MEMORANDUM

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TO: Paul Shriner and Lisa Biddle, EPA
FROM: John Sunda, Tetra Tech
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SUBJECT: Evaluation of EPRI and Riverkeeper Closed-Cycle Cost Estimates

Comparison of EPA to EPRI Costs

In 2007 EPRI provided to EPA a cost worksheet for estimating closed-cycle cooling system retrofit costs at power plants. This worksheet included capital cost factors for retrofits of varying difficulties. These costs factors were developed based on actual and estimated costs for closed-cycle retrofit projects at approximately 50 different power plants. EPA adopted and incorporated the cost approach and costs factors in the 2007 EPRI worksheet in the cost methodology used to estimated closed-cycle recirculating system (CCRS) retrofits for cost options involving the performance requirements based on CCRS technology or its equivalent. Subsequent EPRI worksheet submissions contained no revisions to the methodology. However, EPRI did conduct further research and apparently made some changes to their cost estimation approach, the results of which was presented in the Closed-Cycle Cooling System Retrofit Study (Technical Report # 1022491) in 2011 which was included as an attachment to their Proposal public comment. This more recent study includes additional cost data from a total of over 80 different power plants and appears to be the culmination of EPRI's effort to derived costs for closed-cycle retrofits at power plants. EPRI was able to incorporate into their methodology site-specific facility data obtained through a survey they conducted that was not made available to EPA. While the EPA cost estimates included consideration of all plants with a DIF >2 MGD, this study focuses on compliance costs for requiring closed-cycle cooling for power plants with a design flow >50 MGD that fell within the scope of the 316(b) Phase II Rule. This memo identifies the changes EPRI made in the methodology since 2007 and an analysis of differences in the cost methodology approach and resulting cost estimates between EPA and EPRI for CCRS technology retrofits at generating facilities. The discussion below is divided into major cost components.

Capital Costs

EPA based the Proposed Rule cost estimates for closed-cycle cooling systems on EPRI cost factors and calculations from their draft Tower Calculation Worksheet provided to EPA by EPRI in September 2007. These data are assumed to reflect 2007 dollars. The 2007 EPRI worksheet developed capital costs for three scenarios; easy, average, and difficult. For the capital cost component for power plants EPA made a reasonable assumption that the average difficulty cost would be borne by the typical plant. Using the EPRI Cost Worksheet plus regional cost factors EPA derived a national cost for an average difficulty retrofit of $249/gpm (in 2007 dollars) which becomes $263/gpm when adjusted to 2009 dollars. However, EPA realized that a requirement to install cooling towers at all power plants may include a larger portion of those with more difficult and costly retrofit design components, such as plume and/or noise abatement, than was included in the facilities considered by EPRI in the development of the average difficulty cost factor. To account for this EPA adjusted the costs upward by approximately 11% from $263/gpm to $293/gpm (both costs are adjusted to 2009 dollars) to account for the need for plume/noise abatement at an estimated 25% of the facilities. EPA did not apply a different capital cost factor for nuclear plants since EPRI did not make such a distinction in the 2007 spreadsheet and the EPRI supporting data was inconclusive in this respect, indicating a cost difference of no greater than 10%.

The 2011 EPRI Study (EPRI Report # 1022491) used a slightly more complex approach than presented in their 2007 Cost Worksheet which included the same three retrofit difficulty categories (Easy, Average, Difficult) plus 3 more categories: an additional "More Difficult" category for fossil-fuel plants and two for nuclear plants (Less Difficult Nuclear, More Difficult Nuclear). The EPRI cost estimates used survey data obtained independently by EPRI that was not available to EPA to assign different factors for different subsets of facilities. This allowed EPRI to conduct a more complex cost analysis utilizing site-specific data. No details are provided concerning the assignment of retrofit level of difficulty to different facilities. An overall EPRI $/gpm value can be derived by dividing the EPRI estimated total capital cost for all Phase II Facilities of $62,060 Million by the total EPRI cooling flow of 182,296,000 gpm (EPRI 102491 Table 8-18). The resulting EPRI 2010 overall capital cost factor is $340/gpm. The EPA equivalent value of $302/gpm ($293 adjusted for inflation from 2009 to 2010) used in the EPA cost estimates for all generating plants is only 11% lower the EPRI average. This difference is well within the expected range of accuracy of preliminary estimates of this type.[1]

