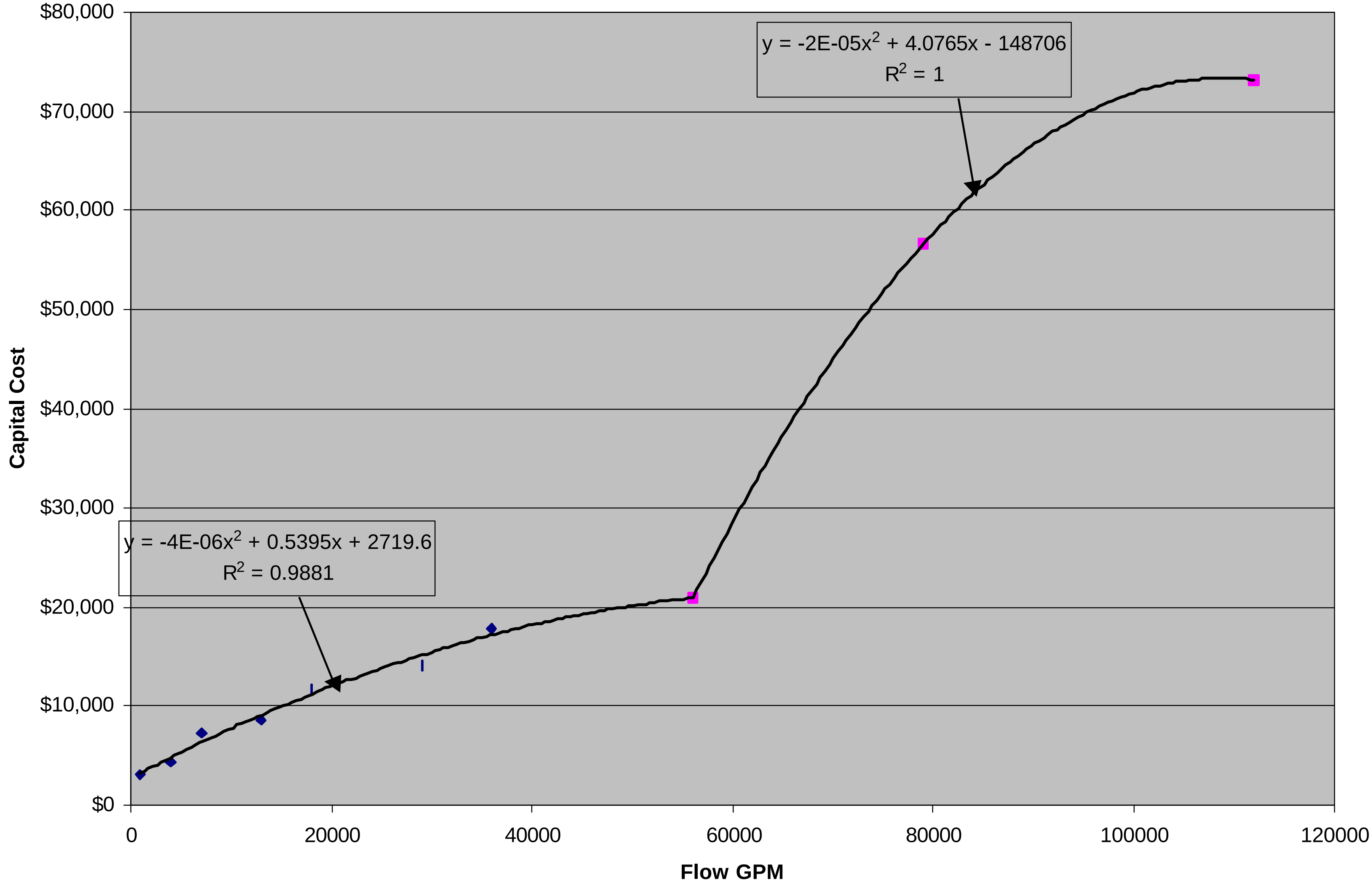


Chart 2-17. Concrete Fittings for Intake Flow Velocity Reduction



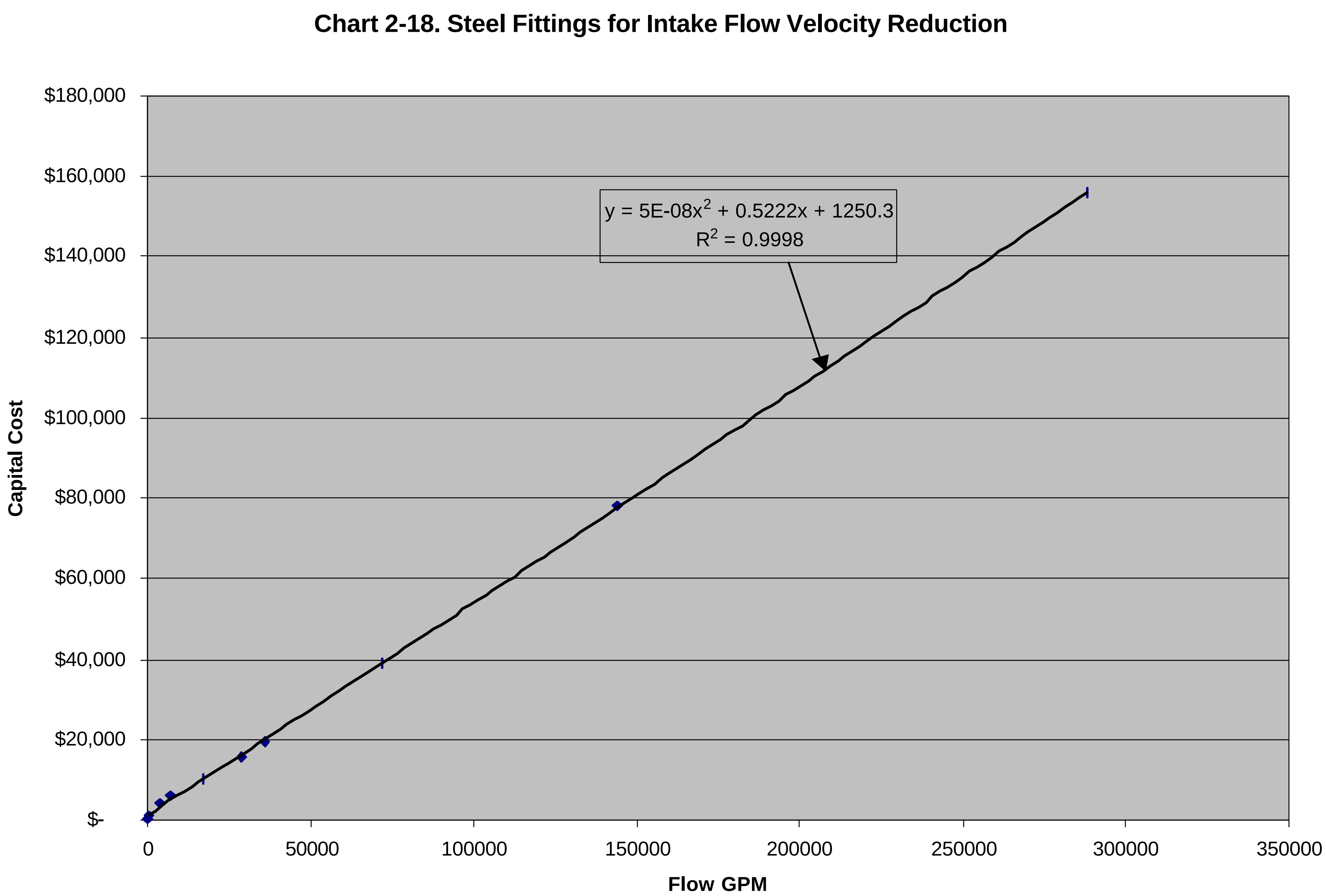


Chart 2-18. Steel Fittings for Intake Flow Velocity Reduction
$180,000
$160,000
$140,000
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$-
Capital Cost
0
50000
100000
150000
200000
250000
300000
350000
Flow GPM
y = 5E-08x2 + 0.5222x + 1250.3
R2 = 0.9998

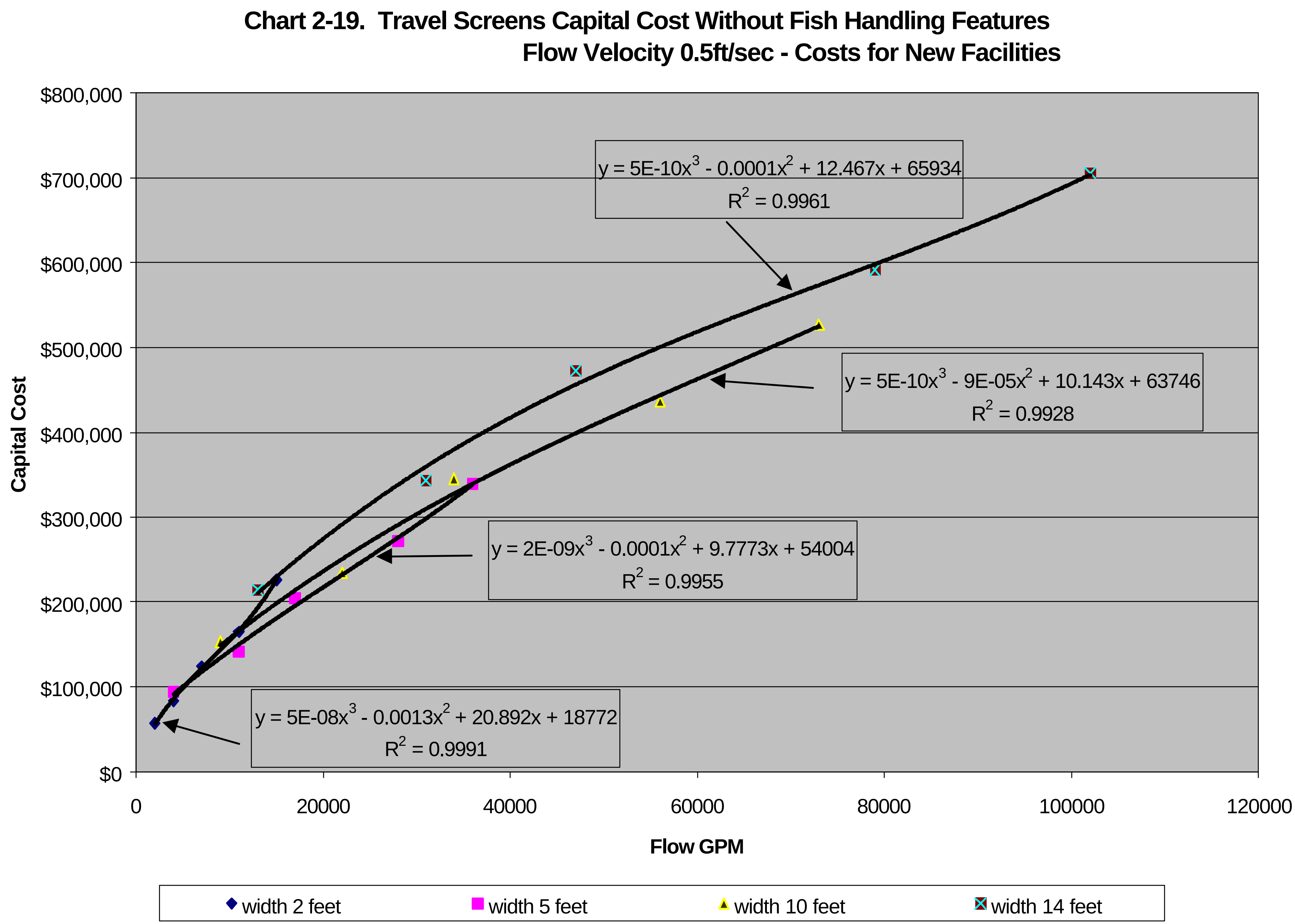


Chart 2-19. Travel Screens Capital Cost Without Fish Handling Features
Flow Velocity 0.5ft/sec - Costs for New Facilities
$800,000
$700,000
$600,000
$500,000
$400,000
$300,000
$200,000
$100,000
$0
Capital Cost
0
20000
40000
60000
80000
100000
120000
Flow GPM
y = 5E-10x3 - 0.0001x2 + 12.467x + 65934
R2 = 0.9961
y = 5E-10x3 - 9E-05x2 + 10.143x + 63746
R2 = 0.9928
y = 2E-09x3 - 0.0001x2 + 9.7773x + 54004
R2 = 0.9955
y = 5E-08x3 - 0.0013x2 + 20.892x + 18772
R2 = 0.9991
width 2 feet
width 5 feet
width 10 feet
width 14 feet

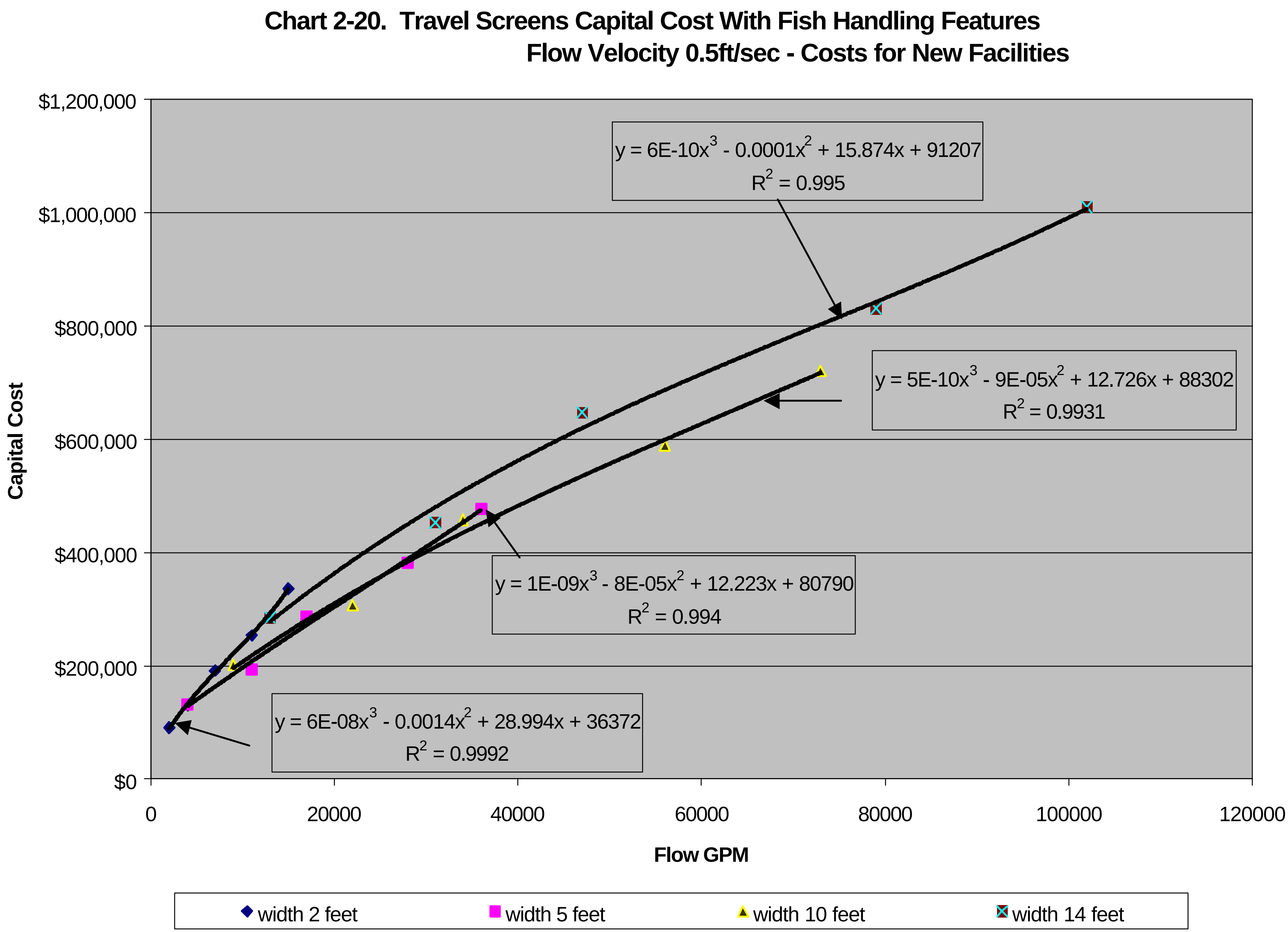
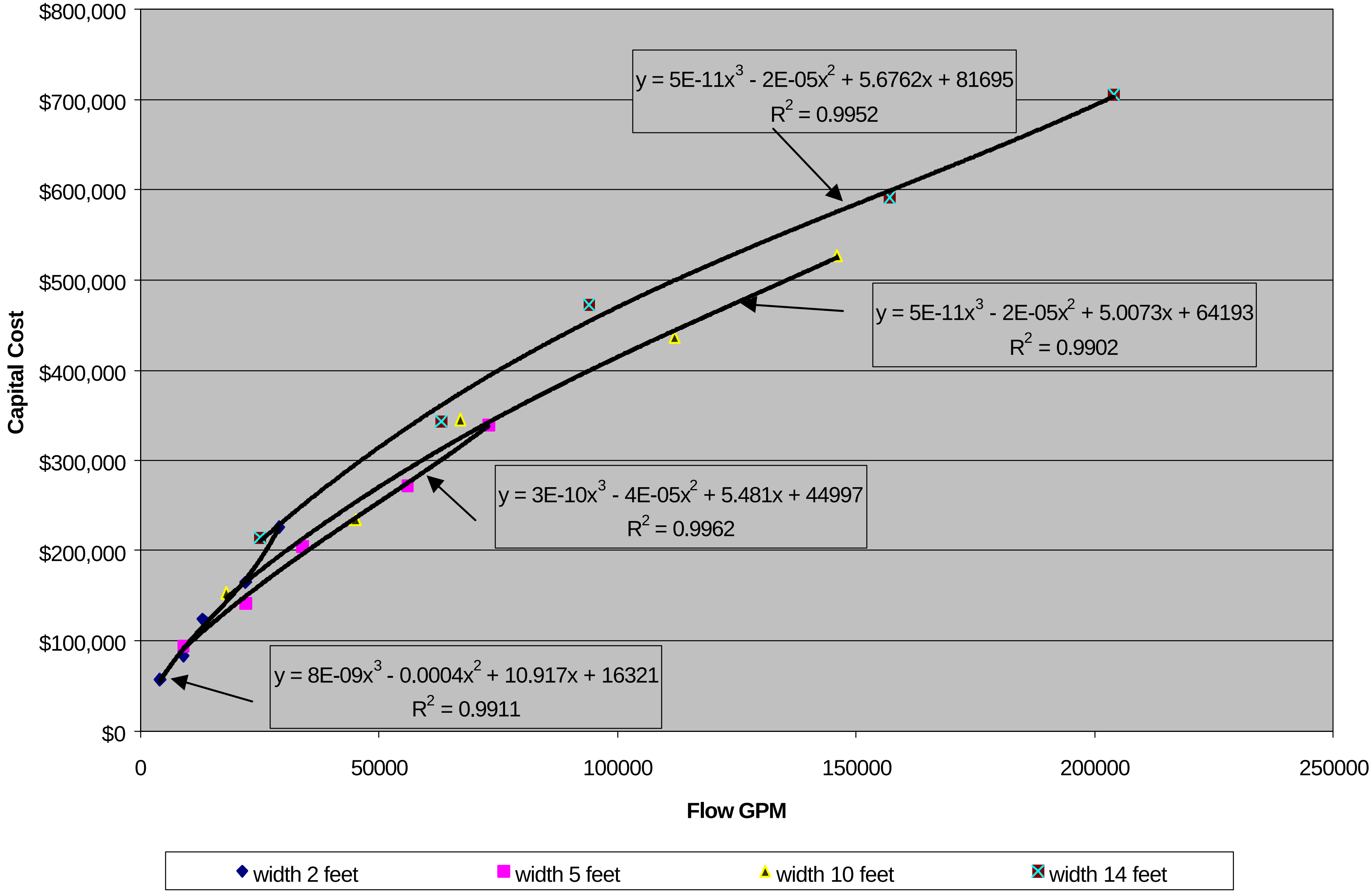


Chart 2-20. Travel Screens Capital Cost With Fish Handling Features
Flow Velocity 0.5ft/sec - Costs for New Facilities
$y = 6E-10x^3 - 0.0001x^2 + 15.874x + 91207$
$R^2 = 0.995$
$y = 5E-10x^3 - 9E-05x^2 + 12.726x + 88302$
$R^2 = 0.9931$
$y = 1E-09x^3 - 8E-05x^2 + 12.223x + 80790$
$R^2 = 0.994$
$y = 6E-08x^3 - 0.0014x^2 + 28.994x + 36372$
$R^2 = 0.9992$
Capital Cost
$1,200,000
$1,000,000
$800,000
$600,000
$400,000
$200,000
$0
0
20000
40000
60000
80000
100000
120000
Flow GPM
width 2 feet
width 5 feet
width 10 feet
width 14 feet

Chart 2-21. Travel Screens Capital Cost Without Fish Handling Features Flow Velocity 1 ft/sec - Costs for New Facilities



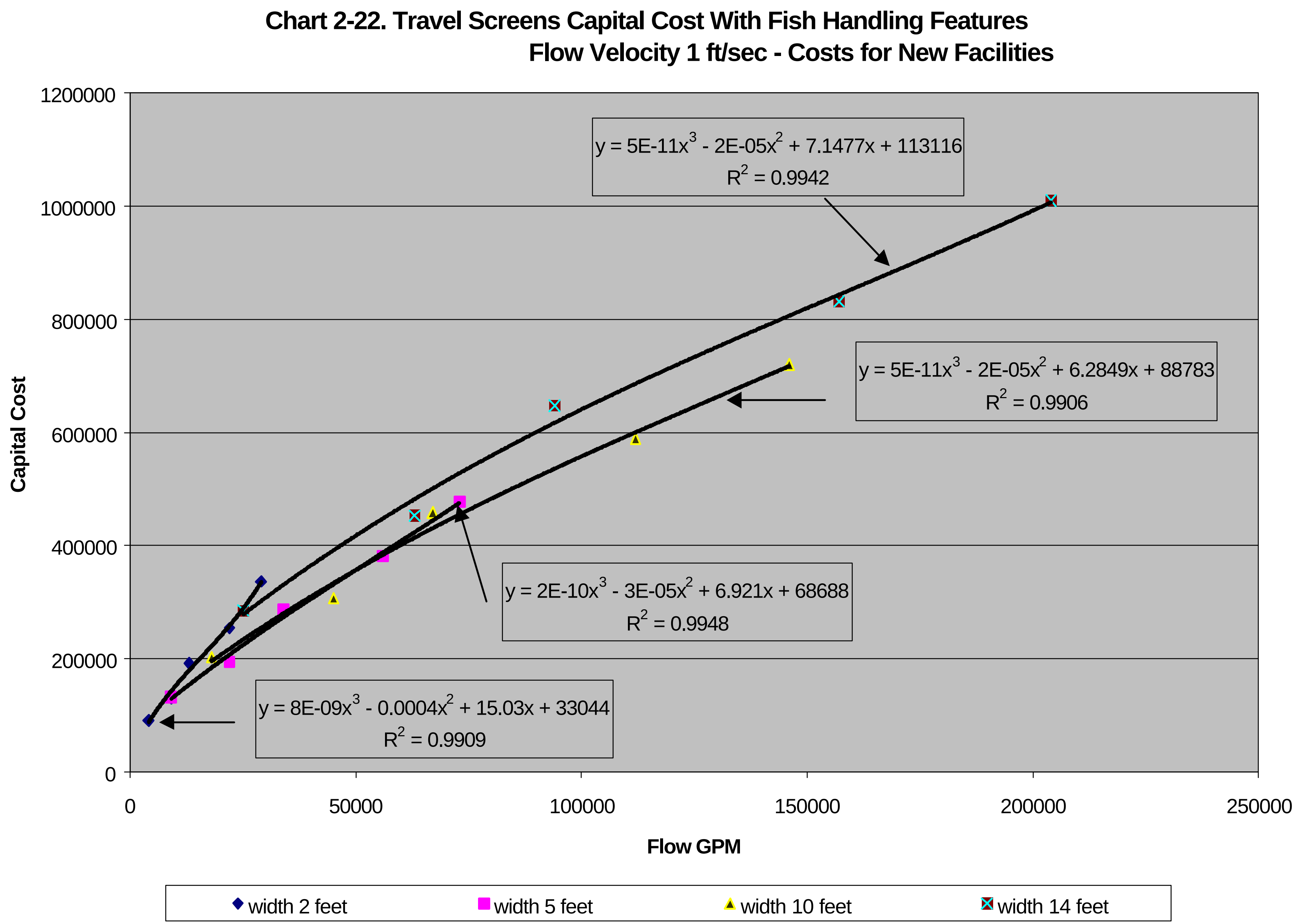
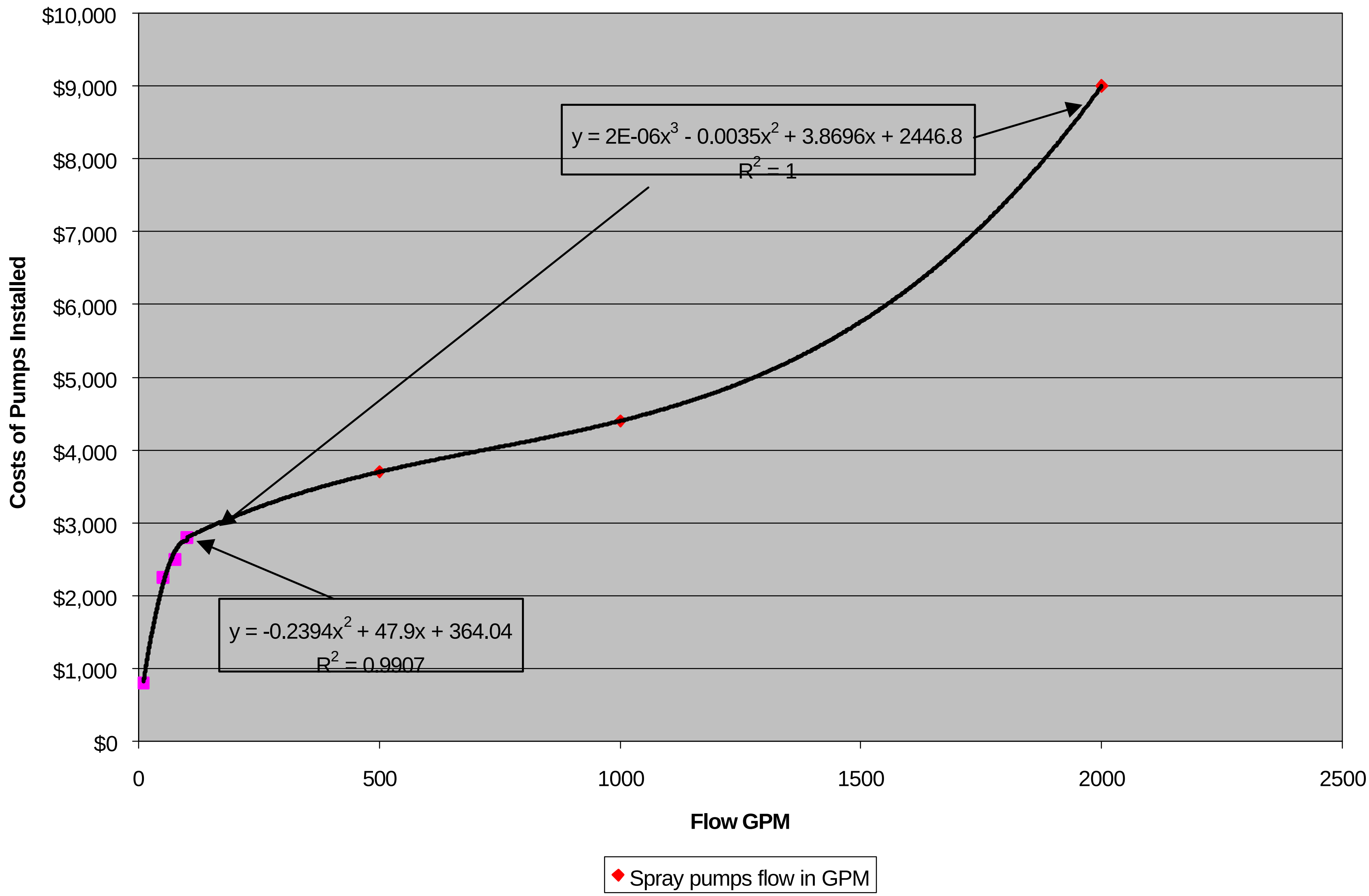


Chart 2-22. Travel Screens Capital Cost With Fish Handling Features
Flow Velocity 1 ft/sec - Costs for New Facilities
y = 5E-11x3 - 2E-05x2 + 7.1477x + 113116
R2 = 0.9942
y = 5E-11x3 - 2E-05x2 + 6.2849x + 88783
R2 = 0.9906
y = 2E-10x3 - 3E-05x2 + 6.921x + 68688
R2 = 0.9948
y = 8E-09x3 - 0.0004x2 + 15.03x + 33044
R2 = 0.9909
Capital Cost
1200000
1000000
800000
600000
400000
200000
0
0
50000
100000
150000
200000
250000
Flow GPM
width 2 feet
width 5 feet
width 10 feet
width 14 feet

Chart 2-23. Fish Spray Pumps Capital Costs - Costs for New Facilities



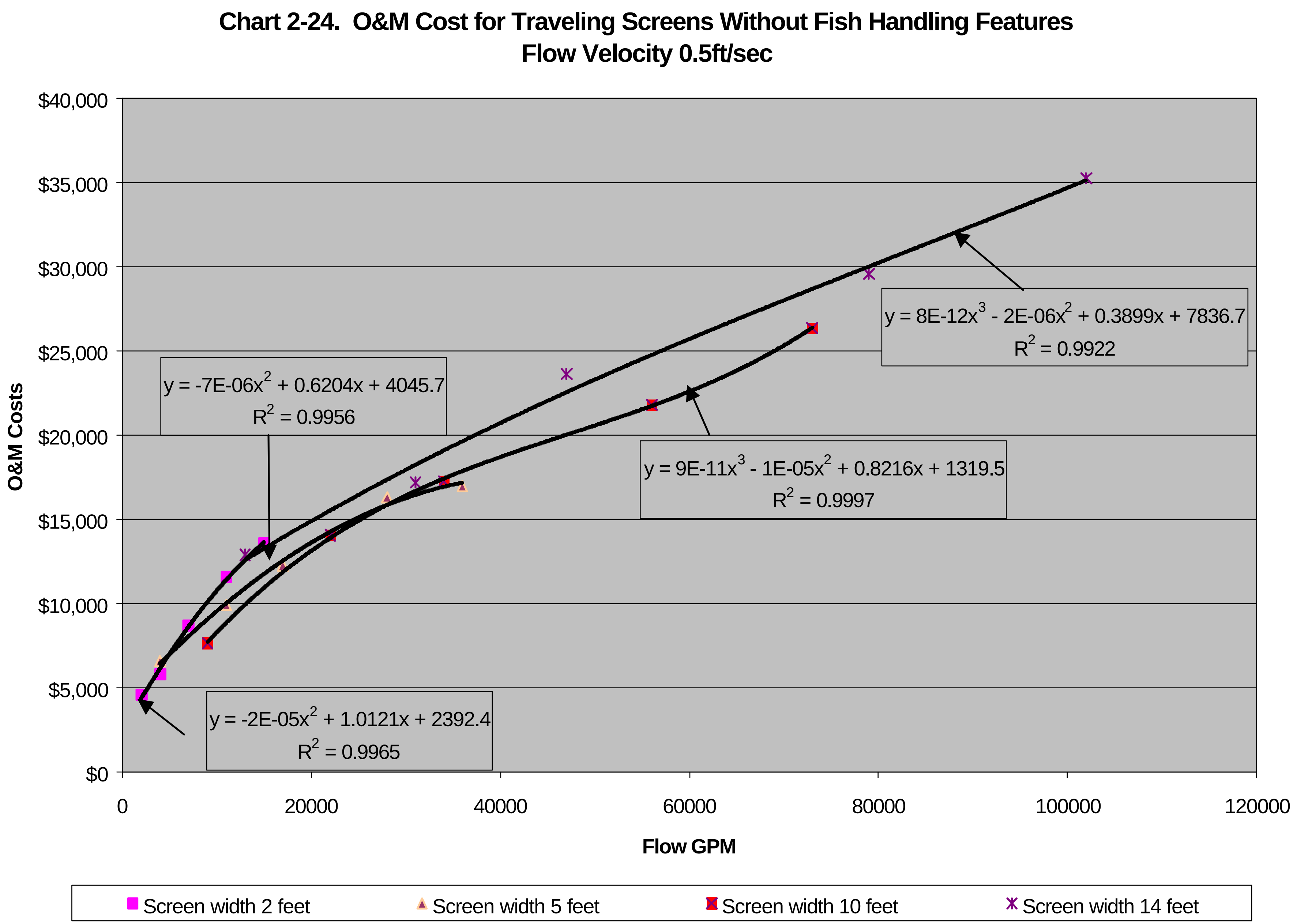


Chart 2-24. O&M Cost for Traveling Screens Without Fish Handling Features
Flow Velocity 0.5ft/sec
O&M Costs
$40,000
$35,000
$30,000
$25,000
$20,000
$15,000
$10,000
$5,000
$0
0
20000
40000
60000
80000
100000
120000
Flow GPM
y = 8E-12x3 - 2E-06x2 + 0.3899x + 7836.7
R2 = 0.9922
y = -7E-06x2 + 0.6204x + 4045.7
R2 = 0.9956
y = 9E-11x3 - 1E-05x2 + 0.8216x + 1319.5
R2 = 0.9997
y = -2E-05x2 + 1.0121x + 2392.4
R2 = 0.9965
Screen width 2 feet
Screen width 5 feet
Screen width 10 feet
Screen width 14 feet

Chart 2-25. O&M Cost for Traveling Screens With Fish Handling Features Flow Velocity 0.5ft/sec

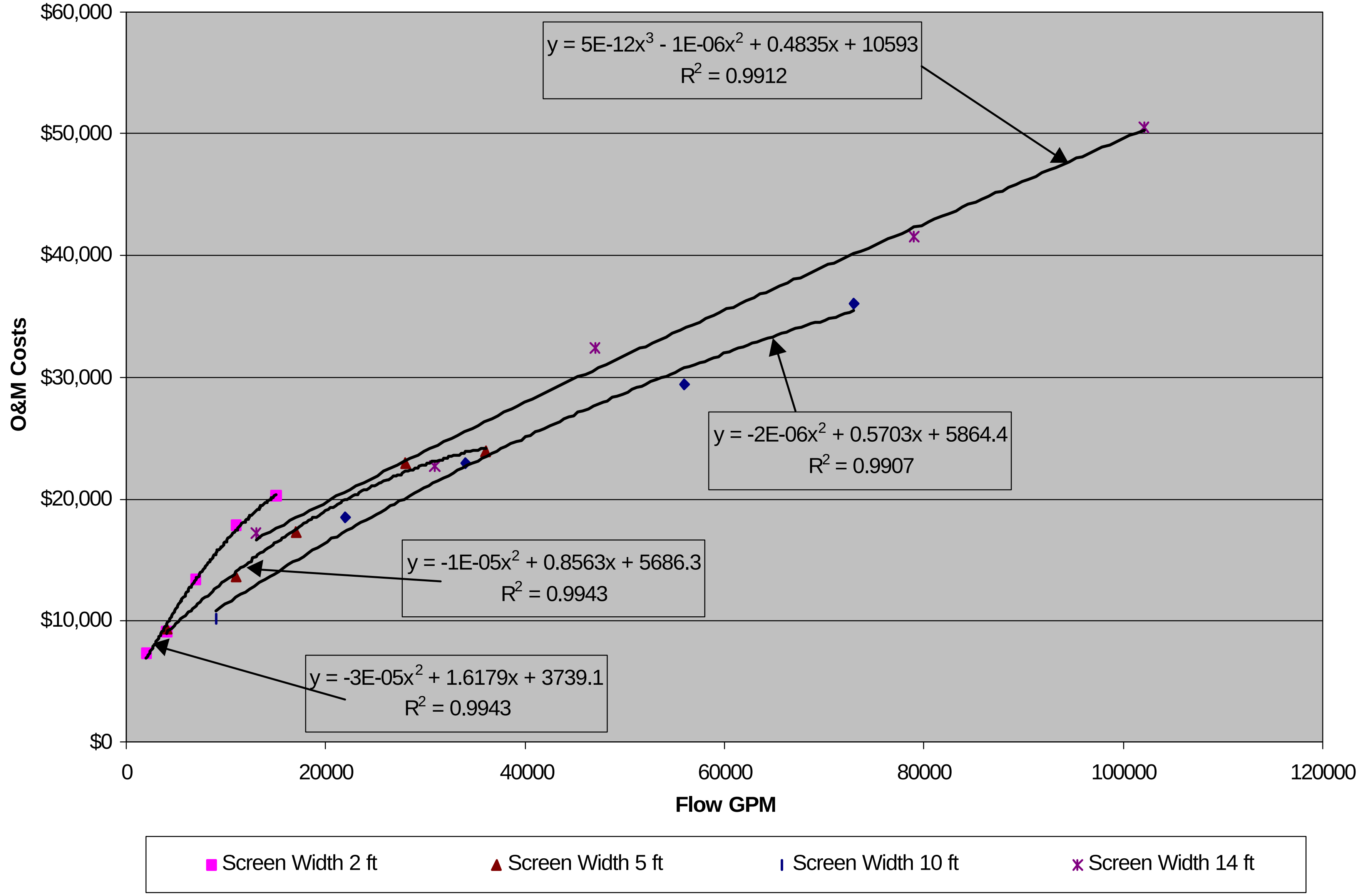


Chart 2-26. O&M Cost for Traveling Screens Without Fish Handling Features
Flow Velocity 1 ft/sec

