UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board
G. Paul Bollwerk, III, Chairman
Nicholas G. Trikouros
Dr. James Jackson

In the Matter of	)	
	)	November 7, 2007
SOUTHERN NUCLEAR OPERATING CO.	)	
	)	Docket No. 52-011-ESP
(Early Site Permit for Vogtle ESP Site)	)	ASLBP No. 07-850-01-ESP-BD01

JOINT INTERVENORS' ANSWER OPPOSING SOUTHERN NUCLEAR OPERATING CO.'S MOTION TO DISMISS AS MOOT, OR IN THE ALTERNATIVE, FOR SUMMARY DISPOSITION OF JOINT INTERVENOR'S CONTENTION 1.3

Joint Intervenors Center for a Sustainable Coast, Savannah Riverkeeper, Southern Alliance for Clean Energy, Atlanta Women's Action for New Directions, and Blue Ridge Environmental Defense League (collectively "Intervenors") hereby enter their answer opposing Southern Nuclear Operating Company's ("SNC" or "Applicant") Motion to Dismiss as Moot or in the alternative for Summary Adjudication ("Motion") of Intervenors' Environmental Contention 1.3 ("E.C. 1.3"). SNC failed to demonstrate that there is no genuine issue as to any material fact regarding the Draft Environmental Impact Statement ("DEIS). Without an adequate analysis of cooling alternatives on record, E.C 1.3 is not moot. Summary adjudication is inappropriate. Pursuant to 10 CFR §2.1205, SNC must demonstrate that there is no genuine issue as to any material fact in dispute. The Applicant must do more than merely issue a statement that there is no issue of material fact to meet its burden under 10 CFR §2.1205. Accordingly the Applicant's Motion should be denied.

The applicant's argument that E.C 1.3 is merely a contention of omission is flawed. As admitted by the Atomic Safety and Licensing Board ("Board"), E.C. 1.3 determined that the existing analysis of alternatives was inadequate. *Memorandum and Order* at 47 (March 12, 2007). The mere submission of information by the SNC or issuance of the DEIS does not render E.C. 1.3 moot. Submissions by SNC and the issuance of the DEIS have failed to provide adequate analysis of cooling alternatives to satisfy E.C. 1.3.

The Board must dismiss the applicant's Motion. The Intervenors will demonstrate that genuine issues of material fact regarding cooling alternative analysis remain in dispute. Furthermore, it will be shown that E.C. 1.3 is not one of omission. For mootness to apply here, the cooling alternative analysis on record must be "adequate." It will be shown that the analysis as required by the ASLB Order remains absent from this record and that E.C. 1.3 is not moot. Because SNC's Motion is unsupported by material fact or by an adequate alternatives analysis, there is no legal basis for granting the Applicant's Motion.

I. INTERVENORS STATEMENT OF GENUINE ISSUES OF MATERIAL FACT IN DISPUTE

On October 17, 2007, SNC concurrently filed its Motion for Summary Adjudication and submitted a "Statement of Undisputed Material Facts." Intervenors hereby reply to SNC's submission and contend that there are genuine issues of material fact still in dispute. Where Intervenors contend that no dispute exists, the statement is followed by the word "ADMITTED"; where the matter remains in dispute, the statement is followed by the word "DENIED or "ADMITTED IN PART AND DENIED IN PART" or "DENIED INSOFAR AS" and statement and/or reference for the basis of denial.

1. As permitted in 10 C.F.R. Part 52, SNC filed an application for an ESP for two additional units at the existing Vogtle Electric Generating Plant ("VEGP"). The 3,169-acre VEGP

site is located on a coastal plain bluff on the southwest side of the Savannah River in eastern Burke County, Georgia. The site is approximately 30 river miles above the U.S. 301 bridge and directly across the river from the Department of Energy's Savannah River Site (Barnwell County, South Carolina). Southern Nuclear Operating Company Vogtle Early Site Permit Application ("Application") Part 1, Section 1. SNC has selected two Westinghouse Electric Company, LLC AP1000 standard reactors as the proposed design to be constructed and operated at the VEGP site. Application Part 2, Section 1.1. **ADMITTED.**