EPRI included re-optimization of the cooling system for all nuclear plants and about half of base-load fossil-fuel plants. Re-optimization is the redesign of the cooling system such that the cooling flow is reduced and condenser temperature rise (range) is increased allowing for smaller towers, smaller pumps and piping and less pumping energy requirements. Re-optimization involves modifying the cooling system design to operate efficiently at a lower cooling flow rates requiring an additional retrofit cost associated with upgrading the condensers (e.g., from single-pass to double-pass) plus the required additional downtime to modify the condensers. The EPRI re-optimization scenario assumes the cooling flow would be cut in half but EPRI does not reduce the cooling tower retrofit capital costs associated with a smaller tower, pumps, and pipes because

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[1] Class 4 level (Study or Feasibility) cost estimates generally have an expected range of accuracy of -30% to +50% (AACE 2004).

they concluded that the added costs of upgrading the condensers from single-pass to double-pass would offset any cost savings of the smaller closed-cycle system. The assumption that these costs would offset each other is reasonable. While EPRI's approach to including re-optimization did not affect capital costs, it did include a substantial increase in downtime duration and a reduction in operating energy requirements.

Downtime

EPRI stated that their downtime duration estimate for nuclear plants was based on a limited number of independent engineering studies and information from a few actual retrofits at fossil plants. EPRI states that "there is relatively little information available to support generalized estimates of this cost element." EPRI used their site-specific survey data to assign different downtime estimates to individual plants based on assumed downtime estimates for assigned categories. Based on available data, EPA used a simpler approach assuming an average net downtime of one month for fossil fuel plants and either zero months or six months for nuclear plants depending on whether they would have the opportunity to schedule the closed-cycle retrofit to coincide with an extended capacity uprating (ECU). See the Economic Analysis for Final 316(b) Existing Facilities Rule for more details. Table 1 presents a comparison of the downtime duration assumptions used by EPRI and EPA in estimating downtime costs. Table 2 shows the reported distribution of retrofit difficulty by generating capacity and the corresponding months of downtime duration.

Table 1
Summary of Assumed Downtime Duration Used by EPRI and EPA
For Estimating Cooling Tower Retrofit Downtime Costs

Fuel Type	Retrofit Difficulty	EPRI Downtime	EPA Downtime
		Months	Months
Fossil-fuel	Easy & Average	0	1
Fossil-fuel	Difficult	4	1
Fossil-fuel	More Difficult	6	1
Fossil-fuel	Re-optimized	6	1
Nuclear	All	6	0 or 6

Table2
EPRI Distribution of Generating Capacity by Retrofit Difficulty Type

Fuel Type	Difficulty	Percent of Fuel Type	Months*
Fossil-fuel	Easy	22%	0
Fossil-fuel	Easy to Average	10%	0
Fossil-fuel	Average	26%	0
Fossil-fuel	Average to Difficult	13%	2
Fossil-fuel	Difficult	24%	4
Fossil-fuel	More Difficult	5%	6
Fossil-fuel	Weighted Average	100%	1.5
Nuclear	Less Difficult	30%	6
Nuclear	More Difficult	30%	6
Nuclear	Intermediate	40%	6

* Assumes average value was applied (e.g., Average to Difficult is assumed 2 - average of 0 and 4)

One major difference in the EPRI approach that affected downtime costs was to assume that certain facilities would chose to re-optimize their cooling system. It is reasonable to expect that the decision to re-optimize would be based on an economic analysis to determine the least cost option over the long term. It is expected that a facility would only choose to re-optimize if it would result in a reduction in the overall costs over the long term. Such a cost analysis would take into consideration, expected plant life, capital costs, downtime costs, operating costs (materials, chemical treatment, labor, auxiliary pump and fan energy) , and the effect on heat rate penalty. For plants with high capacity factors and substantial remaining plant life, the added downtime and condenser costs should be more than offset by the savings in O&M and auxiliary energy and heat rate penalty costs.