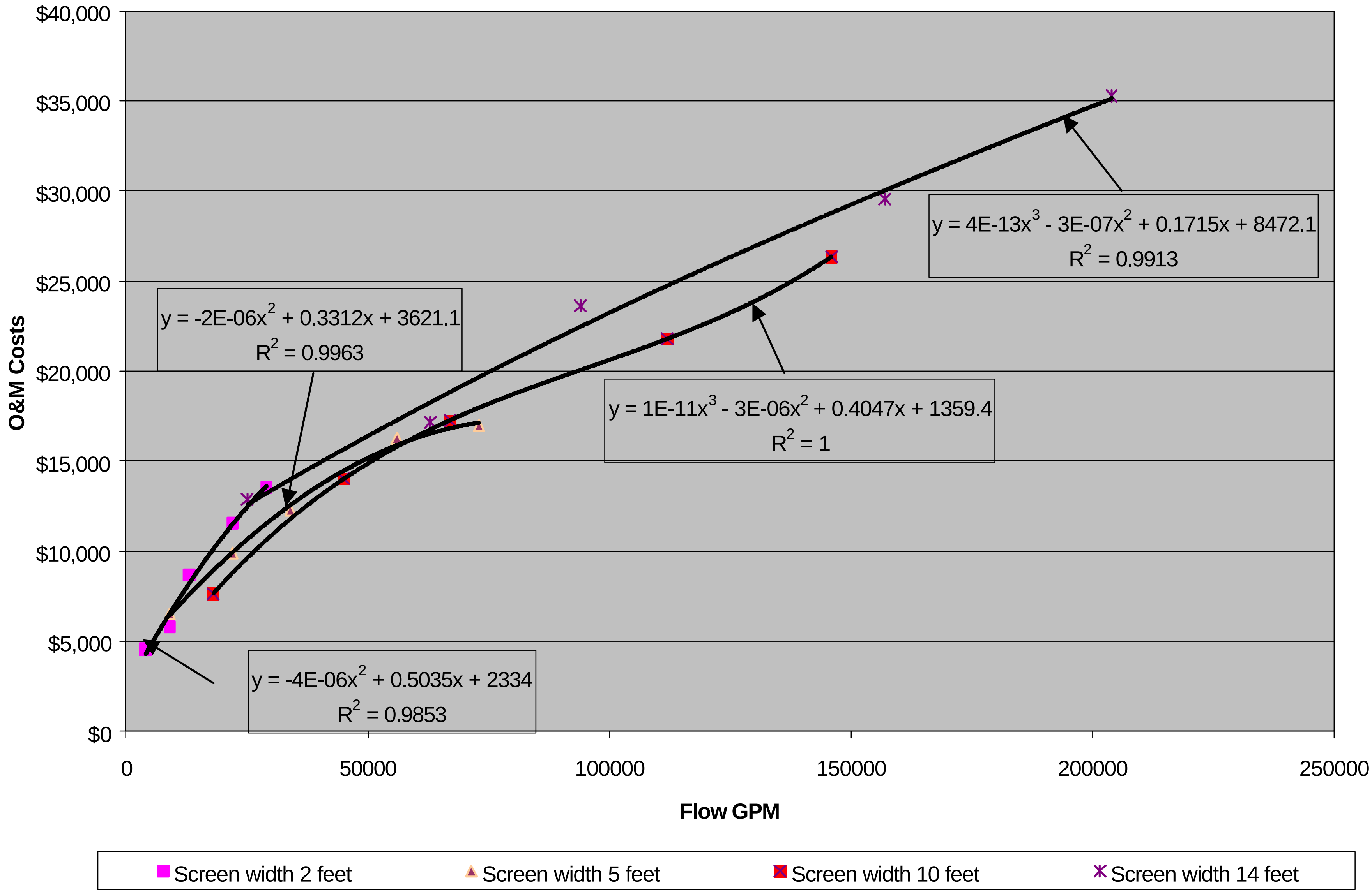
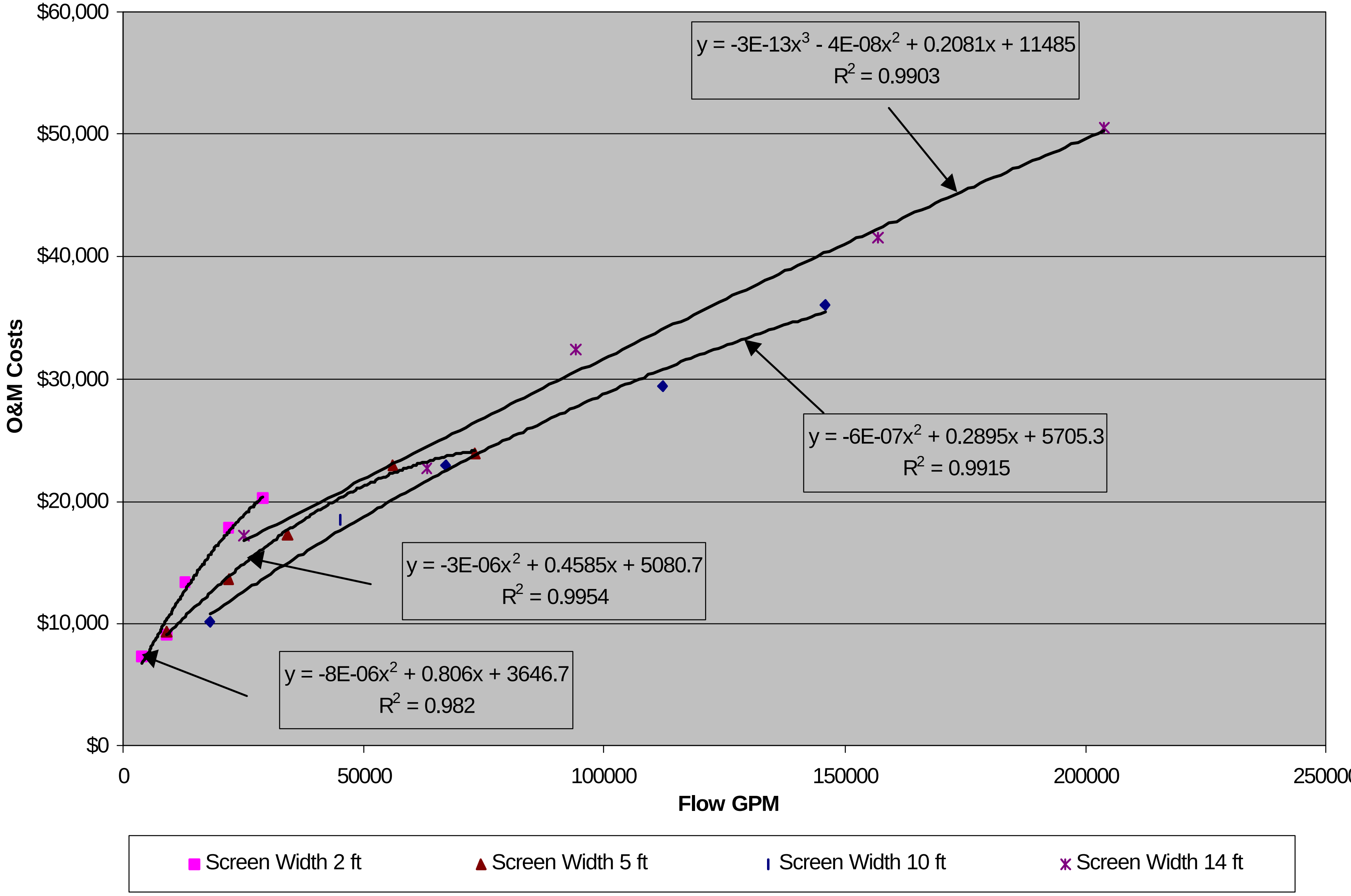


Chart 2-27. O&M Cost for Traveling Screens With Fish Handling Features Flow Velocity 1 ft/sec



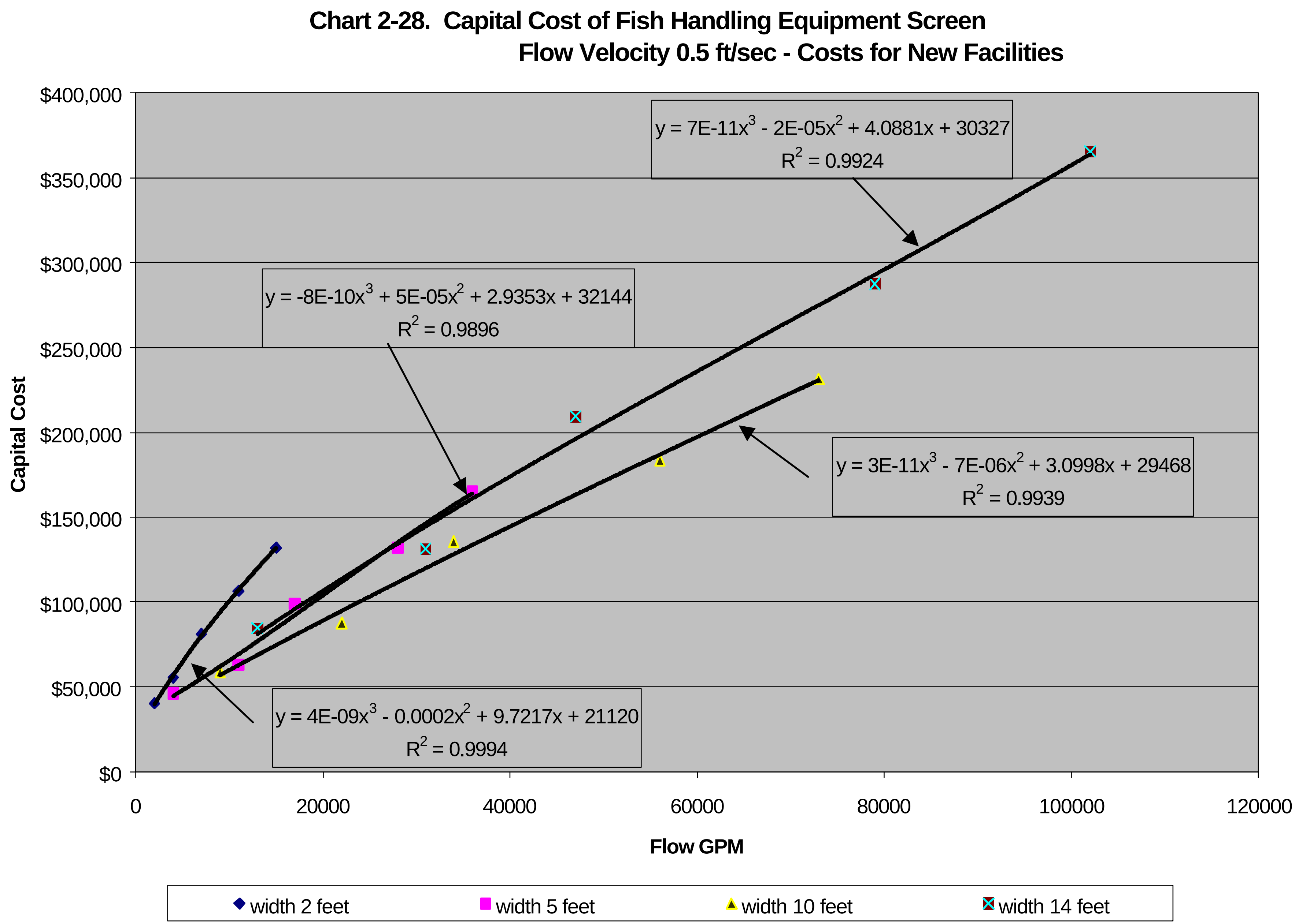


Chart 2-28. Capital Cost of Fish Handling Equipment Screen
Flow Velocity 0.5 ft/sec - Costs for New Facilities
$y = 7E\text{-}11x^3 - 2E\text{-}05x^2 + 4.0881x + 30327$
$R^2 = 0.9924$
$y = -8E\text{-}10x^3 + 5E\text{-}05x^2 + 2.9353x + 32144$
$R^2 = 0.9896$
$y = 3E\text{-}11x^3 - 7E\text{-}06x^2 + 3.0998x + 29468$
$R^2 = 0.9939$
$y = 4E\text{-}09x^3 - 0.0002x^2 + 9.7217x + 21120$
$R^2 = 0.9994$
Capital Cost
$400,000
$350,000
$300,000
$250,000
$200,000
$150,000
$100,000
$50,000
$0
0
20000
40000
60000
80000
100000
120000
Flow GPM
width 2 feet
width 5 feet
width 10 feet
width 14 feet

Chart 2-29. O&M Cost for Fish Handling Features
Flow Velocity 0.5ft/sec

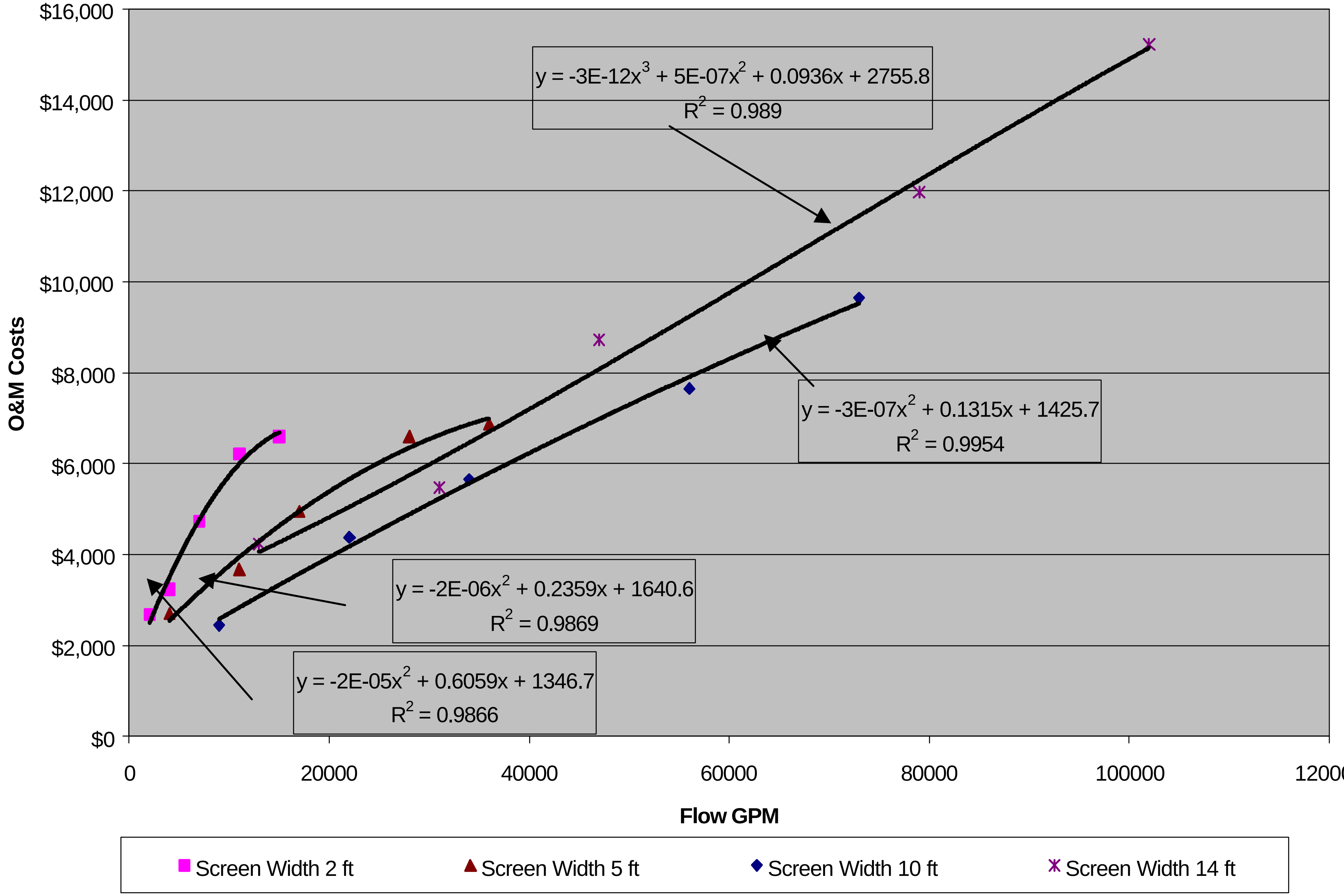
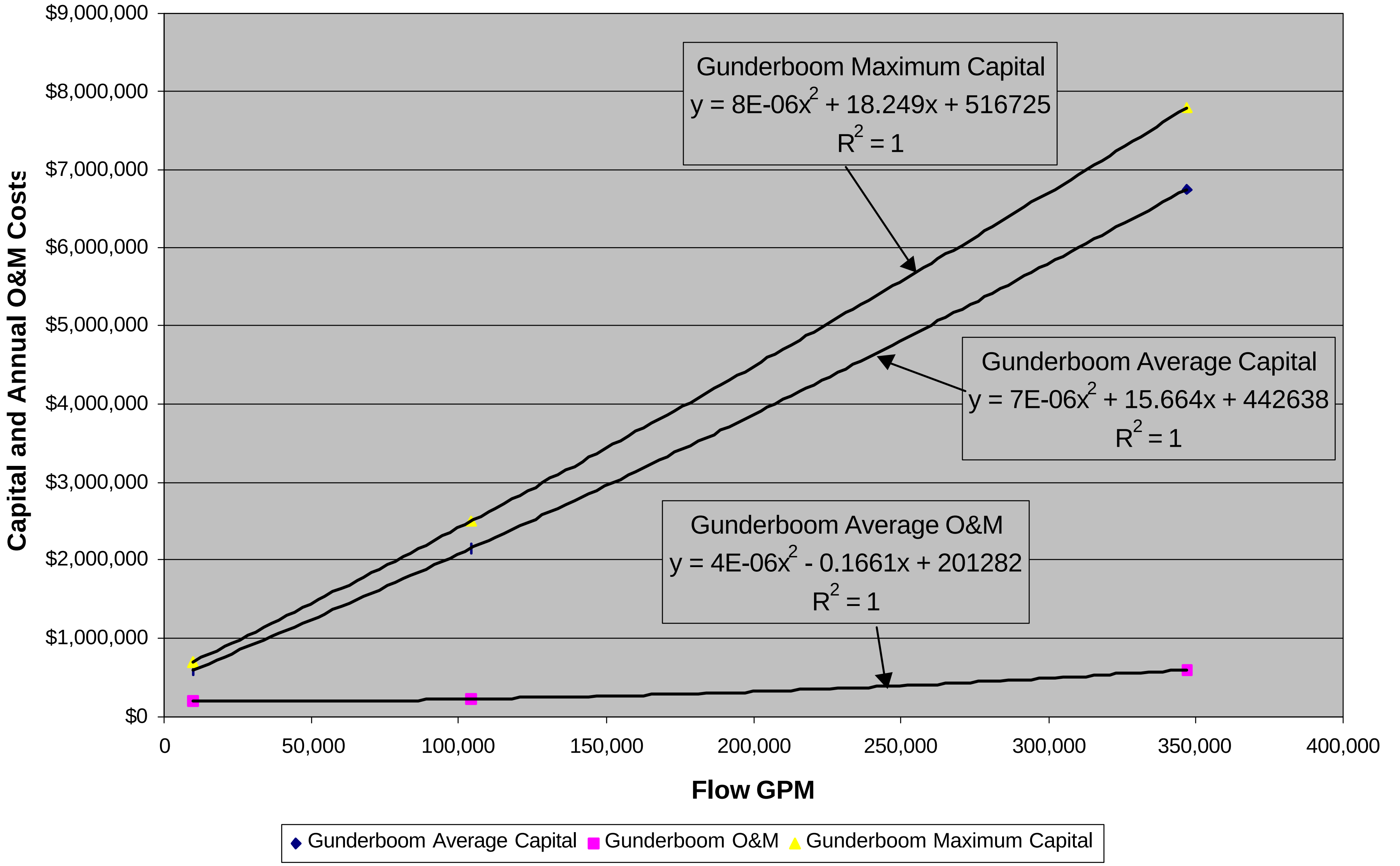


Chart 2-30. Gunderboom Capital and O&M Costs For Simple Floating Structure



Chapter 3: Efficacy of Cooling Water Intake Structure Technologies

INTRODUCTION

To support the Section 316(b) proposed rule for existing facilities, the Agency 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 was used to compare specific regulatory options and their associated costs and benefits. It provides the supporting information for the proposed rule and alternative regulatory options considered. 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.

3.1 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.

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3.2 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 the practicality or effectiveness of alternative technologies may 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 optimize their use.

The remainder of this chapter is organized by groups of technologies. A brief description of conventional, once-through traveling screens is 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.

Habitat restoration projects are an additional means to comply with this proposed rule. 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.

3.3 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 89 percent of all existing facilities within the scope of this rule. (see Chapter 1.3.3 of this document).

3.4 Closed-Cycle Wet Cooling System Performance

Although flow reduction serves the purpose of reducing both impingement and entrainment, these requirements function foremost as a reliable entrainment reduction technology. Throughout this chapter, the Agency compares performance of entrainment reducing technologies to that of recirculating wet cooling towers. To evaluate the feasibility of regulatory options with flow reduction requirements 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.

An additional question that the Agency has considered is the feasibility of constructing salt-water make-up cooling towers. Certain regulatory options considered for this proposal would have required flow reduction commensurate with closed-cycle wet cooling at a significant number of estuarine and ocean facilities. For the development of the New Facility 316(b) rule, 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. The Agency also consulted the 1994 UDI Power Statistics Database (EEI, 1994) to examine additional demonstrations of cooling towers using brackish and saline waters.

3.5 Alternative Technologies

3.5.1 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.

3.5.2 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 “high 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 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 l 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 be sufficient crosscurrent (or low intake velocities) in the waterbody to allow organisms to move or be carried 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 very 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 could 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.

3.5.3 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.

3.5.4 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.

3.5.5 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.

3.5.6 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

3.5.7 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.

3.5.8 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.
- Palisades Nuclear Plant in Michigan

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.

3.5.9 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.

3.5.10 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:

- <u>Light Barriers</u>: 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.

- <u>Sound Barriers</u>: 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).

3.5.11 Other Technology Alternatives

The proposed new facility rule does not specify the individual technology (or group of technologies) to be used to meet the impingement and/or entrainment requirements. 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 could be used in conjunction with other technologies to meet proposed requirements.

- 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.

3.6 INTAKE LOCATION

Beyond design alternatives for CWISs, an operator may able to relocate CWISs offshore or otherwise in areas that minimize I&E (compared to conventional onshore locations), though the ability of existing facilities to do so may be quite limited. As such, this discussion is of limited applicability to the majority of existing facilities, but is included to complete the discussion. 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.

3.7 SUMMARY

Tables 3-1 and 3-2 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 achieve comparable entrainment performance to the proposed entrainment reduction requirements (specific to a subset of regulated facilities) 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 timing and, to a lesser degree for existing facilities, the location 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 to Chapter 3

Cooling Water Intake Structure 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).

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

Intake Screening Systems	Fact Sheet No. 1: Single-Entry, Single-Exit Vertical Traveling Screens (Conventional Traveling Screens)

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.

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. 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).

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).

Intake Screening Systems	Fact Sheet No. 2: Modified Vertical Traveling Screens

- 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. 2: Modified Vertical Traveling Screens

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Intake Screening Systems	**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).

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

Intake Screening Systems	Sheet No. 3: Inclined Single-Entry, Single-Exit Traveling Screens (Angled Screens)

- 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 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-

Intake Screening Systems	Fact Sheet No.4: Fine Mesh Screens Mounted on Traveling Screens

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 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

Intake Screening Systems	**Fact Sheet No.4: Fine Mesh Screens Mounted on Traveling Screens**

environments.

References:

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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.

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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.

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

Passive Intake Systems	Fact Sheet No. 5: Wedgewire Screens

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:

C 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:

Delmarva Ecological Laboratory. Ecological Studies of the Nanticoke River and Nearby Area. Vol II. Profile Wire Studies. Report to Delmarva Power and Light Company. 1980.

Passive Intake Systems	Fact Sheet No. 5: Wedgewire Screens

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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).

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.

Passive Intake Systems	Fact Sheet No. 6: Perforated Pipes

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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).

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.

Passive intake Systems	**Fact Sheet No. 7: Porous Dikes/Leaky Dams**

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).

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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.

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

Fish Diversion or Avoidance Systems	**Fact Sheet No. 8: Louver Systems**

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.

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- 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).

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- 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.

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:

Fish Diversion or Avoidance Systems	Fact Sheet No. 9: Velocity Cap

- 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.

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).

Fish Diversion or Avoidance Systems	Fact Sheet No. 10: Fish Barrier Nets

- 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).

References:

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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.

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.

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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 appears to be controllable through use of the sparging system.
- Impinged organisms released back into the waterbody.
- Benefits relative to cost appear to be very promising, but remain unproven to date.

Fish Diversion or Avoidance Systems	Fact Sheet No. 11: Aquatic Filter Barrier Systems

- 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.
- Recent studies have asserted that biofouling can be significant.
- 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,

Fish Diversion or Avoidance Systems	Fact Sheet No. 12: Sound Barriers

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:

Fish Diversion or Avoidance Systems	Fact Sheet No. 12: Sound Barriers

- 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 4 Cooling System Conversions at Existing Facilities

INTRODUCTION

Reducing the cooling water intake structure's capacity is one of the most effective means of reducing entrainment (and impingement). For the traditional steam electric utility industry, facilities located in freshwater areas that have closed-cycle, recirculating cooling water systems can, depending on the quality of the make-up water, reduce water use by 96 to 98 percent from the amount they would use if they had once-through cooling water systems, though many of these areas generally contain species that are less susceptible to entrainment. Steam electric generating facilities that have closed-cycle, recirculating cooling systems using salt water can reduce water usage by 70 to 96 percent.[1]

Of the 539 existing steam electric power generating facilities that EPA views are potentially subject to the Phase II existing facility proposed rule, 73 of these facilities already have a recirculating wet cooling system (for example, wet cooling towers or ponds).

A closed-cycle recirculating cooling system is an available technology for facilities that currently have once-through cooling water systems. The Agency learned of several examples of existing facilities converting from one type of cooling system to another (for example, from once-through to closed-cycle recirculating cooling system). Converting to a different type of cooling water system, the Agency determined, is significantly more expensive than the technologies on which the performance standards of the proposed rule are based and significantly more expensive than designing new facilities to utilize recirculating systems. EPA has identified four power plants that have converted to closed-cycle recirculating wet cooling tower systems. Three of these facilities--Palisades Nuclear Plant in Michigan, Jefferies Generating Station in South Carolina, and Canadys Station in South Carolina-- converted from once-through to closed-cycle wet cooling tower systems after significant periods of operation utilizing the once-through system. The fourth facility -- Pittsburg Unit 7 – converted from a recirculating spray-canal system to a closed-cycle wet cooling tower system. In this case, the conversion occurred after approximately four years of operation utilizing the original design.

6.1 EXAMPLE CASES OF COOLING SYSTEM CONVERSIONS

Canadys Steam Plant. This 490 MW (nameplate, steam capacity), coal-fired facility with three generating units is located in Colleton County, South Carolina. The first unit initially came online in 1962, the second in 1964, and the third in 1967. All three units operated with a once-through cooling water system for many years. The Canadys Steam plant was converted from a once-through to a closed-cycle recirculating cooling system in two separate projects. Unit 3 (218 MW) was first converted in 1972. Units 1 and 2, both with nameplate capacities of 136 MW, were simultaneously converted from once-through to closed-cycle, a single recirculating wet cooling system in 1992.

The Agency contacted South Carolina Electric & Gas to learn about the cooling system conversions at Canadys

[1] The lower range would be appropriate where State water quality standards limit chloride to a maximum increase of 10 percent over background and therefore require a 1.1 cycle of concentration. The higher range may be attained where cycles of concentration up to 2.0 are used for the design.

(Wicker, 2002). According to plant personnel, the primary motivation for conversion from once-through to recirculating systems related to fresh water availability in both cases. Due to water shortages, the plant chose to convert the cooling systems and avoid water supply and thermal discharge problems.

For the initial cooling system conversion the plant constructed a mechanical-draft, wood cooling tower. The wood tower with design approach of 6 degrees F was refurbished into a fiberglass tower in 1999. The second recirculating cooling system utilizes a concrete mechanical-draft tower, with a design approach of 7 degrees F. For both tower systems, a lack of proximity between the cooling towers and the original intake pumps caused the plant to install new circulating water pumps. The circulating water flows through 84 inch diameter pipes for Unit 3 (with a piping distance of 650 ft from tower to condenser) and 72 inch diameter pipes for the Unit 1, 2 common system (with a piping distance from tower to condenser of 1700 ft). The plant continues to withdraw water through the original intake, although the plant now operates with new intake pumps. In addition, the condensers for each generating unit remained unchanged after the conversions, maintaining the design circulating flow. No condenser problems have emerged due to the recirculating system operation. The principle operational problem for the Canadys Station recirculating system appears to be the quality of the source water, which shows significant algae problems. The station has mitigated this problem through the optimization of tower fill and chemical addition and treatment.(Pearrow, 2001).

The construction of the entire Unit 1, 2 cooling tower system occurred in 8 months. The same information was not available for Unit 3. However, in both cases the cooling system tie-in process lasted approximately 30 days. Although the net downtime was not quantified by South Carolina Power & Light, the owners stated that the tie-in process was scheduled to coincide with planned maintenance outages. Each of the conversions occurred in the Spring, with the Unit 3 tie-in occurring in May of 1972 and that of Unit 1, 2 occurring in roughly May/June of 1992. The Agency has analyzed the historical, monthly-electricity generation for the Canadys Station. The Agency analyzed the generation about the time of the cooling system conversions (specific to the months of, before, and after the conversions). The Agency could not demonstrate that the electricity generation for the months of the conversions differ dramatically from other, non-conversion years. (See DCN 4-2545.)

The Agency inquired of South Carolina Power & Light as to whether they had conducted any historical energy penalty analyses of the cooling system conversions, which they had not. In addition, the Agency did not receive cost information for the cooling tower conversions, outside of the statement from South Carolina Power & Light that it did not experience any significant, unplanned cost overruns for either project.

***Jefferies Coal Units 3 & 4*.** Located in Moncks Corner, South Carolina, this facility has a combined, coal-fired capacity of 346 MW (nameplate, steam). The two coal units (each with 173 MW nameplate capacity) came online in 1970 and operated for approximately 15 years utilizing once-through cooling. Because the U.S. Army Corps of Engineers (USACE) re-diverted the Santee Cooper River, thereby limiting the plant's available water supply, the cooling system was converted from once-through to a closed-cycle recirculating tower system.

The Agency contacted Santee Cooper to learn about the cooling system conversions at Jefferies (Henderson, 2002). The Charleston District of the USACE paid for the construction of the tower system (a common, mechanical-draft, concrete cooling tower unit for both units with a design approach of 10 degree F and a range of 19 degree F) because of the re-diversion of the Santee Cooper River. Both the re-diversion of the river and the construction of the recirculating system occurred between 1983 and 1985. The towers came online in March of 1985. However, the connection of the recirculating system piping to the existing once-through piping occurred in May of 1983, started up in June of 1984, and performance tested in September of 1984. The plant installed valves and a Y-connection in May of 1983, and then continued to operate as a once-through system while the construction of the cooling tower and the re-diversion project finished. After the tower construction and re-diversion had occurred, the Jefferies plant switched the valve over to the recirculating system for full conversion.

The plant was able to utilize the existing circulating water pumps of the Jefferies coal units after the cooling system conversion. However, due to additional pumping head requirements, two small “booster” pumps were added in series after the existing, large circulating water pumps. The plant was able to continue using the original intake without modification, but installed a full new set of intake pumps for the reduced capacity. The condenser flow rate did not change after the conversion. In addition, the plant has not experienced any condenser or tube failure problems as a result of the conversion to a recirculating cooling system. The plant installed new, 108" diameter circulating piping between condenser and tower for a total piping distance of 1700 ft.

Santee Cooper conducted an empirical energy-penalty study over several years to determine the economic impact of the cooling system conversion. Santee Cooper claimed the lost efficiency of the turbines as an economic impact of the closed-cycle cooling system and obtained reimbursement, after significant and extended negotiation, from the USACE. See Chapter 5.6.1 for a discussion of the historical Jefferies Station energy penalty study.

The USACE owns the cooling towers at the Jefferies plant. Because of this arrangement, the USACE has paid for the operation and maintenance (O&M) of the cooling tower system since its construction. The Agency requested historical capital and O&M cost information from the USACE but did not receive it prior to publication of the proposed rule. Because the Agency did not receive the historical O&M information from the plant (which would include the fan and pump operation for the recirculating system), it cannot assess the full energy penalty of the wet cooling tower system at the Jefferies plant.

Palisades Nuclear Generating Plant. Located in Covert, Michigan, the Palisades Nuclear Plant was originally built as an 821 MW (nameplate, steam capacity) plant with a pressurized water reactor, utilizing once-through cooling. The original license for the plant allowed for 700 MW(e) of net generation. The plant is currently rated for 800 MW(e) of power, which is an increase of 100 MW over the initial license, and utilizes a mechanical-draft, wood cooling tower system to condense the steam load of the plant. The plant has replaced the steam generators since originally coming online, and the system now has a nameplate capacity of 812 MW. The plant began operation in early 1972 utilizing the once-through cooling system and subsequently converted to a closed-cycle, recirculating system in May of 1974, when the cooling towers became operational.

Citizen organizations concerned with the impact of the plant on Lake Michigan intervened in the plant’s licensing proceedings. The groups sought to limit radioactive releases from the liquid radwaste system and to limit thermal discharges to Lake Michigan (Gulvas, 2002). Through a settlement agreement, the Palisades plant agreed to adopt a recirculating wet system and to make modifications to the radwaste system. Procurement and construction of the cooling tower system began in mid- to late-1971. Consumers Power Company (now known as Consumers Energy) originally designed the cooling system for a once-through, maximum-design intake flow of 486,380 gpm (30,686 L/sec) (Benda and Gulvas, 1976). The plant maintained its original, operating condenser flow of approximately 400,000 gpm after the conversion. The operating intake flow decreased from 405,000 gpm to 78,000 gpm (Consumers Energy, 2001). Because the plant utilized the existing offshore intake without modification for the reduced flow, the intake velocity decreased from 0.5 ft/sec to less than 0.1 ft/sec. The cooling tower system constructed on plant property comprises two tower systems, each with 18 mechanical-draft cells. The system is designed to reduce the water temperature 30 degrees F. The recirculating flow through the system was designed for 410,000 gpm (NRC, 1978).

A modification to cooling tower operation in 1998 resulted in a decreased intake flow rate of 68,000 gpm. In 1999 the plant obtained approval from the Michigan Department of Environmental Quality to increase its intake flow rate, and has operated with an intake from Lake Michigan of approximately 100,000 gpm since the approval. The plant sought to obtain the intake flow rate increase in order to improve electrical generation efficiency (Consumers Energy, 2001). Subsequently, the cooling water circulation through the condensers increased to 460,700 gpm, but the cooling tower flow rate remained the same (Gulvas, 2002).

The conversion process at Palisades utilized the original, offshore intake for the reduced flow rates in addition to the original 3,300-feet long, 11-feet diameter intake piping. However, the plant installed new intake pumps and removed two traveling screens to install additional "dilution" pumps for the recirculating system. The plant also installed entirely new circulating water pumps to convey water between the condenser and tower systems. The Agency learned initially from Consumers Energy that the original once-through pumps might have been utilized for the recirculating system (DCN 4-2502). However, Consumers Energy's follow-up research indicated that the historical conversion required new circulating pumps due to increased pumping head. Although the plant chose to install the relatively low-head, mechanical-draft cooling towers, the converted system required enough additional power from the pumps in order to warrant full replacement.[2]

The circulating water flow rate through the condensers did not change from before to after the cooling system conversion (though the intake flow rate increase in 1999 apparently increased condenser flow). The plant made no modifications to the condenser in order to accommodate the recirculating system, despite the original once-through design. However, prior to operation with the recirculating system, a significant portion of the condenser tubes had begun to fail. The tubes were failing with the once-through system due to vibration. After conversion of the cooling system, the plant continued to operate with condenser leaks, thereby raising SO_4 levels in the generators. This led to more time necessary to bring the levels in line with specifications before power escalation with the cooling system operating in recirculating mode. After conversion to the recirculating system, the condenser tubes were replaced.
The Agency concludes that the choice of installation of mechanical-draft towers, as opposed to the more traditional nuclear design of natural-draft towers, at the Palisades Nuclear Plant may have been, in part, to minimize the plume migration from the system. The plant is located along a scenic portion of Lake Michigan, in close proximity to sensitive lakeside vegetation and nearby orchards. In addition, within a half-mile of the plant is a highway. According to Consumers Energy, the plant has not experienced any problems with the plumes from the mechanical-draft units interfering with the nearby highway, nor with boating and recreation on the lake (DCN 4-2502). However, vegetation within 90 meters of the towers was damaged by frost induced by the tower plumes. The NRC estimates that drift from the Palisades cooling towers (built with drift eliminators and splash fill) deposits within short distances from the towers, all within 800 feet and 70 percent within 300 feet (NRC, 1978).