2. The Nuclear Regulatory Commission ("NRC" or "Commission") has repeatedly expressed its desire that the next generation of nuclear plants be standardized, including the balance of plant beyond the nuclear island. *See Draft Statement of Policy on Conduct on New Reactor Licensing Proceedings*, 72 Fed. Reg. 32139, 32142 ("the Commission encourages applicants to standardize the balance of their plants insofar as is practicable"). The NRC approved the AP1000 reactor as one of four standard designs that applicants may reference in applications for combined operating licenses. The NRC has encouraged applicants to choose one of those designs to maintain standardization in their license applications. *Draft Statement on Policy of Conduct of new Reactor Licensing Proceedings*, 72 Fed. Reg. 32139 (June 11, 2007), *citing* 10 C.F.R. § 52.63 (2006). Although the balance of plant, including site specific systems such as cooling systems, are not required to be standardized by the design certification rule, the NRC has said it encourages standardization of such systems "insofar as is practicable." 72 Fed. Reg. at 32142. **DENIED**. The above-quoted language constitutes SNC's characterization of a draft NRC policy, and not a statement of material fact. If anything, this is a legal question, not a factual one, and should not be included in a statement of undisputed facts. Furthermore, the applicant relies on a draft rule that discusses standardization in terms of a streamlined application process. 72. Fed. Reg. 3239, 3214. The balance of the "standard design" for the AP1000 does not specify a dry-cool or wet-cool technology preference. Powers Declaration ¶ 12.

3. The conceptual design for the cooling system for the AP1000 Nuclear Plant was developed by Westinghouse/Toshiba with the objective of achieving a generic standardized design for use at all potential sites and for all potential clients. The standardized plant design would facilitate and expedite the licensing, procurement, construction, and commercial operation of all the standardized units. Based on the Commission's policy directive codified in 10 C.F.R. Part 52, Westinghouse and Toshiba conceptualized the design of the turbine island and cooling system components. Cuchens Affidavit, Exhibit 1 at p. 2. **DENIED**. The design by Westinghouse/Toshiba is not sacrosanct. "A standard design serves as a point of departure for customizing the design for a specific site, with specific site constrains." Powers Declaration ¶ 11. The AP 1000 standard design did not contemplate specifics unique to Plant Votgle. See *Id.* By definition the term "generic" implies that "standardized design" is broad enough to accommodate a number of potential sites with certain modifications. The cooling system falls outside the scope of standardization as described by the NRC. The NRC does not require standardization for cooling systems, of systems in the balance of the plant. 72 Fed. Reg. at 32142. The "standard design" by Westinghouse/Toshiba "accommodates

any cooling system, wet or dry, as long as the cooling system maintains steam turbine backpressure within the design limitations." Powers Declaration ¶ 13. In short, the standard design discusses backpressures, and does not, as Cuchens asserts, specify a particular cooling design. *Id.*

4. The standard AP1000 plant cooling system design includes a closed loop cooling system with a traditional steam surface condenser to condense steam from the turbine and a wet evaporative cooling tower. Cooling water is re-circulated from the tower to the condenser (for condensing steam) as the medium for transfer of heat from condensed steam emerging from the turbine. Air flowing through the cooling tower transfers heat to the air via evaporation of warm water (as a steam/plume leaving the cooling tower). Cuchens Affidavit, Exhibit 1 at. p. 3. **ADMITTED IN PART AND DENIED IN PART.** The standard AP 1000 design is not specific to any cooling system, wet or dry. As long as the steam turbine backpressure is maintained a wet or dry cooling technology can be used. Powers Declaration ¶ 12. While it is admitted that a closed loop design proposed by SNC may be integrated into the plant, the plant is not exclusive to any particular dry-cool or wet-cool technology application, contrary to SNC's assertion. *Id.*.