EPRI's re-optimized system costs only included the increase in downtime duration costs plus a reduction in fan and pumping auxiliary energy costs by 50% commensurate with the reduced cooling flow. EPRI's increase in downtime for re-optimization was six months and resulted in an additional lost generation cost for downtime for roughly 15% of the total fossil-fuel generating capacity analyzed by EPRI. None of the other potential savings in operating costs or heat rate penalty are included in EPRI's cost estimates and, as a result, it appears that their application of re-optimization resulted in a net increase in overall costs. A properly designed re-optimization cost estimate should result in long term cost savings when compared to a system designed for the existing condenser flow for units that choose to re-optimize. Recognizing that re-optimization should result in lower costs, EPA chose the more conservative approach and did not consider the potential cost savings of re-optimization because of the limited data available and complex nature of such an analysis. EPA's selection of relatively high values for the heat rate penalty is consistent with this approach.

If re-optimization is not included in the EPRI analysis, based on the distribution in Table 2, the aggregated average EPRI downtime duration for fossil-fuel plants would be around 1.5 months. This is roughly comparable to the EPA estimate of 1.0 month for all fossil-fuel retrofits given the uncertainty of the true value of the estimated downtime duration assigned. Factoring in the 6 months extra downtime for re-optimized plants, the average downtime assigned to fossil-fuel plants is 2.4 months. EPA's revised net nuclear downtime is the same as that used by EPRI. However, for many nuclear facilities that have not yet conducted an ECU, EPA has assumed the net downtime value will be zero.

The decision to include re-optimization I the analysis increased the average downtime duration by nearly one month for fossil-fuel plants. One inconsistency in EPRI's downtime analysis is that the extra costs of downtime for the re-optimized units are much greater than the projected savings in energy costs over a 30 yr. timeframe. Since facilities would choose re-optimization only if it would reduce long term costs, then it is likely the EPRI assumptions regarding re-optimizations are either incorrect or incomplete in that there are likely to be additional cost savings that are not accounted for. One of these savings is that re-optimization may result in a smaller heat rate penalty. Thus a portion of the EPRI downtime costs should be offset by savings in long term operating costs that are not included in the EPRI analysis.

In support of 6 month longer downtimes for complex retrofits, EPRI cited engineering estimates for four large nuclear plants. The estimated total downtime ranged from 5 months for Oyster Creek, 10 months for Indian Point Units 2 and 3, 17 months for Diablo Canyon, and just under 22 months for San Onofre (ENERCON 2010, URS 2006). EPRI assumed that since nuclear plants operate as base-load and would have relatively long remaining service life (NRC license renewals are typically 20 years), re-optimization would be included in the retrofit design. EPA arrived at the same 6 month net downtime estimate using a different approach based on a gross downtime derived under Phase III minus the expected 8 week minimum duration of in-service inspection conducted every 5 years.

Heat Rate Energy Penalty

The heat rate penalty associated with conversion from once-through to closed-cycle cooling is the direct result of the difference in turbine backpressure[2] that result from changes in the cooling water temperature that is associated with the change in cooling water source. These changes vary considerably for different locations, time of year, meteorological conditions, source water conditions, tower design and operation, and turbine design. As such, the lack of site-specific conditions and system design data for the model facilities make it very difficult to estimate "typical" or "annual average" heat rate penalties. In the EPA cost analysis heat rate penalties are expressed as a percent of steam generation. Estimates of heat rate penalties from different source have varied considerably. For the cost estimation for estimating heat rate penalty costs EPA selected a value of 1.5% for fossil steam generating units and 2.5% for nuclear steam generating units. EPA selected these relatively conservative (on the high side) values based on the range of 1.5-2.0% provided by EPRI previously. A larger value was selected for nuclear because penalties tend to be greater for steam units that operate at lower throttle pressures.

The analysis included a detailed evaluation of heat rate penalties at several example facilities in seven different waterbodies/regions of the US. Since the slope of turbine performance curves varies with temperature, EPRI estimated heat rates for different conditions. They estimated that for higher temperatures on hot days the average heat rate will change by 2.0% for each 1.0 inch

[2] Turbine backpressure is typically less than atmospheric pressure and is expressed in inches of Mercury (in. Hg).

of Hg difference in backpressure. And that for the general range of temperatures over the entire year the average heat rate will change by 1.0% for each 1.0 inch of Hg difference in backpressure. Thus, for the annual average, a difference in backpressure of 0.5 in Hg will result in a heat rate penalty of 0.5%. For the cost estimates, EPRI assumes that the hot day period lasts for 10% of the year and that the equivalent cost is $35/Mwh. Table 3 presents the calculated hot day and annual average differences in turbine backpressure for the seven different waterbody /region example facilities along with the calculated heat rate penalty based on assumptions which are not shown in the EPRI Report. This data shows that the average heat rate penalty for the seven facilities evaluated by EPRI can vary from <0% to 2.3%, depending on the time of the year and location. EPRI's description of their heat rate penalty cost calculations indicates that they used the average hot day and annual average values of the seven case studies. EPRI's only distinction between nuclear and fossil-fuel units was in the assumed capacity utilization rates. EPA used a similar approach of applying average heat rate penalty values for the entire nation.

