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November 11, 2010

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

BELL BEND NUCLEAR POWER PLANT
PARTIAL RESPONSE TO
ENVIRONMENTAL REQUESTS FOR
ADDITIONAL INFORMATION
5022, 5023, & 5036
BNP-2010-291 Docket No. 52-039

References:
1) S. Imboden (NRC) to R. Sgarro (PPL Bell Bend, LLC), Bell Bend Env. - Final RAI EIS 9.3 (RAI No.5022)- Alternatives, e-mail dated September 9, 2010

2) S. Imboden (NRC) to R. Sgarro (PPL Bell Bend, LLC), Bell Bend Env. - Final RAI EIS 9.4-4 (RAI No.5023) - Hydro, e-mail dated September 7, 2010

3) S. Imboden (NRC) to R. Sgarro (PPL Bell Bend, LLC), Bell Bend Env. – Final RAI EIS 9.3 (RAI No.5036) - Hydro, e-mail dated September 7, 2010

The purpose of this letter is to respond to several Environmental Report (ER) requests for additional information (RAIs) identified in the referenced NRC correspondence to PPL Bell Bend, LLC (PPL) (References 1, 2, and 3). These RAIs address environmental issues, as discussed in Part 3 of the Bell Bend Nuclear Power Plant Combined License Application (BBNPP COLA).

Enclosure 1 provides our responses to the following RAI Questions:

- RAI 5022 EIS 9.3-19b
- RAI 5022 EIS 9.3-20
- RAI 5023 EIS 9.4-4
- RAI 5036 EIS 9.3-30

Enclosure 2 includes a letter regarding cooling tower comparisons that is cited in the responses to RAI 5022 EIS 9.3-19b and RAI 5023 EIS 9.4-4.

The included responses include revised COLA content. This future revision of the COLA is a new regulatory commitment.

D102
NRO

Should you have questions or need additional information, please contact the undersigned at 570.802.8102.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on November 11, 2010

Respectfully,

Rocco R. Sgarro

RRS/kw

Enclosures: As stated

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Enclosure 1

Responses to Environmental Requests for Additional Information
No. 5022 EIS 9.3-19b & EIS 9.3-20
No. 5023 EIS 9.4-4
No. 5036 EIS 9.3-30
Bell Bend Nuclear Power Plant

RAI No. 5022 EIS 9.3-19b

Summary: *This RAI is related to the second alternative sites audit information need ALT-27.*

Identify (b) the environmental impacts of blowdown from all six heat-dissipation alternatives, as requested in the SRBC March 1, 2010 letter to PPL (pp. 2 & 3).

Full Text (Supporting Information): None.

Response: Enclosure 2 contains PPL letter BNP-2010-192 that was transmitted to the SRBC on October 21, 2010. Table 2 in Attachment C of the letter provides a comparison of alternative heat dissipation blowdown impacts. The comparison is provided for natural draft (two hyperbolic towers), rectangular mechanical draft (four towers), round mechanical draft (four towers), one round mechanical draft (fan-assisted natural draft), dry cooling, and hybrid cooling technologies. The impacts identified in Table 2 include aquatic impacts, thermal impacts, chemical effects, physical effects, and suspended solids impacts.

COLA Impact:

No changes to the BBNPP COLA ER are required as a result of this RAI response.

RAI No. 5022 EIS 9.3-20

Summary: *This RAI is related to the second alternative sites audit information need ALT-29.*

Identify the water source from which construction water would be trucked, the amount needed, its availability, and the truck traffic generated in terms of daily trips and duration. Discuss the effects of such shipments on the level-of-service (LOS) of route(s) that would be used.

Full Text (Supporting Information): None.

Response: The source of construction water to be used at BBNPP is a potable municipal source assumed to be available and suitable for use at all three alternative sites. The supplier of construction water is the Pennsylvania American Water Company (PAWC) of Hershey, Pennsylvania. The sources of water coming from PAWC are permitted ground and surface water sources (65% surface water, 35% well water according to PAWC). The amount of water needed during construction is approximately 77,800 to 138,000 gallons per day (294,000 to 522,000 liters per day). A dedicated water line delivering PAWC water will be installed to support construction water needs at Bell Bend or any of the alternative sites. Consequently, water is not expected to be trucked in to support construction. As such, since the water will be piped in there will be no LOS impact.

COLA Impact:

BBNPP COLA ER Section 4.2.1.3, second paragraph, will be revised, as follows, in a future revision of the COLA:

4.2.1.3 Water Sources and Amounts Needed for Construction

~~Initially, water for construction will be transported on site by trucks and stored onsite in temporary tanks. Once a potable water line is brought to the site, local~~ Local municipal water delivered by pipeline will be the primary source of water for construction. Table 4.2-1 shows the estimated amounts of fresh water needed by construction year. It is currently estimated that a peak water demand of up to approximately 1,200 gpm (4,500 lpm) will be required for BBNPP construction activities (demands include those for construction personnel, concrete manufacturing, dust control, hydro testing and flushing, and filling tanks and piping). Based on the water demand figures presented in Table 4.2-1 average construction water usage would be less and is estimated at 250 gpm (950 lpm). ~~The potential sources of water for construction includes local municipal water, Susquehanna River water, and offsite water trucked to the construction site~~.

BBNPP COLA ER Section 4.2.2.4, third paragraph, will be revised, as follows, in a future revision of the COLA:

4.2.2.4 Water Quantities Available to Other Users

Water required for BBNPP construction is estimated at 250 gpm (946 lpm). This water is expected to come from the local public water supply delivered by pipeline. ~~once the line is brought to the site. Prior to the availability of the public water supply, water will be trucked in and stored onsite in temporary tanks.~~

BBNPP COLA ER Section 4.2.2.7, second paragraph, will be revised, as follows, in a future revision of the COLA:

4.2.2.7 Potential Changes to Surface Water and Groundwater Quality

The BBNPP site will be provided with water expected to come from the local public water supply delivered by pipeline. ~~once the line is brought to the site. Prior to the availability of the public water supply, water will be trucked in and stored onsite in temporary tanks.~~

BBNPP COLA ER Section 5.2.1.2.1.1, first paragraph, will be revised, as follows, in a future revision of the COLA:

5.2.1.2.1.1 Plant Construction

The primary water demands during construction are concrete mixing and curing, dust control, and potable water. Water for construction will come from the local public water supply delivered by pipeline. ~~once the line is brought to the site. Prior to the availability of the public water supply, water will be trucked in and stored onsite in temporary tanks.~~ Ground water extracted via excavation dewatering will be used when possible for construction purpose but not for drinking water. Estimated average construction water demand on work days may range from 77,800 gpd (294,000 lpd) to 138,000 gpd (522,000 lpd). Construction uses of water are described in more detail in Table 5.2-2.

BBNPP COLA ER Section 10.1.3, second paragraph, will be revised, as follows, in a future revision of the COLA:

10.1.3 SUMMARY OF UNAVOIDABLE ADVERSE ENVIRONMENTAL IMPACTS FROM CONSTRUCTION AND OPERATIONS

Protection of surface and subsurface water resources during construction will require limitations on the amount of groundwater withdrawn and the discharge of construction waste waters from dewatering activities. Best management practices will be implemented to limit construction related erosion and sedimentation of surface waters. Construction controls will include use of coffer dams, groundwater flow barriers, spill containment, silt screens, settling basins and dust suppression. Water quality monitoring will be conducted to verify that control measures are adequate. A limited amount of onsite water will be needed to support the construction of BBNPP, and will mostly involve the use of groundwater pumped from excavations for manufacture of concrete in the concrete batch plant, dust control and other construction purposes. ~~Initially, most water required for construction will be trucked in, and stored on-site in temporary tanks. Once a potable water line is brought to the site, local~~ Local municipal water will be the primary source of water for construction. Long-term protection of surface waters will be managed through an onsite NPDES permit which is required under current regulations.

BBNPP COLA ER Section 10.5, second paragraph, will be revised, as follows, in a future revision of the COLA:

10.5.1 CUMULATIVE IMPACTS FROM CONSTRUCTION

The principal source~~s~~ of water for construction ~~include~~ is local municipal water~~, Susquehanna River water and offsite water that will be trucked in~~. Limited amounts of groundwater pumped from excavations for manufacture of concrete will be used during construction. It is estimated

that water use on work days will average from 77,800 gpd (294,000 lpd) to 138,000 gpd (522,000 lpd). Municipal water provided by the Berwick District of Pennsylvania American Water (PAW) will satisfy domestic needs. PAW obtains its water from groundwater wells located in Berwick, PA.

RAI No. 5023 EIS 9.4-4

Summary: *This RAI is related to the second alternative sites audit information need H-4.*

Provide a report on the economics of dry and hybrid cooling towers at the BBNPP site that takes into account the cost and availability of makeup water. The response should include quantitative estimates of water costs, especially during drought periods. Also, provide the details of the technical analyses for dry and hybrid cooling towers, citing the bases for estimates of costs and efficiencies.

Full Text (Supporting Information): Applicant's economic study of alternative cooling towers*, which was made available to the review team at the alternative sites audit, did not appear to account realistically for the cost associated with supplying water during drought periods.