5. The standard design configuration of the AP1000 Nuclear Plant provides for steam to be passed across a steam turbine which turns a generator, creating electricity. The steam leaves the turbine and goes to a steam surface condenser, a large heat exchanger filled with tubes that have cold water flowing through them. The cold water in the tubes absorbs the heat from the steam, causing it to condense back into liquid form; it is then pumped back to the nuclear reactor and the process begins again. The cold water circulating through the condenser tubes is pumped out to a wet cooling tower where it is cooled off by dumping its heat to the surrounding air. Once cool, the water is pumped back through the condenser tubes. Both circuits continue in a continuous process (hence the name – "closed loop cooling system"). Cuchens Affidavit, Exhibit 1 at p. 3. **DENIED**. The standard design configuration does not contemplate a specific cooling technology. Rather, "the standard design accommodates any cooling system, wet or dry as long as the cooling system maintains steam turbine backpressure. Powers Declaration ¶ 12.

6. The Design Control Document (DCD) for the AP1000 provides that the standard turbine generator for the AP1000 Nuclear Plant is a triple exhaust turbine, which means that steam from the turbine(s) will exhaust into three separate steam surface condenser shells. These are generally referred to the high pressure, intermediate pressure, and the low pressure turbines. *Id.* For optimum plant efficiency, the multi-pressure turbine generator for the AP1000 Nuclear Plant is designed to have the following backpressures at the design inlet cold water temperature of 91ºF as indicated below (from DCP/NUS0302).

HP Turbine backpressure 3.57 "HgA
IP Turbine backpressure 2.82 "HgA
LP Turbine backpressure 2.37 "HgA
Avg. Turbine backpressure 2.92 "HgA

Cuchens Affidavit, Exhibit 1 at pp 3-7. **DENIED.** Cuchens is incorrect in asserting that only standard backpressure turbines can be used with the AP1000 design. "High backpressure turbines, rated to 8 HgA backpressure or greater, are normally specified with air-cooled installations. High backpressure turbines are simpler and less expensive than standard backpressure turbines." Powers Declaration ¶ 13.

7. Normal operation of the turbine generator is designed to be within an exhaust pressure (backpressure) range of ~ 1.0 to 5.0 "HgA. The higher the backpressure on the turbine, the less electricity the generator is able to produce, while the lower the backpressure is on the turbine, the more electricity the generator is able to produce (down to choke flow backpressure @ ~ 1.0 "HgA). Further, this corresponding increase in exhaust or backpressure associated with a dry system causes the unit to exceed its alarm point much more frequently than with a wet system, leading to more shutdowns of the unit. Cuchens Affidavit, Exhibit 1 at pp. 3-4, 10. The AP1000 standard condenser is designed to yield a gross unit generation of approximately 1,193 MW. Cuchens Affidavit, Exhibit 1 at p. 8 and Figure 5. **DENIED**. Mr. Cuchens' analysis is flawed because he assumed that only a standard backpressure turbine can be used when in fact, high pressure backpressure turbines may be used with the AP1000 design. Powers Declaration ¶ 13.

8. The AP1000 standard design calls for the turbine generator to be located on a concrete pedestal above the steam surface condenser which allows steam to be routed directly from the turbine to the condenser below. The exhaust duct carrying the steam to the condenser is called the turbine hood which functions as a distribution/transition piece from the turbine to the surface condenser below. Minimizing the pressure losses in the hood from the turbine to the condenser is important to avoid loss of turbine efficiency and electric output. The design of the entire turbine island (thermal cycle) depends on the turbine and condenser performance. The powerhouse building design is dependent on the turbine and condenser arrangement, size, and configuration. The turbine pedestal supports the turbine with the steam surface condenser located directly under the turbine and pedestal. The design of the turbine extraction piping, location of feed-water heaters, and condensate pumps is largely dependent on turbine and condenser design and location. Cuchens Affidavit, Exhibit 1 at pp. 3-4. **DENIED.** The turbine island design does not depend on the condenser performance. In modifying the design of the turbine building, the condenser may be removed and ACC steam ducts may be located in the exact spot below the steam turbine outlet. Powers Declaration ¶ 16. The steam turbine design used with the AP 1000 design, however, would not require any modification. *Id.* at 18.