The EPRI estimation methodology described should produce an equivalent annual average heat rate penalty of 0.9%. However, in reviewing heat rate penalty costs reported in Table 8-17 of the EPRI Technical Report #1022491, it is apparent that the EPRI estimated heat rate penalty costs are not calculated as described in the text. The EPRI calculations use the "%/in Hg" heat rate penalties of 2.0% and 1.0%, for hot day and annual average periods, respectively, instead of the 1.2% and 0.9% values that are derived by multiplying the backpressure increase with the "%/in Hg" shown in Table 3. As a result, the EPRI costs are based on an estimated average value of 1.1% which is approximately 20% higher than it should be if the described method were followed. Regardless, with respect to heat rate penalty, the EPA estimated annual average heat rate penalty of 1.5% for fossil-fuel and 2.5% for nuclear facilities is greater than those used by EPRIs by factors of 1.4 to 2.3, respectively.

Table 3
Results of EPRI Case Study Heat Rate Penalties

Region/ Waterbody	Hot Day			Annual Average			Heat Rate Penalty - Time Weighted Average[2]
	Backpressure Increase (inch Hg) [1]	Assumed Penalty per Inch Hg	Heat Rate Penalty	Backpressure Increase (in. Hg) [1]	Assumed Penalty per Inch Hg	Heat Rate Penalty	
1 North Atlantic--Off-shore	1.15	2%	2.3%	1.13	1%	1.1%	1.2%
2 South Pacific—Offshore	0.74	2%	1.5%	0.95	1%	1.0%	1.0%
3 South Atlantic--Shoreline intake	0.46	2%	0.9%	0.61	1%	0.6%	0.6%
4 Great Lakes	0.34	2%	0.7%	1.41	1%	1.4%	1.3%
5 Large River--North Central	1.12	2%	2.2%	0.79	1%	0.8%	0.9%
6 Small River--Mid Atlantic	0.57	2%	1.1%	0.72	1%	0.7%	0.8%

7 Small lake—South Central	-0.09	2%	-0.2%	0.55	1%	0.6%	0.5%
Average[3]	0.6	2%	1.2%	0.9	1%	0.9%	0.9%
Values Used by EPRI[4]			2.0%			1.0%	1.1%

[1] Source: Tables 7-3 and 7-4 of EPRI Technical Report #1022491

[2] Equivalent EPRI overall annual rate based on assumption that hot day penalty applies to 10% of hours in the year

[3] Average of values reported in Tables 7-3 and 7-4

[4] Values based on costs provided in Table 8-17 of EPRI Technical Report #1022491

Auxiliary Pump and Fan Energy Requirements

EPA used a factor of 0.0000245 MW/gpm as the basis for estimating the auxiliary (pump and fan) energy requirement. This factor was derived from aggregated model facility data and the draft EPRI cooling tower cost worksheet and certain assumptions plus modifications to account for partial use of plume abatement. The EPRI Technical Report #1022491 estimates that the auxiliary energy requirement will range from 0.85% to 1.5% of plant output. Using the EPA factor this is equivalent to cooling flow values of 350 to 700 gpm/MW of generation. EPRI reports in Table 7-1 that the expected range of cooling water flow, expressed in gpm/MW, is a low of 400 and a high of 800. The general agreement of these ranges confirms that the EPA estimates are similar in magnitude to those of EPRI.

Comparison of EPA to Powers Engineering (Riverkeeper) Costs

Appendix D to Riverkeeper's public comment to the Proposed Rule contains "Powers Engineering comments on EPA 316(b) March 28, 2011 TDD". Powers Engineering is hereafter referred to as PE. The PE comment document includes among other things an analysis of the reasonableness of cooling tower retrofit capital costs identified by EPA, the turbine efficiency penalties, cooling tower auxiliary fan and pump loads, and retrofit downtime.