* Sargent and Lundy report 2008-06824, "Engineering and economic evaluation of integrated heat rejection cycle, BBNPP Nuclear Power Plant", UniStar Nuclear Energy, April 2008.

Response: Enclosure 2 contains PPL letter BNP-2010-192 that was transmitted to the SRBC on October 21, 2010. Table 1 in Attachment C of the letter provides a comparison of the cost of alternative heat dissipation options. The comparison is provided for natural draft (two hyperbolic towers), rectangular mechanical draft (four towers), round mechanical draft (four towers), one round mechanical draft (fan-assisted natural draft), dry cooling, and hybrid cooling technologies. The costs presented Table 1 include auxiliary load, make-up water cost, annual operations and maintenance (O&M) cost, O&M cost (40 years), capital cost, and total comparative present value.

In addition to the cost comparison described above, technical feasibility evaluations for dry air cooling and hybrid cooling towers are also included in Enclosure 2.

COLA Impact:

No changes to the BBNPP COLA ER are required as a result of this RAI response.

RAI No. 5036 EIS 9.3-30

Summary: *This RAI is related to the second alternative sites audit information need H-2.*

Provide information on the likely sources of construction water at each alternative site. This should include the availability of municipal or private water supplies, use of groundwater, and water trucked-in.

Full Text (Supporting Information): None.

Response:

The response to RAI No. 5022 EIS 9.3-20 (this letter) provides a response to this question. In summary, the Pennsylvania American Water Company (PAWC) of Hershey, Pennsylvania can provide construction water to any of the alternative sites via pipeline to the site.

COLA Impact:

Note: This revised COLA content is shown against the version of ER Section 9.3 that was submitted November 25, 2009 (BNP-2009-371).

BBNPP COLA ER Section 9.3.2.2.3, fifth paragraph, will be revised, as follows, in a future revision of the COLA:

9.3.2.2.3 Water

A dedicated water line delivering water from the Pennsylvania American Water Company will be installed to support construction water needs. ~~Appropriate permits would be obtained for the use of groundwater for construction activities.~~ The required quantity of water is anticipated to be similar to the quantity described in ER Section 4.2.2. Proper mitigation and management methods implemented during construction would limit the potential water quantity and quality impacts on surface water and groundwater.

BBNPP COLA ER Section 9.3.2.3.3, fourth paragraph, will be revised, as follows, in a future revision of the COLA:

9.3.2.3.3 Water

Hydrologic impacts associated with construction activities could include alteration of the existing watershed surface; disturbance of the ground surface for stockpiles, material storage, and construction of temporary access roads; construction of water intake and discharge structures; construction of cofferdams and storm sewers; construction of structures that might alter shoreline processes; dredging operations; temporary dewatering activities; construction activities contributing to sediment runoff; changes in surface water drainage characteristics; decreases in surface water infiltration (increases of impervious surfaces); increased erosion and sedimentation; changes in groundwater levels related to temporary dewatering activities; and possible subsidence resulting from groundwater withdrawals. A dedicated water line delivering water from the Pennsylvania American Water Company will be installed to support construction water needs. ~~Permitted withdrawal of groundwater would be used for construction activities.~~ The required quantity of water is anticipated to be similar to the quantity described in ER Section

4.2.2. Proper mitigation and management methods implemented during construction would limit the potential water quantity and quality impacts on surface water and groundwater.

BBNPP COLA ER Section 9.3.2.4.3, fourth paragraph, will be revised, as follows, in a future revision of the COLA:

9.3.2.4.3 Water

Hydrologic impacts associated with construction activities could include alteration of the existing watershed surface; disturbance of the ground surface for stockpiles, material storage, and construction of temporary access roads; construction of water intake and discharge structures; construction of cofferdams and storm sewers; construction of structures that might alter shoreline processes; dredging operations; temporary dewatering activities; construction activities contributing to sediment runoff; changes in surface water drainage characteristics; decreases in surface water infiltration (increases of impervious surfaces); increased erosion and sedimentation; changes in groundwater levels related to temporary dewatering activities; and possible subsidence resulting from groundwater withdrawals. A dedicated water line delivering water from the Pennsylvania American Water Company will be installed to support construction water needs. ~~Permitted withdrawal of groundwater would be used for construction activities.~~ The required quantity of water is anticipated to be similar to the quantity described in ER Section 4.2.2. Proper mitigation and management methods implemented during construction would limit the potential water quantity and quality impacts on surface water and groundwater.

Enclosure 2

BNP-2010-192
SRBC Notice of Application Review Response
Avoidance of Consumption
Bell Bend Nuclear Power Plant
October 21, 2010

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BELL BEND NUCLEAR POWER PLANT
SRBC NOTICE OF APPLICATION REVIEW RESPONSE
AVOIDANCE OF CONSUMPTIVE USE
BNP-2010-192 Docket No. 52-039

References: 1) Michael J. Brownell, Susquehanna River Basin Commission, to T.L. Harpster, PPL Bell Bend LLC., "Notice of Application Review for PPL Bell Bend, LLC", dated March 1, 2010.

Please find attached the PPL Bell Bend, LLC (PPL) response to the request for information on avoidance of consumptive use in the Susquehanna River Basin Commission's March 1, 2010, "Notice of Application Review for PPL Bell Bend, LLC" (Reference 1). We have provided detailed information on comparison of cooling tower alternatives including information concerning the technical feasibility of dry air cooling. Also included in this evaluation is consideration of the cost of consumptive use and the environmental impacts of cooling water blowdown for all six heat dissipation alternatives.

Should you or your staff have any questions about this response please contact Bradley Wise at 610.774.6508 or bawise@pplweb.com.

Respectfully,

Terry L Harpster

TLH/kw

Enclosures: 1) NARRATIVE - Avoidance of Consumptive Use
Attachment A – Technical Feasibility and Environmental Impacts - Dry Air Cooling
Attachment B – Technical Feasibility and Environmental Impacts – Hybrid Cooling Towers
Attachment C – Tabular Comparison of Heat Dissipation Alternatives with Respect to Cost and Cooling Tower Blowdown

2) Preface
"Evaluation of Dry Air Cooling for the Bell Bend Nuclear Power Plant", Rev 0, August 25, 2010

cc: (w/ Enclosures)

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Enclosure 1

NARRATIVE – Avoidance of Consumptive Use

Attachment A – Technical Feasibility and Environmental Impacts - Dry Air Cooling

Attachment B – Technical Feasibility and Environmental Impacts – Hybrid Cooling Towers

Attachment C – Tabular Comparison of Heat Dissipation Alternatives with Respect to Cost and Cooling Tower Blowdown

NARRATIVE

Attachment: **Avoidance of Consumptive Use**

Comment: **Applicant must include in their application plans for avoiding or mitigating for consumptive use. [18CFR §806.14(a)(2)(ix)]**

The information submitted in the application and amendment fails to adequately analyze avoidance of consumptive use. The amendment included an analysis of six different cooling modes; however, consumptive water use was not factored into the cost analysis of the six alternative methods of heat dissipation for BBNPP. The only factors considered were impact on power production, initial cost, and maintenance costs. Because the cost of consumptive water use was not included in the analysis, the alternatives that maximize consumptive use appear to be less costly compared to other alternatives that minimize consumptive use, such as dry cooling systems and hybrid cooling towers. The cost of providing supplemental water to mitigate consumptive use could be significant if reservoirs, pipelines, or other measures are required. All costs need to be considered for a valid analysis. Also, the analysis assumed that the environmental impact of all alternatives were similar. This assumption is not valid when dry cooling systems and hybrid cooling towers are included in the environmental analysis. The chosen alternative, natural draft cooling towers, require significant blowdown to maintain proper water chemistry. Blowdown flows returning to the river will be heated and chemicals, including a biocide, will be added, and this may have a negative environmental impact on the river. Dry cooling systems and hybrid cooling towers require significantly less blowdown and may have less environmental impact. The environmental impact of blowdown of all alternatives needs to be analyzed.

The information submitted in the application and amendment fails to include an analysis of the increased evaporation caused by the thermal effects of blowdown discharge from BBNPP. The thermal effects from the BBNPP blowdown discharge are additive to the thermal effects of the Susquehanna Steam Electric Station (SSES). This analysis should be consistent with the SSES Permanent Water Monitoring Plan, submitted to the Commission by PPL Susquehanna, LLC on January 9, 2008.

The information submitted in the application and amendment fails to describe plans to mitigate consumptive use. As noted above, payment for mitigation of consumptive water use may not be a viable option for the amount of consumptive use proposed by the BBNPP. Not only is the magnitude of the consumptive use a concern, but timing of the peak usage is coincident with the typical low flow periods of the year. PPL BB should describe plans during low river flows to release water for flow augmentation equal to the projects total consumptive use, or reduce withdrawal from the river equal to the project's total consumptive use in accordance with 18 CFR §806.22(b)(1)(i) and (ii).

Response:

This response amends the prior Bell Bend heat dissipation alternatives analysis. It considers the cost of consumptive water use mitigation and also includes consideration of both hybrid and dry cooling systems as alternatives to avoid (in whole or in part) water consumption at the Bell Bend Project. It also provides an evaluation of the environmental impacts of cooling water blowdown for each alternative method of heat dissipation. There are two enclosures that are described below.