9. The configuration of the triple exhaust turbine requires the steam surface condenser to also be segmented into three shells, similarly called the high pressure (HP), intermediate pressure (IP), and low pressure (LP) shells. The average pressure of the three condenser shells (HP+IP+LP)/3 is the key parameter for unit performance considerations and operating limitations on the turbine generator. Cuchens Affidavit, Exhibit 1 at p. 4. **ADMMITTED IN PART**. High backpressure turbines in combination with ACC system can be used with the AP1000 design. Powers Declaration ¶ 13.

10. The standard design for an AP1000 Nuclear Plant includes a cooling system utilizing a conventional steam surface condenser and either natural draft or mechanical cooling towers. The system relies on the cooling properties of circulating water, to achieve cooling. The standard steam surface condenser for the AP1000 Nuclear Plant includes the following design parameters:

Type Condenser:		Multi-pressure, Single Pass, Three Shell
Design Tube Material:		Titanium
Design Tube O.D. / Tube Gage:		1.0 " O.D / 22 BWG
Design Tube Velocity:		8.2 FPS
Design Flow:		600,000 GPM
Design Heat Load (MBtu/Hr):		7,565.2 Btu/Hr x 106
Design Inlet Cold Water Temperature:		91.0 °F
Design Range (Delta T - ° F):		25.2 °F
Design Surface Area:		1,235,737 Sq. Ft.
Design TTD - ° F		5.33 °F
Design Pressures	High Pressure (HP) Shell	3.57 "HgA
Intermediate Pressure (IP) Shell	2.82 "HgA	
Low Pressure (LP) Shell	2.37 "HgA	
Average (Avg.) Shell Pressure	2.92 "HgA	

Cuchens Affidavit, Exhibit 1 at p. 7. **DENIED.** Intervenors deny that the standard design of the AP1000 specifies the cooling system described above, or any cooling system. The standard design accommodates any cooling system as long as the cooling system maintains steam turbine backpressure within the design limitations of the steam turbine in the standard AP1000 design. Powers Declaration ¶ 12.

11. In contrast to the wet cooling system described in the AP1000 DCD, a dry cooling system would rely on air pumped from the outside and flowing over large metal-finned tubes to cool the steam. The steam would be piped through large ducts (16 to 20 feet or more in. diameter) to the tubes. In the cooling unit (module), the fans force the air across the finned tubes to achieve optimum heat transfer. As it rejects its heat, the steam would condense to water and be drained to a large tank from which it would be pumped back to the nuclear steam supply system. Cuchens Affidavit, Exhibit 1 at p. 9. **ADDMITTED.**

12. The chief governing design characteristic of an air cooled condenser used in a dry cooling system is the Initial Temperature Difference ("ITD"), the constant difference between the temperature of the outside air and the temperature of the steam condensing within the tube bundles. The higher the ambient temperature in which an air-cooled turbine operates, the higher the steam saturation temperature, and therefore the backpressures, of the turbine will be. Backpressure, in turn, limits the efficiency and operability of the turbine. Current "state-of-the art" air-cooled condensers for the utility industry are designed with an ITD of around 40° F, although there have been a few such condensers

built in the United States with an ITD of 35° F. No manufacturer of air-cooled condensers has successfully designed or built an air-cooled condenser with a lower ITD than this. Air cooled condensers in the United States have typically been employed in connection with smaller, combined cycle generating units with much lower heat loads than the AP1000. Cuchens Affidavit, Exhibit 1 at pp. 10-13. **DENIED** Contrary to Mr. Cuchens' assertion, air cooling at large generating units is employed in the US. Midlothian Energy uses an air cooling system at its 1,650 MW combined cycle plant located near Dallas, Texas. Dominion Resources is proposing a parallel dry-wet cooling system for reactor 3 and dry- cooling system in reactor 4 at their North Anna plant in Virginia. The estimated annual average efficiency penalty of using dry cooling at Plant Vogtle is about 1.5% using a 35 F ITD ACC. Powers Declaration ¶ 15. Contrary to Cuchens' assertion, it is not necessary to maintain the same backpressure with dry cooling at peak conditions that would be achieved with wet cooling. *Id.*