Capital Costs

The PE analysis compares the more recent EPA closed-cycle cooling system capital costs estimates to the previous estimates generated by EPA under Phase II and concludes that the new EPA capital costs based on the EPRI model is 45% higher than those estimated using EPA's previous model for in-line wet cooling towers. A more detailed analysis that compares EPA's composite (25% plume abatement) cost estimate used in the national cost estimate to an equivalent cost based on the previous EPA model and vendor quotes for plume abatement towers concludes that the revised EPA estimate is 30% greater. PE notes that the previous EPA closed-cycle model that EPA abandoned was well documented. This is true for the cooling tower component which was based on Phase I Rule estimates. However, the Phase I costs were for new construction and one important component added for the Phase II estimates was a retrofit factor which EPA assumed to be 20% of installed cooling tower capital costs. This factor was intended to cover the added costs for demolition, reconstruction, and other items not included in estimates for a greenfield installation since retrofits do not include some offsetting costs associated with the once-through alternative that must otherwise be built in a greenfield project. While the Phase II EPA model did include a nominal cost component for intake and blowdown piping and for condenser upgrades at some systems, it did not include costs for the recirculating water piping since it was assumed to be included in the 80% factor added to tower equipment costs to cover installation and associated equipment. While this may be valid for greenfield applications where the costs for the baseline alternative once-through piping would provide some offset, the costs of rerouting and installing new and often longer circulating water piping while working around many existing structural interferences can add significantly to the costs. In fact, the differences associated with the relative difficulty encountered when installing recirculating piping is a major driver of the differences between the EPRI easy and difficult retrofit costs. This 20% retrofit factor was a BPJ estimate that was not based on any supporting analysis or documentation. This 20% factor likely represents an easy retrofit scenario. And in fact, Exhibit 12-2 of the TDD presents a comparison of closed-cycle retrofit costs using EPAs Phase II model and the EPRI model and found that the Phase II model costs are comparable to the EPRI “easy” difficulty costs. EPA presented this table to demonstrate that the costs of new cost model based on EPRI data were comparable to the EPA Phase II model. PE takes the position that they aren’t comparable since EPA selected the “average” difficulty cost factor. While PE presents additional arguments suggesting the Phase II model costs are conservative because EPA used an assumed range of 10 ^{o}F instead of 12 ^{o}F and potentially inflated condenser upgrade costs, the resulting total capital costs all rely upon the same potentially unrepresentative methodology. The decision to revise the closed-cycle cost model was based in part on the fact that the retrofit costs are very site specific and EPA chose to use the EPRI methodology which was based on detailed project estimates and actual costs at a wide range of different facilities. PE noted that the actual costs for retrofits at the Palisades, Pittsburg, and Yates facilities presented in Phase II Proposal TDD (to support the Phase II model) supports their argument. As can be seen, when adjusted for inflation, the capital costs of the Palisades and Pittsburg plants are comparable to the EPRI “easy” costs. The Yates project which was described as requiring additional sitework to prepare the tower location and reinforcement of the cooling water piping, is closer to the EPRI average costs. Additional cost estimates at two more recent retrofit projects at the McDonough and Brayton Point plants suggest that the EPA estimate is more representative of the full range of costs than the three cited in the Phase II Proposal TDD. Table 4 presents the calculated unit capital costs adjusted for inflation to 2009 Dollars.

Table 4
Costs for Actual Closed-Cycle Retrofits

	Year	Flow (gpm)	Capital Cost (Million Dollars)	Unit Capital Costs	
				$/gpm	$/gpm in 2009 Dollars[1]
Palisades[2]	1998	410,000	55.9	136	197
Pittsburg[2]	1998	352,000	34.4	98	142
Yates[2]	2002	460,000	87	189	248
McDonough	2008	272,900	96	352	363
Brayton Point	2011	720,000	570	792	748
2007 EPRI "Easy"	2007	-	-	160	172

EPA/EPRI "Average" w/o Plume Abatement	2009	-	-	263	263
2007 EPRI "Difficult"		-	-	415	446
EPRI Recent Average	2010	-	-	340	330
EPA/EPRI Cost Model	2009	-	-	293	293