The Palisades plant constructed the main portions of the tower system in 1972 and 1973, while the plant operated in once-through mode. Construction finished by early 1974. In August of 1973 the plant experienced the beginning of a sizeable outage (ten months), which according to Consumers Energy was due primarily to the connection and testing of the recirculating system. The Agency had initially learned from a journal article that the plant was off-line for a variety of maintenance outages, which the Agency interpreted as being mostly unrelated to the cooling tower system.[3]

[2] According to cooling tower bid descriptions from three reputable cooling tower manufacturers, the typical total dynamic head requirements of a mechanical draft cooling tower unit is approximately 30 feet. See DCN 4-2501.

[3] Benda, R.S. and J. Gulvas, 1976, states "the plant was shutdown because of various operational problems in August 1973." In addition, during a conference call with the Agency regarding the cooling system conversion,

However, in a letter submitted to the Agency, Consumers Energy stated, "it appears that the outage was primarily for the purpose of installing the new circulating water system and the modifications necessary for its operation." Through research into the historical electricity generation of the plant, the Agency confirms that the outage of ten-months occurred (see DCN 4-2545). However, the Agency notes that it was unable to obtain specific records to show the cause(s) of the outage. The Agency also notes that part of the settlement agreement called for modifications to the radwaste system. In addition, plant operation prior to the conversion had shown problems with the condenser.

The final installed cost of the project was $18.8 million (in 1973-1974 dollars), as paid by Consumers Energy. The key items for this project capital cost included the following: two wood cooling towers (including splash fill, drift eliminators, and 36-200 hp fans with 28 ft blades); two circulating water pumps; two dilution water pumps; startup transformers; yard piping for extension of the plant's fire protection system; modifications to the plant screenhouse to eliminate travelling screens and prepare for installation of the dilution pumps; a new discharge pump stucture with pump pits; a new pumphouse to enclose the new cooling tower pumps; yard piping for the circulating water system to connect the new pumphouse and towers; switchgear cubicles for the fans; roads, parking lots, drains, fencing, and landscaping; and a chemical additive and control system. Additionally, Consumers Energy estimates that the plant abandoned approximately $683,000 (1973/1974 dollars) of original plant equipment. Excluding the sunk costs of the abandoned equipment, the project cost is $58.5 in year 2001 dollars (the cost basis of this proposed rule) or $55.9 in year 1999 dollars (the dollar basis of facility level cost estimates discussed in Chapter 2 of this document). Frequently, in historical studies of cooling system conversions, the cost basis has been presented as dollars per kW. If the Palisades conversion project were presented on such a basis, the ratio would be $68 per kW (1999 $ per kW of nameplate capacity). Utilizing the EPA methodology presented in Chapter 2 for assessing cooling tower "retrofits" gives an estimated installed capital cost of $68 per kW (1999 $) for a nuclear site with the original design characteristics of Palisades.

The Agency learned that Consumers Energy believes that the cooling tower system at Palisades has a significant impact on the efficiency of the plant's generating unit. See Chapter 5.6.3 for a discussion of the Palisades estimates of energy penalty impacts from the operation of cooling towers.

Pittsburg Power Plant, Unit 7. Located in Contra Costa County, California, this 751 MW (nameplate, gas-fired steam) unit was originally constructed with a recirculating canal cooling system. The plant began operation in 1972 and converted to a system with mechanical-draft cooling towers in 1976. The original spray canal system, according to plant personnel, did not operate efficiently enough for the plants needs (DCN 4-2554). The plant then constructed the mechanical-draft cooling tower system between two reaches of the original canal. Because of the proximity of the cooling towers to the original circulating piping that serviced the canal, the plant was able to utilize the majority of this existing circulating piping system with the converted design. The construction of the cooling towers occurred on a very narrow strip of land between the canals. The location provides minimal buffer land surrounding the towers, and indicates that the site required significant prepartion work. The cooling towers extend along the canal divider from about 300 meters away from the generating unit buildings to approximately 800 meters. The mechanical-draft towers consist of two units, each with 13 cells. The water supply used in the system is brackish water from Suisun Bay. The cooling system conversion utilized the existing condenser in addition to the conduit system. The design condenser flow is 352,000 gpm. The plant's design intake flow rate is 20,200 gpm (EEI, 1994).

Consumers Energy stated that operational problems unrelated to the conversion process had been mostly responsible for the extended outage (see DCN 4-2502).

Pacific Gas & Electric, former owners of the Pittsburg Power Plant, reported the total project cost for the cooling conversion at Pittsburg Unit 7 as $16.7 million (1976 $) (DCN 4-2506). This corresponds to $40.87 million in 1999 dollars or $54 per kW (1999 $ per kW of nameplate capacity). Because the plant is in Contra Costa County, California, the cost of construction in this area may not be representative of other areas of the country. The Oakland, California area has a city construction multiplier of approximately 1.19 according to a cost estimating reference (R.S. Means, 2000). Therefore, the costs for the Pittsburg Unit 7 conversion on a national average basis would be approximately $34.4 million for total project capital cost (in 1999 $) or $46 per kW (1999 $ per kW of nameplate capacity). Utilizing the EPA methodology presented in Chapter 2 for assessing cooling tower "retrofits" gives an estimated installed capital cost of $38 per kW (1999 $, national-average cost basis) for a site with the characteristics of Pittsburg Unit 7.

Dry Cooling Conversion Projects. At the time of this proposal, the Agency is unaware of demonstrated cases of cooling system conversions involving dry cooling systems for the size of power plants within the scope of this proposed rule. See Appendix D of this document for a discussion of dry cooling systems and their applicability for retrofit designs.

4.2 Plant Outages for Cooling System Conversions

For three of the cooling system conversion cases examined above, the Agency obtained information from the plants regarding the gross outage duration for converting between cooling system types. The duration of the outages reported to the Agency were 83 hours (gross) for the Jefferies Station, 30 days (gross) for each of the two Canadys conversions, and 10 months (gross) for Palisades Nuclear. The Agency examined historical electricity generation data for these plants and could infer that these outages did occur. However, due to the historical nature of the projects (that is, conversions that occurred from 10 to 30 years ago), the Agency found the documentation of the engineering aspects of the conversions to be limited. For the more recent projects – Jefferies and Canadys Unit 3 – the Agency received information directly from members of the plant staff that participated in, or were employed at the stations during the conversions. For Palisades, the Agency received a significant historical information about the plant, but limited information relating to the specifics of the plant outage for the cooling system conversion.

Based on these limited data points provided to the Agency, conclusions as to the expected duration of outages for a variety of cooling system conversions cannot be conclusively drawn. The only substantial conclusion the Agency can reach is that the gross duration of the outage varies widely, based on the data reported to the Agency, and that the possibility exists for both extremely short outages and those of extremely long duration. The Agency based the economic analysis of the regulatory options summarized in Section 4.3 on a gross outage of one-month per converted plant. The Agency based this estimate on the information it had received from Jefferies and Canadys stations and research into other projections (see below). The Agency did not receive the Palisades information until very late in the development of this proposed rule. Based on the information provided to the Agency (including the late Palisades submission), the estimate of one-month could in some cases over- and others under-estimate the expected outage duration for a cooling system conversion. In addition, there is some evidence that the durations of outages may differ based on fuel type (that is, nuclear versus non-nuclear).

As mentioned above, the Agency researched outage projections from historical 316 demonstrations, where plants conducted engineering studies as to the duration of the expected outage for a site-specific cooling system conversion. Appendix VIII-3 of the Draft Environmental Impact Statement (DEIS) for Bowline Point, Indian Point 2 & 3, and Roseton Generating Stations (Power Tech Associates, 1999) estimates net outage durations for an evaluation of four closed-cycle cooling projects. The DEIS states, "plants must be shut down for construction and commissioning beyond the normal shutdowns of the plants. In the cases of Roseton and Bowline, this period was estimated at one month beyond normal outages." For the two nuclear units of Indian Point, the authors estimate two outages for each unit, with each outage lasting 4 months. The DEIS states that the basis of the longer estimates for the nuclear plants is as follows: "the safety issues have to be addressed during excavation (particularly when blasting is required), tying the new system into the plant, and the extensive testing which must follow." The DEIS estimates that the separate blasting and tying-in outages would last four months each, considerably longer than for the fossil-fueled Bowline Point and Roseton Stations. The Agency notes that there is no detailed engineering basis (such as detailed descriptions of the types of connections to be made, etc.) given by the Authors for any of the projections made in Appendix VIII-3 of the 1999 DEIS.

The Agency also consulted a detailed historical proposal for a Roseton Generating Station cooling system conversion (Central Hudson Gas & Electric, 1977). The report estimates a gross outage period of one-month for the final pipe connections for the recirculating system. The report estimates the net outage as 10 days for one of the two units and no downtime for the second. The reason for the short estimates of downtime are due to the coincidence of the connection process with planned winter maintenance outages. Unlike the projection in the 1999 DEIS described above, this 1977 projection was accompanied by a relatively detailed description of the expected level of effort and engineering expectations for connecting the reciruclating system to existing equipment.

The Agency learned from the NPDES permit application for Salem Generating Station estimates that outages due to construction and conversion to cooling towers are expected to last 7 months per generating unit, in addition to the station's planned outages for refueling (see Appendix F, Attachment 8 of the 1999 PSE&G Permit Application for Salem Generating Station, Permit No. NJ0005622).

In addition, the Agency consulted a variety of sources to determine the typical occurrence and duration of planned maintenance outages. As noted in the example cases described in Section 4.1 above, each of the cooling system conversions coincided with planned maintenance outages. Appendix VIII-2.A of the DEIS for the fossil-fuel Roseton Station states, "a review of historical data indicates that there has[sic] been 30 day maintenance outages occurring nominally from mid-Sept. to mid-Oct."

The 1999 Permit Application for Salem predicts a three year refueling cycle for each unit that is accompanied by outages of approximately 60 days one year, 40 days in a second year, and no outage in the third. This data is consistent with other information the Agency obtained from literature. The Agency learned that for 2000 the industry mean nuclear refueling outage was approximately 40 days (Nucleonics Week, January 18, 2001). In addition, NUREG-1437 shows that nuclear plants undergo periodic and predictable outages for inspections. The following excerpts from NUREG-1437 explain the NRC's view of outages at nuclear plants:

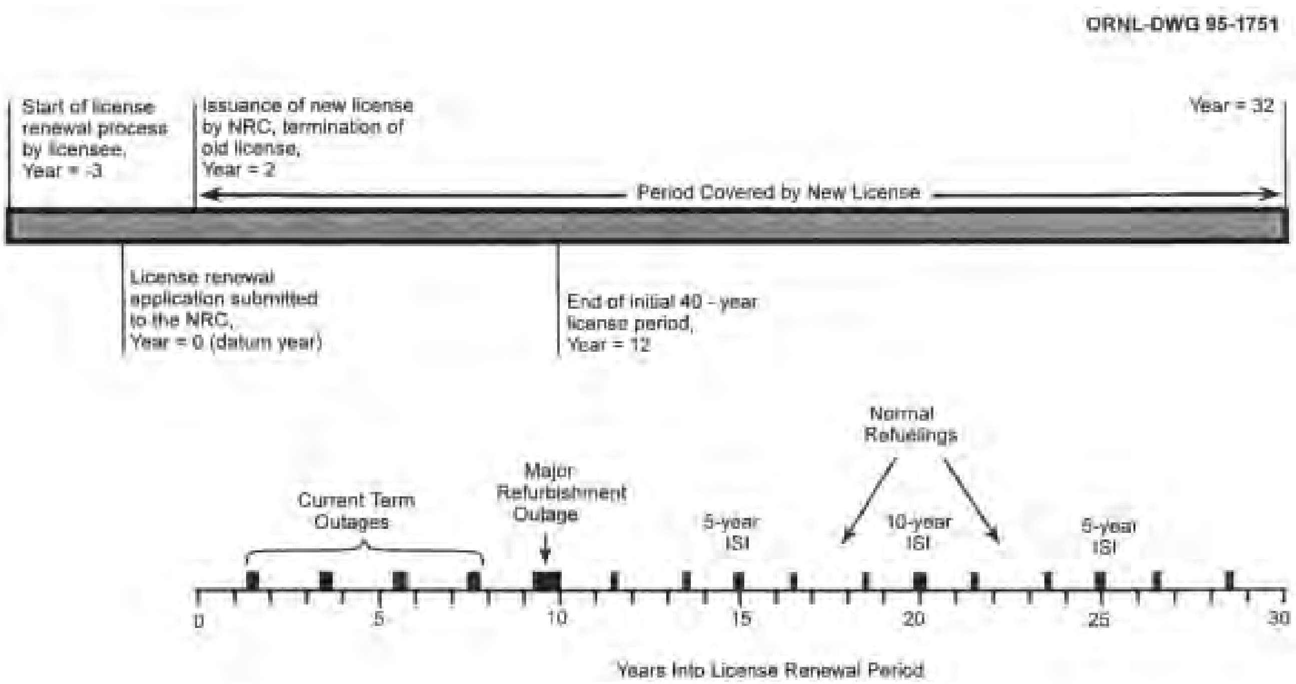
From Section 2.2.6-

> Nuclear power plants must periodically discontinue the production of electricity for refueling, periodic in-service inspection (ISI), and scheduled maintenance. Refueling cycles occur approximately every 12 to 18 months. The duration of a refueling outage is typically on the order of 2 months. Enhanced or expanded inspection and surveillance activities are typically performed at 5- and 10-year intervals. These enhanced inspections are performed to comply with Nuclear Regulatory Commission (NRC) and/or industry standards or requirements such as the American Society of Mechanical Engineers Boiler and Pressure Vessel Code. Five-year ISIs are scheduled for the 5th, 15th, 25th, and 35th years of operation, and 10-year ISIs are performed in the 10th, 20th, and 30th years. Each of these outages typically requires 2 to 4 months of down time for the

plant. For economic reasons, many of these activities are conducted simultaneously (e.g., refueling activities typically coincide with the ISI and maintenance activities).

Many plants also undertake various major refurbishment activities during their operational lives. These activities are performed to ensure both that the plant can be operated safely and that the capacity and reliability of the plant remain at acceptable levels. Typical major refurbishments that have occurred in the past include replacing PWR steam generators, replacing BWR recirculation piping, and rebuilding main steam turbine stages. The need to perform major refurbishments is highly plant-specific and depends on factors such as design features, operational history, and construction and fabrication details. The plants may remain out of service for extended periods of time, ranging from a few months to more than a year, while these major refurbishments are accomplished. Outage durations vary considerably, depending on factors such as the scope of the repairs or modifications undertaken, the effectiveness of the outage planning, and the availability of replacement parts and components.

Each nuclear power plant is part of a utility system that may own several nuclear power plants, fossil-fired plants, or other means of generating electricity. An on-site staff is responsible for the actual operation of each plant, and an off-site staff may be headquartered at the plant site or some other location. Typically, from 800 to 2300 people are employed at nuclear power plant sites during periods of normal operation, depending on the number of operating reactors located at a particular site. The permanent on-site work force is usually in the range of 600 to 800 people per reactor unit. However, during outage periods, the on-site work force typically increases by 200 to 900 additional workers. The additional workers include engineering support staff, technicians, specialty craftspersons, and laborers called in both to perform specialized repairs, maintenance, tests, and inspections and to assist the permanent staff with the more routine activities carried out during plant



outages.

License renewal schedule and outage periods considered for environmental impact initiator definition,

Figure 2.3 from NUREG-1437, Volume I.

The Agency also found information on outage information contained in the April, 2001 accounting report for Mirant, Corp. (form 8K, April 27, 2001). The report gave the following information on planned outages at Mirant's California fossil-fueled power plants:

> Major maintenance is presently scheduled on a three-year cycle for the boilers and a 6-year interval for the steam turbine-generators. The overhaul duration is typically six to eight weeks, depending on the scope of the work to be performed. Virtually all of the Mirant California Facilities' major maintenance for the next few years will be performed during outages dictated by the installation of SCR systems or low-NO(X) burners, both to reduce NO(X) emissions.
>
> Major outages are scheduled for Contra Costa Units 6 and 7 in 2000-2001 to install systems to reduce stack emissions. Low-NO(X) burners were recently installed on Contra Costa Unit 6. Contra Costa Unit 7 is scheduled for installation of a SCR system from March to June of 2001 with Contra Costa Unit 6 SCR installation scheduled for 2003.
>
> Major outages are scheduled for Pittsburg Units 1 through 7 within the next three years to install systems to reduce stack emissions or correct equipment concerns that are affecting reliability. Pittsburg Units 1 through 4 will retube the condensers and perform boiler repair work in 2001. Pittsburg Units 5 and 6 just completed installation of low-NO(X) burners and are scheduled to install SCRs in 2001-2002. Pittsburg Unit 7 is scheduled to install an SCR in 2003. The SCR outages will be between 14 and 20 weeks long.
>
> Potrero Unit 3 will have two major outages in the next four years, 2001 to retube the condenser and make boiler repairs as necessary and 2004 to install an SCR. The scheduled duration of these outages is 10 and 20 weeks respectively.

The Agency located a reference for a project where four condenser waterboxes and tube bundles were removed and replaced at a large nuclear plant (Arkansas Nuclear One). The full project lasted approximately 2 days. The facility, based on experience, had estimated the full condenser replacement to occur over the course of 8 days. Even though the scope of condenser replacements differ from potential cooling system conversions, the regulatory options considered for flow reduction commensurate with wet cooling anticipate that a subset of conversions would precipitate condenser tube replacements. As such, the condenser replacement schedule is important to the consideration of select cooling system conversions.

4.3 Summary of Flow-Reduction Options Considered

The Agency examined regulatory options based on intake flow reduction at in-scope, existing power plants for the proposed rule. The following summaries describe the three wet cooling based options considered by the Agency.

Intake Capacity Commensurate with Closed-Cycle, Recirculating Cooling System for All Facilities

EPA considered a regulatory option that would require Phase II existing facilities having a design intake flow 50 MGD or more to reduce the total design intake flow to a level, at a minimum, commensurate with that which can be attained by a closed-cycle recirculating cooling system using minimized make-up and blowdown flows. In addition, facilities in specified circumstances (for example, located where additional protection is needed due to concerns regarding threatened, endangered, or protected species or habitat; migratory, sport or commercial species of concern) would have to select and implement design and construction technologies to minimize impingement mortality and entrainment. This option does not distinguish between facilities on the basis of the waterbody from which they withdraw cooling water. Rather, it would ensure that the same stringent controls are the nationally applicable minimum for all waterbody types. This is the regulatory approach EPA adopted for new facilities. As stated above, 73 of the facilities potentially subject to this proposed rule already utilize a recirculating wet cooling system (e.g., wet cooling towers or ponds). These facilities would meet the requirements under this option unless they are located in areas where the director or fisheries managers determine that fisheries need additional protection. Therefore, under this option, 466 steam electric power generating facilities would be required to meet performance standards for reducing impingement mortality and entrainment based on a reduction in intake flow to a level commensurate with that which can be attained by a recirculating, closed-cycle wet system.

EPA did not select closed-cycle, recirculating cooling systems as the best technology available for existing facilities because of the generally high costs of such conversions. According to EPA's cost estimates, capital costs for individual high-flow plants to convert to wet towers generally ranged from 130 to 200 million dollars, with annual operating costs in the range of 4 to 20 million dollars. EPA estimates that the total annualized post-tax cost of compliance for this option is approximately $2.26 billion. Not included in this estimate are 9 facilities that are projected to be baseline closures. Including compliance costs for these 9 facilities would increase the total cost of compliance with this option to approximately $2.32 billion. EPA also has serious concerns about the short-term energy implications of a massive concurrent conversion and the potential for supply disruptions that it would entail.

The estimated annual benefits (in $2001) for requiring all Phase II existing facilities to reduce intake capacity commensurate with the use of closed-cycle, recirculating cooling systems are $83.9 million per year and $1.08 billion for entrainment reductions.

Intake Capacity Commensurate with Closed-Cycle Wet Cooling Systems for All Facilities on Oceans, Estuaries, and Tidal Rivers

EPA considered an alternate technology-based option in which closed-cycle, recirculating cooling systems would be required for all facilities on certain waterbody types. Under this option, EPA would group waterbodies into the same five categories as in today's proposal: (1) freshwater rivers or streams, (2) lakes or reservoirs, (3) Great Lakes, (4) tidal rivers or estuaries; and (5) oceans. Because oceans, estuaries and tidal rivers contain essential habitat and nursery areas for the vast majority of commercial and recreational important species of shell and fin fish, including many species that are subject to intensive fishing pressures, these waterbody types would require more stringent controls based on the performance of closed-cycle, recirculating cooling systems. EPA discussed the susceptibility of these waters in a Notice of Data Availability (NODA) for the new facility rule (66 FR 28853, May 25, 2001) and invited comment on documents that may support its judgment that these waters are particularly susceptible to adverse impacts from cooling water intake structures. In addition, the NODA presented information regarding the low susceptibility of non-tidal freshwater rivers and streams to impacts from entrainment from cooling water intake structures.

Under this alternative option, facilities that operate at less than 15 percent capacity utilization would, as in the proposed option, only be required to have impingement control technology. Facilities that have a closed-cycle, recirculating cooling system would require additional design and construction technologies to increase the survival rate of impinged biota or to further reduce the amount of entrained biota if the intake structure was located within an ocean, tidal river, or estuary where there are fishery resources of concern to permitting authorities or fishery managers.

Facilities with cooling water intake structures located in a freshwater (including rivers and streams, the Great Lakes and other lakes) would have the same requirements as under the proposed rule. If a facility chose to comply with Track II, then the facility would have to demonstrate that alternative technologies would reduce impingement and entrainment to levels comparable to those that would be achieved with a closed-loop recirculating system (90% reduction). If such a facility chose to supplement its alternative technologies with restoration measures, it would have to demonstrate the same or substantially similar level of protection. (For additional discussion see the new facility final rule 66 FR 65256, at 65315 columns 1 and 2.)

EPA has estimated that there are 109 facilities located on oceans, estuaries, or tidal rivers that do not have a closed cycle recirculating system and would be required to meet performance standards for reducing impingement mortality and entrainment based on a reduction in intake flow to a level commensurate with that which can be attained by a closed-cycle recirculating system. The other 430 facilities would be required to meet the same performance standards in the in today's proposal.

The potential environmental benefits of this option have been estimated at $87.8 million and $1.24 billion for entrainment reductions annually. Although this option is estimated (a full cost analysis was not done for this option) to be less expensive at a national level than requiring closed-cycle, recirculating cooling systems for all Phase II existing facilities, EPA is not proposing this option. Facilities located on oceans, estuaries, and tidal rivers would incur high capital and operating and maintenance costs for conversions of their cooling water systems. Furthermore, since impacted facilities would be concentrated in coastal regions, there is the potential for short-term energy impacts and supply disruptions in these areas. EPA also invites comment on this option.

Intake Capacity Commensurate with Closed-Cycle, Recirculating Cooling System Based on Waterbody Type

EPA also considered a variation on the above approach that would require only facilities withdrawing very large amounts of water from an estuary, tidal river, or ocean to reduce their intake capacity to a level commensurate with that which can be attained by a closed-cycle, recirculating cooling system.

For example, for facilities with cooling water intake structures located in a tidal river or estuary, if the intake flow is greater than 1 percent of the source water tidal excursion, then the facility would have to meet standards for reducing impingement mortality and entrainment based on the performance of wet cooling towers. These facilities would have the choice of complying with Track I or Track II requirements. If a facility on a tidal river or estuary has intake flow equal to or less than 1 percent of the source water tidal excursion, the facility would only be required to meet the performance standards in the proposed rule. These standards are based on the performance of technologies such as fine mesh screens and traveling screens with well-designed and operating fish return systems. The more stringent, closed-cycle, recirculating cooling system-based requirements would also apply to a facility that has a cooling water intake structure located in an ocean with an intake flow greater than 500 MGD.

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Chapter 5: Energy Penalties of Cooling Towers

INTRODUCTION

For the Existing Facility 316(b) Proposal, the Agency considered regulatory options in which regulated facilities (or a subset thereof) would achieve flow reduction commensurate with closed-cycle wet cooling systems. In addition, the Agency analyzed regulatory options based on flow reduction commensurate with near-zero intake of dry cooling systems. This chapter discusses the topics of energy penalties of such cooling systems.

For the Section 316(b) New Facility Final Rule the Agency researched and derived energy penalty estimates, based on empirical data and proven theoretical concepts, for a variety of conditions. The regulatory analysis conducted by the Agency for this Existing Facility Section 316(b) Proposal utilized the results of the New Facility analysis. This chapter presents the research, methodology, results, and conclusions for the Agency's thorough effort to estimate energy penalties due to the operational performance of power plant cooling systems.

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. The discussion of air pollutant emissions and other potential environmental impacts from cooling towers are presented in Chapter 6 of this document.

The remainder of this chapter is organized as follows:

- Section 5.1 presents the energy penalty estimates used for analysis of the flow reduction regulatory options.
- Section 5.2 presents an introduction to the Agency's energy penalty estimates.
- Section 5.3 focuses on steam turbines and the changes in efficiency associated with using alternative cooling systems.
- Section 5.4 evaluates the net difference in required pumping and fan energy for alternative cooling systems.
- Section 5.5 combines and summarizes the energy impacts of pumping and fan energy requirements for alternative cooling systems.
- Section 5.6 summarizes data from other sources on the potential energy penalty of alternative cooling systems at existing facilities.

5.1 Energy Penalty Estimates for Cooling

Tables 5-1 through 5-4 present the energy penalty estimates utilized for assessing the operational energy impacts of certain, flow-reduction regulatory options considered for this proposal. The Agency presents the methodology for estimation of energy penalties in Sections 5.2 through 5.5 of this chapter.

Table 5-1: National Average, Mean-Annual Energy Penalty, Summary Table

Cooling Type	Percent Maximum Load[a]	Mean-Annual Nuclear Percent of Plant Output	Mean-Annual Combined-Cycle Percent of Plant Output	Mean-Annual 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] For calculating the average annual penalties, the Agency conservatively estimated that plants will operate over the course of the year at non-peak loads. See below for a discussion of percent maximum load.

Table 5-2: National Average, Peak-Summer Energy Penalty, Summary Table

Cooling Type	Percent Maximum Load[a]	Peak-Summer Nuclear Percent of Plant Output	Peak-Summer Combined-Cycle Percent of Plant Output	Peak-Summer 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.

The Agency developed its estimates of average annual energy penalties based on the assumption that during non-peak loads turbines would operate at roughly 67 percent of maximum peak load. Therefore, the Agency's estimates of annual energy penalties in Tables 5-1 and 5-3 represent calculations of turbine energy penalties at 67 percent of maximum load. The Agency considered this to be a conservative assumption for the calculation of energy penalties because turbine efficiency is considerably higher for the 100 percent of maximum load condition. The Agency understands, based on discussions with the Department of Energy, that a significant portion of existing power plants, when dispatched, would likely operate at near maximum loads. Therefore, the turbine energy penalty portion of mean annual energy penalty estimates presented in Tables 5-1 and 5-3 could be overstated. The Agency estimates that had it calculated the mean annual penalties for the 100 percent of maximum load condition, the national average annual energy penalty of wet cooling versus once-through systems would be approximately 0.3 percent for combined-cycle, 1.1 percent for fossil-fuel, and 1.3 for nuclear plants. However, the Agency utilized the higher values in Tables 5-1 and 5-3 for the economic analyses of the regulatory options considered for this proposal.

Table 5-3: 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] For calculating the average annual penalties, the Agency conservatively estimated that plants will operate over the course of the year at non-peak loads. See above for a discussion of percent maximum load.

Table 5-4: Total Energy Penalties at 100 Percent Maximum Load[a]				
Location	**Cooling Type**	**Peak-Summer Nuclear Percent of Plant Output**	**Peak-Summer Combined-Cycle Percent of Plant Output**	**Peak-Summer 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.

5.2 Introduction to Energy Penalty Estimates

This energy penalty discussion presents 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 direct-dry cooling systems using air cooled condensers. However, the methodology is flexible and can 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.

The energy penalties presented in this chapter were developed for new, "greenfield" facilities. As such, the Agency estimates for this proposal for existing facilities that the energy penalties of cooling system conversions from once-through to recirculating wet cooling towers would be similar to the new, "greenfield" cases. The Department of Energy expressed concern that this methodology may underestimate the pumping energy requirements of recirculating wet tower systems for converted cooling systems. This matter, among others, is discussed in Section 5.6 below.

The Agency acknowledges that direct-dry cooling systems are unlikely candidates for cooling system conversions at existing power plants. A direct-dry cooling system (as discussed in Appendix D of this document) condenses the exhaust steam that is fed directly to the dry tower from the generating turbine. However, steam turbines at the existing power plants within the scope of this rule are, without exception, configured to condense steam utilizing a surface condenser system. Therefore, the only type of dry cooling system that would be considered for a cooling system conversion is an indirect-air cooled condenser. Otherwise, the entire steam turbine would be replaced or dramatically reconfigured to feed exhaust steam to a direct-dry cooling system. The engineering feasibility of this type of plant reconfiguration was considered unproven by the Agency and the costs of turbine replacement were also deemed too high for this proposal.

Indirect-dry cooling systems operate less efficiently than direct-dry cooled systems. Therefore, the energy penalties for dry cooling systems presented in this chapter would be higher for the only application that would be considered for existing facilities. The Department of Energy (DOE) studied the peak summer energy penalty resulting from converting plants with once-through cooling to wet towers or indirect dry towers (see DCN 4-2512). DOE modeled five locations – Delaware River Basin (Philadelphia), Michigan/Great Lakes (Detroit), Ohio River Valley (Indianapolis), South (Atlanta), and Southwest (Yuma) – using an ASPEN simulator model. The model evaluated the performance and energy penalty for hypothetical 400-MW coal-fired plants that were retrofitted from using once-through cooling systems to wet- and dry-recirculating systems. The DOE estimates that conversion to an indirect-dry tower could cause peak summer energy penalties ranging from 8.9 percent to 14.1 percent with a design approach of 20 degrees Fahrenheit and 12.7 percent to approximately 18 percent with an approach of 40 degrees Fahrenheit. Note that these peak summer energy penalties are higher than those estimated by EPA (as presented in Tables 5-2 and 5-4 above) for the direct-dry cooling system. The Agency's estimates of direct-dry cooling system peak summer energy penalties range from 7.4 percent to 10.7 percent for fossil-fuel plants. As such, the analysis of energy effects of the dry cooling-based regulatory options considered for this proposal may not reflect the full magnitude of the energy penalty of the indirect-dry cooling systems.

5.2.1 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 often operate 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 and with greater efficiency 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:

$$\text{Plant Energy Efficiency} = 3413 / \text{NPHR} \times 100 \qquad (1)$$

Table 5-5 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 5-5: 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 5-5 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.

5.3 Turbine Efficiency Energy Penalty

5.3.1 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.

5.3.2 Estimated Changes in Turbine Efficiency

Table 5-6 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 5-6. 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 5-6: 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

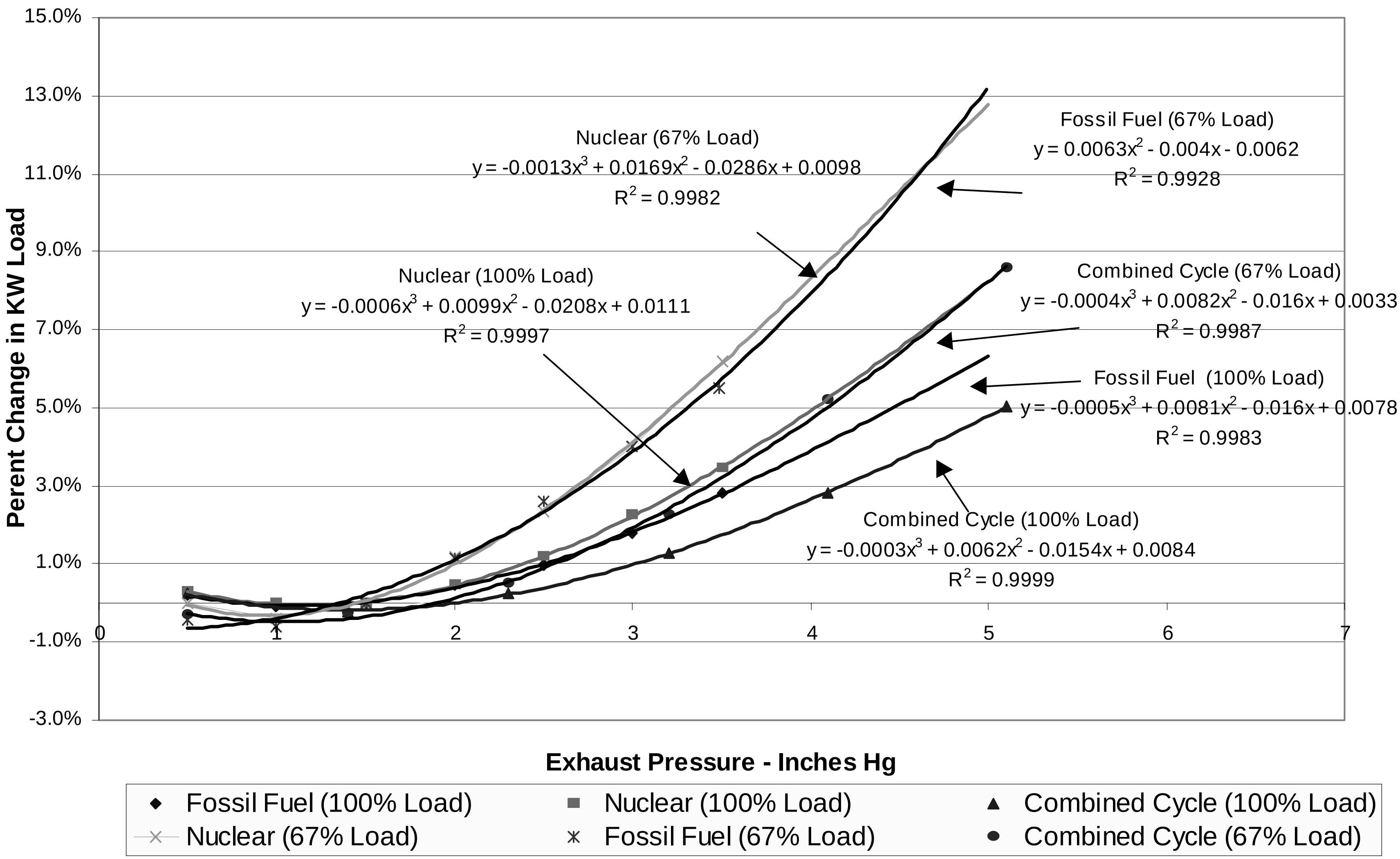
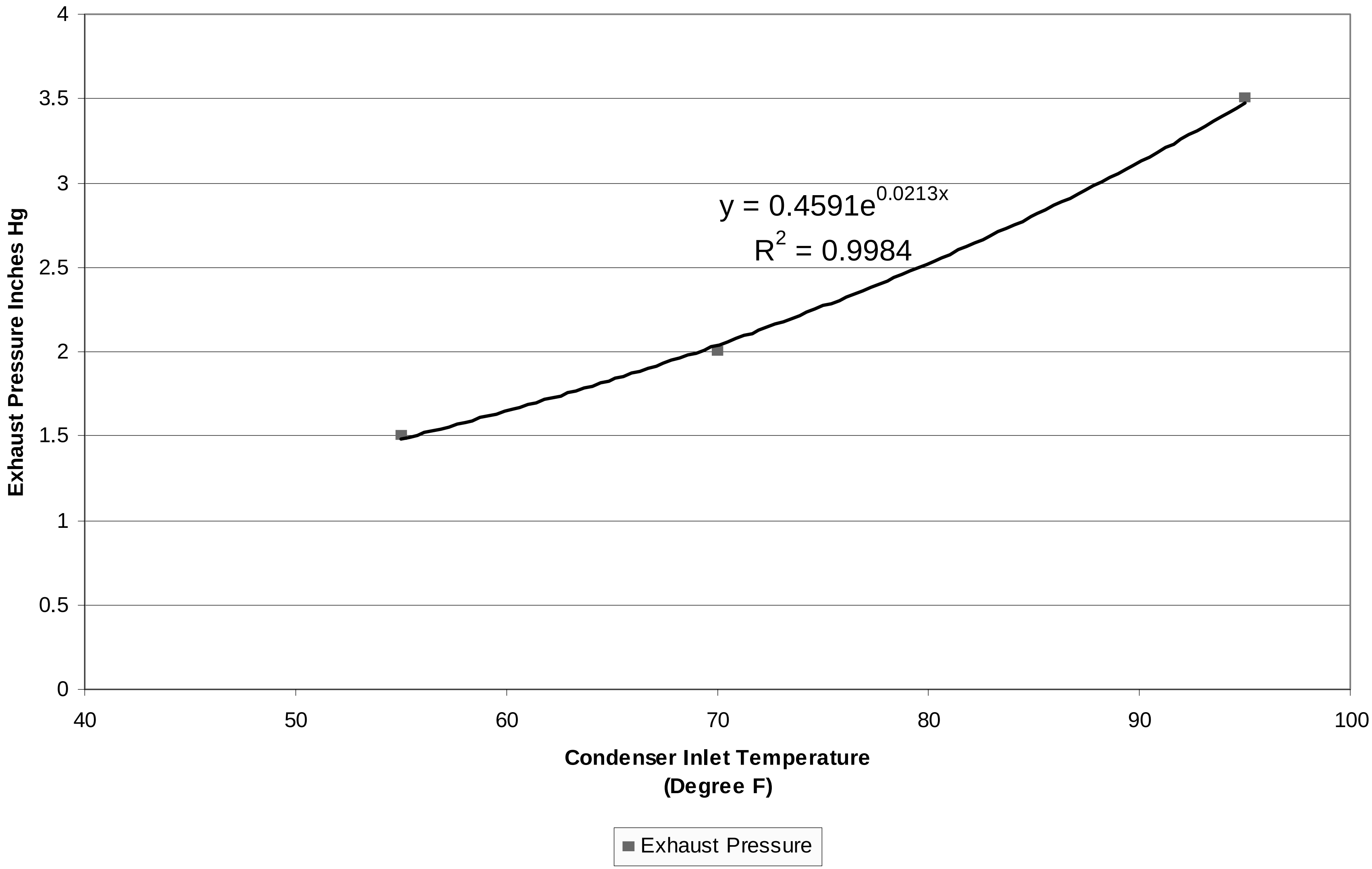


Figure 2
Surface Condenser Cooling Water Inlet Temperature and Steam Pressure Relationship



.3.3 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 5-7 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 analysis for the regulatory options 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.