13. Assuming an ACC could be designed for an AP1000 that can operate at 35ºF ITD, this would result in a steam saturation temperature approaching 133.5°F at 95°F ambient temperature. This steam saturation temperature would increase backpressures on the turbine far above the optimum design backpressure (average of 2.92 "HgA) and exceed the operational limit (5.0 "HgA) in at least one of the sections of the turbine. Thus, at the design ambient temperature of 95ºF, an ACC would seriously undermine the efficiency, electrical output and even the reliability of the standard AP1000 turbine. Cuchens Affidavit, Exhibit 1 at pp. 10-12. Steam duct losses would likely further drive up the unit backpressure from the turbine outlet to the ACC significant enough (0.5-1.0 "HgA) such that that the turbine itself would almost certainly see a pressure in excess of its allowable operating pressure at the design temperature. Because of the current limit of technology as described above (a minimum 35º- 40° F internal temperature differential ITD), an ACC could not provide adequate cooling to an AP1000 standard turbine operating in South Georgia. Cuchens Affidavit, Exhibit 1 at p. 11. In South Georgia, extreme maximum temperatures recorded in the vicinity of the site have ranged from 105°F to 112°F at Louisville IE station. The station record high temperature for the Midville Experiment Station (i.e., 105°F) has been reached on four separate occasions. Individual station extreme maximum temperature records were set at multiple locations on the same or adjacent dates. The similarity of the respective extremes indicates that these statistics are reasonably representative of the temperature extremes that might be expected to be observed at the VEGP site. Application, Part 3, Section 2.7.4.1.1. An ITD of 35° at these ambient temperatures would force steam saturation temperatures for a standard AP1000 above the minimum of 133.5°, and consequently backpressures would far exceed the maximum of 5 "HgA in the high pressure shell. Cuchens Affidavit at p. 11. The minimum ITD is a material limitation on the technical feasibility of an ACC system in conjunction with the AP1000 steam turbine, especially when the peak ambient temperatures in the vicinity of Plant Vogtle are taken into account. Cuchens Affidavit, Exhibit 1 at p. 10-12. **DENIED.** Mr. Cuchens assumptions are flawed. Peak summertime design conditions occur no more than 29 hours a year. During much of the year, the ambient temperature is less than 70 F and there would be little or no differential in the MW output of wet, dry, or parallel fry-wet AP1000 alternatives. Powers Declaration ¶ 20. See Powers Attachment D. In any case, the MW differential between a

dry and a wet cooling system would only be between 15-20 MW at peak conditions. Additionally, high backpressure turbines may be substituted with standard backpressure turbine in the AP1000 design, to address efficiencies at higher temperatures. Powers Declaration ¶ 13.

14. On hot days, water tends to stay cooler than the surrounding air. Unlike wet bulb temperature, the driving force behind a wet cooling system, which remains much more constant over a day, the dry air temperature at the VEGP site can vary up to 20-30 degrees over the course of the same day. Such fluctuations in temperature translate into 20°-30° swings in the ITD. This kind of instability would harm the operation of the power plant and create reliability difficulties for the electric grid as a whole. Cuchens Affidavit, Exhibit 1 at p. 19. **DENIED.** There is no factual evidence to substantiate Cuchens' claim that temperature fluctuations create instability and potentially harm the power plant the grid as a whole. An ambient air environment absent temperature fluctuation does not exist. Considerations of swings in ambient temperature are incorporated in every plant design. Furthermore, to establish a material fact, Cuchens must do more than merely state an assumption. He must support his assertions with facts. His affidavit provides nothing outside his personal assertion that there are reliability and instability issues with temperature swings.