[1] Adjusted for inflation using ENR CCI

[2] Source: PE analysis

[3] Source: McDonough EPA Site Visit Report

The inflation adjusted 2009 unit cost for the Yates project is within 6% of the EPA average retrofit estimate of $263/gpm for non-plume abated systems. The McDonough retrofit which would be considered as a somewhat difficult retrofit shows a unit cost that is consistent with EPAs cost estimates.[3] Items that added to the difficulty of this retrofit included: need for plume abatement, space constraints, need to replace pumps and piping, lack of plans/blueprints for existing underground piping. The Brayton Point unit cost is much higher because the project involved natural draft towers which were chosen to avoid a potentially serious plume related fogging/icing problem for a nearby highway. Natural draft towers costs more in up-front capital costs but have lower operating costs. Rough calculations suggest the Brayton Point power savings could have a net present value as high as $125/gpm.[4] Even after adjusting for these savings, the nearly $623/gpm equivalent cost for a mechanical draft tower at Brayton Point shows just how high "difficult" retrofit costs can be. Also, as discussed below EPA did not include any added cost for nuclear facility retrofits which were assumed to be included in the aggregated EPRI costs. These data demonstrate that the selection of the "average" rather than "easy" EPRI costs factor used in the EPA cost model was a reasonable decision and clearly represents a reasonable approximation of the range of costs that may be incurred nationwide.

The PE concerns regarding condenser upgrade costs are irrelevant since the EPA costs are based on aggregated total project costs that include condenser upgrades where necessary.

Nuclear Plant Retrofits

PE expressed concern that EPA repeated the previous error regarding the application of a cost premium for nuclear facilities. EPA did not include a cost premium for closed-cycle retrofits at nuclear facilities. EPA did apply a cost premium for the installation of impingement technologies for nuclear facilities in the final rule cost analysis because these costs were built up costs derived from vendor and other sources which did not factor in the added costs associated with working at nuclear facilities. However, since the EPRI cost estimates were based on aggregated cost data that included nuclear facilities, EPA assumed that such costs were already factored in to the aggregated cost.

Auxiliary Pump & Fan Energy Requirement

[3] EPA estimated that an average retrofit with plume abatement would cost approximately $383/gpm (DCN 10-6652) which is within 5% of the McDonough unit cost.

[4] Net present value calculated over 50 years at 3% discount rate assuming an average wholesale power cost of $50/MWh using mechanical draft tower cells with 200Hp fans and 12,000 gpm flow/cell operating 75% of time.

PE noted that the EPA auxiliary pump and fan energy requirement was 30% higher than the model estimate provided in the 2002 Phase II TDD. EPA agrees that these requirements are higher but that was the result of a change in the assumed system design. The primary difference is that the 2002 EPA estimate assumed a pumping configuration where a single set of pumps would pump water through both the condenser and cooling tower in series. While this configuration would be the likely choice for a newly built system, EPA decided that the design for retrofits at existing units would in many instances leave the existing circulating pumps in-place and install a second set of pumps that would pump water from the condenser outfall to the existing pump inlet. Both the EPA and EPRI estimates are based on this design configuration and, as a result, do not deduct the once-though pumping energy component. The auxiliary pump and fan energy requirements are based on engineering calculations using typical design parameters and should be reasonably representative of actual requirements.

Heat Rate Penalty

PE expressed concern that EPA's heat rate penalty used in the final rule analysis for fossil-fuel plants was 4 times the EPA model estimates in the 2002 Phase II Proposal TDD and nuclear estimate was 10 times the penalty measured for the Jeffries Plant as presented in the 2002 TDD. PE is also concerned that EPA is using an estimate based on assumed maximum values for annual estimates. EPA's revision of the heat rate penalty from the 2002 Proposal is the result of new information. As noted in the analysis of heat rate energy penalty estimates (DCN 10-6670), the EPA estimated heat rate energy penalty values are consistent with the upper range of estimates provided by DOE and with a nuclear heat rate penalty lower than the somewhat conservative estimates for California coastal power plants. Calculation of national average heat rate penalty is difficult because the penalty for each plant is highly variable, being subject to site-specific conditions including equipment design and factors that vary considerably over time, including operating conditions, meteorological and ambient water conditions. Based on comments, the EPA estimates of the heat rate penalty are representative of the upper end of the possible range of penalty values. Therefore EPA considers the approach and resulting estimates as reasonable.