Enclosure 1
Attachment A provides a summary discussion of the technical aspects of dry air cooling. PPL commissioned a study to evaluate the application of dry air cooling for BBNPP. The study evaluated the feasibility and costs of redesigning the current cooling water system with a dry air cooling system for BBNPP. The study is included as Enclosure 2. The US EPR™ standard design for condenser heat rejection is a wet cooling water system. Dry air cooling has never been previously applied to a project the size of Bell Bend, nor has it been attempted in combination with the US EPR design. Scaling up and design compatibility would be a major risk to the project due to significant technical issues as well as associated major cost increases and uncertainties. PPL is not aware of any large nuclear generating facility (either in operation or in design/licensing phase) that utilizes strictly dry air cooling.

Attachment A also provides a discussion of the environmental impacts of dry air cooling. Although dry air cooling has advantages when it comes to water use and potential aquatic impacts, there are environmental drawbacks that relate to land use and noise.

Attachment B provides a discussion of the technical aspects and potential environmental concerns associated with hybrid cooling alternatives.

Attachment C provides a tabular cost analysis of all six heat dissipation alternatives including hybrid and air cooling (Table 1), and a tabular summary of the potential impacts associated with plant blowdown for each of the six cooling alternatives (Table 2).

The cost analysis in Table 1 includes the cost of water based on current Susquehanna River Basin Commission in-lieu rates which are judged to be representative of possible water mitigation costs[1]. The other costs of the cooling options are based on a US EPR (TM) evaluation and the information was used to revise the BBNPP Environmental Report Table 9.4-1. Due largely to no O&M impacts and no penalty for auxiliary loads, the two planned natural draft cooling tower alternative is clearly the most cost effective alternative even when considering the costs for consumptive use of water.

The environmental impacts of blowdown for the six cooling alternatives are provided in Table 2 in Attachment C and are shown to be small. Included in this Table is consideration of the potential cumulative thermal effects of each cooling option when combined with that of Susquehanna SES. The predicted minimal temperature increase and small areal extent of the blowdown plume is predicted to have no significant impact for each cooling option.

Enclosure 2
Enclosure 2 provides an independent evaluation sponsored by PPL. This study evaluates the use of dry air cooling for the BBNPP in place of the currently planned natural draft cooling

[1] As the Commission is aware, PPL BB is currently investigating consumptive use make-up options to satisfy Commission consumptive use regulations. Final costs associated with expected consumptive use mitigation have not yet been determined, however, final costs are expected to be consistent with the in-lieu payment costs used in this analysis.

towers. A preface page is provided to explain the differences between Table 1 for Dry Air Cooling in Enclosure 1 and the independent evaluation included in Enclosure 2.

The BBNPP plan to mitigate consumptive use is currently in the planning/design phase and will be provided separately as part of the response to the requirements of 18 CFR §806.22(b)(1) cited in the SRBC March 1, 2010 "Notice of Application Review for PPL Bell Bend, LLC" letter to PPL.

Attachment A - Technical Feasibility and Environmental Impacts – Dry Air Cooling

The US EPR™ standard design for condenser heat rejection is a wet cooling water system. The Bell Bend Nuclear Power Plant (BBNPP) application submitted to the Nuclear Regulatory Commission includes this standard design. As a result of the subsequent application for consumptive water use with the Susquehanna River Basin Commission (SRBC), a question was raised concerning the use of a dry air cooling system as an option to avoid or mitigate consumptive water use.

Enclosure 2 provides a summary analysis of the technical feasibility of dry air cooling. The following summarizes the study results.

Direct air cooled condensers are in use in many power plants throughout the world. Many seemingly large plants that use air cooled condensers are combined cycle plants in which only about one third of the power comes from the steam turbine thus requiring reduced condenser cooling. Additionally, even the largest steam plant application, the 4,000 MW Matimba Plant in South Africa consists of multiple 660 MW steam turbine units. An air cooled condenser for BBNPP would be the largest single unit application in the world by a factor of about three (3). Air cooling for a unit of this size has never been designed. Scaling up by this magnitude would be a major risk to the project due to significant technical issues as well as associated cost increases.

In addition, there are other considerations that reduce the attractiveness of installing an air cooled condenser at Bell Bend:

- The use of an air cooled condenser will impose significant changes to the US EPR™ standard design and would impact plant licensing costs and schedule. In fact, the changes would most probably be large enough to endanger the EPR fleet concept, resulting in significantly greater cost impacts that would potentially threaten the project altogether.

- Use of air cooling will bring about a loss of efficiency in plant electrical output. This penalty may be several percent over a year. This loss of generation is not accounted for in Attachment C, Table 1.

The loss of net electrical generation with the air cooled condenser will have to be replaced by electricity from other generating plants, mainly fossil fired units. The benefit of emissions free generation will be lost for the replacement electricity.

Dry air cooling is an alternative cooling method where there is little issue with water availability. The only make-up water is for system losses due to leakage. There are no large evaporative losses and no drift losses such as is experienced when wet systems are utilized. With no evaporative losses, there are no potential issues with blowdown, chemical treatment, fogging, or icing when dry cooling is utilized. Dry air cooling does have some environmental drawbacks when compared to wet systems. Two such drawbacks are addressed in the following paragraphs.

Use of dry air cooling would require a significant increase in land use compared to wet cooling. Wet cooling systems require up to 15 acres. The estimated range for dry air cooling is from 15 to 30 acres to accommodate the number of expected fan cells and steam ducts. The actual size to support a plant the size of BBNPP may actually exceed the 30 acre estimate.

A conceptual dry air cooling design for BBNPP involves 192 fan cells and six steam ducts. Each cell is 43.6 ft wide by 51.1 ft long and they are arranged in an array of 32 cells by 6 cells for a total layout of 1396.3 ft by 306.9 ft. Each cell has a fan with nine blades and a diameter of 36 feet. The fan deck height is 164 feet and the top of the steam distribution duct is 205 feet. The steam ducts are 25 feet in diameter and travel a distance of 1000 feet from the turbine exhaust to the air cooling cells.

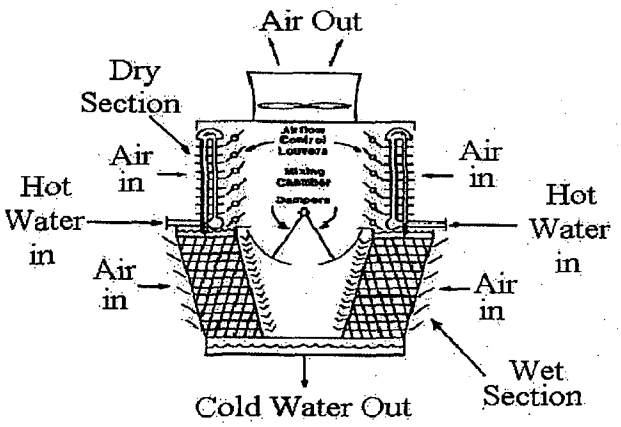
Trying to fit this design to the existing BBNPP plot plan is problematic in two areas. First, any land use needs beyond 15 acres is not available. Second, US EPR™ standard design has an electrical switchgear building located to the north of the turbine building. The electrical switchgear building would have to be relocated to allow for routing the six 25 feet diameter steam ducts. This would represent a major departure from the standard design and result in significant cost increases and uncertainties that would jeopardize the business case for the project.

A second environmental issue is noise. Near field noise for dry air cooling will be < 85 dBA at 3 feet. This is similar for wet cooling systems. The far field noise level for wet cooling systems drops off quickly the further away you go from the source. For a dry air cooling application of 192 fan cells a far field noise level of between 70 and 72 dBA at 400 feet from the fan cells would be expected with standard equipment. The requirement is < 55 dBA. Some form of noise mitigation would most likely be required at a premium cost.

Attachment B - Technical Feasibility and Environmental Impacts – Hybrid Cooling Towers

This section discusses both single-structure hybrid cooling towers and hybrid cooling systems that combine wet and dry cooling components in series or parallel.

A single-structure hybrid cooling tower is on the power generation scene and has options for optimization depending on the desired results. The hybrid cooling tower uses both wet and dry cooling. The bottom section (Wet Section in below diagram) is set up as a typical wet mechanical draft cooling tower. Flow passes through a spray distribution area and then falls down though the fill. Induced air flow travels through the fill and evaporative cooling takes place. With low air temperatures, direct cooling also takes place. In the upper dry section, forced draft fans direct outside air flow across the outside surface of air cooled heat exchangers. The inside of the heat exchanger has a portion of the heated water that is returning to the cooling tower. After passing through the heat exchanger the cooled water returns to the wet cooling tower spray distribution area. The heated air then passes through a mixing section and joins the wet air stream exiting the wet section.



Single Tower - Plume Abatement

If the resulting air mixture is below saturated condition, then no visible plume is produced. This was the objective for the first hybrid cooling systems placed into operation. This type of hybrid cooling tower will reduce water consumption to some extent (~5%) from the amount used by a strictly wet cooling tower, but the primary objective is plume abatement. Large towers of this type are in operation today throughout the world, however they are substantially more costly than wet cooling in exchange for only a small improvement in water efficiency.