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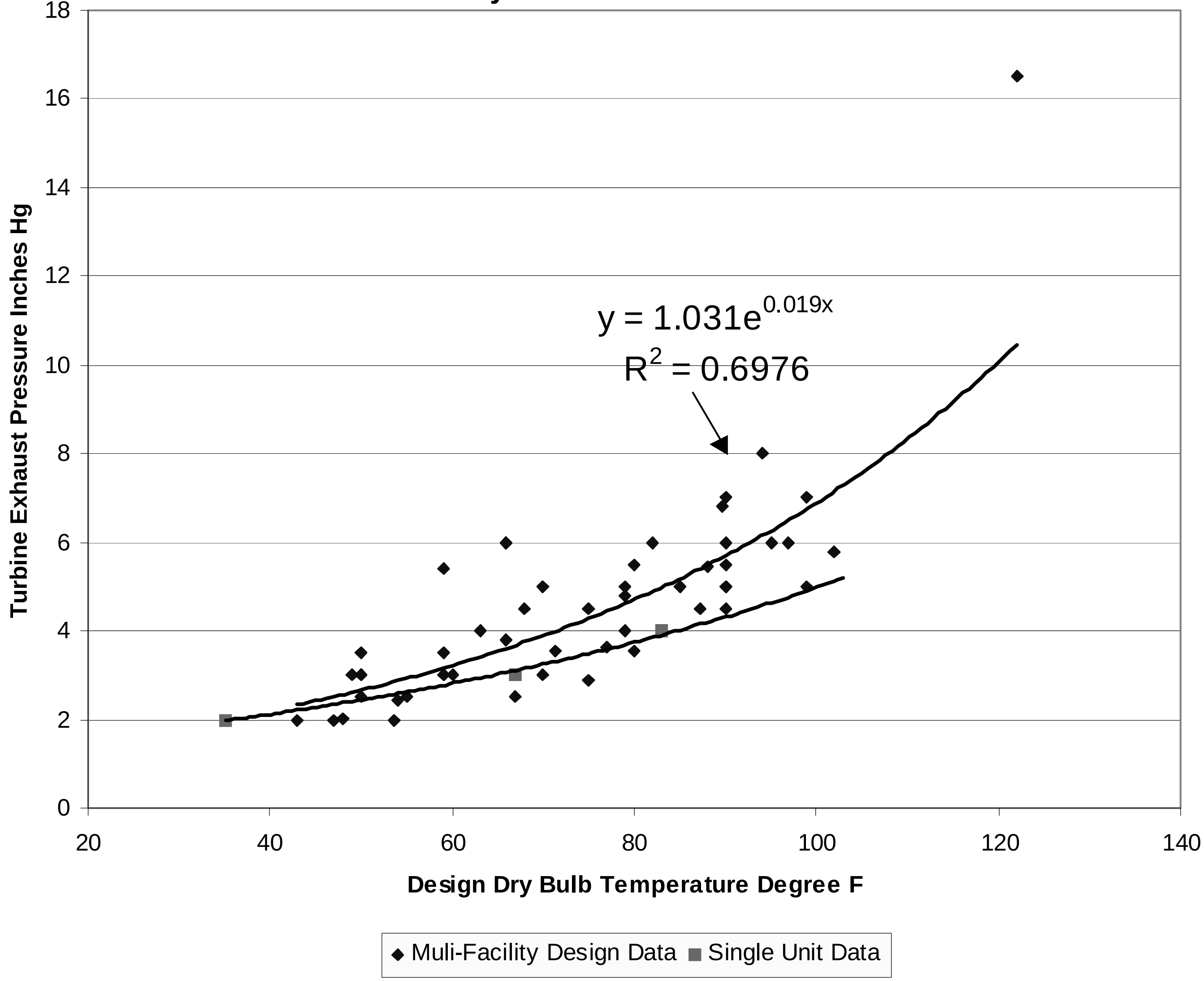
Figure 3
Design Dry Bulb and Design Exhaust Pressure for Recently Installed Air Cooled Condensers



egional 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 5-7 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 5-7: 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 5-8 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 5-9 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 5-8: 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 5-9: 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

5.3.4 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 5-7 and 5-9. 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 5-10 and 5-11 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 5-10 and 5-11 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 5-7 and the 1% percent exceedence wet bulb and dry bulb temperatures from Table 5-8.

EPA notes that the penalties presented in Tables 5-10 and 5-11 **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 5.1 above. The tables below only present the turbine efficiency penalty. Section 5.4 presents the fan and pumping components of the energy penalty.

Table 5-10: 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 5.1 for the total energy penalties. This table presents only the turbine component of the total energy penalty.

Table 5-11: 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 5.1 for the total energy penalties. This table presents only the turbine component of the total energy penalty.

5.4 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 for certain regulatory options developed using the methodologies presented 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.

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).

5.4.1 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 ^{o}F compared to 11 ^{o}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 5-14 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 turbine penalty shown in Tables 5-10 and 5-11 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 5-12. 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 5-12 **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 5-12: 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 5.1 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 ^{o}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.

5.4.2 Cooling Water Pumping Requirements

The Agency notes that it conducted the following analysis for new, "greenfield" facilities and transferred the results of this analysis to the cooling system conversions for existing facilities considered as regulatory options for this proposal. As discussed in Section 5.6 below, the Department of Energy (DOE) concludes in their draft energy penalty analysis that the pumping component of the energy penalty for existing facilities may be higher than calculated herein by EPA for new, "greenfield" facilities.

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.

5.5 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 5-13 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 5-13 and 5-14 **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 5-13: 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 ft.	Static Head ft.	Condenser Head ft	Equiv. Length Misc. Losses ft.	Pipe Velocity fps	Friction Loss Rate ft/1,000ft	Friction Head ft.	Total Head ft.	Net Difference ft	Flow Rate gpm	Hydraulic-Hp Hp	Brake-Hp Hp	Power Required kW	Energy Penalty 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 5.1 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 5-14 presents the energy penalties corresponding to the pumping energy requirements from Table 5-13 using the above factors.

Table 5-14: Comparison of Pumping Power Requirement and Energy Penalty to Power Plant Output

Cooling system Type	Distance Pumped	Static Head	Power Required	Flow Rate	Range	Nuclear Power/ Heat	Nuclear Equiv. Output	Nuclear Pumping	Fossil Fuel Power/ Heat	Fossil Fuel Equiv. Output	Fossil Fuel Pumping	Comb.-Cycle Power/ Heat	Comb.-Cycle Equiv.	Comb.-Cycle Pumping
	ft.	ft.	kW	gpm	ºF	Ratio	(MW)	% of Output	Ratio	(MW)	% of Output	Ratio	Output (MW)	% 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
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
3-1 for the total energy penalties. This table presents only the pumping component of the total energy penalty

5.5.1 Summary of Cooling System Energy Requirements

EPA chose the piping scenario in Table 5-13 where pumping head is close to 50 ft for both once-through and recirculating systems at new, "greenfield" facilities (that is, once-through at 1,000 ft and 3-42 in. pipes in Table 5-13). Thus, the cooling water pumping requirements for once-through and recirculating wet towers are nearly equal using the chosen site-specific conditions. Table 5-15 summarizes the fan and pumping equipment energy requirements as a percent of power output for each type of power plant. Table 5-16 presents the net difference in energy requirements shown in Table 5-15 for the alternative cooling systems. The net differences in Table 5-16 are the equipment operating energy penalties associated with conversion from one cooling technology to another.

EPA notes that the penalties presented in Tables 5-15 and 5-16 **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 5.1 above. The tables below only present the pumping and fan components. Section 5.3.4 presents the turbine efficiency components of the energy penalty.

Table 5-15: 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 5.1 for the total energy penalties.

Table 5-16: 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 5.1 for the total energy penalties.

5.6 Other Sources of Energy Penalty Estimates

The Agency sought out additional sources of energy penalty estimates for its analysis of regulatory options for the 316(b) Existing Facility proposal. In part due to the lack of robust, empirical data available, the Agency undertook the original energy penalty analysis in support of the New Facility Rule. For this Existing Facility proposal the fact that certain regulatory options involved the conversion of aging cooling systems at existing facilities presented an additional complexity to the Agency. The following sections summarize the Agency's data collection for estimates of energy penalties at existing facilities.

5.6.1 Jefferies Generating Station Energy Penalty Study

As a result of its research for empirical examples of cooling system conversions, the Agency identified an empirical energy penalty study associated with the construction of wet, mechanical-draft cooling towers to replace an original once-through system. The Jefferies Generating Station -- a 346 MW, coal-fired plant in South Carolina – owned by Santee Cooper, conducted a turbine efficiency loss study in the late 1980s. The facility converted their cooling system (after many years of operation utilizing a once-through system) to a full recirculating, mechanical-draft system around 1985. Due to the unusual arrangement whereby the U.S. Army Corps of Engineers (USACE) paid for the construction and operation of the cooling tower, Santee Cooper began an empirical study to assess the economic impact of the operation of the cooling towers over the previous once-through system, in order to obtain reimbursement from the USACE. The study lasted several years (1985 to 1990). However, the empirical stage of data gathering occurred primarily in 1988. Santee Cooper determined (and the USACE eventually agreed) that the cooling tower had decreased the efficiency of each of the plant's steam turbines. The efficiency penalties determined by Santee Cooper were a maximum of 0.97 percent of plant capacity (for both units, combined) and an annual average of 0.16 percent for the year 1988. Note, that because the USACE maintains and pays for the operation of the cooling towers, Santee Cooper only examined the turbine portion of the energy penalty at the plant. The Agency requested documentation on the historic operation of the towers from the USACE (in addition to the construction costs from 1986) but did not receive this information at the time of publication of this proposal. The study conducted by Santee Cooper is included in the record of today's proposal (see DCN 4-2527). The Agency notes that its fossil-fuel estimate for the national-average, peak-summer, turbine energy penalty is 0.90 percent and the mean-annual, national-average energy penalty is 0.35 percent (at 100 percent of maximum load). For the model plant in Jacksonville, Florida the Agency calculated a fossil-fuel peak-summer turbine energy penalty of 0.61 percent and the mean-annual turbine energy penalty of 0.38 percent (at 100 percent of maximum load).

5.6.2 U.S. Department of Energy Peak-Summer Energy Penalty Study

The U.S. Department of Energy (DOE), through its Office of Fossil Energy, National Energy Technology Laboratory (NETL), and Argonne National Laboratory (ANL), studied the energy penalty resulting from converting plants with once-through cooling to wet towers or indirect dry towers. DOE modeled five locations – Delaware River Basin (Philadelphia), Michigan/Great Lakes (Detroit), Ohio River Valley (Indianapolis), South (Atlanta), and Southwest (Yuma) – using an ASPEN simulator model. The model evaluated the performance and energy penalty for hypothetical 400-MW coal-fired plants that were retrofitted from using once-through cooling systems to indirect-wet- and indirect-dry-recirculating systems. The modeling was done to simulate the hottest time of the year using temperature input values that are exceeded only 1 percent of the time between June through September at each modeled location. At DOE's request, EPA provided, discharge temperature data and thermal discharge permit limits for facilities at or near the DOE study locations for use in the model. EPA also provided comments regarding the framework of the modeling project, which are included in the record of this proposal (see DCN 4-2512)

After completing their initial modeling, DOE shared the results of their working draft report with the EPA, which is included in the record of this proposal (see DCN 4-2511). DOE estimates that conversion to a wet tower could cause peak-summer energy penalties ranging from 2.8 percent to 4.0 percent. Therefore, DOE estimates that the plant will produce 2.8 percent to 4.0 percent less electricity with a wet tower than it did with a once-through system while burning the same amount of coal. Further, DOE estimates that conversion to an indirect-dry tower could cause peak-summer energy penalties ranging from 8.9 percent to 14.1 percent with a design approach of 20 degrees Fahrenheit and 12.7 percent to approximately 18 percent with an approach of 40 degrees Fahrenheit.

EPA did not model indirect-dry cooling systems, and therefore cannot directly compare its estimates to those developed by DOE. However, EPA can compare its estimates of peak summer energy penalties for mechanical draft wet cooling towers to those developed by DOE. The Agency finds that its estimates of peak summer energy penalties are significantly lower than those developed by DOE (see section 5.1 for EPA's estimates of peak summer energy penalties of mechanical draft cooling towers). EPA and DOE believe that the difference in these estimates is most likely due to two key factors: (1) the estimated energy penalty attributable to the parasitic energy use of cooling water pumps and (2) the estimated design temperature ranges of cooling water from condenser inlet to outlet.

As discussed at Section 5.3 above, EPA developed energy penalty estimates for this proposal based on its estimates for the 316(b) New Facility Rule. For the energy penalty estimates of the 316(b) New Facility Rule, the Agency conducted an analysis of a variety of pumping scenarios for once-through versus recirculating systems at new "greenfield" facilities. The Agency concluded that for "greenfield" facilities, the cooling towers would generally be sited in close proximity to condenser units. Therefore, the Agency estimated that pumping distances for recirculating systems would be significantly less than those for once-through systems. (The Agency provided this analysis for public comment in the June 2001 Notice of Data Availability). In the analysis of energy penalties for new, "greenfield" plants, the Agency concluded that the difference in pumping distance for a once-through system would offset the additional static head pumping requirements of a typical mechanical draft cooling tower (see section 5.4.2 for the Agency's analysis of pumping energy requirements). Therefore, the analysis of energy penalties used by the Agency for this proposal estimates 0.0 percent energy penalty due to pumping requirements. DOE, on the other hand, estimates that a retrofitted wet cooling tower would require significantly more pumping energy than a baseline, once-through cooling system. The results of the DOE study show pumping energy penalties ranging from 0.2 to 0.7 percent. The Agency views the DOE estimates to be reasonable for a variety of retrofit scenarios at existing facilities and will reconsider this subject in the analysis of regulatory options for the final rule.

While EPA did not directly estimate design temperature range in its modeling approach, in effect DOE and EPA used different design temperature ranges, which can dramatically affect energy penalty estimates. The DOE modeling approach used simulated inlet and discharge water temperatures for the chosen sites. EPA provided thermal discharge permit information, which DOE incorporated into a parametric analysis of design temperature ranges (that is, DOE examined a variety of temperature ranges, from 5 degrees F to 25 degrees F). For example, the design ranges examined by DOE for their Michigan site show peak energy penalties that vary by 1 percent, from 3.95 % for a 7 degree F design range to 2.94 % for a 25 degree F design range. In the case of other model sites, such as Georgia, a design range increase of 5 degrees F (from 5 degrees F to 10 degrees F) can dramatically effect the results of the energy penalty estimates. The DOE model estimates a 3.99 % percent energy penalty for the 5 degrees F design range in Georgia and 2.78 % for the 10 degrees F design range assumption. As EPA noted in its comments on DOE's proposed energy penalty analysis, EPA believes that design temperature ranges of less than 13 degrees F are not realistic at most locations and are likely to lead to energy penalty estimates that are higher than would occur under realistic operating conditions.

In addition to the two key factors described above, DOE expressed concern to EPA that the Agency's modeling analysis of turbine energy penalties did not incorporate subtle effects on the condenser duty. Specifically, DOE did not believe that the Agency's model takes into account the increase in turbine exhaust temperature (or steam temperature to condenser) resulting from a corresponding increase in condenser duty when changing the once-through cooling water system to a wet cooling tower. Under peak energy penalty periods, the temperature of the condenser cooling water will be greater under wet cooling tower operation then the same plant operated under once-through cooling because of the difference between ambient wet-bulb and surface water temperatures. DOE believes that the increased condenser duty for the wet cooling tower results in an increase in cooling water flow which increases the cooling water pump and cooling tower fan energy penalties compared to the Agency's approach.

DOE also points out that the Agency's model does not consider a second effect that since the steam is condensed at a slightly higher temperature for the wet cooling tower case, the reheating of the recirculated steam condensate will require a reduction in the amount of steam bleed from the turbine system. This results in a slightly higher steam flowrate through the turbines and into the condenser. This again increases the condenser duty and would again increase the parasitic energy penalties. However, this would probably be offset by an increase in power due to a small increase in the steam flowrate in the turbines. DOE estimates that these effects may contribute a maximum of 0.5 percentage points to the Agency 's evaluation of the peak-summer energy penalty.

5.6.3 Catawba and McGuire Nuclear Plant Comparison

One literature source the Agency encountered calculated the energy penalty of a nuclear plant employing a mechanical-draft wet cooling system by comparing the electrical ratings of the Catawba and McGuire Nuclear Plants. Because the two plants were constructed nearly identically, the author hypothesized that the percent difference electrical rating between the two plants would represent the energy usage of a cooling tower. The Agency notes that even though a comparison of this type would theoretically calculate the net energy use of the pumps and fans of the wet cooling tower system as compared to the once-through system, there are a variety of complicating factors that are not accounted for or are overlooked in this case. The electrical rating of a nuclear plant does not, to the Agency's knowledge, account for the turbine efficiency penalty component. This key portion of the energy penalty would not be included in the electrical rating calculations of the plant. The comparison could, therefore, underestimate the total energy penalty of the cooling system.

Nonetheless, the Agency examined the historical energy penalty estimate for the Catawba versus McGuire case and determined that the source had made an error in calculating an estimate of 3 percent for the overall energy use of the cooling towers over the once-through system. The error made was to assume that each plant had the same gross capacity. In fact, the McGuire plant has a gross capacity that is 31 MW greater than Catawba. Therefore, a comparison of the percentage difference between gross and net capacity for the two plants actually should be calculated as 1.7 percent. This energy penalty estimate for the fan and pumping components is higher than that estimated by the Agency elsewhere in this chapte for nuclear facilities. The Agency estimates that the total of the fanning and pumping components for a nuclear plant would be 0.9 percent. As described in Section 5.3 of this chapter, the Agency's estimates of the pumping components developed for new, "greenfield" facilities calculate no net change in the pumping requirements between once-through and recirculating wet cooling tower systems. As stated in Section 5.6.2 above, this may also explain to some degree the differences between the Agency's and the Catawba/McGuire estimate.

5.6.3 Palisades Cooling System Conversion Energy Penalty Estimate

The Agency learned from discussions with, and information submitted by, Consumers Energy that the cooling tower system at Palisades might have a significant impact on the efficiency of the plant's generating unit. Though the plant was unable to provide historical studies of the energy penalty of the cooling tower system, they estimate that the effect could be approximately 7 percent (Gulvas, 2002). Prior to the 1970's conversion, the Nuclear Regulatory Commission (NRC) estimated that the cooling tower system would affect plant efficiency by 3 percent (Gulvas, 2002). Consumers Energy estimates that the cooling system fans utilize 4 MW of electricity for operation, and the circulating and intake pumps utilize approximately 16 MW and 3 MW, respectively (Gulvas, 2002). Consumers Energy further estimate that the cooling tower system reduces the efficiency of the steam turbine by 6 to 8 percent compared to the original once-through system. Consumers Energy did not provide supporting documentation for the turbine efficiency penalties or pumping and fanning losses as submitted to the Agency.

Based on the Agency's energy penalty methodology, the turbine energy penalty for a nuclear unit (at peak summer conditions) would be approximately 1.4 percent (11.3 MW for Palisades). The Agency calculated this penalty using the historic cooling water temperature data for Palisades provided by Consumers Energy and ambient dry bulb and wet bulb air temperatures specific to Chicago, IL (Consumers, 2001).[1] This estimate of turbine efficiency penalty is substantially less than that estimated by Consumers Energy. The Agency notes that Consumers Energy did not estimate the original pumping requirements of the once-through system, and, therefore, the net energy penalty (that is, wet cooling tower energy use less the once-through system energy use) of the conversion estimated by Consumers Energy may not be the appropriate comparison. The Agency also notes that the electricity usage of 36-200 hp fans would be 5.4 MW with each fan at full operation, slightly higher than the estimate by Consumers Energy. EPA also estimated the pumping energy penalty for the recirculating system at Palisades and compared this to the pumping energy required for the former once-through operation of the plant. EPA determined, conservatively (that is, erring on the high side), that the circulating pumping requirements of the cooling tower system currently in place at Palisades would require approximately 7.5 MW (that is, 8.5 MW less than the estimate given by Palisades above). The original once-through system would have required approximately 5 MW to convey water 3,300 feet from the offshore intake through 11 ft diameter pipe, through the condenser, and to discharge at the lake shore. The Agency did not analyze the "dilution" pumping requirements estimated by Consumers Energy as 3 MW above. Therefore, the Agency estimates that the total energy penalty of the recirculating tower system at Palisades may have a peak energy penalty close to 2.7 percent and an annual penalty approaching 1.8 percent as compared to the original once-through system (Sunda, et al., 2002).

[1] The EPA calculations for energy penalties specific to Palisades and Lake Michigan utilized the data from the 2001 Consumers Energy permit document with the energy penalty methodology outlined in this chapter.

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Attachment A to Chapter 5: Heat Diagram for Steam Power Plant

(Source: Ishigai 1999)

See Hard Copy

Attachment B to Chapter 5: 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)

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Attachment C to Chapter 5: 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 5: Tower Size Factor Plot

(Source: Hensley 1985)

See Hard Copy

Attachment E to Chapter 5: Cooling Tower Wet Bulb versus Cold Water Temperature Typical Performance Curve

(Source: Hensley 1985)

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Chapter 6: Non-Water Quality Impacts

INTRODUCTION

This chapter discusses side effects of the operation of recirculating wet cooling towers including increased air emissions due to energy penalties, vapor plumes, noise, salt or mineral drift, water consumption through evaporation, and solid waste generation due to wastewater treatment of tower blowdown.

6.1 AIR EMISSIONS INCREASES

Due to recirculating wet cooling system energy penalties, as described in Chapter 5, EPA estimates that air emissions may marginally increase from power plants that retrofit from once-through to recirculating wet cooling systems. The energy penalties reduce the efficiency of the electricity generation process and increase auxiliary power consumption; thereby increasing the quantity of fuel consumed per unit of electricity generated. EPA assumes facilities will seek to compensate for the energy penalties and maintain their electricity generation levels because of contractual obligations and market conditions. EPA believes the facilities will be capable of compensating for the energy penalties based on its analysis of unused capacity in the industry. EPA presents the estimates of annual air emissions increases under the flow reduction-waterbody option (Option 1) in Table 6-1 below. This analysis describes estimated increases only for Option 1.

EPA developed estimates of incremental increases in air emissions of carbon dioxide (CO_2), mercury (Hg), sulfur dioxide (SO_2), nitrogen oxides (NOx), and particulate matter (PM2.5 and PM10) for the facilities projected to upgrade their cooling systems under the flow reduction-waterbody option in today's proposed rule. These facilities include nuclear, combined-cycle, and fossil fuel-fired power plants. Generally, combined-cycle plants produce significantly less air emissions per kilowatt-hour of electricity generated than fossil fuel-fired plants. Because a 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 other fossil fuels, the combined-cycle plant produces less air emissions than fossil fuel-fired plants, even after such plants are equipped with state-of-the-art emissions controls. Nuclear power plants utilize radioactive materials as fuel and have extremely low or negligible emission rates of CO_2, Hg, SO_2, NOx, PM2.5, and PM10 in comparison to those found at either combined-cycle or fossil fuel-fired facilities.

EPA assumed that a facility incurring an energy penalty from retrofitting a once-through cooling system to a recirculating wet cooling system would seek to compensate for that penalty by increasing their electricity generation and would be able to do so by increasing electricity generation on-site. Most facilities do not operate at full electricity generation capacity on an annual basis. EPA believes such facilities would be able to compensate on an annual basis for the annual energy penalty due to conversion to a recirculating wet cooling system by increasing on-site electricity generation.

EPA could alternatively assume that plants incurring an energy penalty will not increase their fuel consumption on-site to overcome incurred energy penalties. Instead, facilities affected by the requirements of this rule would purchase replacement power from the grid. Under this scenario, the air emissions increases associated with a particular energy penalty at an affected plant would be released by the rest of the grid as a whole, thereby comprising small increases at a large number and variety of power plants. During the development of the Section 316(b) Final Rule addressing new facilities, 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. Nuclear facilities, in particular, may not be able to increase generation on-site. EPA has not calculated the national marginal increase in air emissions associated with purchase of electricity from the grid, though it notes that such purchases are a possible outcome of cooling system conversions. The Agency believes that the outcome of a national analysis would be similar to that of the facility-specific analysis because the distribution of facility types and their associated emissions profiles in each analysis would be comparable.

The estimated air emissions increases presented in Table 6-x below represent facility-specific increases and are based on the estimated energy penalty for each facility, the facility's historic average electricity generation level, and its average historic emission rates. 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 major 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. E-GRID 2000, however, does not provide information on emissions of particulate matter. The data source for historic emissions rates of PM2.5 and PM10 is the EPA-developed database titled National Emission Trends (NET). The NET database is an emission inventory that contains data on stationary and mobile sources that emit criteria air pollutants and their precursors. The NET is released every three years (e.g., 1996 and 1999) and includes emission estimates for all 50 States, the District of Columbia, Puerto Rico, and the Virgin Islands. The database compiles information from EPA air programs and the Department of Energy, and the information it contains was found to be consistent with the information found in E-GRID 2000.

A facility that increases on-site electricity generation to compensate for the energy penalty associated with retrofitting its cooling water system may, because of the resultant on-site increase in air pollutant emissions, be subject to new source review (NSR). Major stationary sources of air pollution undergoing major modifications are required by the Clean Air Act to obtain an air pollution permit before commencing construction. The process is called new source review and is required whether the major source or modification is planned for an area where the national ambient air quality standards (NAAQS) are exceeded (nonattainment areas) or an area where air quality is acceptable (attainment and unclassifiable areas).

There are costs associated both with undergoing NSR and with measures taken to ensure compliance with new air emission control requirements delineated during the NSR process. If a facility purchases electricity from the grid, it does not need to undergo NSR and can therefore avoid the associated costs. EPA believes that some facilities retrofitting their cooling systems under the proposed regulatory alternative requiring flow reduction commensurate with closed cycle wet cooling based on water body type may choose to purchase energy from the grid rather than incur the costs associated with NSR. The resulting increase in emissions would be similar to that estimated given on-site generation of additional electricity.

However, to provide a conservative estimate of the number of facilities potentially subject to NSR costs under today's proposed Option 1, EPA first assumed all facilities would undergo NSR review before attempting to purchase energy off the grid. To yield a conservative estimate of the number of facilities potentially subject to NSR costs, EPA assumed that all facilities would be operating at full capacity once they had increased electricity generation to compensate for the energy penalty associated with retrofitting their cooling systems. This assumption maximizes the estimated marginal increase in air pollutant emissions associated with energy penalty compensation. This conservative screen indicated that 29 facilities could potentially be subject to NSR costs.

Table 6-1. Estimated Increase in Emissions under Flow Reduction-Waterbody Option*

Facility Code**	Annual CO_2 (tons)	Annual SO_2 (tons)	Annual NO_x (tons)	Annual Hg (lbs)	Annual PM2.5 (tons)	Annual PM10 (tons)
1	-	-	-	-	-	-
2	-	-	-	-	-	-
3	15,417	0.1	5.8	-	0.05	0.05
4	17,024	0.1	6.8	-	0.04	0.04
5	17,421	0.1	16.7	-	0.04	0.04
6	14,528	0.1	1.0	-	0.03	0.03
7	22,678	-	18	-	0.06	0.06
8	24,968	0.4	19.2	-	0.06	0.05
9	12,560	0.3	4.7	-	0.02	0.02
10	26,722	0.2	5.1	-	0.09	0.09
11	282,344	1,718.2	695.6	7.1	25.07	11.31
12	130,879	1,217	636	5.5	8.55	4.54
13	232,551	1,923.6	809.4	7.2	27.52	11.23
14	82,957	658.4	229.9	2.7	6.90	3.15
15	142,339	1,103.0	407.6	5.5	12.91	6.36
16	-	-	-	-	-	-
17	-	-	-	-	-	-
18	-	-	-	-	-	-
19	39,928	477.2	168.8	-	4.38	3.91
20	37,846	471	89	-	2.53	2.11
21	71,247	587.4	166.4	-	4.56	3.93
22	40,005	116.5	68.9	-	2.25	1.96
23	20,016	59	31	-	0.98	0.84
24	-	-	-	-	-	-
25	96,279	0.8	154.9	-	0.30	0.30
26	8,330	-	18	-	0.02	0.02
27	70,291	0.6	154.1	-	0.20	0.20

Table 6-1. Estimated Increase in Emissions under Flow Reduction-Waterbody Option*

Facility Code**	Annual CO_2 (tons)	Annual SO_2 (tons)	Annual NO_x (tons)	Annual Hg (lbs)	Annual PM2.5 (tons)	Annual PM10 (tons)
28	39,540	0.3	62.9	-	0.12	0.12
29	29,876	-	49	-	0.08	0.08
30	71,191	552.5	188.0	3.1	4.41	2.00
31	147,288	1,464.5	462.0	6.7	10.26	4.65
32	47,497	209.7	227.3	0.2	1.76	0.97
33	48,034	279.2	159.1	1.8	3.60	1.64
34	2,802	-	0.8	-	-	-
35	-	-	-	-	-	-
36	-	-	-	-	-	-
37	52,664	255	104	1.9	3.07	1.89
38	80,985	461.7	322.2	2.4	18.24	7.91
39	821	-	2	-	0.02	0.01
40	1,626	7	3	-	0.06	0.06
41	1,204	1.4	3.3	-	0.02	0.02
42	3,095	1.0	3.8	-	0.08	0.07
43	15,848	81	26	-	0.56	0.26
44	74,962	549.4	114.9	0.1	9.76	4.96
45	154,087	851.1	264.3	3.8	12.27	5.77
46	116	-	-	-	-	-
47	1,974	-	-	-	-	-
48	32,941	0.7	36.1	-	0.63	0.63
49	66,131	31	74	-	0.70	0.61
50	-	-	-	-	-	-
51	-	-	-	-	-	-
52	-	-	-	-	-	-
53	76,207	290.2	79.6	-	0.11	0.09
54	41,229	263.9	52.7	-	2.95	2.60
55	22,708	98.9	27.9	-	1.15	0.99
56	56,147	242	75	-	3.87	2.04
57	-	-	-	-	-	-
58	50,286	291.2	67.0	-	3.05	2.71
59	7	-	-	-	-	-

Dashes indicate negligible emissions increases.
*This table includes information from those facilities with capacity utilization rates below 15% .
**EPA developed model plants representing existing facilities for analyzing regulatory options and developing costs. To protect confidential business information, EPA has assigned these model plants a random code number.

6.2 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).

As discussed in Chapter 4, the Agency considered regulatory options based on flow reduction commensurate with closed-cycle wet cooling systems. The Department of Energy (DOE) expressed concern to the Agency that plume abatement technologies would be required for a subset of existing plants projected to adopt wet cooling towers under these options. The DOE believed that the options based on flow reduction should consider a significant portion of existing facilities converting from once-through systems to hybrid wet/dry cooling towers, instead of the wet (only) towers examined by the Agency.

Historically, plants have adopted plume reduction technologies for the following reasons: visual aesthetics,[1] liability relating to icing and fogging of nearby transportation routes (US EPA Reg I, 2002), and potentially elevated moisture levels affected nearby agriculture. For the 316(b) New Facility Final Rule, the Agency considered plume effects of wet cooling towers. The Agency determined that for the limited number of new, "greenfield" facilities that may adopt towers to meet the flow reduction requirements of the rule,[2] that the plume effects would not be a sufficient environmental concern, especially in comparison to the significant aquatic environmental benefits of intake flow reduction.[3] However, in the Agency's view, the issue of vapor plume effects at existing facilities requires a slightly different consideration. Existing facilities do not have the advantage of siting and designing the plant layout to minimize plume effects, which is far and away the most economic means of plume mitigation. Through the utilization of terrain features, buffer areas, prevailing wind directions, and site selection, the new, "greenfield" facility has a set of tools that provide a distinct advantage for plume mitigation over an existing plant converting its cooling system. Therefore, the Agency examined historic studies and example cases of plumes and plume mitigation to understand the prevalence and necessity of plume abatement for cooling tower installations at existing facilities.

Hybrid wet/dry tower systems are the technology most frequently associated with plume abatement. The primary type of wet/dry tower employed in practice is a configuration where an air-cooled condensing unit sits atop a wet evaporative unit. This technology, in effect, reduces the amount of moisture transferred to the air by raising the temperature and lowering the relative humidity of the exhaust air. The heated water from the condensers is fed first to the top, dry portion of the tower, where air flows around the air-cooled condenser and heat transfers to the environment without evaporation of water. The water then disperses through the wet portion of the system, where heat transfer from the water to the air occurs primarily through the more efficient means of evaporation. Because the air-cooled portion creates an elevated temperature environment for the exhaust plume and reduces the temperature of the water before entering the evaporative section, the frequency and extent of the exhaust vapor plume is reduced. The air-cooled portion of the hybrid-wet/dry tower is relatively inefficient in comparison to the wet-cooled system,

[1] November 2001, "Hearing Report and Recommended Decision by State of New York, in the Matter of Mirant Bowline, LLC, Application for a State Pollutant Discharge Elimination System." The report states, "Mirant has explained that the primary reason for revising the cooling/intake proposal is to reduce cooling tower steam plumes, thereby further reducing adverse visual impacts of the project."

[2] Note: the 316(b) New Facility Rule estimated that nine-new, "greenfield" facilities over a twenty year period would comply with the rule by installing wet cooling towers. However, the New Facility rule did not mandate a compliance technology and provides flexible compliance options through a multi-track framework.

[3] Chapter 3 of the Technical Development Document of the Final Regulations Addressing Cooling Water Intake Structures for New Facilities.

and the overall efficiency of the hybrid system is reduced compared to a wet (only) cooling tower. However, advances in the design of the hybrid tower systems allow bypassing of the air-cooled condenser portion, thereby allowing the tower to function in the more efficient wet (only) cooling mode when the meteorological conditions do not favor visual plume formation or electricity demand requires maximum capacity of the plant (BDT Engineering, 2000) (US EPA Reg I, 2002). The Agency notes that the type of hybrid tower used for plume abatement generally does not reduce water intake compared to a wet cooling tower and would, therefore, have no appreciable reduction in the potential aquatic impacts of cooling water intakes. In addition, the technology may, through the fact that it is less efficient than a wet (only) cooling tower system, cause the plant to emit more air pollutants due to the energy penalty as compared to a wet cooling tower system and a once-through system.

The ratio of the capital cost of the hybrid tower systems (alone, without the necessary and costly auxiliary components such as piping, pumps, etc.) to the cost of wet (only) towers (without necessary, auxiliary components) generally is on the order of 2.0 to 3.0 (Mirsky, et al., 1992) (Power Tech Associates, 1999). For a typical new facility installation, including all of the auxiliary components of yard piping, pumps and motors, basin, sump, electrical wiring and controls, excavation, site preparation, water treatment, etc., the cooling tower unit will comprise a portion of the total capital costs. The Utility Water Act Group, in comments submitted to the Agency for the 316(b) New Facility Proposed Rule presented wet (only) cooling tower unit costs as approximately 45 percent of the total cooling tower system direct capital costs and approximately 35 percent of total estimated costs (Burns and Michiletti, 2000). Several turnkey costs that the Agency received from cooling tower engineering firms showed the wet cooling tower unit portion of total project costs varied from approximately 25 to 40 percent. The Agency expects that the hybrid wet/dry tower would not appreciably affect the auxiliary component costs of a full cooling tower installation. Therefore, the Agency concludes that hybrid wet/dry tower unit would increase the overall capital costs for the total cooling tower system (including all auxiliary components) at a new, "greenfield" facility by approximately 25 to 80 percent as compared to a wet (only) unit. For cooling systems conversions, the Agency estimates that the cooling tower unit would be identical to that of a new, "greenfield" facility, but that the auxiliary components would be considerably more expensive. The Agency estimates that the overall cooling tower project costs would be roughly 20 percent more expensive, due mostly to the increase in costs of the auxiliary components. Hence, for existing-facility cooling tower retrofits, the Agency estimates the increase in overall project cost for a hybrid wet/dry cooling tower unit over a wet (only) unit would range between 20 and 65 percent.[4]

As stated above, the primary reasons for adopting plume abatement are considerations of visual aesthetics, transportation interference liability, and agricultural interference. The Agency is not aware of a database or a combination of sources of information that identify the prevalence of installations of hybrid wet/dry cooling systems. Approximately 80 of the 539 plants for which the Agency has detailed information employ some form of recirculating cooling system, many of these are cooling towers. The Agency's data collection, unfortunately, did not distinguish between the type of cooling tower in-place at these facilities. However, several other data sources do specify the type of cooling tower in-place for many existing power plants: the Power Statistics Unit Design Data File Part B of the 1994 UDI Database and NUREG-1437, the Generic Environmental Impact Statement prepared by the Nuclear Regulatory Commission. After consulting these two data additional data sources, the Agency was unable to specifically identify any of the 539 plants that utilize hybrid wet/dry towers. The Agency, however, did learn from one of the world's largest cooling tower vendors that roughly 3 to 5 percent of their recent installations utilize plume abatement. This figure alone does not form adequate basis for deciding the necessity of plume abatement, which can only truly be gauged by detailed meteorological studies at each site. In order to gauge the prevalence of cooling towers and their proximity to transportation corridors, the Agency examined a significant portion of the facilities

[4] Power Tech Associates (1999) state, when referring to their estimates of cooling system conversion costs for the four Hudson River plants, "the effect of using wet/dry towers is much less than a 25 percent increase in the overall conversion costs."

within the scope of this rule that have closed cycle systems in-place in cold climates (that is, any climate deemed to have periods each year with predictable freezing and icing). The Agency mapped as many of these plants as possible and examined their proximity to highways, navigable rivers and lakes, and railways. The Agency identified 16 facilities with full-recirculating cooling systems and very large megawatt (steam) capacities that were within close proximity (that is, several meters to several hundred meters) to major highways, navigable rivers and lakes, and railways. Only one of these facilities (Bergen Generating Station) utilizes a form of plume abatement, to the Agency's knowledge. The other plants – Keystone Generating Station (PA), Conemaugh Generating Station (PA), Trojan Nuclear (OR, now retired and decommissioning), Michigan City Station (IN), Sherbourne County Station (MN), General J M Gavin (OH), Mill Creek Units 2 & 3 (KY), Cardinal Unit 3 (OH), W H Zimmer (OH), Ghent Station (KY), Rockport Station (IN), Big Sandy (KY), Muskingum River (OH), John E Amos (WV), and Muskogee Station (OK) – utilize either natural draft or mechanical draft wet (only) towers (US EPA, 2002).