15. No one has ever built a triple pressure turbine that could operate continuously at pressures higher than 5 "HgA. Even if a non-standard turbine were designed to operate at high backpressures necessary for utilization of an air-cooled condenser, significant inefficiencies, loss of standardization, adverse environmental consequences and prohibitive increases in cost would result. Cuchens Affidavit, Exhibit 1 at pp. 10-13. **DENIED.** There would be no loss of standardization as outlined by the NRC draft rules. Standardization does not apply to the balance of the plant. Cooling systems are ancillary and standardization is not necessary, required or preferred. See 72 Fed. Reg. 3239, 3214 The cost of would not be prohibitive.

16. Any increase in backpressure below the trip point for the current turbine would result in a substantial reduction in electrical output. For example, assuming an *average* turbine backpressure of 4 "HgA could be achieved using an ACC in conjunction with the standard AP1000 turbine, which as noted above could not be achieved during the periods of the year in which the unit was needed most, the result would be a loss of around 40 MW out of the generator as compared to operation at the current design backpressure of 2.92 "HgA. Cuchens Affidavit, Exhibit 1 at pp. 10-12. In addition, increased station service requirements for an air-cooled system would decrease net output by another approximately 41 MW and steam duct losses of approximately 37 MW. Cuchens Affidavit, Exhibit 1 at pp. 11, 14. Thus, the minimum reduction in net output per unit would amount to approximately 118 MW. Georgia Power Company and the other utility-owners of Vogtle 3 and 4, would need to obtain other generating resources to make up the shortfall. Cuchens Affidavit, Exhibit 1 at pp. 15-16. **DENIED**. Mr. Cuchens miscalculated the minimum reduction per unit. Mr. Cuchens analysis is critically flawed. He rounds the power output differential between wet and dry cooling at peak conditions from 37MW to 40MW. Powers Declaration ¶ 20. Then he mistakenly

assumes that this differential is maintained every hour of the year. *Id.* Peak summertime conditions occur no more than 29 hours of the 8,760 hours in a year. *Id.* Calculated correctly, the average MW differential would be in the range of 15 to 20 MW during peak conditions. *Id.* And, See Powers, Attachment C. During much of the year, whenever ambient temperature is less than 70º F, there would be little or no differential in the MW output of wet, dry, or parallel dry-wet AP-1000 alternatives. See Powers Declaration, Attachment D.

17. Designing a dry cooling system to match the AP1000 steam surface condenser performance is purely academic, since no such system exists and the lack of any experience with a multi-pressure turbine suggests caution in assuming viability of concept. To approximate backpressure low enough to permit efficient operation of the turbine the ACC would need to operate at an ITD of less than 20ºF, i.e. more than 40% less than the minimum ITD using current technology. Cuchens Affidavit, Exhibit 1 at pp. 12-13. **DENIED.** A dry-cool system designed to match the AP1000 design is not academic. See Powers Attachment A. See Powers Declaration ¶ 23.

18. The closed-cycle wet cooling system described in the AP1000 approved design, and included as the basis for SNC's application for an ESP, capitalizes on the cooling properties of the water to cause evaporation, something the dry system cannot do. Due to this degradation in efficiency, an air-cooled system must be significantly larger than a comparable wet system to maintain the same unit performance. Cuchens Affidavit, Exhibit 1 at p. 12-18. **DENIED**. The AP 1000 "approved design" is not limited to a closed-cycle wet cooling system. There are alternative designs to dry-cool that would reduce land requirements, such as a parallel dry-cooling tower. Powers Declaration ¶12.

19. Assuming the limits of current technology of dry cooling could be improved to the point that an ACC could operate at an ITD of 20ºF in order to deliver appropriate backpressures to the turbine, the VEGP site would necessitate construction of approximately 334 modules linked with large ducts and would require SNC to clear an additional area equivalent to seven football fields, or more than half a linear mile, by 300 feet for each additional VEGP unit. Cuchens Affidavit, Exhibit 1 at pp. 12-20. The additional construction and land use would harm the environment, such as by necessitating filling existing bodies of water on or on the border of the site. Such adverse environmental impacts would include the grubbing and clearing of several wooded areas, excavation impacts, and adverse impacts to Mallard Pond, a natural area within the site. Application, Part 3, Section 2.3.1.1; Affidavit of Thomas C. Moorer. **DENIED**. Only 230 modules would be required. Cuchens affidavit (14-15) identifies an ACC system composed of 230 modules at the cost of $200 million. Here, however Cuchens asserts that the only viable ACC design consists of 334 modules at a cost of $341 million. The 230 module ACC with a 30 MW parasitic fan load would result in the same annual energy penalty as the 334 module with a parasitic fan load of 44MW. Powers Declaration ¶ 15. No reason is given by Mr. Cuchens as to why the 230 ACC module is excluded from his feasibility study in favor of the larger, costlier design with no discernable advantage. Furthermore the Cuchens Affidavit offers no explanation as to