Downtime

PE states that EPA overestimated downtime duration at fossil-fuel plants by a factor of two and states that EPA presented a strong case for one month as a reasonable and conservative outage period. PE notes that at the Canadys Station and Jefferies Station sites, the closed-cycle system hook-up was completed within the scheduled plant outage period. EPA agrees that in many instances, like those cited, the net downtime may be zero which is supported by the EPRI estimate of zero net downtime for "easy" to "average" retrofits (see Table 2). However, the single value used by EPA represents a national average and should be representative of the full range of downtime values that would occur. As noted elsewhere in this analysis, the weighted average of the EPRI net downtime estimates which represent the full range of difficulties is 1.5 months (if much longer estimates for optimization are excluded). Also, EPA has obtained new data that supports the 2 month total (one moth net) estimate. During the site visits EPA learned that both the McDonough and Yates Plants in GA, experienced a tie-in outage for the cooling tower retrofit of 6-8 weeks (see DCN 10-6536 and DCN 10-6537). These projects would be classified as average to difficult retrofits. This new information supports EPA's estimate used in the cost analysis of 4 weeks net (8 weeks minus the assumed 4 weeks of scheduled maintenance). Since there are a limited number of examples to draw from and EPA's estimate falls between the values suggested by Riverkeeper and EPRI, EPA feels that its estimate is reasonable and that the new data supports the assumption.

PE believes there is no justification for the 7 month downtime for nuclear facilities. Based on data regarding recent nuclear generating system upgrades, PE states that the additional outage should be no longer than 2 months. In response to comments received since proposal and upon evaluation of additional data, EPA has revised the downtime estimates for closed-cycle retrofits at nuclear facilities in a way that substantially reduces the overall downtime estimate to an aggregate value similar to that suggested by PE. In the revised approach, facilities are divided into two groups: those that have conducted or are currently planning to conduct an extended capacity uprate (ECU) and those that have not. An important characteristic of an ECU is that it involves considerably more construction activities compared to simple refueling outages (including replacement of portions of the generating system) and therefore involves outages much longer than those for refueling. These projects provide an ideal opportunity to further reduce downtime if the closed-cycle retrofit is performed concurrently. Data regarding ECU scheduling was readily available and revisions to the final rule have given the Director greater flexibility in establishing compliance schedules for entrainment requirements would allow for scheduling of the closed-cycle retrofit to occur concurrently with an ECU. For those facilities where ECUs are unlikely to occur in the future (i.e., facilities where an ECU has been performed or is currently planned), EPA took a more conservative approach similar to the approach used at proposal but with the duration adjusted downward to a level consistent with new information. At proposal, EPA used the 7 month (28 week) closed-cycle retrofit outage for all nuclear facilities on the Phase II NODA estimate which was based on the only nuclear closed-cycle retrofit actually performed at an existing nuclear facility (Palisades) in the 1970s. For the revised final rule estimate, EPA evaluated the EPRI net downtime estimate of 6 months used in their cost estimate (EPRI Report Number 1022491, provided as an attachment to EPRI's comments on the proposed rule; see EPA-HQ-OW-2008-0667-2200). In support of the 6 month estimate, EPRI cited engineering estimates for four nuclear plants that ranged from 5 to 22 months and noted that the expected downtime was difficult to predict since there was a great degree of uncertainty given the lack of actual data. A closed-cycle retrofit for these facilities that will not conduct an ECU would likely occur concurrently with a refueling outage which now typically takes about 4 to 6 weeks (See DCN 12-6876). Thus, the EPRI net downtime estimate of 6 months or 24 weeks would be consistent with a total retrofit downtime of about 28 weeks. EPA notes that this 28 week value is consistent with the duration of the first steam generator replacement project for SONGs Unit 2[5] and while this outage length is the higher of the two similar projects at SONGS, the difference demonstrates that complex projects for which contractors and engineers have little previous experience will tend to take longer. The actual duration of the outage required for a nuclear closed-cycle retrofit is still unknown and will be influenced by site-specific factors. Given this uncertainty, EPA concluded that a 24 week estimate was reasonable and applied this value in the economic analysis.