In addition to the examples above, the Agency examined the US Capitol Power Plant (DC) and Pawtucket Power (RI). Although the US Capitol Power Plant operates a small, 7-cell mechanical-draft wet (only) cooling tower system, the proximity of the cooling tower and plume to an elevated interstate and many of the United States primary landmarks is striking. The thirty-foot tall cooling tower system frequently projects a vapor plume that extends across and into several lanes of traffic along one of the nation's busiest interstates, an elevated highway. The Pawtucket Power Station near Providence is another small plant situated adjacent to a major highway. The mechanical draft cooling towers of this 70-MW plant produce plumes in the winter in New England that the Agency observed migrating across I-95 and several stories high. The Agency considers these examples of wet cooling towers in close proximity to transportation routes and in cold climates as examples of a relatively pervasive practice.

The Agency contacted Bergen Station regarding their cooling tower system, which is within 700 feet of the New Jersey Turnpike (and nearby to a bridge on the same road). Bergen Station conducted a study of the possible plume impacts to the interstate. The model (a SACTI model) projected a 1-hour impact within a 5-year period. The station mitigated this risk by installing a hybrid-wet/dry cooling system that employs several cells of wet (only) units. The plant has the capability to switch between wet and dry modes and operates under the hybrid mode during the winter and, on occasion, during humid days in the spring for aesthetic reasons (US EPA Reg. I, 2002).

The Agency also consulted the detailed historical study conducted by four Hudson River steam-electric plants (Central Hudson Gas & Electric, 1977). The report examined the environmental and economic impacts from the potential installation and operation of natural-draft wet (only) cooling towers at Bowline Point, Indian Point 2 and 3, and Roseton Generating Stations along the Hudson River in New York. The calculation of multi-plant induced fog and icing impacts from the potential operation of 4 large natural-draft wet cooling towers was, "not expected to be substantial." The Agency notes that this analysis focused on the operation of natural-draft wet cooling towers, which have significantly larger and taller plumes than mechanical-draft wet cooling towers (the modern basis for the vast majority of new cooling tower construction in the United States). Therefore, the effects of potential mechanical-draft units would be even less than those studied.

Considering the evidence that it collected, the Agency determined that it should examine the sensitivity of compliance costs for certain regulatory options based on the installation of plume abatement technologies at a small portion of facilities expected to retrofit their cooling systems. Therefore, the Agency examined the sensitivity of the overall national costs of regulatory option 1 (that is, the option based on flow reduction and installation of closed-cycle cooling systems at approximately 53 facilities) to plume abatement installation costs at 3 facilities (that is, 6 percent of 53). The overall impact on the annual compliance costs for regulatory option 1 was an increase of approximately 2 percent. This is based on the calculation of increased cooling system retrofit capital costs as discussed above (that is, a conservative 65 percent increase of overall project-capital costs for three plants with compliance costs centered about the median) and O&M increases as estimated by the operation multiplier factors recommended in literature (Mirsky, et al., 1992). If as many as 6 facilities out of 53 (that is, a 3 fold increase over the percentage estimated by the reputable tower supplier) would adopt plume abatement installation costs, the impact on the option's annual compliance costs would be approximately a 4 percent increase. Based on the evidence gathered by the Agency, installation of plume abatement at more than 10 percent of the facilities projected to convert cooling systems as a result of regulatory option 1 would not be probable.

6.3 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. The land requirements of mechanical draft wet cooling towers do not approach the size of the campus. 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. In addition, the displacement of wetlands on an industrial site such as a large existing power plant is not a probable outcome of cooling tower construction, in the Agency's opinion.

6.4 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. The DOE expressed concern to the Agency that salt drift may be problematic for the types of plants potentially subject to the regulatory option 1. This could 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 inexpensive drift reducing technologies (called drift eliminators) that have been developed to minimize salt or mineral drift effects.

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. The Agency has considered the capital costs for the abatement of drift for all model plants projected to install cooling towers through regulatory option 1. The approximate change in total annual compliance costs for this option would be less than 1 percent. High efficiency drift eliminators, which reduce drift by an order of magnitude, increase the capital cost of a cooling tower unit (which, as in the case of plume abatement above, is a portion of the total project costs for a retrofit cooling system) by approximately 4 percent and the fan brake horsepower by a similar margin (Mirsky, et al., 1992). These increases, as evidenced by the approximate analysis conducted by the Agency, show very minimal cost impacts on regulatory Option 1.

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 conclusions 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."

The historical study conducted by Central Hudson, et al. (1977) examined the economic and environmental impacts of drift from the four estuarine power plants along the Hudson – Bowline Point, Indian Point 2 and 3, and Roseton Generating Station – for proposed natural draft cooling tower systems. The analysis found the total economic impact from drift damage to vegetation to range from $226,000 to $654,000 (sum present worth - 1977 $). In the Agency's view, these economic impacts are relatively small in comparison to the quantified benefits of entrainment reduction.

6.5 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 and inexpensive component of modern cooling tower designs (See Appendix B, Charts 2-1 through 2-6 for a comparison of low-noise tower costs and other types of tower modifiers). The cost contribution of low noise fans would comprise a very small portion of the total installed capital cost of a retrofitted cooling system (on the same order as drift elimination technologies). 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."

6.6 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. For facilities operating cooling towers with brackish or saline waters, the concentration of salts within the tower and blowdown are a primary design factor. As such, these systems can have elevated salt concentrations over most freshwater sources. However, the concentration of salts is a treatable condition for blowdown from towers. The costing model adopted by the Agency for the capital and O&M costs of cooling towers accounts for the treatment of tower blow-down (see Chapter 2). The increase in solids wastes would be a manageable problem for option 1, where approximately 53 cooling towers would be installed under the considered option. However, for all 539 facilities (a ten fold increase) the issue of solids waste disposal may take on a greater concern to the Agency.

6.7 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 notes that for option 1, the only cooling towers projected to be installed would be in saline and brackish waters. Competing uses for these waters is not as great a concern as that for freshwater. As such, the Agency did not quantitatively determine water consumption levels for this considered regulatory option. For considered options in which cooling towers were projected in freshwaters, the Agency determined that the option was economically impracticable, and as such, did not complete a quantitative analysis of the consumptive water use of this option.

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Appendix A: Compliance Cost Estimates for the Proposed Rule

In order to execute the option for determining whether the compliance costs of a facility are significantly greater than those considered for this rule, the compliance cost estimates prepared by the Agency provide the basis of comparison for permit writers and regulated entities. In the case where a facility's compliance costs are significantly greater than those considered by the Agency, the proposed rule states that the facility would qualify for a site-specific determination of the best technology available. In that case the Director would approve less costly technologies to the extent justified by the significantly greater cost. To document that its site-specific costs would be significantly greater than those EPA considered, the facility would need to develop engineering cost estimates as part of its Comprehensive Cost Evaluation Study. The facility would then consider the model plants presented herein, determine which model plant most closely matches its fuel source, mode of electricity generation, existing intake technologies, waterbody type, geographic location, and intake flow and compare its engineering estimates to EPA's estimated cost for this model plant. The Agency notes that geographic location (an important factor for the consideration of installation capital costs) is not included in the data presented here. This is due to the fact that the Agency, at this juncture, could not reconcile a means to protect a limited amount of confidential business information claimed by respondents to the questionnaires and the need to provide this data to the public for the purposes of evaluating this proposed cost test option. The Agency has worked diligently to protect confidential information and, yet, meet the needs of presenting information to the public. In the interests of refining the information for the final rule, the Agency intends to follow-up on this manner and determine a means of incorporating geographic location without compromising the confidentiality of a limited amount of information claimed by respondents to the questionnaires.

To adequately demonstrate site-specific compliance costs, EPA believes that a facility would need to provide engineering cost estimates that are sufficiently detailed to allow review by a third party. The preferred cost estimating methodology, in the Agency's view, is the adaption of empirical costs from similar projects tailored to the facility's characteristics. The submission of generic costs relying on engineering judgment should be verified with empirical data wherever possible. In the cases where empirical demonstration costs are not available, the level of detail should allow the costs to be reproduced using standard construction engineering unit cost databases. These costs should be supported by estimates from architectural and engineering firms. Further, the engineering assumptions forming the basis of the cost estimates should be clearly documented for the key cost items.

The Agency and other regulatory entities have reviewed recent cost estimates submitted by permittees for several section 316(b) and 316(a) demonstrations. As discussed in Appendix C, where the level of detail provided by the permittee was sufficient to afford a detailed review, EPA has some concerns about the magnitude of these cost estimates. In other cases, the engineering assumptions that formed the basis of the cost submissions were insufficiently documented to afford a critical review. Based in part on these examples, the Agency emphasizes the importance of empirically verified and well documented engineering cost submissions.