why the wet cooled system must match performance of the standard wet tower condition during peak conditions. Powers Declaration ¶ 15.

20. Specifically, installation of a dry cooling system to an AP1000 would require substantial changes to the AP1000 standard turbine building design. In place of the current steam surface condenser, three large ducts would have to be constructed beneath the turbine. These ducts would then have to be run through the walls of the turbine building and outside to a distance a minimum of 100 feet away prior to routing the ducts to individual sections of the dry cooling system up to 2000 feet away. This would necessitate changes to the wall of the turbine building and potentially the turbine pedestal. It could also cause layout changes to other equipment in order to provide a path for the steam ducts. Cuchens Affidavit, Exhibit 1 at pp. 12-18. **DENIED.** Dry cooling would not require a substantial change to the AP1000. "Removal of surface condensers will create adequate space for ACC steam ducts in the exact spot where these ducts need to be located below the steam turbine outlet." Powers Declaration ¶ 16. Although holes will have to be cut in the turbine building wall to allow the steam ducts to be interconnected to the ACC, this "in no way rises to the level of reworking the entire turbine building." No changes in the turbine pedestal would be required. Powers Declaration ¶ 16.

21. Another change that an ACC would certainly necessitate is to relocate the feed-water heaters that are currently designed to be placed in the neck of the steam surface condenser. Since there would no longer be an exhaust hood in the steam surface condenser in which to mount them, the heaters would have to be moved to a different location within the turbine building. The changes would also represent significant further deviation from the standardization of the AP1000 design. Cuchens Affidavit, Exhibit 1 at p. 19. **DENIED.** The turbine building would not have to be redesigned. These adjustments present no engineering challenge. Powers Declaration ¶ 4. Every power plant requires number of modification to a generic standard design to accommodate site-specific conditions. Powers Declaration ¶ 9. No surface condensers are used with an ACC. Powers Declaration ¶ 16. Once removed, there will be adequate space for ACC steam ducts below the steam turbine outlet.

22. The cost of constructing approximately 334 modules alone is estimated to be an additional $361 million for each nuclear unit over the cost of the standard closed cycle wet cooling system for the AP1000. Cuchens Affidavit, Exhibit 1 at p. 14. **ADMITTED IN PART, DENIED IN PART.** It is admitted that 334 modules are estimated to cost $361 million. It is denied, however, that this is a reasonable cost estimation for an ACC system. Cuchens initially identifies a 230 module system at the cost of $200 million. Yet the cooling cost study consists of 334 modules at a cost of $361 million. Powers Declaration ¶ 14. "It makes no sense to build a 334 module ACC that costs $361 and has a 44MW parasitic fan load, when a 230 module ACC with 30 MW parasitic fan load would have the same results." Powers Declaration ¶ 5. Essentially, Mr. Cuchens has ramped up the size and load of the dry-cool option, increasing fiscal and environmental costs and impacts to the dry-cool alternative. This is unreasonable as Cuchens already identified a feasible dry-cool system that was smaller and cheaper.