There are several configurations possible for a hybrid wet and dry cooling system that is intended for water conservation. There could be a single tower or separate wet and dry towers, using series or parallel airflow and series or parallel cooling water flow. One option is a hybrid cooling system with an evaporative cooling tower and an air cooled condenser as separate structures. The air cooled condenser would handle the entire cooling load except for the hottest periods, when part of the cooling load would be handled by the wet cooling tower. These towers are currently being designed and placed in operation in small to mid-size applications.

The largest known application for a power plant is for a 550 MW mine-mouth coal-fire plant. This application offers a 70% reduction in water use over a wet system on an average basis, and less savings during hot summer periods when wet cooling would be required to achieve effluent thermal limits. A hybrid cooling system for water conservation for a unit the size of BBNPP has also never been designed. Scaling up by this magnitude would be a major risk to the project due to significant technical issues as well as associated major cost increases.

In addition, there is one environmental issue that would require mitigation. This additional environmental issue is noise. Near field noise for hybrid cooling will be ~ 96.7 dBA at 3 feet. The township requirement is < 55 dBA. Some form of noise mitigation would be required at a premium cost. This is typical for hybrid cooling towers. The mitigation measures also bring about the need for a larger tower to offset the loss in efficiency caused by the mitigation measures.

Attachment C – Tabular Comparison of Heat Dissipation Alternatives With Respect to Cost and Cooling Tower Blowdown

Table 1 – Cost of Alternative Heat Dissipation Options

Type of Cooling	Footprint per Plant Unit (1,562 MWe)	Noise	Auxiliary Load Difference [a]	Auxiliary Load Present Value[b]	Average Daily Water Makeup[c]	Make-up Water Cost Present Value [d]	Annual O&M Cost [a] [e]	O&M Cost Present Value[b]	Capital Cost [f]	Total Comparative Present Value[g]
	Acres	dBA @ 1 m	MW	10^3 USD	10^3 mgd	10^3 USD	10^3 USD	10^3 USD	10^3 USD	10^3 USD
Natural Draft (2 Hyperbolic Towers)	16	82	0	***0***	19.84	***39,656***	0	***0***	***173,727***	213,383
Rectangular Mechanical Draft (4 Towers)	24	88	6.22	***74,920***	19.84	***39,656***	468	***8,054***	***130,710***	253,340
Round Mechanical Draft (4Towers)	16	88	4.05	***48,782***	19.84	***39,656***	374.4	***6,443***	***143,103***	237,985
One Round Mechanical Draft (aka Fan-assisted Natural Draft)	8	88	8.49	***102,262***	19.84	***39,656***	374.4	***6,443***	***135,429***	283,790
Dry Cooling	7-30	88	13-79	***204,764[h]***	0.2[i]	***400***	5,975	***102,826***	***298,727***	606,717
Hybrid Cooling	5-6	96.7	21.85	***263,182***	18.85[j]	***37,678***	3,791	***65,241***	***189,527***	555,628

Notes:
USD = U. S. Dollars
mgd = million gallons per day
(a) The value shown is the difference between the identified option and the Natural Draft (2 Hyperbolic Towers) option.
(b) The Auxiliary Load Present value was calculated over 40 years starting in 2019 and includes an assumed 8% cost of money, 2.5% escalation per year, 91% plant capacity factor and price of power of $87.80 per MWh.
(c) All water-cooling options are based on the Natural Draft option except as noted.
(d) The Make-up Water Cost Present value was calculated over 40 years starting in 2019, is based on the SRBC current In-lieu payment rate of $280/MG, and includes an assumed 8% cost of money, 2.5% escalation per year, 91% plant capacity factor.
(e) O&M costs are calculated at 1% or 2% of the capital cost, based on vendor input.
(f) The cost includes the initial cost of the cooling tower(s) and construction cost in 2019 dollars.
(g) This is the sum from the row's Auxiliary Load PV, Make-up Water Cost PV, O&M Cost PV, and Capital Cost values that are ***bold/italicized.***
(h) A nominal value of 17 MW was used to determine the present value.
(i) Value is based on a value of 139 gpm provided by a vendor.
(j) This is a plume-abated hybrid tower with an assumed 95% make-up water requirement compared to the other wet towers.

▪ Table 2 – Comparison of Alternative Heat Dissipation Blowdown Impacts

Type of Cooling	Aquatic Impacts	Thermal Effects	Chemical Effects	Physical Effects	Suspended Solids Impacts
Natural Draft (2 Hyperbolic Towers)	No substantial detrimental impacts are expected based on Ecology III studies of Susquehanna Steam Electric Station (SSES) since operation began in 1983. The BBNPP diffuser is similar in design to that of SSES. SSES blowdown flow is on the order of 18 mgd (2 units) while BBNPP will be about 10 mgd. The cooling tower blowdown will meet state water quality standards and will therefore be expected to have no meaningful impact on the Susquehanna River aquatic community in the vicinity of BBNPP.	The BBNPP And SSES diffusers are separated by 380 feet and the combined effects of the two plumes is very small. In-river average monthly evaporation due to BBNPP will range from 0.02 to 0.06 mgd. The surface excess temperatures are < 0.8°F for August and < 0.3°F for January. Based on thermal plume modeling and SSES experience, the minimal temperature increase and small areal extent of the plume are predicted to have no significant impact. The potential for fish kills resulting from attraction of fish to the BBNPP plume are unlikely given that the existing SSES plume temperatures are typically less than 1°F above ambient temperature and no fish kills are known to have occurred as a result of the plume. The BBNPP consumptive use value takes into account in-river evaporations due to the blowdown discharge consistent with the Susquehanna Steam Electric Station's Permanent Water Monitoring Plan.	Concentrations in the BBNPP discharge as allowed by National Pollutant Discharge Elimination System (NPDES) permit issued by the Pennsylvania Department of Environmental Protection will be lower than concentrations that could harm aquatic organisms present in the Susquehanna River.	The BBNPP diffuser design is similar to the SSES design which has limited physical impacts due to turbulence and thermal block across the river. The physical impacts associated with BBNPP blowdown will be small.	➢ The BBNPP Raw Water System removes suspended solids in the water withdrawn from the river and the backwash effluent is sent to the Waste Water Retention Basin. Suspended solids in the cooling tower basin water will settle out to some extent. The cooling tower blowdown discharges to the Waste Water Retention Basin. This basin is designed to allow settling to occur. All settled material is disposed of on land. Taking this settling of suspended solids into consideration, the net impact from BBNPP operation is to reduce the suspended solids in the river. This is true for the full range of 3-5 cycles of concentration and the full range of anticipated evaporation losses in both the Raw Water System and the Circulating Water Supply System. ➢ The concentration of suspended solids in the blowdown water from the Waste Water Retention Basin is quickly dispersed based on the action of the diffuser jets. ➢ The low velocities at which water will be withdrawn from the river and returned to the river as blowdown will not cause any riverbed materials to be drawn into suspension. ➢ There is no negative impact from BBNPP operation on suspended solids in the Susquehanna River.
Rectangular Mechanical Draft (4Towers)	Comparable to Natural Draft	Comparable to Natural Draft	Comparable to Natural Draft	Comparable to Natural Draft	Comparable to Natural Draft
Round Mechanical Draft (4Towers)	Comparable to Natural Draft	Comparable to Natural Draft	Comparable to Natural Draft	Comparable to Natural Draft	Comparable to Natural Draft

Type of Cooling	Aquatic Impacts	Thermal Effects	Chemical Effects	Physical Effects	Suspended Solids Impacts
One Round Mechanical Draft (aka Fan-assisted Natural Draft)	Comparable to Natural Draft	Comparable to Natural Draft	Comparable to Natural Draft	Comparable to Natural Draft	Comparable to Natural Draft
Dry Cooling	Insignificant	Insignificant	Insignificant	Insignificant	No negative impact
Hybrid Cooling	Less than Natural Draft due to reduced blowdown flow rate	Less than Natural Draft due to reduced blowdown flow rate	Less than Natural Draft due to reduced blowdown flow rate	Less than Natural Draft due to reduced blowdown flow rate	Less than Natural Draft due to reduced blowdown flow rate

Enclosure 2

Preface

"Evaluation of Dry Air Cooling for the Bell Bend Nuclear Power Plant", Rev 0,
August 25, 2010

Preface to Evaluation of Dry Air Cooling for PPL Bell Bend Nuclear Power Plant

The attached study evaluates the use of dry air cooling for the Bell Bend Nuclear Power Plant (BBNPP) in place of the currently planned natural draft cooling towers. This evaluation was performed at the request of PPL and is specific to BBNPP. The values in this report are different but are generally comparable to the values used in the preceding Enclosure 1, Attachment C, Table 1. See below comparison. The cost-related values have the greatest difference due to the conceptual nature of the alternative heat dissipation design, as performed by two independent engineering firms. The same conclusions can be drawn from using either set of dry air cooling costs: That dry air cooling is not technically feasible or cost justifiable for the Bell Bend Project.