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
1	Estuary/Tidal Riv	Coal	190,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$1,805,761	$1,805,761	$47,101	$47,101	$90,000
2	Fresh Stream/Riv	Coal	360,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
3	Fresh Stream/Riv	Coal	68,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$835,790	$835,790	$25,450	$25,450	$75,000
4	Lake/Reservoir	Other	980,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
5	Fresh Stream/Riv	Coal	220,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,858,940	$1,858,940	$51,560	$51,560	$75,000
6	Lake/Reservoir	Other	330,000	OnceThrough	No	No	Fish Handling and Return System	$660,652	$660,652	$23,416	$23,416	$75,000
7	Estuary/Tidal Riv	Coal	500,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,676,159	$3,676,159	$130,875	$130,875	$90,000
8	Fresh Stream/Riv	Nuclear	1,450,000	Recirculating	Yes	No	None	$0	$0	$0	$0	$75,000
9	Lake/Reservoir	Coal	950,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
10	Estuary/Tidal Riv	Oil	2,560,000	OnceThrough	No	No	None	$0	$0	$0	$0	$90,000
11	Lake/Reservoir	Coal	290,000	OnceThrough	Yes	Yes	None	$0	$0	$0	$0	$75,000
12	Lake/Reservoir	Other	1,460,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
13	Fresh Stream/Riv	Other	680,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$6,414,541	$6,414,541	$177,697	$177,697	$75,000
14	Fresh Stream/Riv	Coal	400,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
15	Estuary/Tidal Riv	Coal	570,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$5,462,857	$5,462,857	$142,194	$142,194	$90,000
16	Fresh Stream/Riv	--	690,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
17	Estuary/Tidal Riv	Coal	520,000	Other	No	No	Fine Mesh Trav w/ Fish Handling	$3,412,701	$3,412,701	$134,395	$134,395	$90,000
18	Lake/Reservoir	Coal	580,000	OnceThrough	No	No	Fish Handling and Return System	$1,152,074	$1,152,074	$39,823	$39,823	$75,000
19	Fresh Stream/Riv	Coal	410,000	OnceThrough	No	No	Fish Handling and Return System	$981,350	$981,350	$27,619	$27,619	$75,000
20	Lake/Reservoir	Other	760,000	OnceThrough	No	No	Fish Handling and Return System	$1,494,307	$1,494,307	$52,216	$52,216	$75,000
21	Estuary/Tidal Riv	Other	60,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$630,600	$630,600	$20,915	$20,915	$90,000
22	Estuary/Tidal Riv	Other	1,100,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$5,996,854	$5,996,854	$179,811	$179,811	$90,000
23	Lake/Reservoir	Nuclear	120,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
24	Fresh Stream/Riv	Coal	48,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
25	Fresh Stream/Riv	Coal	270,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
26	Lake/Reservoir	Other	910,000	OnceThrough	No	No	Fish Handling and Return System	$2,383,489	$2,383,489	$63,722	$63,722	$75,000
27	Estuary/Tidal Riv	Other	350,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$2,596,753	$2,596,753	$63,142	$63,142	$90,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
28	Estuary/Tidal Riv	Nuclear	2,100,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$18,247,203	$18,247,203	$349,615	$349,615	$90,000
29	Lake/Reservoir	Coal	270,000	OnceThrough	No	No	Fish Handling and Return System	$619,002	$619,002	$20,420	$20,420	$75,000
30	Estuary/Tidal Riv	Coal	190,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,727,234	$1,727,234	$47,075	$47,075	$90,000
31	Estuary/Tidal Riv	Oil	750,000	Combination	Yes	No	Fish Handling and Return System	$1,651,646	$1,651,646	$51,765	$51,765	$90,000
32	Ocean	Nuclear	1,850,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$19,139,311	$19,139,311	$449,533	$449,533	$90,000
33	Lake/Reservoir	Nuclear	610,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
34	Fresh Stream/Riv	Coal	130,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
35	Fresh Stream/Riv	Other	1,060,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
36	Fresh Stream/Riv	Coal	56,000	OnceThrough	No	No	Fish Handling and Return System	$148,068	$148,068	$4,864	$4,864	$75,000
37	Estuary/Tidal Riv	Other	770,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$4,367,081	$4,367,081	$133,295	$133,295	$90,000
38	Fresh Stream/Riv	Other	320,000	OnceThrough	No	No	Fish Handling and Return System	$671,217	$671,217	$22,837	$22,837	$75,000
39	Ocean	Other	520,000	OnceThrough	No	No	Fish Handling and Return System	$1,421,831	$1,421,831	$36,956	$36,956	$90,000
40	Lake/Reservoir	Other	81,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
41	Estuary/Tidal Riv	Coal	500,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,989,369	$3,989,369	$131,120	$131,120	$90,000
42	Fresh Stream/Riv	Coal	89,000	OnceThrough	Yes	No	Fish Handling and Return System	$272,572	$272,572	$7,453	$7,453	$75,000
43	Fresh Stream/Riv	Coal	260,000	OnceThrough	No	No	Fish Handling and Return System	$640,529	$640,529	$19,768	$19,768	$75,000
44	Estuary/Tidal Riv	Oil	2,450,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$21,731,505	$21,731,505	$578,568	$578,568	$90,000
45	Lake/Reservoir	Coal	240,000	OnceThrough	Yes	No	Fish Handling and Return System	$628,037	$628,037	$18,615	$18,615	$75,000
46	Estuary/Tidal Riv	Coal	61,000	Recirculating	No	No	Fine Mesh Trav w/ Fish Handling	$618,401	$618,401	$0	$0	$90,000
47	Lake/Reservoir	Other	340,000	OnceThrough	No	No	Fish Handling and Return System	$685,536	$685,536	$24,217	$24,217	$75,000
48	Estuary/Tidal Riv	Oil	770,000	OnceThrough	No	No	Fish Handling and Return System	$1,952,860	$1,952,860	$52,985	$52,985	$90,000
49	Estuary/Tidal Riv	Other	280,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,160,144	$2,160,144	$78,597	$78,597	$90,000
50	Lake/Reservoir	Other	370,000	OnceThrough	No	No	Fish Handling and Return System	$727,639	$727,639	$25,525	$25,525	$75,000
51	Lake/Reservoir	Coal	79,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
52	Fresh Stream/Riv	Coal	63,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
53	Fresh Stream/Riv	Coal	38,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
54	Fresh Stream/Riv	Coal	94,000	Combination	No	No	Fish Handling and Return System	$246,956	$246,956	$7,739	$7,739	$75,000
55	Fresh Stream/Riv	Coal	370,000	Combination	No	No	Fish Handling and Return System	$922,742	$922,742	$25,892	$25,892	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
56	Fresh Stream/Riv	Coal	64,000	OnceThrough	No	No	Fish Handling and Return System	$194,875	$194,875	$6,013	$6,013	$75,000
57	Lake/Reservoir	Nuclear	50,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
58	Fresh Stream/Riv	Coal	470,000	OnceThrough	Yes	No	None	$0	$0	$0	$0	$75,000
59	Fresh Stream/Riv	Nuclear	68,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
60	Fresh Stream/Riv	Coal	66,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
61	Lake/Reservoir	Other	500,000	OnceThrough	No	No	Fish Handling and Return System	$1,013,679	$1,013,679	$35,857	$35,857	$75,000
62	Fresh Stream/Riv	Coal	310,000	OnceThrough	Yes	Yes	Fine Mesh Traveling Screen	$2,198,242	$2,198,242	$59,178	$59,178	$75,000
63	Lake/Reservoir	Oil	400,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
64	Fresh Stream/Riv	Other	45,000	OnceThrough	No	No	Fish Handling and Return System	$136,324	$136,324	$4,215	$4,215	$75,000
65	Estuary/Tidal Riv	Other	300,000	Combination	No	No	None	$0	$0	$0	$0	$90,000
66	Estuary/Tidal Riv	Other	600,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$3,271,616	$3,271,616	$101,715	$101,715	$90,000
67	Ocean	Other	250,000	OnceThrough	Yes	No	None	$0	$0	$0	$0	$90,000
68	Fresh Stream/Riv	Coal	190,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,672,082	$1,672,082	$47,931	$47,931	$75,000
69	Ocean	Other	180,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,731,569	$1,731,569	$46,197	$46,197	$90,000
70	Ocean	Nuclear	2,110,000	OnceThrough	Yes	Yes	Fine Mesh Traveling Screen	$18,025,893	$18,025,893	$350,546	$350,546	$90,000
71	Fresh Stream/Riv	Coal	230,000	OnceThrough	Yes	No	Fish Handling and Return System	$515,448	$515,448	$17,883	$17,883	$75,000
72	Fresh Stream/Riv	Coal	290,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,638,235	$2,638,235	$80,265	$80,265	$75,000
73	Fresh Stream/Riv	Coal	170,000	OnceThrough	No	No	Fish Handling and Return System	$353,994	$353,994	$11,888	$11,888	$75,000
74	Ocean	Comb Cycle	77,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$935,072	$935,072	$27,151	$27,151	$90,000
75	Fresh Stream/Riv	Other	52,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
76	Fresh Stream/Riv	Other	51,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$430,310	$430,310	$18,797	$18,797	$75,000
77	Lake/Reservoir	Nuclear	510,000	OnceThrough	Yes	No	Fish Handling and Return System	$1,323,813	$1,323,813	$36,406	$36,406	$75,000
78	Fresh Stream/Riv	Coal	230,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
79	Lake/Reservoir	Coal	680,000	Recirculating	Yes	Yes	None	$0	$0	$0	$0	$75,000
80	Estuary/Tidal Riv	Other	420,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,894,496	$3,894,496	$100,601	$100,601	$90,000
81	Lake/Reservoir	Coal	310,000	Recirculating	Yes	No	None	$0	$0	$0	$0	$75,000
82	Fresh Stream/Riv	Coal	120,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
83	Fresh Stream/Riv	Coal	130,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,155,458	$1,155,458	$37,459	$37,459	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
84	Lake/Reservoir	Other	160,000	OnceThrough	No	No	Fish Handling and Return System	$327,227	$327,227	$11,607	$11,607	$75,000
85	Lake/Reservoir	Coal	370,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
86	Estuary/Tidal Riv	Oil	960,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$8,491,006	$8,491,006	$239,747	$239,747	$90,000
87	Estuary/Tidal Riv	Other	120,000	OnceThrough	Yes	No	Fine Mesh Trav w/ Fish Handling	$1,046,549	$1,046,549	$35,490	$35,490	$90,000
88	Lake/Reservoir	Nuclear	460,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
89	Lake/Reservoir	Other	66,000	OnceThrough	No	No	Fish Handling and Return System	$162,937	$162,937	$6,132	$6,132	$75,000
90	Ocean	Oil	690,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$7,550,835	$7,550,835	$179,251	$179,251	$90,000
91	Lake/Reservoir	Other	130,000	OnceThrough	No	No	Fish Handling and Return System	$276,698	$276,698	$9,644	$9,644	$75,000
92	Lake/Reservoir	Coal	45,000	Recirculating	Yes	Yes	None	$0	$0	$0	$0	$75,000
93	Estuary/Tidal Riv	Oil	1,230,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$7,473,140	$7,473,140	$206,406	$206,406	$90,000
94	Fresh Stream/Riv	Coal	150,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,321,383	$1,321,383	$41,419	$41,419	$75,000
95	Fresh Stream/Riv	Coal	310,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
96	Fresh Stream/Riv	Coal	60,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
97	Lake/Reservoir	Nuclear	450,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
98	Fresh Stream/Riv	Coal	500,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$3,151,370	$3,151,370	$91,926	$91,926	$75,000
99	Fresh Stream/Riv	Coal	52,000	Combination	No	No	Fish Handling and Return System	$116,865	$116,865	$4,641	$4,641	$75,000
100	Fresh Stream/Riv	Coal	1,090,000	OnceThrough	No	No	Fish Handling and Return System	$2,427,985	$2,427,985	$71,333	$71,333	$75,000
101	Lake/Reservoir	Nuclear	59,000	Combination	No	No	None	$0	$0	$0	$0	$75,000
102	Fresh Stream/Riv	Other	1,330,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
103	Estuary/Tidal Riv	Coal	320,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$2,333,617	$2,333,617	$59,460	$59,460	$90,000
104	Estuary/Tidal Riv	Coal	290,000	Combination	No	Yes	Fine Mesh Traveling Screen	$2,168,475	$2,168,475	$56,716	$56,716	$90,000
105	Lake/Reservoir	Other	2,130,000	Recirculating	Yes	Yes	None	$0	$0	$0	$0	$75,000
106	Fresh Stream/Riv	Coal	2,570,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
107	Lake/Reservoir	Coal	140,000	OnceThrough	No	No	Fish Handling and Return System	$366,143	$366,143	$10,484	$10,484	$75,000
108	Estuary/Tidal Riv	Coal	790,000	OnceThrough	No	No	None	$0	$0	$0	$0	$90,000
109	Fresh Stream/Riv	Coal	390,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,167,570	$3,167,570	$97,102	$97,102	$75,000
110	Fresh Stream/Riv	Coal	410,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
111	Estuary/Tidal Riv	Other	300,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,807,761	$2,807,761	$81,333	$81,333	$90,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
112	Estuary/Tidal Riv	Coal	230,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$1,873,642	$1,873,642	$68,278	$68,278	$90,000
113	Lake/Reservoir	Nuclear	890,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
114	Great Lake	Coal	910,000	OnceThrough	No	No	Fish Handling and Return System	$2,199,596	$2,199,596	$63,682	$63,682	$75,000
115	Lake/Reservoir	Nuclear	110,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
116	Lake/Reservoir	Other	180,000	OnceThrough	No	No	Fish Handling and Return System	$355,684	$355,684	$12,514	$12,514	$75,000
117	Estuary/Tidal Riv	Nuclear	1,210,000	OnceThrough	Yes	Yes	None	$0	$0	$0	$0	$90,000
118	Fresh Stream/Riv	Coal	66,000	Combination	No	No	None	$0	$0	$0	$0	$75,000
119	Fresh Stream/Riv	Nuclear	650,000	Combination	No	Yes	Fine Mesh Traveling Screen	$5,379,051	$5,379,051	$106,937	$106,937	$75,000
120	Lake/Reservoir	Coal	450,000	OnceThrough	No	No	Fish Handling and Return System	$1,025,291	$1,025,291	$28,979	$28,979	$75,000
121	Fresh Stream/Riv	Coal	210,000	Combination	No	No	None	$0	$0	$0	$0	$75,000
122	Fresh Stream/Riv	Coal	920,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$8,021,959	$8,021,959	$232,343	$232,343	$75,000
123	Lake/Reservoir	Other	73,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
124	Fresh Stream/Riv	Coal	500,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
125	Fresh Stream/Riv	Coal	51,000	Combination	No	No	None	$0	$0	$0	$0	$75,000
126	Estuary/Tidal Riv	Other	420,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,910,893	$3,910,893	$100,887	$100,887	$90,000
127	Fresh Stream/Riv	Coal	290,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,652,473	$2,652,473	$80,641	$80,641	$75,000
128	Estuary/Tidal Riv	Coal	140,000	OnceThrough	Yes	Yes	Fine Mesh Traveling Screen	$969,148	$969,148	$28,076	$28,076	$90,000
129	Estuary/Tidal Riv	Other	1,080,000	OnceThrough	No	No	Fish Handling and Return System	$2,127,820	$2,127,820	$71,248	$71,248	$90,000
130	Ocean	Other	120,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,226,742	$1,226,742	$36,102	$36,102	$90,000
131	Lake/Reservoir	Other	580,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
132	Lake/Reservoir	Coal	1,020,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
133	Lake/Reservoir	Other	210,000	OnceThrough	No	No	Fish Handling and Return System	$408,905	$408,905	$14,030	$14,030	$75,000
134	Lake/Reservoir	Coal	550,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
135	Estuary/Tidal Riv	Other	370,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$2,684,782	$2,684,782	$64,671	$64,671	$90,000
136	Fresh Stream/Riv	Coal	360,000	Combination	No	No	Fish Handling and Return System	$767,347	$767,347	$25,355	$25,355	$75,000
137	Lake/Reservoir	Coal	180,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
138	Estuary/Tidal Riv	Nuclear	780,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$6,341,110	$6,341,110	$133,732	$133,732	$90,000
139	Estuary/Tidal Riv	Oil	86,000	OnceThrough	No	No	None	$0	$0	$0	$0	$90,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
140	Lake/Reservoir	Comb Cycle	190,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
141	Fresh Stream/Riv	Coal	170,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
142	Fresh Stream/Riv	Coal	730,000	Combination	No	No	None	$0	$0	$0	$0	$75,000
143	Fresh Stream/Riv	Oil	130,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$805,636	$805,636	$26,003	$26,003	$75,000
144	Fresh Stream/Riv	Coal	260,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,476,270	$2,476,270	$74,729	$74,729	$75,000
145	Great Lake	Coal	590,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$5,096,487	$5,096,487	$145,462	$145,462	$75,000
146	Fresh Stream/Riv	Coal	250,000	OnceThrough	No	No	Fish Handling and Return System	$574,081	$574,081	$19,368	$19,368	$75,000
147	Fresh Stream/Riv	Coal	190,000	OnceThrough	No	No	Fish Handling and Return System	$433,686	$433,686	$13,093	$13,093	$75,000
148	Estuary/Tidal Riv	Comb Cycle	370,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,702,457	$2,702,457	$93,376	$93,376	$90,000
149	Great Lake	Coal	1,230,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$10,370,446	$10,370,446	$299,579	$299,579	$75,000
150	Estuary/Tidal Riv	Other	1,120,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$7,850,357	$7,850,357	$181,826	$181,826	$90,000
151	Fresh Stream/Riv	Coal	47,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
152	Estuary/Tidal Riv	Oil	210,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,499,969	$1,499,969	$50,329	$50,329	$90,000
153	Fresh Stream/Riv	Coal	140,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
154	Estuary/Tidal Riv	Other	330,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,063,444	$3,063,444	$87,529	$87,529	$90,000
155	Lake/Reservoir	Nuclear	510,000	Combination	No	No	Fish Handling and Return System	$961,373	$961,373	$36,025	$36,025	$75,000
156	Estuary/Tidal Riv	Oil	530,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$3,091,754	$3,091,754	$94,964	$94,964	$90,000
157	Fresh Stream/Riv	Nuclear	50,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
158	Fresh Stream/Riv	Coal	200,000	Combination	No	Yes	None	$0	$0	$0	$0	$75,000
159	Estuary/Tidal Riv	Nuclear	80,000	Recirculating	No	Yes	Fine Mesh Traveling Screen	$925,206	$925,206	$20,477	$20,477	$90,000
160	Fresh Stream/Riv	Nuclear	150,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
161	Fresh Stream/Riv	Coal	160,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
162	Ocean	Other	1,680,000	OnceThrough	Yes	Yes	None	$0	$0	$0	$0	$90,000
163	Fresh Stream/Riv	Coal	130,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
164	Estuary/Tidal Riv	Other	650,000	OnceThrough	No	No	Fish Handling and Return System	$1,305,785	$1,305,785	$42,693	$42,693	$90,000
165	Fresh Stream/Riv	Coal	450,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,143,587	$3,143,587	$105,377	$105,377	$75,000
166	Estuary/Tidal Riv	Nuclear	540,000	Recirculating	No	Yes	Fine Mesh Traveling Screen	$3,462,339	$3,462,339	$95,722	$95,722	$90,000
167	Lake/Reservoir	Other	370,000	OnceThrough	No	No	Fish Handling and Return System	$960,544	$960,544	$25,654	$25,654	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
168	Fresh Stream/Riv	Oil	110,000	OnceThrough	No	No	Fish Handling and Return System	$287,461	$287,461	$8,473	$8,473	$75,000
169	Fresh Stream/Riv	Coal	360,000	OnceThrough	No	No	Fish Handling and Return System	$736,780	$736,780	$25,389	$25,389	$75,000
170	Fresh Stream/Riv	Coal	5,350,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$45,223,779	$45,223,779	$1,262,104	$1,262,104	$75,000
171	Lake/Reservoir	Coal	170,000	OnceThrough	No	No	Fish Handling and Return System	$405,292	$405,292	$11,840	$11,840	$75,000
172	Lake/Reservoir	Other	440,000	OnceThrough	No	No	Fish Handling and Return System	$843,501	$843,501	$28,694	$28,694	$75,000
173	Fresh Stream/Riv	Other	620,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$3,456,701	$3,456,701	$103,550	$103,550	$75,000
174	Fresh Stream/Riv	Coal	220,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
175	Fresh Stream/Riv	Coal	220,000	Combination	No	Yes	Fine Mesh Traveling Screen	$1,413,188	$1,413,188	$35,606	$35,606	$75,000
176	Lake/Reservoir	Coal	740,000	OnceThrough	No	No	Fish Handling and Return System	$1,475,184	$1,475,184	$51,319	$51,319	$75,000
177	Lake/Reservoir	Nuclear	1,910,000	OnceThrough	Yes	No	Fish Handling and Return System	$4,471,237	$4,471,237	$126,492	$126,492	$75,000
178	Estuary/Tidal Riv	Other	550,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$90,000
179	Lake/Reservoir	Coal	440,000	OnceThrough	No	No	Fish Handling and Return System	$850,359	$850,359	$28,856	$28,856	$75,000
180	Lake/Reservoir	Other	770,000	Recirculating	No	Yes	None	$0	$0	$0	$0	$75,000
181	Fresh Stream/Riv	Coal	850,000	Combination	No	No	Fish Handling and Return System	$1,897,495	$1,897,495	$56,236	$56,236	$75,000
182	Fresh Stream/Riv	Nuclear	1,020,000	OnceThrough	No	No	Fish Handling and Return System	$2,469,785	$2,469,785	$68,455	$68,455	$75,000
183	Lake/Reservoir	Coal	770,000	OnceThrough	No	No	Fish Handling and Return System	$1,763,704	$1,763,704	$52,955	$52,955	$75,000
184	Fresh Stream/Riv	Coal	130,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,318,605	$1,318,605	$37,764	$37,764	$75,000
185	Ocean	Other	89,000	OnceThrough	No	No	None	$0	$0	$0	$0	$90,000
186	Lake/Reservoir	Coal	920,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
187	Fresh Stream/Riv	Nuclear	470,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
188	Lake/Reservoir	Coal	150,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
189	Lake/Reservoir	Coal	630,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
190	Lake/Reservoir	Coal	310,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
191	Fresh Stream/Riv	Coal	1,540,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$12,311,066	$12,311,066	$365,482	$365,482	$75,000
192	Fresh Stream/Riv	Comb Cycle	43,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
193	Fresh Stream/Riv	Coal	610,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$5,046,381	$5,046,381	$148,708	$148,708	$75,000
194	Fresh Stream/Riv	Coal	330,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,378,321	$2,378,321	$85,979	$85,979	$75,000
195	Fresh Stream/Riv	Coal	50,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
196	Lake/Reservoir	Other	420,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
197	Fresh Stream/Riv	Coal	170,000	OnceThrough	No	No	Fish Handling and Return System	$433,985	$433,985	$12,273	$12,273	$75,000
198	Lake/Reservoir	Coal	550,000	Recirculating	No	Yes	None	$0	$0	$0	$0	$75,000
199	Lake/Reservoir	Other	500,000	OnceThrough	No	No	Fish Handling and Return System	$1,017,517	$1,017,517	$35,981	$35,981	$75,000
200	Fresh Stream/Riv	Coal	90,000	OnceThrough	No	No	Fish Handling and Return System	$209,422	$209,422	$7,499	$7,499	$75,000
201	Lake/Reservoir	Coal	1,510,000	OnceThrough	No	No	Fish Handling and Return System	$2,915,937	$2,915,937	$99,551	$99,551	$75,000
202	Fresh Stream/Riv	Coal	710,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$6,000,929	$6,000,929	$182,006	$182,006	$75,000
203	Fresh Stream/Riv	Coal	280,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,624,121	$2,624,121	$78,660	$78,660	$75,000
204	Estuary/Tidal Riv	Nuclear	1,000,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$8,707,797	$8,707,797	$169,706	$169,706	$90,000
205	Lake/Reservoir	Nuclear	550,000	OnceThrough	No	No	Fish Handling and Return System	$1,018,849	$1,018,849	$38,532	$38,532	$75,000
206	Lake/Reservoir	Nuclear	200,000	Combination	No	No	None	$0	$0	$0	$0	$75,000
207	Fresh Stream/Riv	Coal	120,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
208	Lake/Reservoir	Nuclear	1,130,000	OnceThrough	No	No	Fish Handling and Return System	$2,310,521	$2,310,521	$78,289	$78,289	$75,000
209	Fresh Stream/Riv	Coal	230,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,192,914	$2,192,914	$69,478	$69,478	$75,000
210	Fresh Stream/Riv	Coal	950,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$7,906,569	$7,906,569	$236,873	$236,873	$75,000
211	Fresh Stream/Riv	Coal	420,000	Other	No	No	None	$0	$0	$0	$0	$75,000
212	Lake/Reservoir	Other	76,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
213	Lake/Reservoir	Comb Cycle	77,000	Combination	No	No	None	$0	$0	$0	$0	$75,000
214	Fresh Stream/Riv	Coal	200,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,693,858	$1,693,858	$49,004	$49,004	$75,000
215	Lake/Reservoir	Other	44,000	OnceThrough	No	No	Fish Handling and Return System	$102,577	$102,577	$4,165	$4,165	$75,000
216	Lake/Reservoir	Coal	140,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
217	Ocean	Nuclear	560,000	OnceThrough	Yes	No	None	$0	$0	$0	$0	$90,000
218	Fresh Stream/Riv	Coal	64,000	OnceThrough	No	No	Fish Handling and Return System	$147,805	$147,805	$6,027	$6,027	$75,000
219	Fresh Stream/Riv	Coal	70,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
220	Fresh Stream/Riv	Other	260,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
221	Lake/Reservoir	Nuclear	79,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
222	Fresh Stream/Riv	Coal	160,000	OnceThrough	No	No	Fish Handling and Return System	$331,890	$331,890	$11,364	$11,364	$75,000
223	Fresh Stream/Riv	Coal	88,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
224	Lake/Reservoir	Coal	820,000	OnceThrough	No	No	Fish Handling and Return System	$1,623,313	$1,623,313	$55,009	$55,009	$75,000
225	Ocean	Other	170,000	OnceThrough	Yes	No	Fish Handling and Return System	$459,989	$459,989	$11,992	$11,992	$90,000
226	Estuary/Tidal Riv	Oil	560,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$4,073,795	$4,073,795	$140,592	$140,592	$90,000
227	Estuary/Tidal Riv	Other	230,000	OnceThrough	No	No	None	$0	$0	$0	$0	$90,000
228	Fresh Stream/Riv	Coal	73,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$700,542	$700,542	$26,346	$26,346	$75,000
229	Fresh Stream/Riv	Coal	260,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
230	Estuary/Tidal Riv	Other	1,280,000	OnceThrough	No	No	Fish Handling and Return System	$3,411,906	$3,411,906	$84,707	$84,707	$90,000
231	Ocean	Nuclear	440,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$90,000
232	Lake/Reservoir	Coal	71,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
233	Lake/Reservoir	Oil	1,270,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
234	Estuary/Tidal Riv	Other	290,000	OnceThrough	No	No	Fish Handling and Return System	$603,732	$603,732	$21,529	$21,529	$90,000
235	Fresh Stream/Riv	Coal	850,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$7,316,195	$7,316,195	$204,078	$204,078	$75,000
236	Estuary/Tidal Riv	Other	100,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,171,873	$1,171,873	$32,521	$32,521	$90,000
237	Fresh Stream/Riv	Oil	660,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
238	Fresh Stream/Riv	Coal	130,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$913,055	$913,055	$26,501	$26,501	$75,000
239	Fresh Stream/Riv	Coal	61,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
240	Fresh Stream/Riv	Other	340,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
241	Estuary/Tidal Riv	Oil	2,680,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$18,748,809	$18,748,809	$435,154	$435,154	$90,000
242	Lake/Reservoir	Other	430,000	OnceThrough	No	No	Fish Handling and Return System	$825,540	$825,540	$28,255	$28,255	$75,000
243	Fresh Stream/Riv	Nuclear	460,000	Other	No	No	Fine Mesh Trav w/ Fish Handling	$4,594,450	$4,594,450	$123,881	$123,881	$75,000
244	Fresh Stream/Riv	Coal	340,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,239,456	$2,239,456	$88,464	$88,464	$75,000
245	Lake/Reservoir	Coal	130,000	OnceThrough	No	No	Fish Handling and Return System	$342,708	$342,708	$10,077	$10,077	$75,000
246	Fresh Stream/Riv	Coal	110,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,099,875	$1,099,875	$34,353	$34,353	$75,000
247	Lake/Reservoir	Coal	480,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
248	Estuary/Tidal Riv	Other	580,000	OnceThrough	No	No	Fish Handling and Return System	$1,542,186	$1,542,186	$39,638	$39,638	$90,000
249	Great Lake	Other	440,000	Combination	Yes	No	Fine Mesh Trav w/ Fish Handling	$3,666,639	$3,666,639	$104,091	$104,091	$75,000
250	Fresh Stream/Riv	Coal	100,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$931,121	$931,121	$31,977	$31,977	$75,000
251	Lake/Reservoir	Other	450,000	OnceThrough	No	No	Fish Handling and Return System	$929,538	$929,538	$33,096	$33,096	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
252	Lake/Reservoir	Coal	180,000	OnceThrough	No	No	Fish Handling and Return System	$373,886	$373,886	$12,393	$12,393	$75,000
253	Fresh Stream/Riv	Coal	180,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,355,807	$1,355,807	$46,172	$46,172	$75,000
254	Lake/Reservoir	Coal	74,000	OnceThrough	No	No	Fish Handling and Return System	$232,739	$232,739	$6,583	$6,583	$75,000
255	Fresh Stream/Riv	Nuclear	630,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
256	Fresh Stream/Riv	Other	75,000	OnceThrough	No	No	Fish Handling and Return System	$188,492	$188,492	$6,631	$6,631	$75,000
257	Fresh Stream/Riv	Other	1,070,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
258	Fresh Stream/Riv	Coal	430,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
259	Estuary/Tidal Riv	Nuclear	110,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$1,030,036	$1,030,036	$23,752	$23,752	$90,000
260	Lake/Reservoir	Coal	1,050,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
261	Fresh Stream/Riv	Coal	140,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
262	Great Lake	Coal	41,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$464,121	$464,121	$16,467	$16,467	$75,000
263	Fresh Stream/Riv	Coal	88,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
264	Lake/Reservoir	Nuclear	5,440,000	OnceThrough	No	No	Fish Handling and Return System	$9,882,287	$9,882,287	$356,995	$356,995	$75,000
265	Fresh Stream/Riv	Other	66,000	OnceThrough	No	No	Fish Handling and Return System	$217,718	$217,718	$6,137	$6,137	$75,000
266	Lake/Reservoir	Coal	440,000	OnceThrough	No	No	Fish Handling and Return System	$858,875	$858,875	$28,905	$28,905	$75,000
267	Estuary/Tidal Riv	Other	38,000	OnceThrough	No	No	None	$0	$0	$0	$0	$90,000
268	Estuary/Tidal Riv	Coal	2,120,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$15,282,924	$15,282,924	$509,611	$509,611	$90,000
269	Ocean	Oil	360,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,851,922	$3,851,922	$91,062	$91,062	$90,000
270	Lake/Reservoir	Coal	63,000	OnceThrough	No	No	Fish Handling and Return System	$161,118	$161,118	$5,985	$5,985	$75,000
271	Lake/Reservoir	Coal	810,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
272	Fresh Stream/Riv	Coal	300,000	OnceThrough	No	No	Fish Handling and Return System	$749,245	$749,245	$22,251	$22,251	$75,000
273	Lake/Reservoir	Other	320,000	OnceThrough	No	No	Fish Handling and Return System	$648,883	$648,883	$23,031	$23,031	$75,000
274	Fresh Stream/Riv	Coal	45,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
275	Fresh Stream/Riv	Coal	400,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
276	Fresh Stream/Riv	Coal	240,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,926,190	$1,926,190	$70,751	$70,751	$75,000
277	Estuary/Tidal Riv	Oil	220,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$1,372,571	$1,372,571	$35,941	$35,941	$90,000
278	Fresh Stream/Riv	Coal	120,000	OnceThrough	No	No	Fish Handling and Return System	$316,951	$316,951	$9,138	$9,138	$75,000
279	Fresh Stream/Riv	Coal	80,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
280	Estuary/Tidal Riv	Nuclear	2,020,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$16,834,637	$16,834,637	$327,747	$327,747	$90,000
281	Lake/Reservoir	Coal	370,000	OnceThrough	No	No	Fish Handling and Return System	$846,303	$846,303	$25,572	$25,572	$75,000
282	Lake/Reservoir	Coal	700,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
283	Estuary/Tidal Riv	Coal	390,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$2,206,407	$2,206,407	$66,950	$66,950	$90,000
284	Fresh Stream/Riv	Coal	230,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
285	Lake/Reservoir	Coal	1,010,000	OnceThrough	No	No	Fish Handling and Return System	$1,992,079	$1,992,079	$68,370	$68,370	$75,000
286	Estuary/Tidal Riv	Coal	1,500,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$90,000
287	Fresh Stream/Riv	Coal	250,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
288	Estuary/Tidal Riv	Oil	330,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,467,266	$2,467,266	$86,864	$86,864	$90,000
289	Fresh Stream/Riv	Coal	590,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
290	Estuary/Tidal Riv	Other	500,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$4,741,804	$4,741,804	$130,499	$130,499	$90,000
291	Fresh Stream/Riv	Coal	120,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
292	Lake/Reservoir	Comb Cycle	72,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
293	Lake/Reservoir	Other	720,000	Combination	No	No	Fish Handling and Return System	$1,432,577	$1,432,577	$50,358	$50,358	$75,000
294	Ocean	Other	370,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,571,824	$2,571,824	$92,909	$92,909	$90,000
295	Fresh Stream/Riv	Coal	180,000	OnceThrough	No	No	Fish Handling and Return System	$448,331	$448,331	$12,630	$12,630	$75,000
296	Estuary/Tidal Riv	Other	100,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$90,000
297	Fresh Stream/Riv	Other	510,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
298	Estuary/Tidal Riv	Other	350,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,391,514	$3,391,514	$90,901	$90,901	$90,000
299	Fresh Stream/Riv	Coal	39,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
300	Estuary/Tidal Riv	Comb Cycle	240,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$1,957,099	$1,957,099	$50,798	$50,798	$90,000
301	Estuary/Tidal Riv	Coal	440,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$4,016,929	$4,016,929	$103,736	$103,736	$90,000
302	Fresh Stream/Riv	Other	910,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
303	Fresh Stream/Riv	Nuclear	61,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
304	Fresh Stream/Riv	Coal	490,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
305	Lake/Reservoir	Coal	250,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
306	Estuary/Tidal Riv	Other	140,000	OnceThrough	No	No	None	$0	$0	$0	$0	$90,000
307	Estuary/Tidal Riv	Oil	230,000	Combination	No	Yes	None	$0	$0	$0	$0	$90,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
308	Fresh Stream/Riv	Oil	180,000	OnceThrough	No	No	Fish Handling and Return System	$435,199	$435,199	$12,499	$12,499	$75,000
309	Lake/Reservoir	Other	660,000	OnceThrough	No	No	Fish Handling and Return System	$1,273,883	$1,273,883	$43,246	$43,246	$75,000
310	Lake/Reservoir	Other	100,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
311	Fresh Stream/Riv	Coal	130,000	OnceThrough	No	No	Fish Handling and Return System	$287,270	$287,270	$10,113	$10,113	$75,000
312	Fresh Stream/Riv	Other	83,000	OnceThrough	No	No	Fish Handling and Return System	$190,035	$190,035	$7,113	$7,113	$75,000
313	Fresh Stream/Riv	Other	190,000	OnceThrough	No	No	Fish Handling and Return System	$468,083	$468,083	$13,300	$13,300	$75,000
314	Fresh Stream/Riv	Coal	950,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$7,825,161	$7,825,161	$237,278	$237,278	$75,000
315	Fresh Stream/Riv	Coal	270,000	OnceThrough	No	No	Fish Handling and Return System	$699,405	$699,405	$20,414	$20,414	$75,000
316	Lake/Reservoir	Nuclear	380,000	OnceThrough	Yes	Yes	None	$0	$0	$0	$0	$75,000
317	Fresh Stream/Riv	Other	180,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
318	Lake/Reservoir	Other	280,000	OnceThrough	No	No	Fish Handling and Return System	$589,745	$589,745	$21,056	$21,056	$75,000
319	Fresh Stream/Riv	Coal	360,000	Other	No	No	Fine Mesh Trav w/ Fish Handling	$2,332,769	$2,332,769	$91,387	$91,387	$75,000
320	Lake/Reservoir	Coal	1,010,000	OnceThrough	No	No	Fish Handling and Return System	$1,859,551	$1,859,551	$68,197	$68,197	$75,000
321	Lake/Reservoir	Comb Cycle	150,000	OnceThrough	No	No	Fish Handling and Return System	$326,129	$326,129	$11,118	$11,118	$75,000
322	Fresh Stream/Riv	Coal	520,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$3,364,264	$3,364,264	$93,702	$93,702	$75,000
323	Lake/Reservoir	Coal	650,000	OnceThrough	No	No	Fish Handling and Return System	$1,558,441	$1,558,441	$42,662	$42,662	$75,000
324	Fresh Stream/Riv	Coal	70,000	OnceThrough	No	No	Fish Handling and Return System	$201,299	$201,299	$6,356	$6,356	$75,000
325	Fresh Stream/Riv	Nuclear	870,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$8,084,704	$8,084,704	$206,638	$206,638	$75,000
326	Fresh Stream/Riv	Nuclear	76,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
327	Estuary/Tidal Riv	Oil	2,400,000	OnceThrough	No	No	Fish Handling and Return System	$6,379,540	$6,379,540	$157,514	$157,514	$90,000
328	Estuary/Tidal Riv	Coal	82,000	OnceThrough	No	No	None	$0	$0	$0	$0	$90,000
329	Fresh Stream/Riv	Coal	1,370,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$9,113,298	$9,113,298	$234,978	$234,978	$75,000
330	Fresh Stream/Riv	Coal	110,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,065,898	$1,065,898	$34,257	$34,257	$75,000
331	Lake/Reservoir	Coal	440,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
332	Great Lake	Coal	310,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,587,410	$2,587,410	$82,934	$82,934	$75,000
333	Estuary/Tidal Riv	Coal	130,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$1,068,066	$1,068,066	$26,804	$26,804	$90,000
334	Fresh Stream/Riv	Other	320,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
335	Fresh Stream/Riv	Coal	1,080,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$7,564,068	$7,564,068	$257,171	$257,171	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
336	Fresh Stream/Riv	Coal	690,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$4,962,647	$4,962,647	$178,383	$178,383	$75,000
337	Fresh Stream/Riv	Coal	1,050,000	OnceThrough	No	No	Fish Handling and Return System	$2,157,319	$2,157,319	$69,773	$69,773	$75,000
338	Fresh Stream/Riv	Coal	200,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$1,373,019	$1,373,019	$49,203	$49,203	$75,000
339	Fresh Stream/Riv	Nuclear	360,000	Combination	No	Yes	None	$0	$0	$0	$0	$75,000
340	Fresh Stream/Riv	Coal	700,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$4,545,063	$4,545,063	$125,850	$125,850	$75,000
341	Fresh Stream/Riv	Coal	100,000	Combination	No	Yes	None	$0	$0	$0	$0	$75,000
342	Fresh Stream/Riv	Coal	310,000	Recirculating	No	Yes	None	$0	$0	$0	$0	$75,000
343	Lake/Reservoir	Coal	42,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
344	Fresh Stream/Riv	Coal	110,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
345	Fresh Stream/Riv	Other	1,050,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
346	Estuary/Tidal Riv	Other	1,050,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$90,000
347	Lake/Reservoir	Nuclear	810,000	Combination	Yes	No	Fish Handling and Return System	$1,542,486	$1,542,486	$54,459	$54,459	$75,000
348	Fresh Stream/Riv	Coal	150,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
349	Fresh Stream/Riv	Coal	190,000	OnceThrough	No	No	Fish Handling and Return System	$396,969	$396,969	$13,144	$13,144	$75,000
350	Lake/Reservoir	Coal	130,000	OnceThrough	No	No	Fish Handling and Return System	$292,561	$292,561	$10,031	$10,031	$75,000
351	Estuary/Tidal Riv	Comb Cycle	65,000	OnceThrough	No	No	None	$0	$0	$0	$0	$90,000
352	Fresh Stream/Riv	Coal	820,000	Combination	No	Yes	Fine Mesh Traveling Screen	$4,601,345	$4,601,345	$137,922	$137,922	$75,000
353	Ocean	Other	420,000	OnceThrough	Yes	No	Fine Mesh Trav w/ Fish Handling	$3,939,024	$3,939,024	$101,372	$101,372	$90,000
354	Fresh Stream/Riv	Other	130,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$985,436	$985,436	$36,506	$36,506	$75,000
355	Fresh Stream/Riv	Coal	270,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,420,874	$2,420,874	$76,748	$76,748	$75,000
356	Fresh Stream/Riv	Coal	70,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$771,245	$771,245	$25,669	$25,669	$75,000
357	Fresh Stream/Riv	Coal	200,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
358	Estuary/Tidal Riv	Coal	1,710,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$12,330,972	$12,330,972	$409,972	$409,972	$90,000
359	Estuary/Tidal Riv	Other	140,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$90,000
360	Fresh Stream/Riv	Nuclear	67,000	OnceThrough	No	No	Fish Handling and Return System	$171,556	$171,556	$6,200	$6,200	$75,000
361	Fresh Stream/Riv	Coal	500,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,572,845	$3,572,845	$130,325	$130,325	$75,000
362	Lake/Reservoir	Coal	390,000	OnceThrough	No	No	Fish Handling and Return System	$766,332	$766,332	$26,664	$26,664	$75,000
363	Estuary/Tidal Riv	Other	65,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$639,845	$639,845	$24,760	$24,760	$90,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
364	Lake/Reservoir	Comb Cycle	130,000	OnceThrough	No	No	Fish Handling and Return System	$274,030	$274,030	$9,819	$9,819	$75,000
365	Fresh Stream/Riv	Other	830,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
366	Fresh Stream/Riv	Coal	190,000	OnceThrough	No	No	Fish Handling and Return System	$396,532	$396,532	$13,041	$13,041	$75,000
367	Fresh Stream/Riv	Coal	87,000	OnceThrough	Yes	No	Fine Mesh Trav w/ Fish Handling	$693,184	$693,184	$29,089	$29,089	$75,000
368	Ocean	Nuclear	1,030,000	OnceThrough	Yes	No	Fine Mesh Trav w/ Fish Handling	$8,182,772	$8,182,772	$249,720	$249,720	$90,000
369	Lake/Reservoir	Coal	400,000	OnceThrough	No	No	Fish Handling and Return System	$973,966	$973,966	$27,075	$27,075	$75,000
370	Fresh Stream/Riv	Coal	550,000	OnceThrough	No	No	Fish Handling and Return System	$1,314,223	$1,314,223	$38,449	$38,449	$75,000
371	Fresh Stream/Riv	Coal	270,000	OnceThrough	No	No	Fish Handling and Return System	$738,387	$738,387	$20,134	$20,134	$75,000
372	Fresh Stream/Riv	Other	39,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
373	Fresh Stream/Riv	Coal	340,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,019,394	$3,019,394	$88,587	$88,587	$75,000
374	Estuary/Tidal Riv	Coal	210,000	Combination	Yes	No	Fine Mesh Trav w/ Fish Handling	$1,373,170	$1,373,170	$51,369	$51,369	$90,000
375	Fresh Stream/Riv	Coal	42,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
376	Lake/Reservoir	Coal	170,000	OnceThrough	No	No	Fish Handling and Return System	$405,704	$405,704	$12,323	$12,323	$75,000
377	Fresh Stream/Riv	Nuclear	140,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
378	Fresh Stream/Riv	Coal	67,000	OnceThrough	No	No	Fish Handling and Return System	$175,112	$175,112	$6,189	$6,189	$75,000
379	Fresh Stream/Riv	Coal	450,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
380	Fresh Stream/Riv	Other	91,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
381	Fresh Stream/Riv	Comb Cycle	120,000	Combination	No	Yes	None	$0	$0	$0	$0	$75,000
382	Lake/Reservoir	Coal	500,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
383	Fresh Stream/Riv	Coal	97,000	OnceThrough	No	No	Fish Handling and Return System	$261,841	$261,841	$7,930	$7,930	$75,000
384	Fresh Stream/Riv	Coal	300,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$2,607,043	$2,607,043	$80,990	$80,990	$75,000
385	Fresh Stream/Riv	Oil	110,000	OnceThrough	No	No	Fish Handling and Return System	$301,754	$301,754	$8,961	$8,961	$75,000
386	Fresh Stream/Riv	Coal	780,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$5,533,505	$5,533,505	$193,850	$193,850	$75,000
387	Fresh Stream/Riv	Coal	370,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
388	Fresh Stream/Riv	Nuclear	1,180,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
389	Fresh Stream/Riv	Coal	74,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
390	Estuary/Tidal Riv	Other	380,000	OnceThrough	No	No	Fish Handling and Return System	$842,401	$842,401	$26,320	$26,320	$90,000
391	Fresh Stream/Riv	Coal	240,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,262,696	$2,262,696	$70,725	$70,725	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
392	Fresh Stream/Riv	Coal	1,030,000	OnceThrough	No	No	Fish Handling and Return System	$2,402,438	$2,402,438	$69,117	$69,117	$75,000
393	Estuary/Tidal Riv	Other	520,000	OnceThrough	Yes	No	Fine Mesh Trav w/ Fish Handling	$4,708,410	$4,708,410	$133,910	$133,910	$90,000
394	Fresh Stream/Riv	Coal	54,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
395	Estuary/Tidal Riv	Other	2,100,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$14,707,137	$14,707,137	$349,761	$349,761	$90,000
396	Lake/Reservoir	Coal	200,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
397	Great Lake	Coal	170,000	OnceThrough	No	No	Fish Handling and Return System	$411,092	$411,092	$12,118	$12,118	$75,000
398	Fresh Stream/Riv	Coal	180,000	OnceThrough	No	No	Fish Handling and Return System	$327,604	$327,604	$12,448	$12,448	$75,000
399	Fresh Stream/Riv	Coal	190,000	Other	No	Yes	Fine Mesh Traveling Screen	$1,006,660	$1,006,660	$33,417	$33,417	$75,000
400	Great Lake	Coal	840,000	OnceThrough	Yes	No	Fine Mesh Trav w/ Fish Handling	$6,968,299	$6,968,299	$202,908	$202,908	$75,000
401	Fresh Stream/Riv	Coal	620,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
402	Estuary/Tidal Riv	Oil	570,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$3,279,537	$3,279,537	$98,996	$98,996	$90,000
403	Fresh Stream/Riv	Coal	280,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,494,743	$2,494,743	$77,936	$77,936	$75,000
404	Lake/Reservoir	Coal	1,120,000	OnceThrough	No	No	Fish Handling and Return System	$2,163,010	$2,163,010	$72,624	$72,624	$75,000
405	Fresh Stream/Riv	Coal	480,000	OnceThrough	No	No	Fish Handling and Return System	$1,153,848	$1,153,848	$34,608	$34,608	$75,000
406	Estuary/Tidal Riv	Coal	310,000	Combination	No	Yes	None	$0	$0	$0	$0	$90,000
407	Fresh Stream/Riv	Other	300,000	OnceThrough	No	No	Fish Handling and Return System	$628,979	$628,979	$21,986	$21,986	$75,000
408	Lake/Reservoir	Nuclear	83,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
409	Fresh Stream/Riv	Coal	1,000,000	OnceThrough	No	No	Fish Handling and Return System	$2,254,314	$2,254,314	$67,586	$67,586	$75,000
410	Fresh Stream/Riv	Other	89,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
411	Estuary/Tidal Riv	Other	95,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$829,916	$829,916	$30,663	$30,663	$90,000
412	Lake/Reservoir	Nuclear	2,200,000	OnceThrough	No	No	Fish Handling and Return System	$4,230,547	$4,230,547	$143,782	$143,782	$75,000
413	Fresh Stream/Riv	Coal	1,900,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$13,190,121	$13,190,121	$456,702	$456,702	$75,000
414	Fresh Stream/Riv	Other	350,000	Recirculating	No	Yes	None	$0	$0	$0	$0	$75,000
415	Ocean	Oil	1,990,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$14,339,794	$14,339,794	$471,062	$471,062	$90,000
416	Lake/Reservoir	Other	160,000	OnceThrough	No	No	Fish Handling and Return System	$333,612	$333,612	$11,814	$11,814	$75,000
417	Lake/Reservoir	Coal	610,000	Recirculating	No	Yes	None	$0	$0	$0	$0	$75,000
418	Lake/Reservoir	Other	650,000	OnceThrough	No	No	Fish Handling and Return System	$1,248,502	$1,248,502	$42,636	$42,636	$75,000
419	Estuary/Tidal Riv	Other	1,200,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$6,563,060	$6,563,060	$203,833	$203,833	$90,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
420	Fresh Stream/Riv	Coal	350,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
421	Fresh Stream/Riv	Coal	65,000	OnceThrough	No	No	Fish Handling and Return System	$207,206	$207,206	$6,084	$6,084	$75,000
422	Fresh Stream/Riv	Other	230,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,900,594	$1,900,594	$52,865	$52,865	$75,000
423	Fresh Stream/Riv	Other	330,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
424	Estuary/Tidal Riv	Coal	970,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$90,000
425	Estuary/Tidal Riv	Other	450,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$4,193,037	$4,193,037	$105,501	$105,501	$90,000
426	Estuary/Tidal Riv	Comb Cycle	510,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$4,923,758	$4,923,758	$132,842	$132,842	$90,000
427	Ocean	Other	610,000	OnceThrough	Yes	No	Fine Mesh Trav w/ Fish Handling	$5,742,626	$5,742,626	$149,148	$149,148	$90,000
428	Lake/Reservoir	Other	1,200,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
429	Fresh Stream/Riv	Coal	160,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,307,249	$1,307,249	$41,836	$41,836	$75,000
430	Estuary/Tidal Riv	Other	440,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$4,073,922	$4,073,922	$103,620	$103,620	$90,000
431	Fresh Stream/Riv	Other	160,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,540,048	$1,540,048	$43,180	$43,180	$75,000
432	Lake/Reservoir	Coal	630,000	OnceThrough	No	No	Fish Handling and Return System	$1,224,686	$1,224,686	$42,037	$42,037	$75,000
433	Estuary/Tidal Riv	Other	58,000	OnceThrough	No	No	Fish Handling and Return System	$139,315	$139,315	$5,012	$5,012	$90,000
434	Fresh Stream/Riv	Coal	220,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$1,266,020	$1,266,020	$35,819	$35,819	$75,000
435	Lake/Reservoir	Coal	70,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
436	Fresh Stream/Riv	Coal	40,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
437	Lake/Reservoir	Nuclear	2,020,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
438	Estuary/Tidal Riv	Oil	950,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$5,472,686	$5,472,686	$165,133	$165,133	$90,000
439	Fresh Stream/Riv	Coal	150,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,335,549	$1,335,549	$40,565	$40,565	$75,000
440	Lake/Reservoir	Other	260,000	OnceThrough	No	No	Fish Handling and Return System	$557,464	$557,464	$19,958	$19,958	$75,000
441	Estuary/Tidal Riv	Coal	190,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,383,422	$1,383,422	$47,522	$47,522	$90,000
442	Estuary/Tidal Riv	Nuclear	1,670,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$10,835,998	$10,835,998	$278,379	$278,379	$90,000
443	Lake/Reservoir	Coal	3,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
444	Ocean	Other	360,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$90,000
445	Fresh Stream/Riv	Coal	390,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$2,665,218	$2,665,218	$66,902	$66,902	$75,000
446	Fresh Stream/Riv	Coal	780,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$5,539,282	$5,539,282	$193,651	$193,651	$75,000
447	Fresh Stream/Riv	Coal	1,390,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
448	Estuary/Tidal Riv	Other	380,000	OnceThrough	No	No	None	$0	$0	$0	$0	$90,000
449	Lake/Reservoir	Nuclear	2,100,000	OnceThrough	No	No	Fish Handling and Return System	$4,144,255	$4,144,255	$140,006	$140,006	$75,000
450	Fresh Stream/Riv	Coal	380,000	Combination	No	No	Fish Handling and Return System	$774,817	$774,817	$26,095	$26,095	$75,000
451	Great Lake	Other	120,000	OnceThrough	No	No	Fish Handling and Return System	$308,792	$308,792	$9,260	$9,260	$75,000
452	Great Lake	Coal	460,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,845,181	$3,845,181	$123,415	$123,415	$75,000
453	Fresh Stream/Riv	Coal	460,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
454	Great Lake	Coal	240,000	OnceThrough	Yes	No	Fine Mesh Trav w/ Fish Handling	$2,281,101	$2,281,101	$71,240	$71,240	$75,000
455	Fresh Stream/Riv	Nuclear	98,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
456	Estuary/Tidal Riv	Coal	620,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$5,910,341	$5,910,341	$150,407	$150,407	$90,000
457	Fresh Stream/Riv	Coal	300,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$2,307,751	$2,307,751	$57,931	$57,931	$75,000
458	Fresh Stream/Riv	Coal	110,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
459	Fresh Stream/Riv	Coal	14,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
460	Fresh Stream/Riv	Coal	120,000	Recirculating	No	Yes	None	$0	$0	$0	$0	$75,000
461	Fresh Stream/Riv	Coal	990,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
462	Great Lake	Coal	550,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$4,693,678	$4,693,678	$139,331	$139,331	$75,000
463	Lake/Reservoir	Nuclear	600,000	Combination	No	No	Fish Handling and Return System	$1,088,627	$1,088,627	$40,708	$40,708	$75,000
464	Fresh Stream/Riv	Coal	300,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,459,139	$2,459,139	$81,839	$81,839	$75,000
465	Fresh Stream/Riv	Coal	560,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$4,709,936	$4,709,936	$141,360	$141,360	$75,000
466	Fresh Stream/Riv	Coal	46,000	OnceThrough	No	No	Fish Handling and Return System	$135,272	$135,272	$4,272	$4,272	$75,000
467	Fresh Stream/Riv	Other	70,000	OnceThrough	No	No	Fish Handling and Return System	$166,824	$166,824	$6,356	$6,356	$75,000
468	Fresh Stream/Riv	Coal	300,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
469	Fresh Stream/Riv	Coal	40,000	Other	No	Yes	None	$0	$0	$0	$0	$75,000
470	Fresh Stream/Riv	Nuclear	360,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$2,604,583	$2,604,583	$91,795	$91,795	$75,000
471	Fresh Stream/Riv	Coal	450,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
472	Estuary/Tidal Riv	Other	240,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$1,487,122	$1,487,122	$50,391	$50,391	$90,000
473	Estuary/Tidal Riv	Other	530,000	OnceThrough	Yes	Yes	Fine Mesh Traveling Screen	$3,787,393	$3,787,393	$94,673	$94,673	$90,000
474	Great Lake	Coal	380,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$3,192,473	$3,192,473	$95,412	$95,412	$75,000
475	Lake/Reservoir	Coal	790,000	Combination	No	No	None	$0	$0	$0	$0	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
476	Fresh Stream/Riv	Coal	530,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
477	Fresh Stream/Riv	Coal	610,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$5,206,954	$5,206,954	$149,533	$149,533	$75,000
478	Lake/Reservoir	Nuclear	1,170,000	OnceThrough	No	No	Fish Handling and Return System	$2,313,355	$2,313,355	$79,908	$79,908	$75,000
479	Fresh Stream/Riv	Coal	300,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$2,518,999	$2,518,999	$81,047	$81,047	$75,000
480	Estuary/Tidal Riv	Coal	970,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$7,117,155	$7,117,155	$167,017	$167,017	$90,000
481	Fresh Stream/Riv	Coal	520,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
482	Fresh Stream/Riv	Other	90,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$876,076	$876,076	$29,591	$29,591	$75,000
483	Fresh Stream/Riv	Comb Cycle	130,000	Combination	No	No	None	$0	$0	$0	$0	$75,000
484	Fresh Stream/Riv	Oil	260,000	OnceThrough	No	No	Fish Handling and Return System	$705,356	$705,356	$19,678	$19,678	$75,000
485	Estuary/Tidal Riv	Coal	180,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$1,331,750	$1,331,750	$32,154	$32,154	$90,000
486	Fresh Stream/Riv	Coal	140,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$962,776	$962,776	$27,700	$27,700	$75,000
487	Lake/Reservoir	Other	520,000	OnceThrough	No	No	Fish Handling and Return System	$1,034,640	$1,034,640	$36,526	$36,526	$75,000
488	Fresh Stream/Riv	Coal	220,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
489	Fresh Stream/Riv	Other	63,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$685,831	$685,831	$24,262	$24,262	$75,000
490	Fresh Stream/Riv	Coal	38,000	Recirculating	No	No	None	$0	$0	$0	$0	$75,000
491	Great Lake	Coal	66,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$756,310	$756,310	$24,959	$24,959	$75,000
492	Fresh Stream/Riv	Coal	690,000	Combination	No	No	Fish Handling and Return System	$1,654,100	$1,654,100	$48,730	$48,730	$75,000
493	Fresh Stream/Riv	Coal	75,000	OnceThrough	No	No	Fish Handling and Return System	$182,461	$182,461	$6,639	$6,639	$75,000
494	Lake/Reservoir	Other	370,000	OnceThrough	No	No	Fish Handling and Return System	$727,770	$727,770	$25,529	$25,529	$75,000
495	Fresh Stream/Riv	Coal	460,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$3,059,435	$3,059,435	$87,083	$87,083	$75,000
496	Fresh Stream/Riv	Coal	38,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$423,094	$423,094	$15,837	$15,837	$75,000
497	Lake/Reservoir	Coal	1,240,000	OnceThrough	No	No	Fish Handling and Return System	$2,414,364	$2,414,364	$83,162	$83,162	$75,000
498	Great Lake	Coal	210,000	OnceThrough	Yes	No	Fine Mesh Trav w/ Fish Handling	$1,788,730	$1,788,730	$51,230	$51,230	$75,000
499	Ocean	Other	180,000	OnceThrough	No	No	Fish Handling and Return System	$489,001	$489,001	$12,663	$12,663	$90,000
500	Great Lake	Coal	190,000	Combination	No	No	Fine Mesh Trav w/ Fish Handling	$1,505,392	$1,505,392	$46,877	$46,877	$75,000
501	Fresh Stream/Riv	Coal	39,000	OnceThrough	No	No	Fish Handling and Return System	$108,943	$108,943	$3,840	$3,840	$75,000
502	Estuary/Tidal Riv	Comb Cycle	44,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$493,753	$493,753	$17,343	$17,343	$90,000
503	Fresh Stream/Riv	Coal	200,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,581,199	$1,581,199	$48,949	$48,949	$75,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
504	Fresh Stream/Riv	Coal	140,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,246,248	$1,246,248	$38,937	$38,937	$75,000
505	Fresh Stream/Riv	Other	35,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$421,139	$421,139	$15,043	$15,043	$75,000
506	Fresh Stream/Riv	Other	1,010,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$5,518,710	$5,518,710	$170,854	$170,854	$75,000
507	Fresh Stream/Riv	Other	72,000	OnceThrough	No	No	Fish Handling and Return System	$210,378	$210,378	$6,442	$6,442	$75,000
508	Fresh Stream/Riv	Oil	75,000	Recirculating	No	Yes	None	$0	$0	$0	$0	$75,000
509	Lake/Reservoir	Coal	290,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
510	Estuary/Tidal Riv	Nuclear	2,400,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$16,875,397	$16,875,397	$393,401	$393,401	$90,000
511	Estuary/Tidal Riv	Other	160,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,539,775	$1,539,775	$42,000	$42,000	$90,000
512	Lake/Reservoir	Other	280,000	OnceThrough	No	No	Fish Handling and Return System	$584,577	$584,577	$20,881	$20,881	$75,000
513	Estuary/Tidal Riv	Oil	110,000	OnceThrough	No	No	Fish Handling and Return System	$240,807	$240,807	$8,532	$8,532	$90,000
514	Ocean	Oil	180,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$1,932,155	$1,932,155	$45,646	$45,646	$90,000
515	Fresh Stream/Riv	Coal	90,000	OnceThrough	No	No	Fish Handling and Return System	$214,580	$214,580	$7,499	$7,499	$75,000
516	Lake/Reservoir	Coal	110,000	Other	No	No	Fish Handling and Return System	$314,859	$314,859	$8,653	$8,653	$75,000
517	Fresh Stream/Riv	Coal	320,000	OnceThrough	No	No	Fish Handling and Return System	$745,665	$745,665	$22,821	$22,821	$75,000
518	Lake/Reservoir	Other	720,000	OnceThrough	No	No	Fish Handling and Return System	$1,437,569	$1,437,569	$50,511	$50,511	$75,000
519	Fresh Stream/Riv	Coal	950,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
520	Lake/Reservoir	Coal	560,000	OnceThrough	No	No	Fish Handling and Return System	$1,381,513	$1,381,513	$38,776	$38,776	$75,000
521	Lake/Reservoir	Other	190,000	OnceThrough	No	No	Fish Handling and Return System	$391,428	$391,428	$13,268	$13,268	$75,000
522	Fresh Stream/Riv	Other	140,000	Combination	No	Yes	Fine Mesh Traveling Screen	$820,949	$820,949	$27,388	$27,388	$75,000
523	Estuary/Tidal Riv	Other	360,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$2,673,080	$2,673,080	$63,952	$63,952	$90,000
524	Fresh Stream/Riv	Other	210,000	OnceThrough	No	Yes	None	$0	$0	$0	$0	$75,000
525	Lake/Reservoir	Coal	78,000	OnceThrough	No	No	Fish Handling and Return System	$214,248	$214,248	$6,835	$6,835	$75,000
526	Fresh Stream/Riv	Coal	1,160,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$8,179,249	$8,179,249	$287,687	$287,687	$75,000
527	Fresh Stream/Riv	Coal	680,000	OnceThrough	No	No	None	$0	$0	$0	$0	$75,000
528	Fresh Stream/Riv	Coal	110,000	Combination	No	No	Fish Handling and Return System	$250,951	$250,951	$8,789	$8,789	$75,000
529	Fresh Stream/Riv	Comb Cycle	41,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$490,252	$490,252	$16,484	$16,484	$75,000
530	Lake/Reservoir	Coal	100,000	OnceThrough	Yes	No	Fish Handling and Return System	$297,106	$297,106	$8,195	$8,195	$75,000
531	Estuary/Tidal Riv	Other	42,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$432,089	$432,089	$13,737	$13,737	$90,000

Model Plant Compliance Costs for the Section 316(b) Existing Facility Proposed Rule

Plant Code *	Water Body Type	Steam Plant Fuel Type	Design Intake Flow (gpm)	Baseline Cooling System **	Passive Intake?	Fish Handling and/ or Return?	Compliance CWIS Technology Modification	CWIS Technolgy Retrofit Capital Cost	Total Capital	Intake CWIS Technology O&M	Total O&M Costs	Annual Monitoring Cost
532	Estuary/Tidal Riv	Oil	920,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$5,251,551	$5,251,551	$161,830	$161,830	$90,000
533	Fresh Stream/Riv	Other	70,000	Unknown	No	No	Fish Handling and Return System	$170,133	$170,133	$6,356	$6,356	$75,000
534	Fresh Stream/Riv	Coal	56,000	OnceThrough	No	No	Fish Handling and Return System	$142,950	$142,950	$4,863	$4,863	$75,000
535	Estuary/Tidal Riv	Other	76,000	OnceThrough	No	No	Fine Mesh Trav w/ Fish Handling	$897,385	$897,385	$26,839	$26,839	$90,000
536	Estuary/Tidal Riv	Other	520,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$3,906,397	$3,906,397	$94,129	$94,129	$90,000
537	Lake/Reservoir	Coal	170,000	OnceThrough	Yes	No	Fish Handling and Return System	$437,083	$437,083	$12,031	$12,031	$75,000
538	Estuary/Tidal Riv	Other	43,000	OnceThrough	No	Yes	Fine Mesh Traveling Screen	$367,493	$367,493	$13,969	$13,969	$90,000
539	Fresh Stream/Riv	Coal	41,000	OnceThrough	No	No	Fish Handling and Return System	$109,575	$109,575	$4,011	$4,011	$75,000

* In the effort to protect a limited amount of confidential information claimed by respondents to the questionnaire, the Agency has assigned random codes to mask facility identities.

** For the purposes of the costing methodology used for this proposed rule, the Agency considers combination cooling systems to be the equivalent of once-through. However, compliance requirements may distinguish between the types under certain special cases (for instance, a mixed-mode facility that may operate in essentially recirculating mode save certain time periods).