[5] The first attempt at replacement of the steam generator for SONGS unit 2 took 28 weeks but a similar subsequent project for unit 3 was expected to be shorter (see DCN 10-6548)

For the remainder of facilities that are likely to conduct an ECU in the future, EPA estimates that under favorable conditions, ECUs typically have a duration of two to four months (see DCN 12-6875) but can also take much longer.[6] For this analysis, EPA assumed that facilities performing an ECU would be capable of completing the retrofit concurrently with the ECU and that the scope of the ECU would be extensive enough to push the duration toward the longer end of the 2 to 4 month or longer range. For these projects, EPA assumed zero downtime which is actually a shorter duration than the 2 months suggested by PE. Based on data from the NRC, EPA estimates that roughly one-third of existing nuclear generating units have already performed or have applied for an ECU and therefore are assumed the a 24 week downtime. As a result, the equivalent average net downtime across all nuclear units should be about 8 weeks (2 months). Thus, while the 24 week estimate is still longer than PE's suggested length, EPA has adjusted the overall nuclear closed-cycle retrofit downtime to a value that is consistent with PE's position.

EPA notes that while the replacement of condenser tubing or steam turbines, including those where the containment structure must be opened, are indeed very involved projects, they generally involve only the replacement of existing equipment and do not involve substantial modifications to existing structures (except maybe for access). Whereas, the installation, construction, and tying-in of the new circulating water system to the existing condenser's intake/discharge piping are more involved.

As noted in the EPRI report analysis above, engineering estimates of outage duration for four nuclear plants ranged from 5 to 22 months (about 3.5 to 20.5 months assuming 43 days for refueling[7]). While it is possible that these industry-supplied estimates may be conservative (i.e., on the high side), there are no actual examples of retrofits at nuclear plants where shorter durations occurred upon which EPA could rely to support a duration shorter than its current net of 7 months.

Conclusion

In summary, this analysis supports the following conclusions:

- The EPA capital cost estimate is much higher than the model estimates used in support of the Phase II Rule but is lower than the EPRI cost estimate by about 13%. The EPA and EPRI estimated capital costs are similar in magnitude. The Phase II Rule model estimates were based on the well documented Phase I Rule model for the cooling towers but the retrofit component was BPJ and not well documented. The EPA capital costs for the existing facility final rule are based on the EPRI model which is based on actual and planned system costs.
- The EPRI and EPA cost estimates for the O&M component for auxiliary pumping and fan energy appear to be similar in magnitude. Both are based on well documented engineering calculations and on a reasonable assumption that separate pumps will supply water to the condensers and cooling towers. EPRI provided no estimate of non-energy O&M.

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[6] PE provided examples of ECU-type activities suggesting that a 75 day (10 week) duration which is in agreement with a 2 to 4 week duration cited by engineers (see DCN 12-6875) but there are instances where the duration was much longer. For example, Turkey Point took 5 months and SONGS unit 2 took 28 weeks.

[7] For the past 5 years nuclear refueling outages have averaged 38 to 43 days (NEI 2011).

- The aggregated EPRI estimate for construction downtime is higher than EPAs but much of the difference is based on an assumption that many base-load facilities would re-optimize. In practice a re-optimized design should reduce long term costs but such savings are only partially accounted for in the EPRI analysis resulting in a higher cost for re-optimized systems. The EPA and EPRI downtime estimates are similar when re-optimization is not included.
- The EPA estimate for the heat rate energy penalty is higher than EPRIs and represent a conservative overestimate. The higher heat rate penalty assumed by EPA will help account somewhat for the less efficient performance of the non-re-optimized system design assumed by EPA.

It was not possible to directly compare the aggregated costs of all components for the EPRI and EPA models due to the use of a different universe of facilities and different economic measurements. However, the two approaches appear to be in agreement regarding the general magnitude of the costs. Also, EPRI's estimation of higher downtime costs resulting from the inclusion of re-optimization should be offset by EPA's use of higher heat rate energy penalty costs and inclusion of non-energy O&M costs.

EPRI's approach including some re-optimization is probably a better model of the real world but an approach that includes such a long term costs saving measure should not result in an overall increase in costs by including consideration of added downtime and operating energy savings only. The EPA heat rate energy penalty estimates were not based on a detailed analysis and relatively conservative values were chosen. Given though EPRI's more rigorous estimates are based calculations using several example facilities, their lower estimates are probably more accurate. The effect these differences would have on overall long term costs should be offsetting.

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