Type of Cooling	Footprint per Plant Unit (1,562 MWe)	Auxiliary Load Difference	Water Makeup	Noise	Annual O&M Cost Difference	Capital Cost
	Acres	MW	gpm	dBA @1 meter	10^3 USD	10^3 USD
Table 1 Dry Cooling	7-30	13-79	139	88	5,975	298,727
B & R BBNPP Dry Cooling	17	10-45	230-390	85	3,994	462,468

Evaluation of Dry Air Cooling for the Bell Bend Nuclear Power Plant

Final Report

August 25, 2010

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Evaluation of Dry Air Cooling for PPL Bell Bend Nuclear Power Plant

1.0 Executive Summary

This study evaluates the use of dry air cooling for the Bell Bend Nuclear Power Plant (BBNPP) in place of the currently planned natural draft cooling towers, which take makeup water from the Susquehanna River. The study has been performed to assess whether dry air cooling would be more cost effective than the current wet cooling tower design when the value of water and costs associated with water replacement at low river flow are taken into account. The results of this analysis indicate that the costs for implementing dry air cooling are significant, amounting to a conservative net present value of $431 million in additional capital and operating costs, including the capital costs of offsite water storage for both cases.

The use of dry cooling will save approximately 6,300 million gallons of water per year (see Sections 2.2 and 5.3) expected to be lost by evaporation in the natural draft cooling towers. The Susquehanna River Basin Commission (SRBC) has indicated that a water fee of $0.28 per 1000 gal of water used is sufficient to mitigate the consumption of water from the river. An alternate analysis was performed in which the cost of offsite water storage is eliminated and replaced with an annual payment to SRBC based on the water used and the use fee escalated for future years. The results of this analysis show an increase in cost penalties for dry air cooling to $473 million

In addition to the financial considerations, the use of air cooled condensers poses some design uncertainties as this would be the largest single unit application worldwide and may be considered a First of a Kind for this reason. Many seemingly large plants that use air cooled condensers are combined cycle plants in which only about one third of the power comes from the steam turbine. Additionally, even the largest steam plant application, the 4000 MW Matimba plant in South Africa consists of multiple 660 MW steam turbine units.

Furthermore, the reduction in plant efficiency attributed to dry air cooling will result in the loss of net electric generation which will increase air pollution emissions from other fossil fired plants that will have to make up for the lost electric energy. Based on the above, the use of natural draft cooling towers is the recommended design approach from both a technical and financial perspective for BBNPP.

2.0 Background

2.1 Reason for Re-evaluation of Dry Air Cooling

The Bell Bend Nuclear Power Plant is based on the Areva EPR U.S. design, features two (2) natural draft cooling towers for the dissipation of waste heat from the steam turbine. The cooling tower design at Bell Bend was selected after comparing the cost effectiveness of many cooling tower designs. These included several sizes of natural draft towers as well as several sizes of round and rectangular mechanical draft tower designs. All of the cooling tower designs that were evaluated in detail are of the wet type, which rely on the evaporation of water as the primary means of heat dissipation. Dry air cooling was not considered in detailed evaluation because it is generally accepted that dry air cooling systems

are more costly to build and do not perform as well as wet designs, leading to less efficient power production.

As a result of its application for consumptive water use with the SRBC, PPL developed this analysis comparing wet cooling to dry air cooling for the Bell Bend Nuclear Power Plant to be complete and thorough in its need for and use of water for wet cooling. This study evaluates the feasibility and cost benefits of redesigning the current U.S. EPR plant at Bell Bend with a wet cooling water system (CWS) to a dry air cooling system (ACC).

2.2 Description of Current Cooling System Design

It is important to reiterate that BBNPP uses the EPR design, which is a standard design being shared among several proposed new plants in order to optimize engineering, procurement and licensing costs. The EPR cooling system design incorporates two natural draft cooling towers, each sized to cool 360,000 gallons per minute (gpm) of cooling water from an inlet temperature of 117.5° F to an outlet water temperature of 90° F when the ambient air is 73° F wet bulb temperature and 50% relative humidity. The warm water entering the tower is distributed by a header and sprayed in the tower by nozzles. The water droplets fall by gravity and form thin films on the cooling tower fill material. As the warm water contacts the cooler air in the tower, heat is transferred to the air by evaporation and convection. The transfer of heat and moisture to the air causes its density to decrease and the air rises. The hyperbolic shape of the concrete chimney above the tower fill area induces a natural draft which draws air through the tower.

Only a small portion of the water is evaporated, approximately 2% of the circulating water flow rate, and the bulk of the water is collected in the cooling tower basin below the tower. The EPR design uses a common basin for both towers. The basin drains to a concrete structure which houses four circulating water pumps. The four pumps feed a common header which supplies water to two 11 foot diameter concrete pipes. The pipes convey the water to the main condensers. A small portion of the flow, 10,000 gpm, is diverted to the Closed Cooling Water System which is used for cooling auxiliary equipment.

The main condenser consists of three separate shells which are connected in series with respect to the cooling water flow. The steam turbine has three double flow low pressure (LP) sections, each exhausting into one of the condenser shells. The pressure in a condenser is determined by the temperature at which the steam condenses. Colder water temperature entering a condenser will produce a lower condensing temperature and hence a lower condensing pressure. A lower condensing pressure allows the steam to expand further in the steam turbine producing additional power.

Since the three condenser shells are connected in series, the water temperature entering each section is higher than the previous one resulting in different condensing pressures for each section. Because the performance of a steam turbine is not linear with respect to exhaust pressure, it has been found that this multi-pressure arrangement provides a slight improvement in output as compared to a single pressure arrangement. This is standard industry practice.

The water flow exiting the last condenser shell is routed back to the cooling towers via another two 11 foot diameter concrete pipes, completing the water circuit. This is considered to be a closed cooling water system but it is not completely closed because some of the water is lost to evaporation in the cooling tower. It is planned to draw water from the Susquehanna River to replace the water lost to evaporation and for blowdown, which is returned to the river. The river water, like all natural water bodies, has certain minerals dissolved in it. When water evaporates in the cooling tower, those minerals are left in the remaining water. Over time, the concentration of those minerals in the circulating water will increase until it reaches a point where the water can no longer absorb them and they would begin to

deposit on the equipment causing fouling and corrosion. To avoid this, a small portion of water is constantly drawn from the cooling tower basin and released to a retention pond, which eventually drains back to the river. This flow, commonly called blowdown, will be designed to be about 50% of the amount of water flow lost to evaporation. This will assure that the concentration of minerals in the circulating water does not exceed three times the normal level in the water. The total water drawn from the river will be 1.5 times the evaporation rate but the excess is returned to the river as blowdown.

At the design point of the cooling system, which is at the peak summer wet bulb temperature of 73° F, the makeup water flow rate is estimated to be 23,800 gpm (34.3 million gallons per day (MGD) of which 7900 gpm (11.4 MDG) is returned to the river as blowdown[1]. In the warmer weather most of the heat transferred to the air is by evaporation but in cooler weather, the portion of heat transferred by convection increases and so there is less evaporation. On the average, the makeup water flow rate is about 18,000 gpm (25.9 MGD) with 6,000 gpm (8.6 MGD) being returned as blowdown. The difference between these two values, 12,000 gpm (17.3 MGD), is referred to as consumptive use for the two main cooling towers. Plant consumptive use by the Raw Water Supply System is not changed by this evaluation.

2.3 Differences between Dry Air Cooling and Current Design

There are fundamental differences in the method in which heat is transferred to the air between dry air cooling and wet cooling towers. In the current design, which uses natural draft cooling towers, most of the heat is transferred to the air by evaporating water. The evaporation process takes place at a constant temperature and so a great deal of heat is transferred to the air without raising the air temperature. Of course, there is some increase in the temperature of the air as a portion of the heat is transferred by convection as well. With dry air cooling, all of the heat is transferred to the air by convection resulting in a much larger temperature increase in the airflow. Higher increases in the air temperature rise translate into higher condensing temperatures. As stated previously, the electric output of the steam turbine generally decreases with higher condensing pressures that result from higher condensing temperatures.

One way to compensate for this is to use greater air flow rates with dry cooling. This, however, results in much larger units consuming more auxiliary power to run fans that move the air. Another way is to use a direct air cooled condenser. In the current design, heat is transferred from the condensing steam to the circulating water in the condenser. That heat is then transferred from the circulating water to the air by intimate contact in the cooling tower. With a direct air cooled condenser, the intermediate circulating water system is eliminated and the steam condenses directly in the air cooled condenser. This is possible because without evaporation, there is no need for intimate contact of the water with the air.

Because of this advantage, the direct air cooled condenser was selected as the preferred design for dry air cooling. The direct air cooled condenser is the technology that is currently being used for power applications requiring dry air cooling. An example of this in a similar region of the country is the 600 MW combined cycle plant in Linden, New Jersey, which includes three nominal 90 MW steam turbines. The direct air cooled condenser will still require an airflow rate of about 6 times greater than the proposed BBNPP natural draft cooling tower and will have a significant auxiliary electric power load associated with the fan power. In addition, the condenser pressure, particularly in the warm weather will be significantly higher, resulting in a reduction in electric generator output.