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Appendix B: Technology Cost Curves

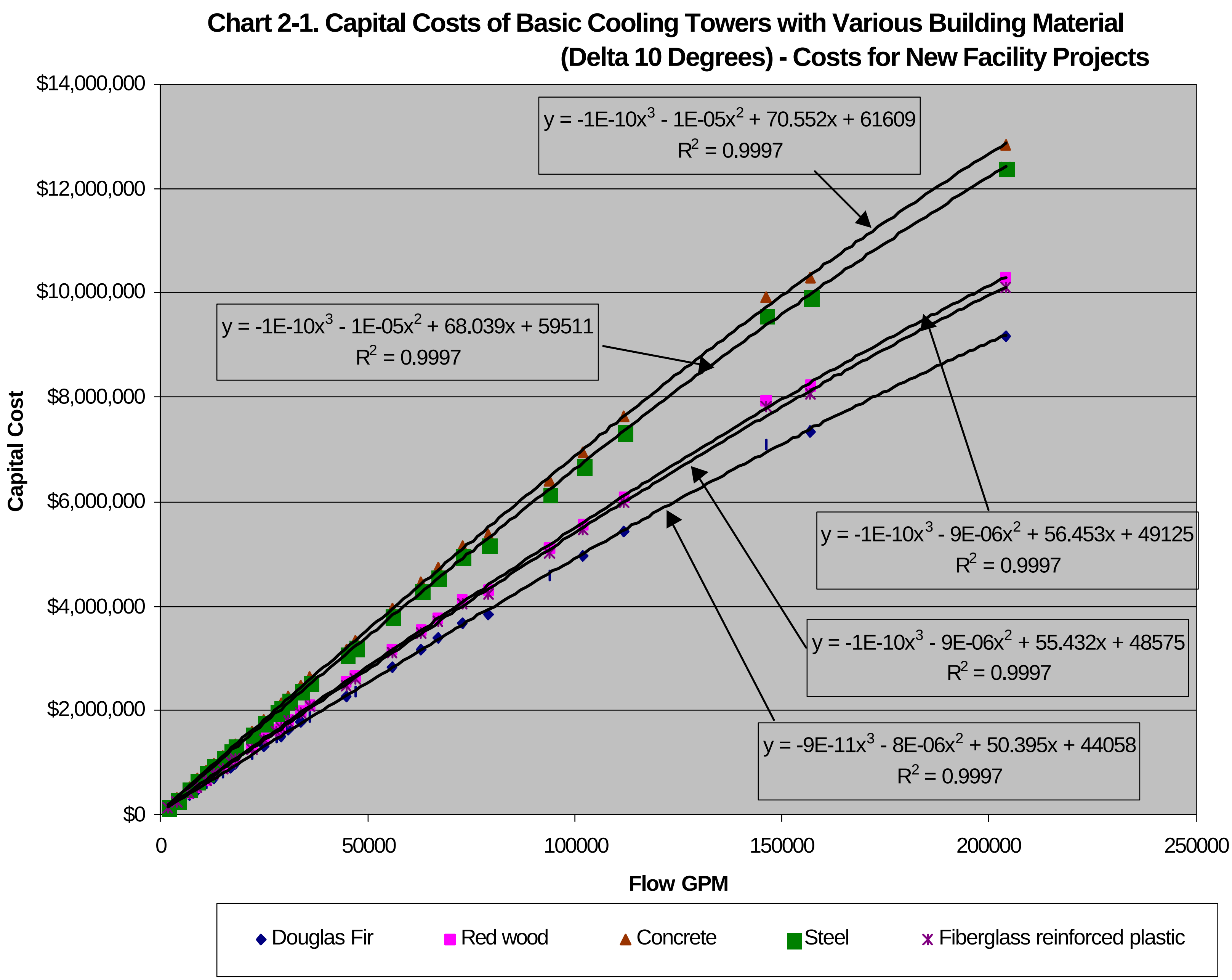


Chart 2-1. Capital Costs of Basic Cooling Towers with Various Building Material (Delta 10 Degrees) - Costs for New Facility Projects
$14,000,000
$12,000,000
$10,000,000
$8,000,000
$6,000,000
$4,000,000
$2,000,000
$0
Capital Cost
0
50000
100000
150000
200000
250000
Flow GPM
y = -1E-10x3 - 1E-05x2 + 70.552x + 61609
R2 = 0.9997
y = -1E-10x3 - 1E-05x2 + 68.039x + 59511
R2 = 0.9997
y = -1E-10x3 - 9E-06x2 + 56.453x + 49125
R2 = 0.9997
y = -1E-10x3 - 9E-06x2 + 55.432x + 48575
R2 = 0.9997
y = -9E-11x3 - 8E-06x2 + 50.395x + 44058
R2 = 0.9997
Douglas Fir
Red wood
Concrete
Steel
Fiberglass reinforced plastic

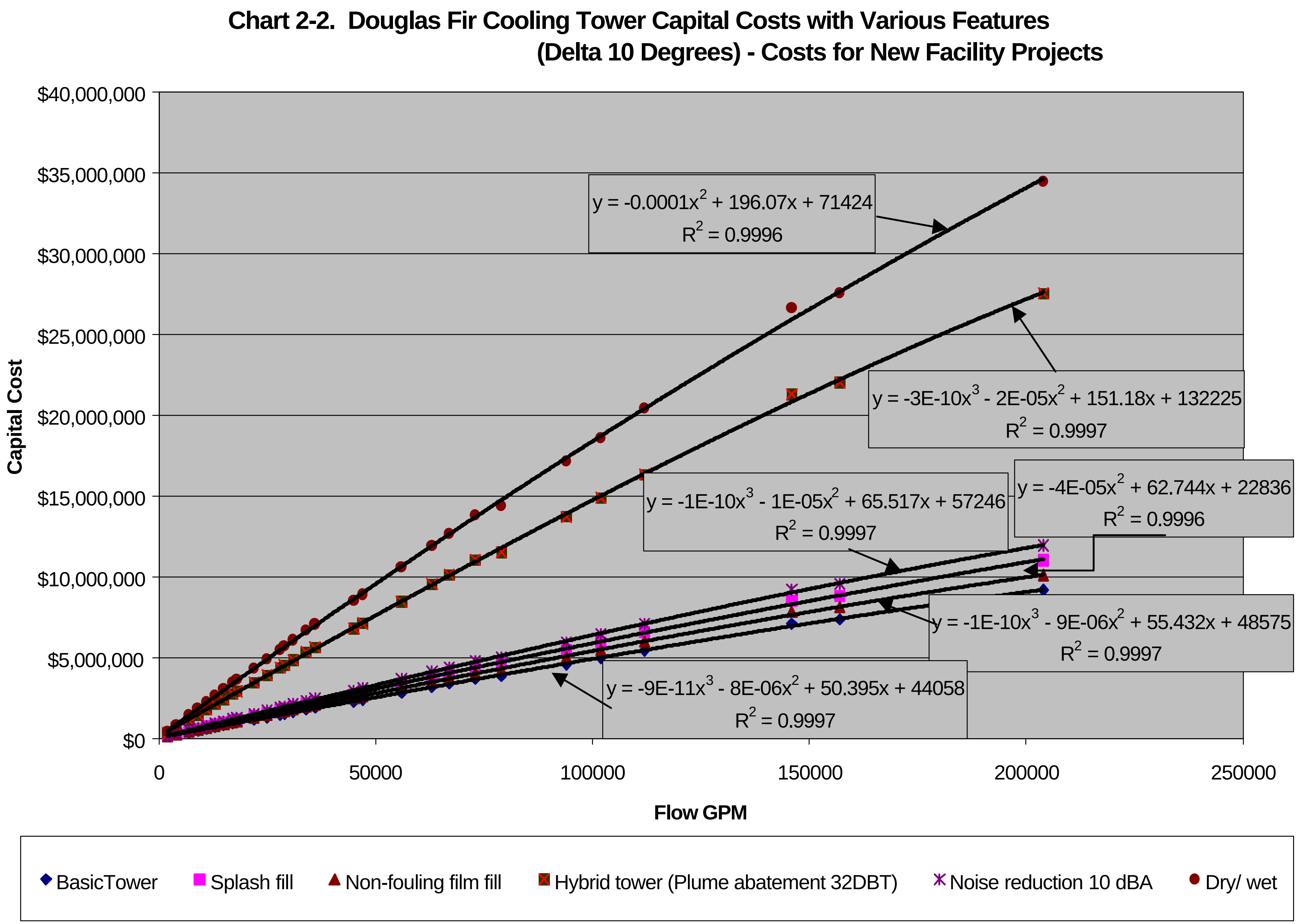


Chart 2-2. Douglas Fir Cooling Tower Capital Costs with Various Features
(Delta 10 Degrees) - Costs for New Facility Projects
$40,000,000
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$0
Capital Cost
0
50000
100000
150000
200000
250000
Flow GPM
y = -0.0001x2 + 196.07x + 71424
R2 = 0.9996
y = -3E-10x3 - 2E-05x2 + 151.18x + 132225
R2 = 0.9997
y = -1E-10x3 - 1E-05x2 + 65.517x + 57246
R2 = 0.9997
y = -4E-05x2 + 62.744x + 22836
R2 = 0.9996
y = -1E-10x3 - 9E-06x2 + 55.432x + 48575
R2 = 0.9997
y = -9E-11x3 - 8E-06x2 + 50.395x + 44058
R2 = 0.9997
BasicTower
Splash fill
Non-fouling film fill
Hybrid tower (Plume abatement 32DBT)
Noise reduction 10 dBA
Dry/ wet

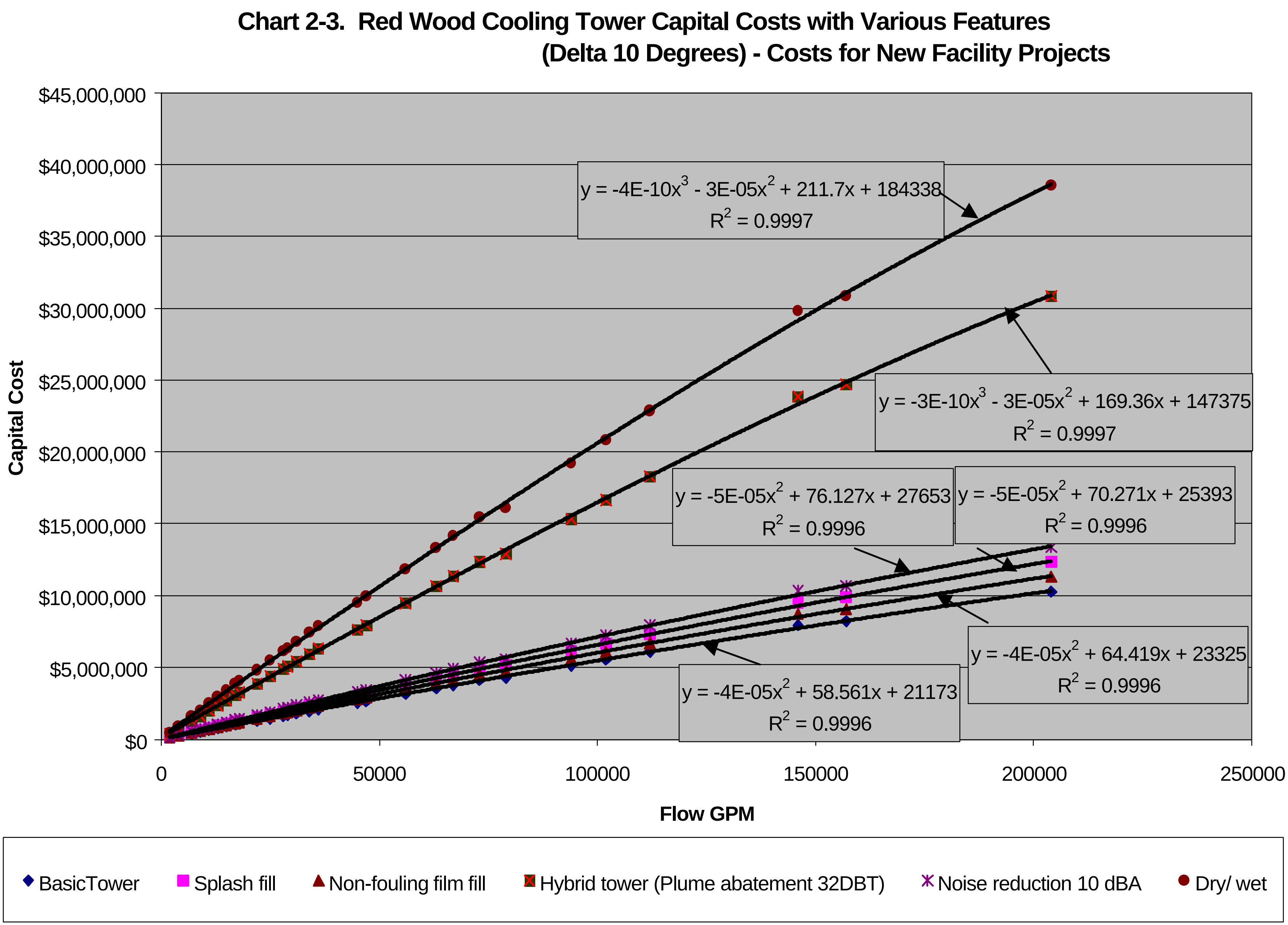


Chart 2-3. Red Wood Cooling Tower Capital Costs with Various Features (Delta 10 Degrees) - Costs for New Facility Projects
Capital Cost
Flow GPM
$45,000,000
$40,000,000
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$0
0
50000
100000
150000
200000
250000
y = -4E-10x3 - 3E-05x2 + 211.7x + 184338
R2 = 0.9997
y = -3E-10x3 - 3E-05x2 + 169.36x + 147375
R2 = 0.9997
y = -5E-05x2 + 76.127x + 27653
R2 = 0.9996
y = -5E-05x2 + 70.271x + 25393
R2 = 0.9996
y = -4E-05x2 + 64.419x + 23325
R2 = 0.9996
y = -4E-05x2 + 58.561x + 21173
R2 = 0.9996
BasicTower
Splash fill
Non-fouling film fill
Hybrid tower (Plume abatement 32DBT)
Noise reduction 10 dBA
Dry/ wet

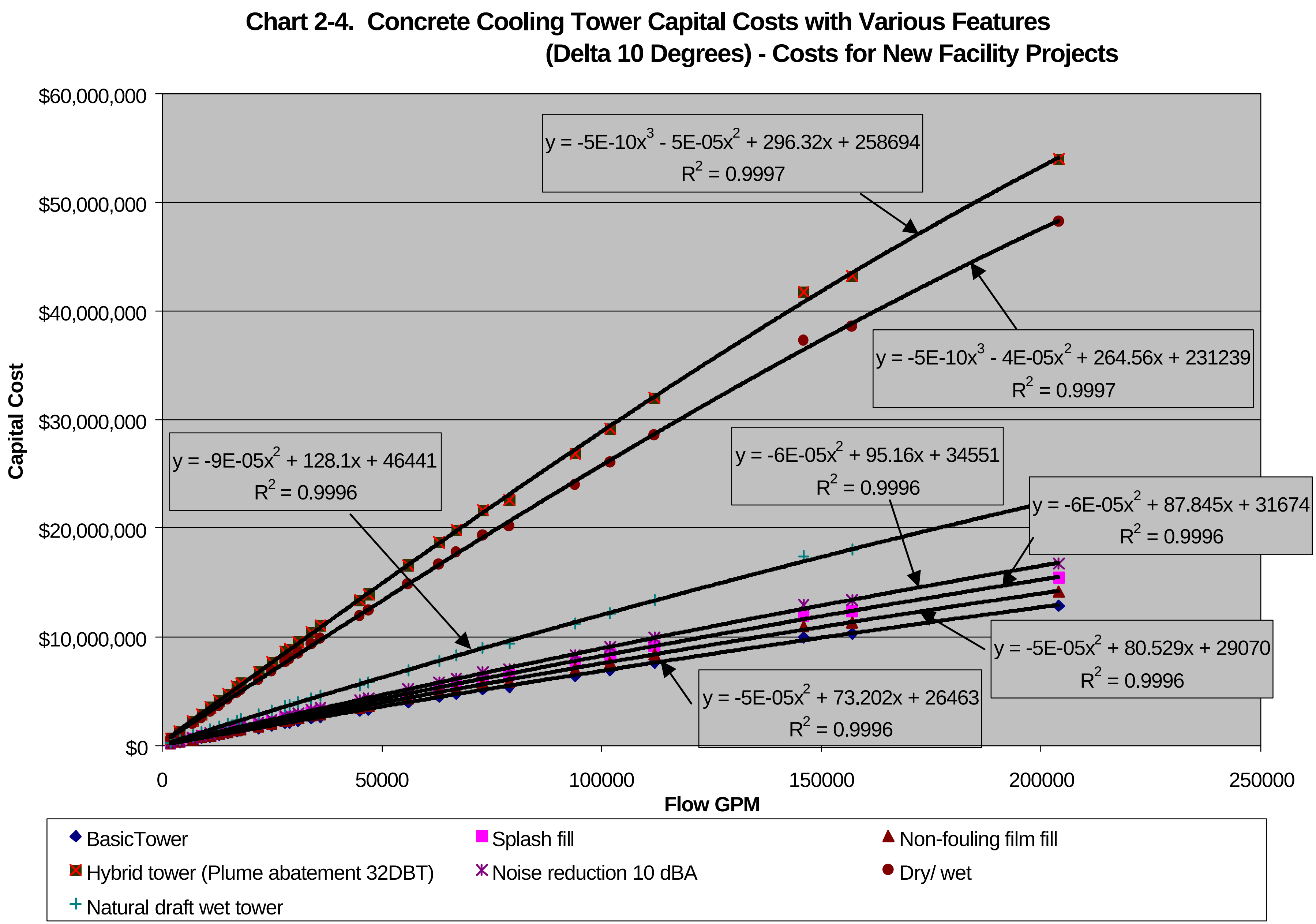


Chart 2-4. Concrete Cooling Tower Capital Costs with Various Features
(Delta 10 Degrees) - Costs for New Facility Projects
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$0
Capital Cost
0
50000
100000
150000
200000
250000
Flow GPM
y = -5E-10x3 - 5E-05x2 + 296.32x + 258694
R2 = 0.9997
y = -5E-10x3 - 4E-05x2 + 264.56x + 231239
R2 = 0.9997
y = -9E-05x2 + 128.1x + 46441
R2 = 0.9996
y = -6E-05x2 + 95.16x + 34551
R2 = 0.9996
y = -6E-05x2 + 87.845x + 31674
R2 = 0.9996
y = -5E-05x2 + 80.529x + 29070
R2 = 0.9996
y = -5E-05x2 + 73.202x + 26463
R2 = 0.9996
BasicTower
Splash fill
Non-fouling film fill
Hybrid tower (Plume abatement 32DBT)
Noise reduction 10 dBA
Dry/ wet
Natural draft wet tower

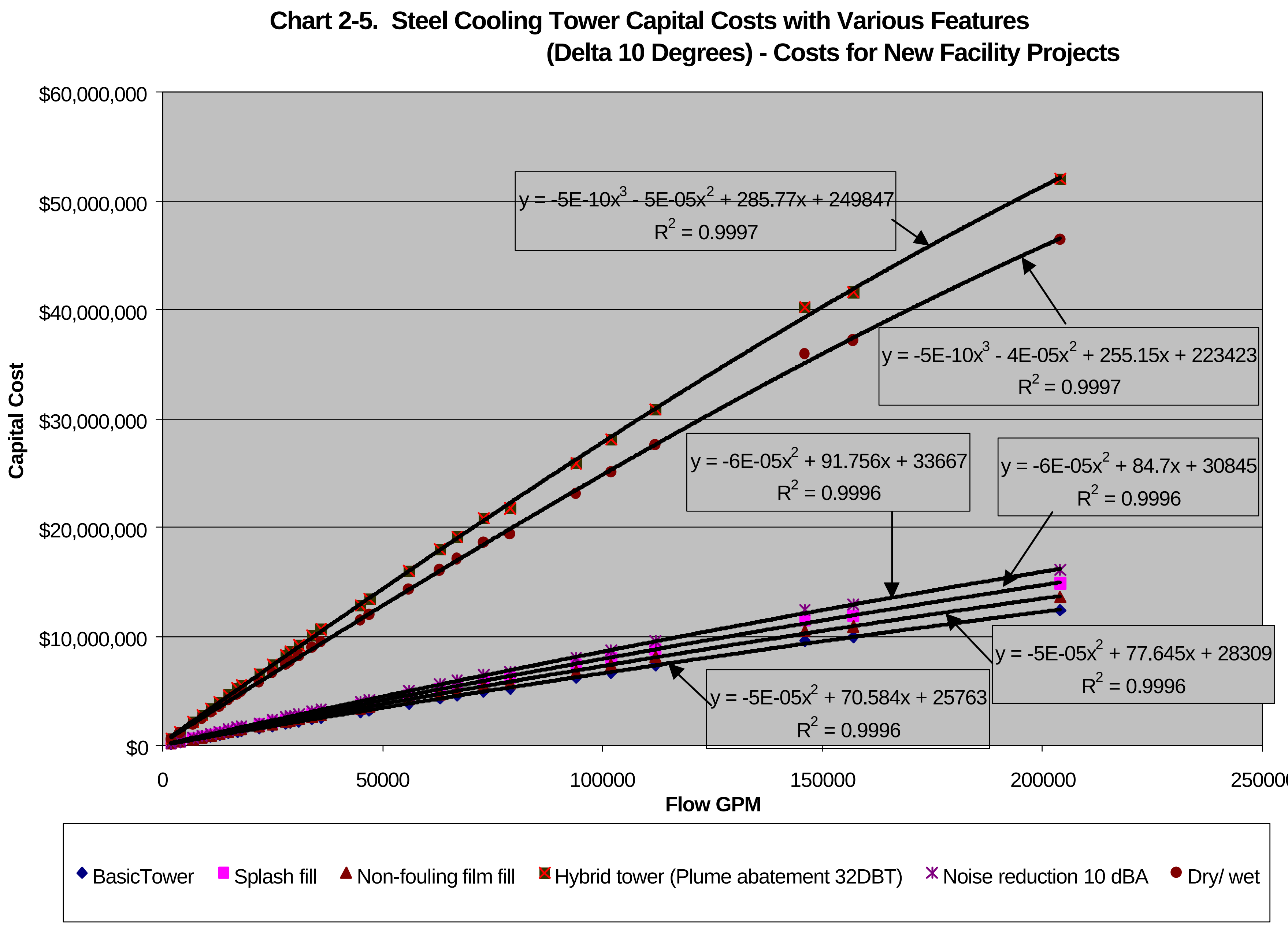


Chart 2-5. Steel Cooling Tower Capital Costs with Various Features
(Delta 10 Degrees) - Costs for New Facility Projects
Capital Cost
$60,000,000
$50,000,000
$40,000,000
$30,000,000
$20,000,000
$10,000,000
$0
0
50000
100000
150000
200000
250000
Flow GPM
y = -5E-10x3 - 5E-05x2 + 285.77x + 249847
R2 = 0.9997
y = -5E-10x3 - 4E-05x2 + 255.15x + 223423
R2 = 0.9997
y = -6E-05x2 + 91.756x + 33667
R2 = 0.9996
y = -6E-05x2 + 84.7x + 30845
R2 = 0.9996
y = -5E-05x2 + 77.645x + 28309
R2 = 0.9996
y = -5E-05x2 + 70.584x + 25763
R2 = 0.9996
BasicTower
Splash fill
Non-fouling film fill
Hybrid tower (Plume abatement 32DBT)
Noise reduction 10 dBA
Dry/ wet

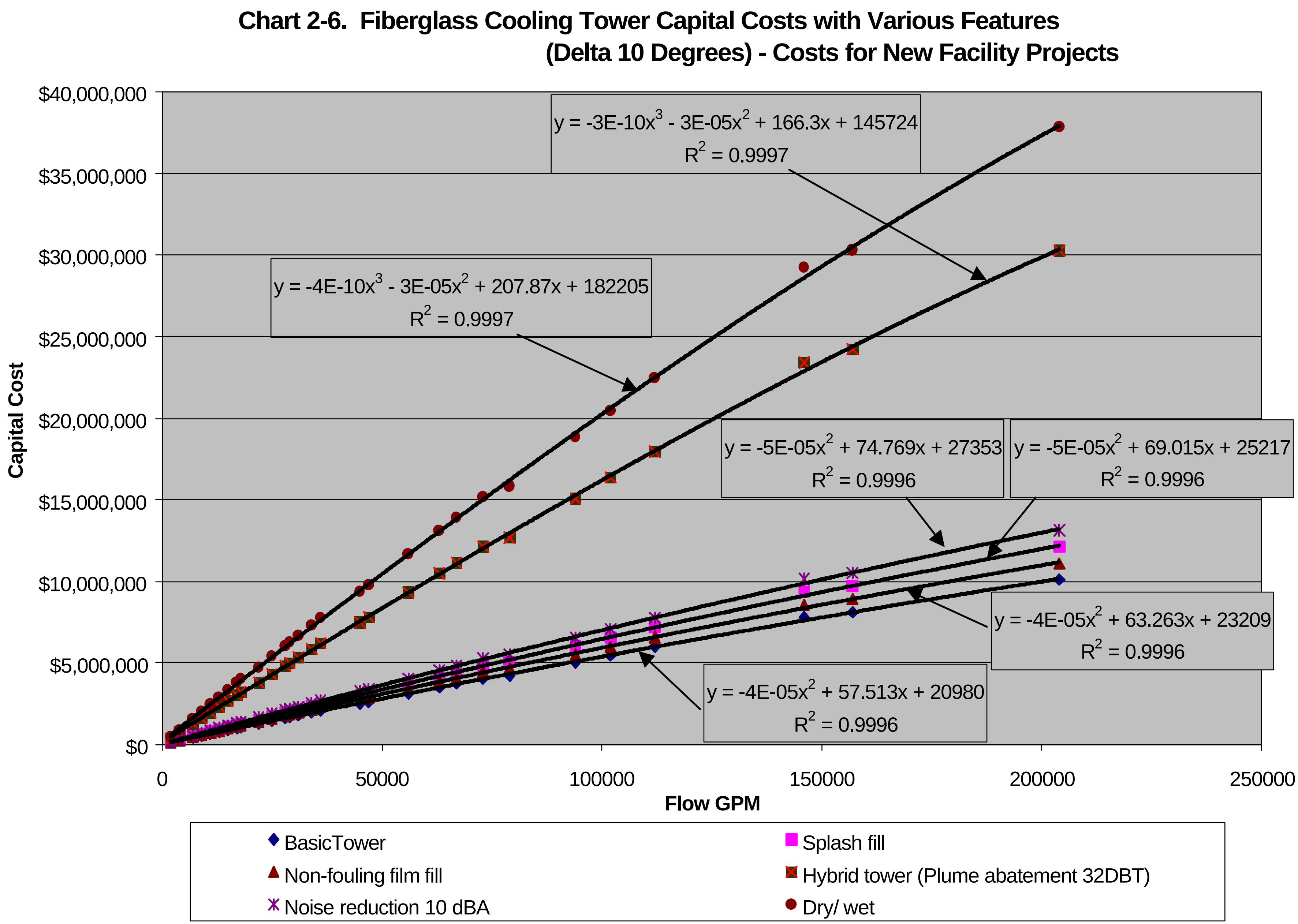


Chart 2-6. Fiberglass Cooling Tower Capital Costs with Various Features
(Delta 10 Degrees) - Costs for New Facility Projects
Capital Cost
$40,000,000
$35,000,000
$30,000,000
$25,000,000
$20,000,000
$15,000,000
$10,000,000
$5,000,000
$0
0
50000
100000
150000
200000
250000
Flow GPM
y = -3E-10x3 - 3E-05x2 + 166.3x + 145724
R2 = 0.9997
y = -4E-10x3 - 3E-05x2 + 207.87x + 182205
R2 = 0.9997
y = -5E-05x2 + 74.769x + 27353
R2 = 0.9996
y = -5E-05x2 + 69.015x + 25217
R2 = 0.9996
y = -4E-05x2 + 63.263x + 23209
R2 = 0.9996
y = -4E-05x2 + 57.513x + 20980
R2 = 0.9996
BasicTower
Splash fill
Non-fouling film fill
Hybrid tower (Plume abatement 32DBT)
Noise reduction 10 dBA
Dry/ wet

Chart 2-7. Actual Capital Costs for New Facility Tower Projects and Comparable Costs from EPA Cooling Tower Cost Curves

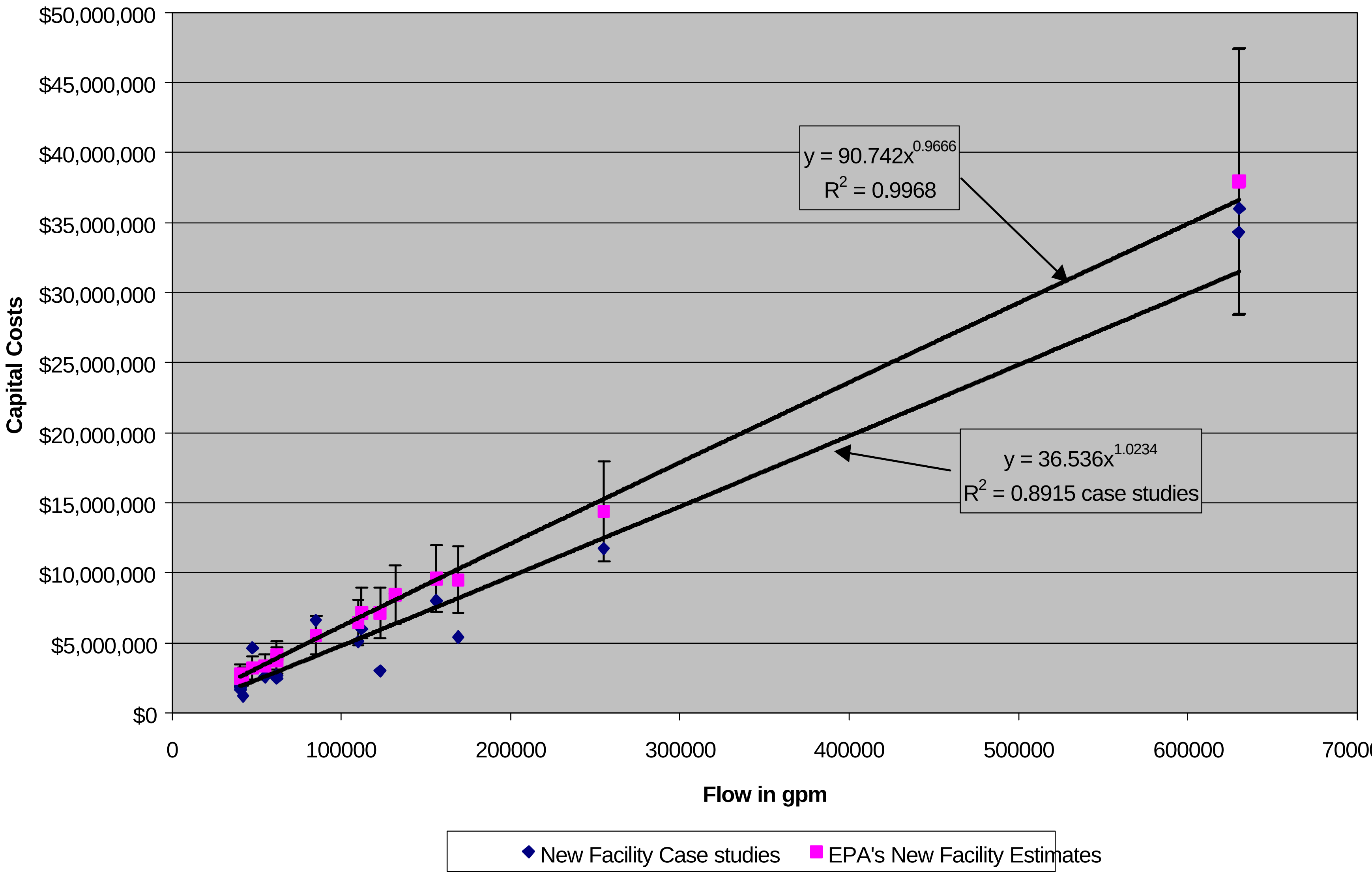


Chart 2-8. O&M Redwood Tower Annual Costs

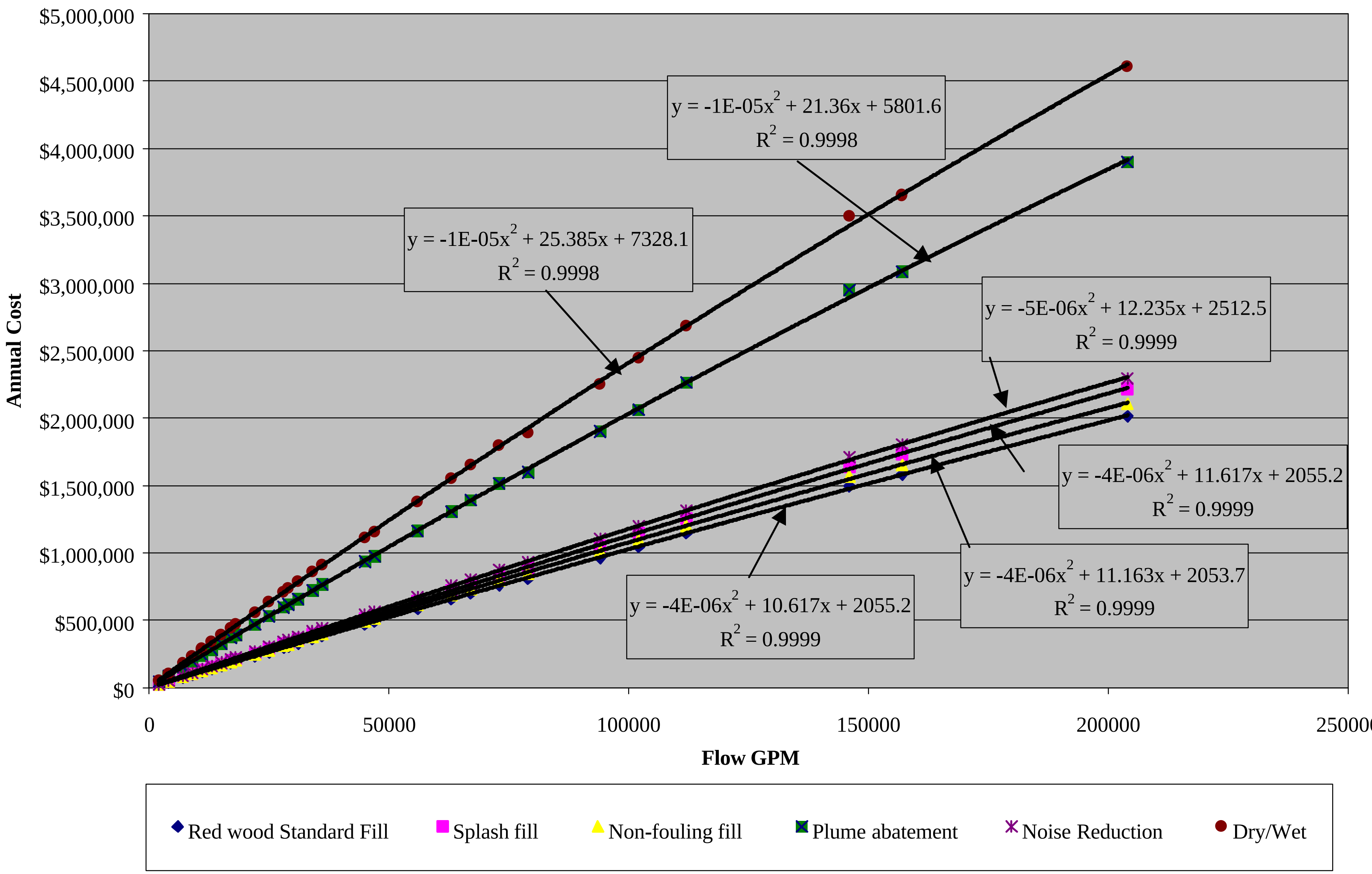
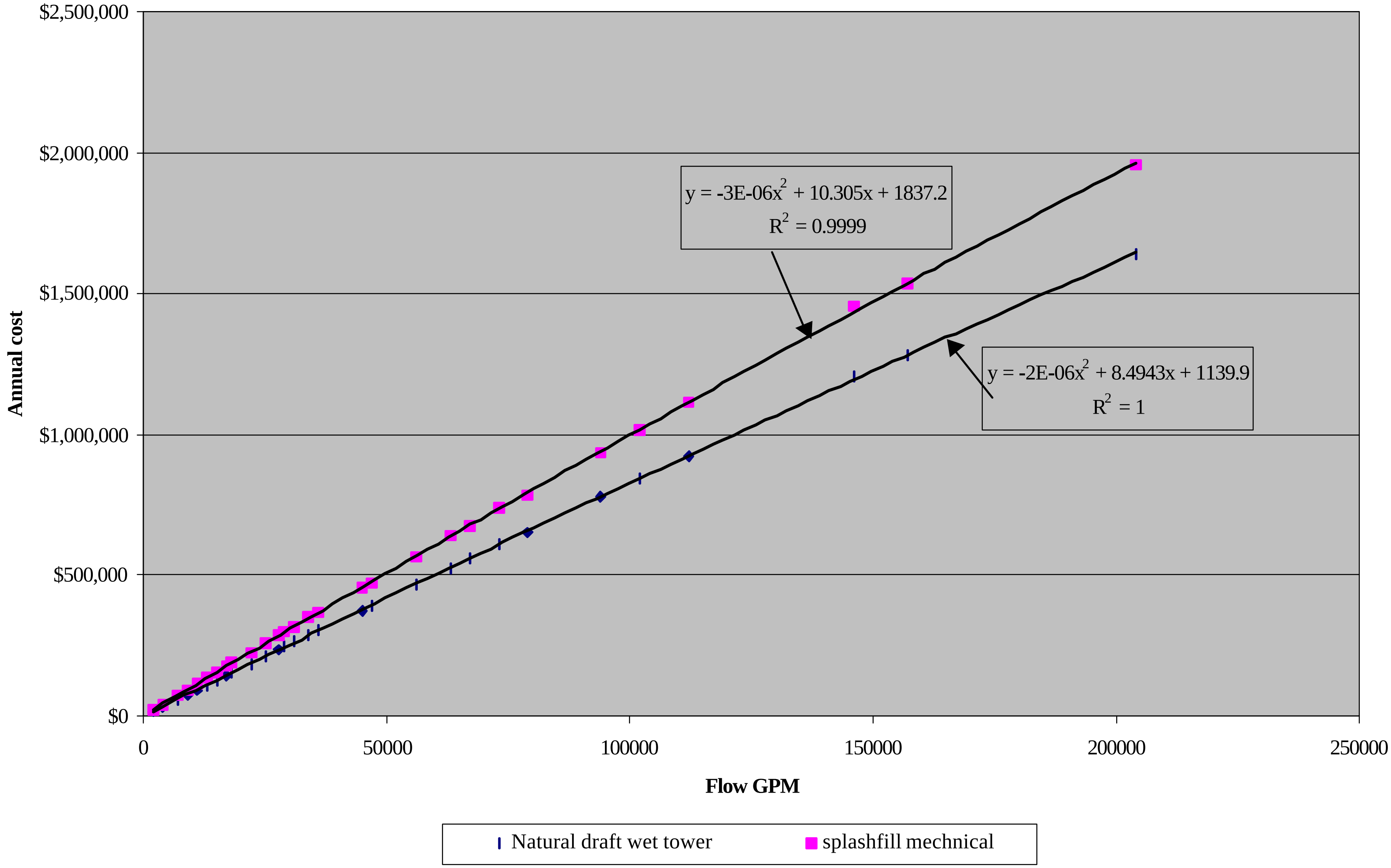


Chart 2-9. O&M Concrete Tower Annual Costs



Appendix C: Cost Estimate Report for a Hypothetical Cooling System Conversion

The Agency conducted a detailed analysis of cost estimates for the hypothetical installation of a cooling tower system at Bowline Point Station along the Hudson River in New York State. The Agency compared the results of its analysis to that included in the Draft Environmental Impact Statement (DEIS) of four Hudson River power plants. Power Tech Associates of New Jersey examined the costs of converting Bowline Point's cooling system from once-through to recirculating in Appendix VIII-3 of the DEIS, which was submitted to New York State in December, 1999. Section IV-B of the DEIS contains detailed information on the existing cooling water system and site characteristics. The Power Tech report presents a narrative review of cooling tower technologies, a description of most key engineering assumptions for and site characteristics affecting unit cost estimates, an environmental impact discussion of the cooling towers, capital cost estimates at the aggregate level, and an economic analysis of these costs.