[1] UniStar Nuclear Report, "Engineering and Economic Evaluation of the Integrated Heat Rejections Cycle", February, 2008

There is another inherent disadvantage of the air cooled condenser that limits its effectiveness in colder weather. With the current cooling system design, the surface condenser sits directly below the LP turbine sections and there is virtually no pressure drop from the turbine exhaust to the condenser. The air cooled condenser, by virtue of its size, must be located at a distance from the turbine exhaust, causing a higher pressure drop than the current cooling system. This is further exacerbated by the fact that there will be six separate condensers connecting to each turbine exhaust end. A large steam duct (25 feet in diameter) is required to transfer the steam from each turbine exhaust to the air cooled condenser which will impose a pressure drop. In addition, the steam is condensed in the condenser tubes, which imposes an additional pressure drop, unlike the current design in which the steam condenses on the surface of the tubes. At the design point, which will give a turbine backpressure of 5 inches of mercury (in Hg), the total pressure drop in the steam duct and condenser tubes is estimated to be about 0.3 in Hg. At a turbine backpressure of 2 in Hg, the pressure drop doubles due to the increased specific volume of the steam and at 1 in Hg the pressure drop is about 1 in Hg. Effectively, regardless of the actual pressure in the air cooled condenser, the turbine exhaust will never see a pressure lower than about 2 in Hg. This limits the plants ability to take advantage of low ambient temperatures as is available in the current design, which permits higher generation output at lower ambient temperatures.

3.0 Design Basis of the Dry Air Cooling System

At the outset, it is important to note that much engineering for the EPR cooling system design is well in progress and that changing to air cooled condensers would require a major balance-of-plant redesign, which would significantly affect the current plant configuration. Not only the cooling system but even the steam turbine itself as, currently designed, is not optimized for use with an air cooled condenser. Changing the steam turbine design, even modestly, would be enough to challenge the concept of a standard fleet EPR design causing significant delays and increase in cost. For the purpose of this study, it is assumed that the current steam turbine design is maintained and the air cooled condenser is designed within those constraints. Although this may not be optimal from the standpoint of the air condenser design, it will represent a reasonable design and may be a necessary constraint to keep enough parameters within the framework of the EPR design.

The major steam turbine constraint relates to the maximum turbine backpressure, which is limited to 5 in Hg. Typically, steam turbines designed for use with air cooled condensers are special high backpressure units that allow operation at higher than 5 in Hg. For this analysis, an air cooled condenser was specified to provide a backpressure of 5 in Hg at the turbine exhaust when the ambient dry bulb temperature is 90°F. GEA Power Cooling Systems, a world renowned and major provider of air cooled condensers, has provided a budget cost quotation and performance curves for an air cooled condenser to meet the needs of BBNPP. A unit designed for a higher backpressure would cost less but would have greater performance penalties.

A small mechanical draft wet cooling tower would also be installed to provide 10,000 gpm of cooling water for the Closed Cooling Water System. While it is possible to use air cooling for the auxiliaries as well, this would impose significant changes to the EPR design and the savings in water use would be minimal.

3.1 Design Changes for Using Air Cooled Condensers

Two cost estimates have been prepared in order to assess the capital cost increase for a U.S. EPR using air cooled condensers. One includes the capital costs that will be removed from the current design to account for equipment that will not be required. These include the natural draft cooling towers, the cooling tower basins, the circulating water pumps, the circulating water pump-house, the circulating water

piping and the main steam condensers. In addition, the costs for providing power to the circulating water system are also estimated. The costs include equipment and installation costs but not full engineering costs, much of which have already been spent. The second cost estimate is for the use of an air cooled condenser. It includes the air cooled condensers, piping, ductwork, foundations, installation, power and control to the fans, the auxiliary cooling tower, circulating water pumps and piping. Additional electrical costs associated with larger auxiliary transformers are also evaluated. This represents a major change in the auxiliary electrical system. The current system includes service to (4) circulating water pumps with a nameplate rating of 9600 HP each. The dry air cooled option includes 192 fans with a nameplate rating of 250 HP each plus two additional fans for the auxiliary cooling tower and its circulating water pumps.

These costs include a factor for engineering and, in some cases, re-engineering existing designs. Estimates for licensing and permitting cost are also included. No additional cost for land use is included as explained in Section 5.2.

In addition to these direct plant items, an offsite water storage facility is required to mitigate water use during times of low water flow rate in the Susquehanna River. The Susquehanna River Basin Commission (SRBC) requires the plant to store a quantity of water equal to 90 days of water usage at the maximum consumption rate. For the current U.S. EPR design at Bell Bend, the maximum daily water consumption rate is 31 MGD[2]. Of this, about 25 MGD is attributed to evaporative losses from the cooling towers with the balance (6 MGD) for other plant water uses. With the air cooled condenser design, the storage requirement is reduced to about 6.3 MGD to account for the other plant water uses, which remain the same plus about 0.3 MGD for the auxiliary cooling tower.

3.2 Commercial Experience with Large Air Cooled Condensers

Direct air cooled condensers are in use in many power plants throughout the world. Most applications are much smaller than what is required for BBNPP. Many seemingly large plants that use air cooled condensers are combined cycle plants in which only about one third of the power comes from the steam turbine. Additionally, even the largest steam plant application, the 4000 MW Matimba plant in South Africa consists of multiple 660 MW steam turbine units. An air cooled condenser for the Bell Bend plant would be the largest single unit application in the world by a factor of about three. This is important because the larger the air cooled condenser is, the further the steam has to be piped to get to the far ends of the condenser. This poses logistics and plant configuration problems and will lead to higher piping system pressure increases and increased penalties for electrical generation output. With multiple units, such as in the Matimba plant, the air cooled condensers can be located closer to each of the steam turbines, minimizing the piping losses.

4.0 Comparative Capital Cost Estimates for Dry Air Cooling vs. Current Design

A pre-conceptual cost estimate was developed to identify the potential impact of changing from a closed cycle cooling water system for the Bell Bend Nuclear Plant, incorporating two natural draft cooling towers, with makeup water provided by the Susquehanna River, to an air cooled condenser, minimizing the use of makeup water from the River.

[2] Bell Bend Nuclear power Plant, Application for Consumptive Water Use to the Susquehanna River Basin Commission, May 2009

A budgetary estimate was provided by GEA, an internationally recognized provider of air cooled condensers. The costs for the two natural draft cooling towers were based on budgetary costs provided by UniStar[1]. The remainder of the costs for equipment and construction were developed by Burns and Roe from standard industry available information, as well as proprietary information from its nuclear plant cost data base. Commodity pricing is based upon the Burns and Roe in-house data base.

A positive contingency factor of 30% was allocated to the ACC option. This level of contingency is based on guidance provided by the U.S. Department of Energy in its cost estimating guide[3] for Class 4 and 5 estimates

Class 5 estimates are prepared for any number of strategic business planning purposes, such as but not limited to market studies, assessment of initial viability, evaluation of alternate schemes, project screening, project location studies, evaluation of resource needs and budgeting, long range capital planning, etc. Accuracy for Class 5 estimates ranges from 30% to 100% on the high side.

Class 4 estimates are prepared for a number of purposes, such as but not limited to, detailed strategic planning, business development, project screening at more developed stages, alternative scheme analysis, confirmation of economic and/or technical feasibility, and preliminary budget approval or approval to proceed to next stage. Accuracy for Class 4 estimates range from 20% to 50% on the high side.

Based upon the above descriptions, the limited amount of information available for the ACC for BBNPP, and the significant scale up of the technology, the positive contingency value was set at low end of the Class 5 estimate range, or 30%, which is in the mid-range of a Class 4 estimate.

A positive contingency factor of 15% was allocated to the current design. This level of contingency is based on guidance provided by the U.S. Department of Energy in its cost estimating guides for a class 3 estimate.

Class 3 estimates are generally prepared to form the basis for budget authorization, appropriation, and/or funding. As such, they typically form the initial control estimate against which all actual costs and resources will be monitored. Typically, engineering is from 10% to 40% complete, and would comprise at a minimum the following: process flow diagrams, utility flow diagrams, preliminary piping and instrument diagrams, plot plan, developed layout drawings, and essentially complete engineered process and utility equipment lists. Estimate accuracies for Class 3 estimates range from 10% to 30% on the high side.

The 15% contingency factor was selected since the reactor plant planned for the Bell Bend site is at least in the preliminary design stage, is not a significant scale up of earlier plant designs and is similar to plants, of the same size, currently being designed and constructed in the United States and around the world.

Engineering costs for the ACC were assumed to be 10% of the estimated capital cost of the ACC. Remaining engineering costs for the CWS were estimated at 5% of the estimated capital cost, taking credit for the design effort completed to date.

In addition to the design changes in the plant, the use of an ACC will reduce the size of the offsite water storage required by the SRBC to mitigate water use during periods of low river water flow. The cost for makeup water storage is currently under evaluation. Two methods are being considered, expansion of existing lakes and storage in abandoned mines. The latter method is expected to be the least expensive

[3] DOE 430.1-1X., Cost Estimating Guide for Program and Project Management", April 2004.

alternative but cost estimates for the mine storage method are not yet completed. For the purpose of this evaluation, lake storage will be considered for both designs. The least expensive lake storage option is estimated to cost $105 million for a nominal 30 MGD capacity. An expansion of the same lake for a smaller capacity (10 MGD) is estimated to cost $60 million. Using the same cost scaling factor to go from 30 MGD to 10 MGD, a lake expansion for 6.3 MGD is estimated to be $48 million.

The results of the cost estimating effort are included in Table 1.

TABLE 1

Summary Comparison of Capital Costs of Existing Circulating Water System and an Air Cooled Condenser System

	Existing Circulating Water System	Air Cooled Condenser System
Capital Cost Elements		
Civil	$58,312,112	$27,058,885
Mechanical	$132,428,501	$204,542,370
Electrical	$845,434	$29,473,913
Subtotal	$191,586,047	$261,075,168
Other		
Contractor Indirects	$18,013,693	$39,528,696
Contractor Fee	$20,959,975	$30,060,386
Engineering	$9,579,302	$19,580,640
Licensing	$1,000,000	$2,000,000
Permitting	$3,000,000	$1,500,000
Procurement	$0	$2,000,000
Subtotal	$52,552,970	$94,669,722
Contingency	$36,620,852	$106,723,200
Total Onsite Costs	$280,759,869	$462,468,090
Offsite Water Storage	$105,000,000	$48,000,000
Total Onsite Plus Offsite Costs	$385,760 000	$510,470,000
Capital Cost Difference for ACC system versus existing CWS for the Bell Bend Nuclear Plant		$124,710,000

Note the Contractor Indirects are noticeably higher for the air cooled condenser because the GEA quotation did not include installation, whereas installation was included n the cooling tower cost.

5.0 Impacts of Dry Air Cooling System vs. Current Design

5.1 Performance Penalties for ACC

The air cooled condenser selected for analysis in this study will deliver a turbine backpressure of 5 in Hg when the ambient temperature is 90° F and the turbine is operating at full load. The current cooling system design with the natural draft tower will deliver a backpressure of about 3 in Hg at the same conditions. According to the steam turbine backpressure correction curves presented in the Cooling Tower Study[4], the output penalty for the 5 in Hg case is -2.09% versus a penalty of -0.45% for the 3 inches of Mercury (in Hg) case. These are unusually low penalties. Typically for other steam turbines, the output penalty for a backpressure of 5 in Hg is around 6% or 7% as compared to a base pressure of 2.5 in Hg. It can be lower if the exhaust end is heavily loaded, although a higher penalty than 2%, even for a heavily loaded back end would be expected. Nonetheless, these low backpressure penalties are used in this evaluation, which are conservative and favor the dry air cooling option.

The other penalty for the air cooled condenser stems from the auxiliary power used to run the fans. The GEA proposal indicates that the ACC has 192 cells, each with a fan driven by a 250 hp motor. The operating load for these fans is estimated to be 34,740 kW. A portion of this load is offset by the circulating water pumps, which are no longer required. The operating load for these four pumps is estimated to be 21,600 kW. The air cooled option will also have an additional electric load of about 450 kW for the auxiliary cooling tower and pumps.

At other times of the year, when the ambient conditions are cooler, both cooling systems will perform better and the penalties will be less. In cold weather, both systems are oversized and will probably be operated at reduced capacity to conserve auxiliary power. The only way to reduce the capacity of the natural draft cooling tower would be to turn off one of the four circulating water pumps. The steam turbine backpressure correction curve suggests that there is little to no advantage to operate with a turbine backpressure below 1.5 in Hg. In fact, the net output will increase by saving the auxiliary power of the pump.

For the air cooled condenser, as stated previously, the backpressure at the turbine exhaust will never be below about 2 in Hg, regardless of how low the pressure is in the condenser due to piping losses. In the cold weather, some fans can be turned off to save auxiliary power without affecting the steam turbine performance. The cooling tower vendor has not provided performance estimates with reduced water flow nor has the air cooled condenser vendor provided performance estimates with some fans off. Some approximate estimates have been incorporated in the performance analysis to simulate these conditions.

5.2 Changes in Land Use

Based on preliminary information provided by GEA, the land area required for the air cooled condensers is about 10 acres which is smaller in size than the land area used by the natural draft cooling towers, about 15 acres. It should be noted that GEA has indicated that greater spacing may be needed among the units to minimize recirculation of air flow. For these reasons, the land use for the ACC units is considered to be similar to the space allocated for the natural draft cooling towers.

The location of the area used for the cooling towers, however, is not optimally located for the air condensers, being about 1000 feet away from the turbine exhausts. The air cooled condenser will require

[4] "Engineering and Economic Evaluation of the Integrated Heat Rejection Cycle, Rev 1, April 18, 2008 " by Sargent & Lundy for Unistar

the above ground routing of 6 steam ducts, each 25 feet in diameter, from the turbine exhausts to the air condenser array. The routing of the steam ducts will take up about 7 acres of land, assuming a 50 foot path for each duct. This will require extensive re-design of the plant layout in that area between the turbine exhausts and the air cooled condensers. The actual routing of the steam ducts and the relocation of equipment in their paths has not been laid out for this study effort. When that is done, it is likely that the overall land use for the dry cooling design will increase.

5.3 Reduction in Water Use

On the average with the current wet cooling design, the Bell Bend Plant will consume a net of about 12,000 gpm of water (17.3 MGD) from the Susquehanna River to make up for evaporation losses An additional 6,000 gpm (8.6 MGD) will be drawn from the river but will be returned as blowdown.

While the air cooled condensers have no evaporation losses themselves, their use requires the addition of a small mechanical draft cooling tower to provide for auxiliary cooling loads. The evaporation losses for the auxiliary tower will average around 180 gpm (0.3 MGD). The average blowdown flow will be 60 gpm (0.1 MGD). The use of dry cooling will save approximately 17.1 MDG of water consumption or 6,300 million gallons per year.

During periods of low water flow in the Susquehanna River, the plant may be required to curtail water use for a period of up to 90 days. In order to continue operation during this period, makeup water will either be supplied from onsite storage or else offsite storage will be added to the river flow to compensate for the water removed at the plant. The use of air cooled condensers would greatly reduce the required size of the water storage.

6.0 Economic Comparison of Dry Air Cooling vs. Current Design

It is evident from the capital cost analysis and the performance comparison that the use of air cooled condensers will increase capital costs and maintenance costs and reduce net plant output. All of these components translate to increased costs. The purpose of this economic evaluation is to quantify the magnitude of the cost increases associated with dry air cooling.

The major cost impact (in terms of decreased generation and associated revenue) is the reduced net electric output resulting from high turbine back pressures and higher auxiliary power loads. In order to assess this cost, the performance of the plant is estimated for the current design and the air cooled condenser case on an annual basis. The performance estimates are made for each month of the year using average monthly weather data. This approach has a tendency to underestimate the negative impacts of the air cooled condensers. The reason for this is that the output penalties increase greatly at higher temperatures in a non-linear fashion, so using the average temperature underestimates the penalties. However, for the purpose of this evaluation, the average method is used to simplify the estimating process. It should be noted that this method is conservative and favors the ACC design. In order to understand the penalties for ACC at the higher temperatures, a few hours of performance are shown at the peak summer conditions. The results are shown on Table 2. The annual performance summary is shown on Table 3.

COMPARISON OF NET PLANT OUTPUT WITH COOLING SYSTEM DESIGNS

TABLE 2

	Wet Bulb Temp deg F	Relative Humidity %	Performance with Natural Draft Cooling System					
			CT Water Temp deg F	Cond. Press in Hg	Kilowatt Change* %	Generator Output kW	Cooling System kW	Net** Output kW
Jan	24.1	70.9	51.20	1.19	0.57%	1,773,022	14,309	1,758,713
Feb	25.6	67.9	53.40	1.27	0.56%	1,772,798	14,307	1,758,491
Mar	32.3	64.7	59.70	1.52	0.49%	1,771,624	14,301	1,757,323
Apr	42.3	61.4	68.30	1.95	0.30%	1,768,229	14,289	1,753,939
May	52.0	64.3	73.41	1.91	0.34%	1,768,971	19,036	1,749,935
June	60.5	69.5	79.39	2.27	0.13%	1,765,237	19,020	1,746,217
July	64.5	70.4	82.79	2.50	-0.04%	1,762,380	19,010	1,743,370
Aug	63.5	72.7	81.89	2.44	0.01%	1,763,193	19,013	1,744,180
Sept	57.2	74.4	76.32	2.08	0.25%	1,767,364	19,029	1,748,335
Oct	46.7	71.6	70.00	2.04	0.24%	1,767,304	14,287	1,753,017
Nov	37.6	70.9	62.50	1.65	0.44%	1,770,747	14,298	1,756,449
Dec	27.9	71.6	54.10	1.29	0.55%	1,772,710	14,307	1,758,403
Peak	73.1	44.0	89.63	3.03	-0.45%	1,755,133	18,988	1,736,144