The focus of the Agency's analysis was to develop detailed unit cost estimates for comparison to the Power Tech aggregate capital cost estimates. Although the Appendix VIII-3 cost estimates are at the aggregate level, the DEIS (in addition to historical engineering work on behalf of the four Hudson plants) provides sufficient detail to afford comparison to detailed unit cost estimates developed by EPA. The sources of cost data and reference information for the Agency's unit cost estimates are presented below. The Agency chose to develop the detailed unit cost estimates for the Bowline Plant, in order to examine the overall veracity of the estimates prepared by Power Tech Associates. The Agency could have chosen to examine any of the four Hudson Plants, but selected Bowline because the degree of detail in the DEIS (and supporting documentation) was high and the uncertainty about site characteristics was the lowest amongst the four plants. For instance, the Agency had intended to also examine the Roseton Station, but was unable to determine the distance between the proposed towers and the condensers from the Power Tech report. In turn, the Agency was unable to develop detailed unit costs for the Roseton Station due to this key data omission.[1]

The Agency notes that the Mirant Bowline, LLC (the new owners and operators of Bowline Point Station) currrently are in the process of obtaining approval for expansion of the plant with planned construction of a third, combined-cycle unit on the site. If this construction commences as planned, the configuration of the plant would be significantly altered. The land proposed by Power Tech Associates for construction of the cooling tower system for units 2 and 3 (as analyzed herein) would likely be utilized in part for the new generating unit. Therefore, for this reason and others, this analysis should be considered hypothetical in nature.

[1] The Agency, however, obtained schematics of the Roseton Station retrofit design (1977) late in the development of this report. The design schematic by Central Hudson (1977, Exhibit 2) proposes nearly complete reuse of the existing circulating piping system with minimal additional circulating piping required to connect the tower system. From the detailed schematic, EPA estimates that the lineal feet of new circulating water piping as less than 900 feet (that is, 2300 feet less than the Power Tech design for Bowline Point Station). In addition, the Central Hudson schematic proposes for the existing intake discharge piping to be completely reused, thereby eliminating the need for new makeup and blowdown piping. Therefore, significant piping and civil works cost savings would be afforded for the Roseton Station over the comparably sized and situated Bowline Point Station. A rough estimate based on the detailed costs of Bowline Point developed by EPA would provide a total project capital cost savings of approximately $6 million.

Bowline Point Station is a fossil-fueled plant cooled by a once-through system withdrawing from the Hudson River. The station is located approximately forty miles north of New York City in Haverstraw. The plant is located on a flat expanse of land. The property encompasses a cove (referred to as Bowline Pond) from which cooling water is withdrawn. The station utilizes two steam generators, each sized at 622 megawatts, nameplate capacity. The units were installed in 1972 and 1974. Their utilization had slumped in the mid-1990s, with a rise shown after 1997. The existing once-through cooling system services two condensers at a maximum design flow rate of 1,110,000 gallons per minute (gpm). However, the plant generally operates with reduced pump usage for a design flow rate of 740,120 gpm. Both of these flow rates represent greater than one percent of the mean tidal flow as presented in the DEIS. The Agency notes that in the facility's response to the detailed questionnaire, Bowline Point reported a significantly lower flow rate for its design intake flow than either capacity described here. In fact, the design intake flow reported by Bowline for the detailed questionnaire was very similar to the average annual intake (in gallons per day) for the year 1998. In turn, the Agency intends to update its questionnaire response database to reflect the design flows above. This is an important fact for the consideration of the Agency's methodology for estimating costs of conversions from once-through to recirculating wet cooling systems (which is outlined in Chapter 2 of this document), as the Agency utilizes the design intake flow as the basis for assessing these costs.

The design circulating cooling flow estimated by Power Tech for the cooling towers is 642,000 gpm. Power Tech based their analysis on four-hybrid, wet-dry cooling towers each with 160,500 gpm of design circulating capacity. Power Tech states in Appendix VIII-3, page 10, "based on a conservative approach, the wet/dry mechanical draft tower was chosen as the best way to evaluate economic…concerns associated with retrofitting cooling towers to the Hudson River plants." As discussed in Grogan (2000), "a wet only (wet mechanical cooling tower) cooling water system will have substantially less environmental impact and be less costly to the NY consumers. The trade-off is that the water vapor plume will be visible during more days of the year." The Agency agrees with the Grogan assessment and considers the benefits of a wet/dry cooling system to be debatable for this installation. In 1977, Consolidated Edison conducted a detailed study of the potential effects of a natural-draft wet (only) cooling tower on the local environment near the Roseton Generating Station. The analysis of plume effects from the natural-draft towers (each projected to be about 400 ft tall) showed induced fogging at the station for a total of 85 hours per year, with a peak in February of 40 hours (Con. Ed, 1977; Table 4-1). Outside of 0.8 miles from the station the study predicted 7 hours or less of fogging, in any direction, for the entire year. Plume induced icing, according to the 1977 study, would occur for a total of 45 hours in a single year at the station itself. Outside of 0.8 miles the total hours of icing for any nearby area would be 6 hours or less per year. Because of the similarities in size and location between Roseton and Bowline Stations, the Agency considers these results to be relatively transferable to the Bowline Point location. However, the remote fogging and icing effects of a natural-draft tower system would be significantly greater than those for a comparably sized mechanical-draft tower, which would be roughly 50 feet in height with a plume that is approximately 30 percent smaller than that of a natural-draft tower. In addition, Central Hudson, et al. (1977) quantified the economic impacts of these effects in the *Report on Cost-Benefit Analysis of Operation of Hudson River Steam-Electric Units with Once-through and Closed-cycle Cooling Systems*. In the report the authors state, "the impact of the operation of the proposed closed-cycle cooling systems in terms of induced fog and icing is not expected to be substantial." This summary refers to the combined total of the four power plants potentially converting to natural-draft wet cooling tower systems. The effects for less than four plants (or a single plant) converting to a mechanical-draft wet cooling tower system would be even less pronounced. Therefore, based on these 1977 analyses by Con. Ed. and Central Hudson, et al., the Agency considers the mechanical draft wet (only) cooling towers to be a viable option for Bowline Point.

Regardless of the configuration of the tower (that is, wet only or hybrid, wet-dry), the cooling flow would be equivalent between the two types. Additionally, the land requirements, site preparation, and civil construction would be nearly identical for both types of tower installations, with the exception of potential support piling requirements. For the wet-dry models, marginal additional support piling (due to increased load) may be necessary. The Agency, in its analysis, has estimated all costs based on mechanical-draft wet (only) cooling towers.

Bowline Point is located roughly 30 miles from Poughkeepsie, NY, which is one of the nearest towns to Bowline included in the city cost index of R.S. Means. The R.S. Means City Cost Index contains other towns in the vicinity of Haverstraw in addition to Poughkeepsie, such as Suffern and White Plains. Haverstraw is, in effect, equidistant from each of these three cities. Poughkeepsie's cost index represents the median and near to the average of these three surrounding city cost indexes. Therefore, the Agency utilized costs index multipliers specific to the median of these three cities for its cost estimates. The DEIS states that truck traffic through Haverstraw would be disruptive to the town, which the Agency cannot dispute. Therefore, in all cases, the Agency estimated the hauling requirements as conservative (that is, small to medium trucks) and to account for alternative routing (that is, long round-trips) to minimize and avoid town traffic disruptions. Additionally, the Bowline Point site covers 245 acres. Based on the detailed aerial photographs (proprietary photos published by www.mapquest.com **and available to the general public through the website, but not for publication), significant available land for staging of construction operations is available.**

Power Tech estimates that the cooling tower system would occupy a total of 6 acres. However, they assert that 13 acres would require clearing and preparation for construction. The plot of land projected for construction would be approximately 800 feet east of the generators in a relatively low-lying, flat area. Power Tech assert that this plot of land is populated by second-growth timber. Detailed aerial photographs reveal brush and small trees covering approximately half of the 13 acres. Additionally, the Power Tech report asserts that the land shows signs of being wetlands, but the body of the DEIS states that the NY DEC does not designate any wetland areas on the Bowline Point property. The USDA soil survey included in Appendix IV-B.1-1 indicates that the tower would be constructed in part urban land, part wet substratum. Based on these factors, the Agency's analysis estimates that significant dewatering control and foundation piling would be required for the construction project.

The existing intake structure is a surface shoreline intake located to the south and west of the generator units. The intake pumps sit immediately behind the intake screens, and, due to a lack of proximity, would not be of use for circulating cooling water between the projected cooling tower location and the condensers. The intake and discharge piping passes approximately 150 meters immediately to the east of the generator house and bends southwesterly to and from the discharge and intake. This piping is in relatively close proximity to the projected location of the cooling towers and could be used for a retrofit design, though, notably, Power Tech does not address this prospect in their engineering assessment. In turn, the detailed cost estimates included in this file estimate that only the existing intake and discharge structures will be used for the conversion design and minimal existing piping will be utilized. Based on the example cooling system conversion cases discussed in Chapter 4, the Agency views this design as potentially unrealistic and perhaps overly conservative with respect to capital costs. In addition, as discussed in footnote 1 above, the detailed engineering schematics the Agency obtained for

the historical, proposed Roseton Generating Station cooling system conversion show significant reuse of existing circulating water piping for that design.

Based on the detailed description provided in the DEIS, the existing intake bays present flexibility for converting to a reduced intake flow for makeup cooling water. Because the intake is comprised of 6 separate bays with dedicated pumping stations, several of the bays could be retrofitted with a reduced size pump or a new variable speed motor to provide makeup water to the cooling towers. The piping delivery to the tower could be configured to branch from the existing piping. Other configurations that maintain the capability to return to once-through cooling could be examined (such as diverting the flow from two bays to the makeup piping and retaining the other four bays for peak-demand, once-through operation). For the Agency's conservative analysis, the design assumes demolition and replacement of three intake pumps, in addition to construction of wholly new intake and discharge piping.

The subject of plant outage for conversion of the cooling system is addressed in Appendix VIII-3 of the DEIS (page 19), where Power Tech states, "it was assumed that each of the [Bowline and Roseton] plants would experience about one month of outage during the winter months." EPA notes that several data sources indicate that the outages could be appreciably lower than this estimate. One data source is an engineering report on Roseton Station from Central Hudson Gas & Electric Corporation (July 1977), which estimates, "as a conservative approach…the downtime cost was calculated for one (1) unit and for ten (10) days," to convert from a once-through to recirculating cooling system. Additionally, the Agency obtained two empirical examples of cooling system conversion projects with durations in one-case significantly less than thirty days and 83 hours in the other (as discussed in the Chapter 4).

The results of the Agency's detailed cost analysis for Bowline Point show that the capital cost estimates presented in Appendix VIII-3 of the DEIS overstate the potential cost to convert from a once-through to recirculating cooling system. The Agency did not compare each line item of the Power Tech prepared capital costs in Appendix VIII, but, rather, focused on the civil works estimates. The Agency prepared two sets of cost estimates: high unit costs and moderate unit costs. The Agency based the high unit costs on extremely conservative assumptions for design variables. The moderate costs are also conservative, but utilize optimized design variables that would reflect a moderate engineering cost estimate. In both cases, the Agency's analysis demonstrates that the Power Tech estimates overstate direct capital costs by approximately 24 to 36 percent. Further, the Agency disagrees with several estimates of project overhead rates used by Power Tech.[2] Considering the total project costs differences, in the Agency's view, the Appendix VIII-3 estimates may overstate total project capital costs by 31 to 42 percent. As described above, the Agency disputes the utility of the wet-dry, hybrid tower for this location. The Agency considers the incorporation of this technology into the DEIS analysis, as stated in Appendix VIII, to be an overly conservative approach. The Agency's analysis, therefore, focuses on the wet only mechanical draft tower system. However, had the Agency incorporated the Power Tech cost estimates for the wet-dry, hybrid system, the Appendix VIII-3 total project capital costs would remain overestimated by 20 to 30 percent, according to the Agency's analysis. Table C-1 shows the Agency's unit cost estimates as compared to those included in Appendix VIII-3 of the DEIS.

[2] In the Agency's view, Appendix VIII-3 incorrectly states the tax rate for New York State, double-counts contractor profit, and double-counts freight and insurance on materials.

Table C-1. Capital Cost Comparison for Hypothetical Cooling System Conversion

Cost Component (1999 $)	App. VIII-3 Estimated Capital Costs	EPA Estimated Capital Costs - Moderate	EPA Estimated Capital Costs - High
Cooling Towers	**21,009,935**	**11,063,569**	**11,063,569**
Site Preparation **Excavation/Backfill for Towers** **Piling for Towers** **CW Piping Civil Works** **CW Pipe** **CW Pumphouse Civil/Structural** **CW Pumps** **CW Pumphouse Cranes**	**41,099,318**	**26,326,577**	**35,084,076**
Concrete Basin for Towers	**2,450,963**	**2,450,963**	**2,450,963**
~~**Condenser Tube Cleaning**~~	**2,081,000**	**-**	**-**
Water Treat and Chem Add			
Electrical	**8,677,100**	**8,677,100**	**8,677,100**
Instrumentation & Controls			
Total Direct Cost (TDC)	**$ 75,318,316**	**$ 48,518,208**	**$ 57,275,708**
~~**Freight & Ins**~~	**2,644,788**	**-**	**-**
Eng & Design	**4,519,099**	**2,911,092**	**3,436,542**
Indirect & Und Costs	**7,531,832**	**4,851,821**	**5,727,571**
Construction Mgt	**3,012,733**	**1,940,728**	**2,291,028**
Sales Tax	**696,301**	**191,264**	**191,264**
Contingency ~~**& Contractor Profit**~~	**15,063,663**	**4,851,821**	**5,727,571**
Turnkey Contract Cost (TCC)	**$ 108,786,731**	**$ 63,264,934**	**$ 74,649,684**
Owner's Costs (3% of TCC)	**3,263,602**	**1,897,948**	**2,239,491**
Start-up & Testing (0.5% of TCC)	**543,934**	**316,325**	**373,248**
Total Project Cost	**$ 112,594,000**	**$ 65,479,000**	**$ 77,262,000**
Approximate $ per kW (nameplate)	91	53	62

Note that the Agency utilized the capital costs for concrete basins, water treatment and chemical addition, and instrumentation and controls presented in Appendix VIII-3 of the DEIS without examining the basis of the cost estimates. In addition, the Agency did not utilize the condenser tube cleaning system as proposed. In the Agency's view, this is a cost that would benefit the performance of the condensers regardless of the cooling system in operation and would not be a critical component of cooling system conversion. The detailed unit cost worksheets developed by the Agency are in the public record of this proposal at DCN 4-2537. The Agency utilized the following references in preparation of the analysis:

References Used in the Cost Analysis:

J.M. Burns and Michilletti, W.C., 2000, "Comparison of Wet and Dry Cooling Systems for Combined Cycle Power Plants," Appendix F to the Comments of the Utility Water Act Group (UWAG) on EPA's Proposed Sec. 316(b) Rule for New Facilities.

J.M. Burns and Tsou, J.L., 2001, "Modular Steam Condenser Replacement Using Corrosion Resistant High Performance Stainless Steel Tubing," Proceedings of the 2001 Conference of the American Society of Mechanical Engineers.

Central Hudson Gas & Electric Corporation, 1977, "Engineering, Environmental (Non-Biological), and Economic Aspects of a Closed-Cycle Cooling System," Roseton Generating Station.

Central Hudson Gas & Electric Corporation, et al., July 1977, "Report on Cost-Benefit Analysis of Operation of Hudson River Steam-Electric Units with Once-through and Closed-cycle Cooling Systems," prepared by Mathtech, Inc., a subsidiary of Mathematica, Inc.

Central Hudson Gas & Electric Corp., et al., 1994, "Utility Responses to New York State Department of Environmental Conservation/Tellus Institute Commnets and Questions on Preliminary DEIS for SPDES Permits for Indian Point 2 and 3, Bowline, and Roseton Power Plants."

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M.S. Peters and Timmerhaus, K.D., 1991, "Plant Design and Economics for Chemical Engineers, Fourth Edition," McGraw-Hill, Inc., New York.

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Appendix D: Dry Cooling

INTRODUCTION

This appendix presents a synopsis of the design and operation of an air-cooled condenser system (dry cooling) and its applicability for existing power plants. The majority of the background information included in this discussion on dry cooling is from references listed at the end of this appendix, the background discussion draws primarily from Burns and Michiletti, 2000.

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. In the Agency's determination, indirect-dry cooling generally is the only application of the technology that would be considered for retrofit situations at existing power plants because a condenser would already be in place for a once-through or recirculated cooling system. For dry cooling towers the turbine exhaust steam exits directly to an air-cooled, finned-tube condenser. In the Agency's view, if this application would be applied to an existing plant, the entire steam turbine would necessarily be replaced or reconfigured in an unprecedented fashion. The costs of steam turbines are significantly more expensive than any type of recirculating cooling system, including the dry cooling systems. The Agency has determined that the feasibility of direct-dry cooling systems for existing plants is not demonstrated and because of the limitations and potential costs is not a candidate for retrofit situations. Therefore, the Agency does not further consider direct-dry cooling systems for existing facilities, though they are referred to significantly throughout the remainder of this appendix. Because direct-dry cooling systems would be more efficient and less costly than indirect-systems (ignoring the feasibility issues addressed above), the Agency's analyses of dry cooling systems using direct-dry cooling systems would show increased energy penalties and signficantly higher costs.

For indirect-dry cooled systems, recirculating fluid (usually water) passes through an air-cooled, finned tube tower. In contrast to direct-dry cooling, indirect-dry cooling does not operate as an air-cooled condenser. In other words, the steam is not condensed within the structure of the dry cooling tower, but instead indirectly through an indirect heat exchanger (that is, a surface condenser). Therefore, the indirect-dry cooling system would need to overcome additional heat resistance in the shell of the condenser compared to the direct dry cooling system. Ultimately, the inefficiency penalties of indirect dry cooling systems will exceed those of direct-dry cooling systems in all cases. Similar to the direct-dry cooling systems, the arrangement of the finned tubes are most generally of an A-frame pattern (which reduces the land area required compared to other configurations). 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. Additionally, because indirect-dry cooled systems also utilize a surface condenser, with additional heat transfer inefficiencies compared to a direct-dry cooled system, the indirect systems are generally considered to be significantly larger than direct systems for comparable heat loads. 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 considerably larger than would be used in a mechanical-draft wet cooling tower.

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%.

Direct-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. However, each of the demonstrations that the Agency has studied is for a direct-dry cooling system configured for a new facility project. As demonstrated in Chapter 5, the comparative energy penalty of a direct-dry cooling plant in a hot environment at peak summer conditions can exceed 12 percent. Additionally, the indirect-dry cooling system would be even less efficient, producing maximum energy penalties of 18 percent according to the Department of Energy (DOE, 2001). Additionally, indirect-dry cooling systems would likely cause prohibitively high exhaust turbine backpressures, thereby potentially debilitating the operation of some plants at peak-summer, peak-demand conditions (DOE, 2001).

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, for direct-dry cooling systems a larger, more costly dry cooling system will produce a smaller temperature difference across the dry cooling tower and, therefore, a lower turbine exhaust pressure. However, as calculated by DOE, the 40 degree F approach indirect-dry cooling towers may actually be less efficient than smaller sized 20 degree F towers in the cases modeled by DOE.

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. Even the highest values of operable exhaust pressures may be exceed with retrofitted indirect-dry cooling systems. For existing facilities, many with aged turbines, this is a fundamental engineering problem for the feasibility of the retrofitted dry cooling system.

In an analysis for the New Facility rule, EPA examined turbine exhaust pressures at the highest design dry bulb temperatures in the U.S. (which were around 100 °F), which 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 showed 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). EPA prepared all of this analysis in the context of direct-dry cooling systems installed at new facility projects. For hypothetical indirect-dry systems at existing facilities, the backpressures would be significantly higher than the values examined by the Agency for the New Facility rule.

In addition, the issue of demonstrated dry cooling systems (even for new facilities) emerges in the context of fossil-fuel and nuclear plants. The largest operating coal-fired 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 a vast number of coal-fired plants within the scope of this proposal. In addition, the design temperature of the direct-dry cooled 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). The Agency reiterates its reservation of applying requirements based on dry cooling at the sizes of coal-fired and nuclear plants in the scope of this proposal.

Costs of Dry Cooling

For the New Facility Final Rule, the Agency projected that the total annualized cost for the dry cooling alternative was $490 million (in 2000 dollars) for 121 facilities. This proposed rule applies to 539 facilities, and therefore, a regulatory option based on dry cooling for all plants would impose a dramatically higher annual compliance cost than that estimated for the New Facility Final Rule. In addition, the costs the dry cooling system would be even more dramatic, due to the fact that the majority of existing facilities within the scope of this rule operate with once-through cooling systems, whereas for the New Facility Final Rule, the vast majority of plants were projected to install recirculating wet cooling at baseline, thereby reducing marginal cost increases.

Although the dry cooling option is extremely effective at reducing impingement and entrainment and would yield annual benefits of $138.2 million for impingement reductions and $1.33 billion for entrainment reductions at existing facilities, it does so at a cost that would be unacceptable. EPA recognizes that dry cooling technology uses extremely low-level or no cooling water intake, thereby reducing impingement and entrainment of organisms to dramatically low levels. However, EPA interprets the use of the word "minimize" in section 316(b) in a manner that allows EPA the discretion to consider technologies that very effectively reduce, but do not completely eliminate, impingement and entrainment and therefore meet the requirements of section 316(b). Although EPA has rejected dry cooling technology as a national minimum requirement, EPA does not intend to restrict the use of dry cooling or to dispute that dry cooling may be the appropriate cooling technology for some facilities. For example, facilities that are repowering and replacing the entire infrastructure of the facility may find that dry cooling is an acceptable technology in some cases. A State may choose to use its own authorities to require dry cooling in areas where the State finds its fishery resources need additional protection above the levels provided by these technology-based minimum standards.

Methodology for Dry Cooling Cost Estimates at Existing Facilities

For the purposes of approximating the hypothetical costs of retrofitting to dry cooling for existing facilities, the Agency used the following methodology for developing facility-level costs estimates:

- Capital costs for the dry cooling towers were estimated using the cost equation that was developed for the New Facility Rule (see the next section for the New Facility dry cooling cost estimates).
- The cost equations are based on equivalent cooling water flow rates (gpm) using the once-through design intake cooling flow as the independent variable. To aviod using the equation outside of its valid range, for facilities with

intake flows greater than 225,000 gpm (which is the maximum equation input value plus 10%), costs for multiple equal size "units" were developed and then added together.
- An additional 5 percent was added to the capital costs as an "allowance" for unforseen costs.
- A cost factor of 5 percent was added to the dry tower capital costs to account for retrofit costs.
- Intake pumping was assumed to decrease to zero or near zero. Therefore, no costs are included for intake or piping modifications.

The dry cooling capital cost equation is shown below:

$$\text{Capital Cost (Dollars)} = -0.00000000008*(\text{gpm})^3 + 0.0001*(\text{gpm})^2 + 189.77*(\text{gpm}) + 800490$$

Note that the capital costs do not include any consideration for replacement or modification of the steam turbines. Nor do the O&M costs below include consideration of the effects on turbine efficiency resulting from the differences in turbine exhaust pressure caused by changes in the cooling system.

Dry Cooling O&M Costs

EPA has revised the O&M costs using a different basis than was used for the New Facility Rule compliance cost estimates. Rather than base the costs on factors applied to the capital cost as was previously done, EPA based the O&M cost on energy requirements and cost information obtained from facility personnel and an air-cooled condenser manufacturer.

O&M cost components include the following:

- Labor costs starting at $12,000/yr for a 2,000 gpm equivalent system increasing to a maximum of two full time maintenance personnel (at a salary of $55,250/yr) for a 204,000 gpm equivalent system.
- Fan energy costs are based on 800 gpm/MW and $6,000/MW. The $6,000/MW value is based on EPA's estimated fan energy penalty of 2.4% plus an annual operating duration of 7860 hours and an average electricity value of $30/MW-hr**.
- Costs for grease, oil, and high pressure spray cleaning starting at $500/yr for a 2,000 gpm equivalent system increasing to $19,500 for a 204,000 gpm equivalent system.
- Costs for blade replacement, gaskets and other minor items not covered by warranty starting at $3,000/yr for a 2,000 gpm equivalent system increasing to $9,600/yr for a 204,000 gpm equivalent system.
- Since intake volumes are reduced to near zero, post-compliance monitoring costs are assumed to be zero.

The dry cooling O&M cost equation is shown below:

$$\text{O\&M (Dollars)} = 53.122*(\text{gpm})^{0.8442}$$

A dry cooling system manufacturer has indicated that major components including the air cooled condenser and fan motors should not require replacement over the 30 yr life of the equipment.

** the average electricity price of $30 per MWh is a combination of the energy price and the capacity price for the 530 in-scope facilities modeled by the Integrated Planning Model (IPM). It is a weighted average of the 530 facilities, based on the 2008 IPM base case run using the EPA electricity demand growth projections.

Methodology for Dry Cooling Cost Estimates at New Facilities

EPA estimated the capital costs using relative cost factors for various types of wet towers and air cooled condensers (that is, direct-dry cooling systems), using the cost of a comparable wet tower constructed of Douglas Fir as the basis. EPA used cost factors developed by industry experts who manufacture, sell and install cooling towers, including air cooled systems, for power plants and other applications. EPA based the capital 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 ºF) 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 ºF to yield capital cost estimates for a dry tower with a delta of 5 ºF. 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.

Note that the source document for the factors forming the basis of the estimates 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 §316(b) analyses 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.

Using the estimated costs, EPA developed cost equations using a polynomial curve fitting function. Table 1 presents capital cost equations for dry towers with deltas of 5 and 10 degrees.

Table 1. Capital Cost Equations of Dry Cooling Towers with Delta of 5 °F and 10 °F

Delta	Capital Cost Equation[1]	Correlation Coefficient
5 ºF	$y = -2E\text{-}10x^3 + 0.0002x^2 + 337.56x + 973608$	$R^2 = 0.9989$
10 ºF	$y = -8E\text{-}11x^3 + 0.0001x^2 + 189.77x + 800490$	$R^2 = 0.9979$

1) x is for flow in gpm and y is cost in dollars.

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 ºF 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 ºF (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)

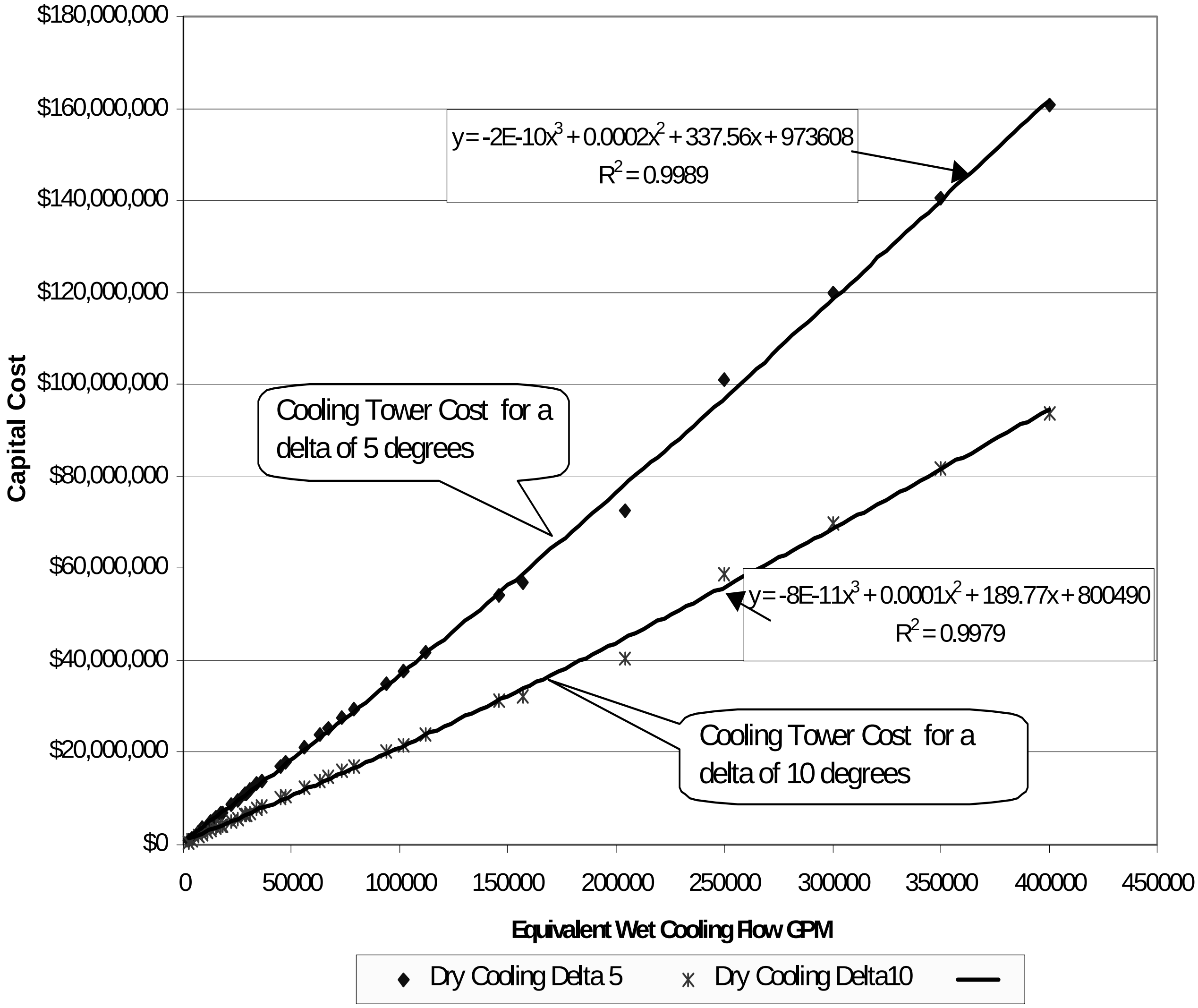
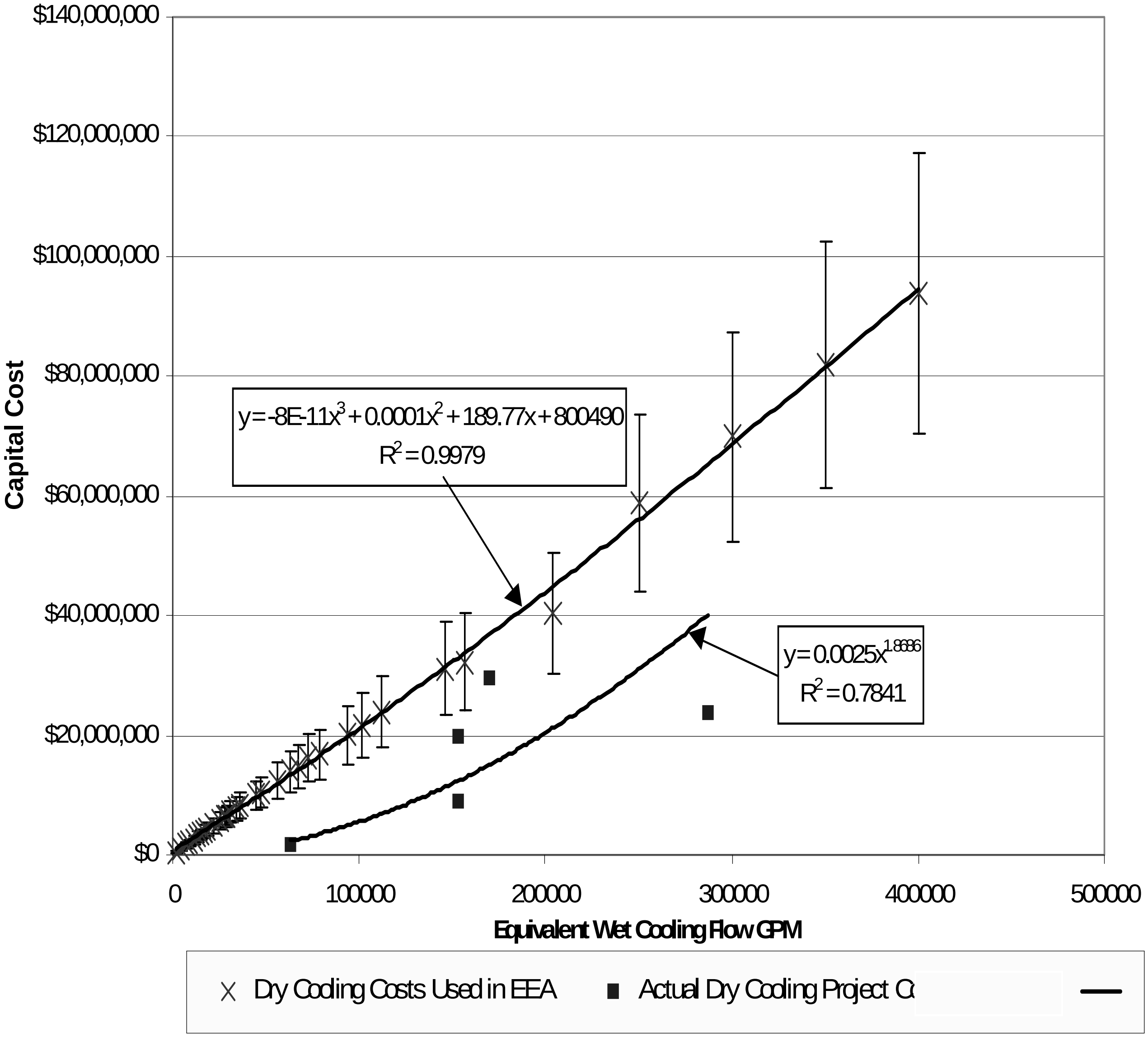


Chart 4-2. Actual Capital Costs of Dry Cooling Tower Projects and Comparable Costs from EPA Cost Curves



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.

First, EPA concluded that dry cooling is not demonstrated nor likely feasible for the existing facilities within the scope of this proposed rule. As noted previously, indirect-dry cooling generally is the only application of the technology that would be considered for retrofit situations at existing power plants because a condenser would already be in place for a once-through or recirculating wet cooling system. As estimated by the DOE (2001), the comparative energy penalty of a retrofitted indirect-dry cooling plant in a hot environment at peak-summer conditions can approach 18 percent at a facility, thereby making dry cooling extremely unfavorable in many areas of the U.S. for some types of power plant types. Additionally, the predicted turbine backpressures of these systems may debilitate the operation of some plants, thereby severely disrupting energy supply and distribution.

In addition, EPA evaluated a regulatory option for dry cooling systems, based on favorable cost assumptions and concluded that the costs of dry cooling systems are prohibitively high in comparison to the benefits.

In summary, EPA concluded that dry cooling is not technically or economically feasible for the existing facilities potentially subject to this proposed rule, would increase air emissions due to dramatic energy penalties, and has a cost that is orders of magnitude more than requirements of this proposed rule. For these reasons, EPA concluded that dry cooling does not represent the "best technology available" for minimizing adverse environmental impact.

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