	Dry Bulb Temp deg F	Performance with Air Cooled Condenser						
		Cond. Press in Hg	Exhaust Press in Hg	Kilowatt Change* %	Generator Output kW	Cooling System kW	Net** Output kW	Output Diff.*** kW
Jan	26.8	1.07	2.00	0.35%	1,769,171	19,786	1,749,384	-9,329
Feb	28.7	1.07	2.00	0.35%	1,769,171	20,442	1,748,729	-9,762
Mar	36.4	1.07	2.00	0.35%	1,769,171	25,030	1,744,140	-13,183
Apr	48.2	1.07	2.00	0.35%	1,769,171	35,845	1,733,325	-20,614
May	58.7	1.53	2.29	0.16%	1,765,807	35,190	1,730,617	-19,318
June	66.9	2.13	2.74	-0.18%	1,759,838	35,190	1,724,648	-21,569
July	71.2	2.50	3.03	-0.42%	1,755,678	35,190	1,720,488	-22,882
Aug	69.5	2.35	2.91	-0.31%	1,757,455	35,190	1,722,265	-21,915
Sept	62.2	1.77	2.46	0.03%	1,763,523	35,190	1,728,333	-20,003
Oct	51.3	1.07	2.00	0.35%	1,769,171	35,190	1,733,981	-19,037
Nov	41.4	1.07	2.00	0.35%	1,769,171	28,734	1,740,437	-16,012
Dec	30.8	1.07	2.00	0.35%	1,769,171	21,622	1,747,549	-10,854
Peak	90.5	4.65	4.97	-2.09%	1,726,201	35,190	1,691,011	-45,133

Assumptions and Notes

Expected Generator Output at 2.5 in Hg	1,763,000	kW
Air Condenser Fan Load - kW	34,740	kW
Auxiliary Cooling Tower Fans and Pumps	450	kW
Total Cooling System Load	35,190	kW

* Kilowatt Change is referenced to 2.5 in Hg

** Net Output is Gross output less Cooling Load

*** Output Diff. is from current design with natural draft cooling towers

TABLE 3

ANNUAL PERFORMANCE AND WATER COMSUMPTION COMPARISON

Month	Days Per Month	Capacity Factor %	Average Penalty kW	Electric Energy MWh	Makeup Water			
					CWS gpm	ACC gpm	CWS 1000 gal	ACC 1000 gal
January	31	91%	-9,329	-6,316	15,000	230	609,336	9,343
February	28	91%	-9,762	-5,970	15,600	230	572,383	8,439
March	31	91%	-13,183	-8,925	18,200	270	739,328	10,968
April	30	91%	-20,614	-13,506	20,100	300	790,171	11,794
May	31	91%	-19,318	-13,079	21,800	330	885,568	13,405
June	30	91%	-21,569	-14,132	23,000	350	904,176	13,759
July	30	91%	-22,882	-14,992	23,300	350	915,970	13,759
August	31	91%	-21,915	-14,837	23,000	350	934,315	14,218
September	30	91%	-20,003	-13,106	22,100	330	868,795	12,973
October	31	91%	-19,037	-12,889	20,600	310	836,821	12,593
November	30	91%	-16,012	-10,491	18,900	280	742,997	11,007
December	31	91%	-10,854	-7,349	17,300	260	702,768	10,562
Peak	1	100%	-45,133	-1,083	26,100	390	37,584	562
Annual	365.0	20.0		-136,676	18,151	273	9,540,212	143,382

The annual loss in net electric output for the air cooled condenser case has a value associated with it. This incremental electric energy could otherwise be sold on the market at marginal rates or displace purchases made at the marginal rates. PP&L is a winter peaking utility and has excess capacity in the summer months so it is likely that most of this lost energy will represent loss of marginal sales. PP&L has provided estimates of marginal electricity prices for the year 2019 when the plant is expected to be in full operation. The electricity is evaluated at that price and escalated for future years. All economic values including electricity rates, interest rates and escalation rates are included in Table 4.

TABLE 4

ASSUMPTIONS

Excess Electricity Sales Price (2019$)	$90/MWh
Electric Escalation Rate (beyond 2019)	2.5%
Economic Life of Project	40 years
Property Taxes	0.025%
Insurance Rate for Capital Costs	0.05%
Capital Cost Escalation Rate	3.0%
Interest During Construction	6.0%
Present Worth Discount Factor	7.0%

The evaluation also includes differences in annual maintenance costs. The major component of the difference in maintenance costs is the servicing and maintenance of the cooling tower fans, motors and speed reducers. A value of $5,000 per fan per year was used for this value in the Cooling Tower Study based on a recommendation from the cooling tower vendor. The fans used in the air cooled condensers are similar to those used in mechanical draft wet cooling towers so that value is also used in this study. There are 192 fans in the air cooled condenser plus two additional fans in the auxiliary tower for a total of 194 fans and an annual cost of $970,000. For the current design with natural draft cooling towers, the only mechanical components are the four circulating water pumps. These are large slow speed devices that require very little maintenance and so these costs are neglected.

The current design uses chemicals to control bacterial growth, pH and inhibit corrosion in the circulation water loop. These chemical costs are estimated to be $100,000 per year.[5]

The net increase in annual operating and maintenance costs for the dry air cooled option is $870,000 at today's cost levels. These costs are escalated for future years.

In addition, the increase in capital costs also carries increases in annual property taxes and insurance. The rates for additional taxes and insurance are also shown in Table 4.

The economic evaluation computes year by year costs for marginal electricity sales along with other operating and maintenance cost differences. The evaluation is projected over a period of forty years. The present value of the forty years of operating expenses is calculated.

The capital cost estimates are based on today's cost levels. In order to bring these costs up to the date of commercial operation, they are escalated to a time of 3 years before commercial operation and then 3 years of interest during construction is added to the escalated cost. The present worth of the annual operating costs is added to the total capital cost at the commercial operation date to produce the total net present value of the increase associated with dry air cooling.

The Net Present Value of Operating Costs, $253,850,000, is the present value, in 2019 dollars, of the additional operating costs including the value of lost electricity sales. The Total Net Present Value of Dry Air Cooling Costs of $431,200,000 includes the capital cost at the commercial operation date of $177,360,000 to the Present Value of Operating Costs.

[5] Estimate is based on input from Burns &Roe in-house water treatment subject matter expert

An alternate economic evaluation was also performed in which the offsite water storage capital costs are not included but are replaced by an annual Consumptive Use Mitigation Fee as specified in the SRBC Regulatory Program Fee Schedule published in January, 2010. This fee is currently $0.28 per 1000 gallons of water consumed. Although there is no mechanism in the fee schedule for escalating the mitigation fee, it is assumed that the fee will be adjusted periodically to reflect inflation. An escalation rate of 2.5% per year has been included in the analysis for future price projections.

The Net Present Value of the annual Operating Costs decrease as compared to the base evaluation, to $214,700,000 but the Total Net Present Value increases to $473,100,000 due to the increase in capital cost difference.

7.0 Summary and Conclusions

The study has examined the technical and economic feasibility of replacing the currently planned and in design wet cooling system for the Bell Bend Nuclear Power Plant with a dry air cooled condenser. As a result of its application for consumptive water use with the SRBC, PPL pursued this analysis to be complete and thorough in its need for and use of water for wet cooling. This study clearly shows that there is a significant cost increase to change to a direct air cooled design, even including the expected costs of mitigation under both the air cooled design and the wet cooling design. The air cooled design is not cost effective and may not be technically feasible because it represents a first of a kind in this size for a single steam turbine unit.

This study has evaluated installing a direct air cooled condenser in place of the natural draft cooling towers and other supporting portions of the circulating water system. A conceptual bill of materials has been prepared for the air cooled condenser system and its impacts on capital cost and performance have been estimated. While the design may be feasible from a technical point, the size of the ACC is three times larger than any unit ever constructed for a single steam turbine unit, which creates many uncertainties.

The cost penalties for changing the cooling system design to Air Cooled Condensers are high, including both capital and operating.

The capital cost increases for changing the design to an air cooled condenser, including water mitigation costs, are estimated to be almost $124.7 million in today's costs requiring an investment of $177 million to account for escalation and interest during construction at the commercial operation date. Over 40 years of operation, the net present value of increased operating and maintenance costs plus electricity cost penalties amount to over $253.8 million. The total net present value of the capital and operating cost increases is calculated to be $431 million in 2019 dollars.

On an annual basis, the use of air cooled condensers will save about a net of 6,300, million gallons of water from the river. The Susquehanna River Basin Commission has proposed that a water fee of $0.28 per 1000 gal is sufficient to mitigate the use of water from the river. An alternate economic evaluation was prepared using the SRBC water fee as an annual operating expense and eliminating the offsite water storage. This evaluation shows an even greater cost penalty for dry cooling of $473 million, $42 million greater than the base case with offsite water storage. Clearly, the use of dry cooling cannot be justified on an economic basis, even considering the value of the water saved.

In addition, there are other considerations that reduce the attractiveness of installing air cooled condensers as follows:

- Although there are many applications of dry air cooled condensers throughout the world, this would be the largest unit by far, servicing a single steam turbine. This is significant because it is one of the few cases in which a larger design is more challenging than a smaller one. The larger the steam flow rate, the further it has to travel to reach the far ends of the condenser. This unit will require 6 steam ducts, each 25 feet in diameter, from the turbine exhaust to the air condenser.
- The loss of net electric generation will have to be replaced by electricity from other generating plants, mainly fossil fired units. The benefit of emissions free generation will be lost for the replacement electricity.
- The use of an air cooled condenser will impose significant changes to the EPR design and would impact plant licensing costs and schedule. In fact, the changes would most probably be large enough to endanger the EPR fleet concept, potentially resulting in even greater costs for BBNPP than what are reflected in this analysis.