23. The cost of a dry cooling system is estimated to be approximately five times greater than that of the closed-cycle wet system SNC proposed in its ESP. Cuchens Affidavit, Exhibit 1 at pp. 19-20 and Appendix. This cost comparison does not take into account the additional costs arising out of changes to the re-design of the turbine building and powerhouse and of the equipment, such as condensate storage tanks, air removal systems and piping. Neither does this estimate calculate the costs of the 16-20 foot (or more) wide ducts, which no one has ever designed for turbines as large as those necessary for the AP1000. Cuchens Affidavit, Exhibit 1 at pp. 19-20 and Appendix. **DENIED.** Though Cuchens initially proposes a 230 ACC module system costing $200 million (pp 14-15), he assumes a 360 ACC modules system costing $361 million in his feasibility study. Contrary to Mr. Cuchens' assertion, the use of Air cool would not require an entire rework of the turbine building. Powers Declaration ¶ 16. In fact, Mr. Cuchens states that the AP1000 with an air-cooled condenser would be a simpler design than the design incorporating a wet-cool design. See Cuchens p.11.

24. The Draft Environmental Impact Statement ("DEIS") analyzes a dry cooling system as an alternative cooling method for Vogtle 3 and 4. The DEIS concluded that a dry cooling system, larger in size than the proposed wet cooling system, would occupy more land, affecting land use and increasing terrestrial impacts of the plant. DEIS at 9-26. **DENIED.** The DEIS discusses a hybrid wet/dry cooling system but does not provide any basis or data to support this assertion. Size estimates are limited to characterizations as "large units," or "more land" compared to wet-cooling. *Id.* The DEIS did not determine to what extent dry-cooling would impact the land beyond impacts already imposed by the existence of the two reactors already present. There are already two nuclear reactors on site. With the addition of two more nuclear reactors and support structures, the environmental impact of dry-cooling systems might be negligible in context of entire site. Absent, any analysis on a dry-cooling system, however, the DEIS merely makes an assertion that its environmental benefits do not offset its impacts.

25. The DEIS concluded that a dry cooling system at VEGP would have greater environmental impacts, because the cooling fans would create more noise pollution, and the dry cooling system would consume more electricity. The DEIS concludes that "based on the environmental impacts related with increased land use, fuel use, spent fuel transport, spent fuel storage, and the small impact that the proposed natural draft wet-cooling tower would have on the site environment and the Savannah River, the Staff concludes that a wet cooling tower system is preferable to either a dry or hybrid wet/dry cooling system for VEGP Units 3 and 4. *Id.* **ADMITTED IN PART, DENIED IN PART**. It is admitted that the DEIS erroneously concluded that dry-cooling would pose environmental impacts and fuel requirements as stated above. As the DEIS did not include any data upon which its conclusions were based, it is unclear how the staff reached this conclusion. The parasitic load for a dry cooling system could largely be eliminated by utilizing a parallel dry-wet cooling system similar to the one Dominion Resources is proposing for North Anna 3 nuclear reactor in Virginia. Powers Declaration ¶ 20. During most of the year "whenever the ambient temperature is less than approximately 70º F, there would be little or no differential in the MW output of the wet, dry or parallel dry-wet AP 1000 alternative. *Id.* See Powers Declaration Attachment D.

Furthermore, the land use and impacts to land would be mitigated to a large extent by designing an ACC system requiring only 230 modules. Powers Declaration ¶ 15. The DEIS concluded that the dry-cooling option would "largely eliminate" impacts on aquatic biota in the Savannah River. DEIS at 9-25. Furthermore, a dry-cool system would significantly decrease the risks associated with drought and water availability. DEIS at 9-26. Given the current drought Georgia is experiencing, issues of water usage are not adequately addressed here.

26. The need for more electricity would create more spent fuel to transport and to store. *Id.* **DENIED.** The parasitic load for a dry cooling system could largely be eliminated by utilizing a parallel dry-wet cooling system similar to the one Dominion Resources is proposing for North Anna 3 nuclear reactor in Virginia. Powers Declaration ¶ 20. During most of the year "whenever the ambient temperature is less than approximately 70º F, there would be little or no differential in the MW output of the wet, dry or parallel dry-wet AP 1000 alternative. *Id.* See Powers Declaration Attachment D.

27. The DEIS concluded that the additional expenses associated with a dry cooling system would make it significantly less cost effective than the wet system. DEIS at 9-25. **DENIED.** The DEIS did not conclude that additional expenses purportedly associated with dry cooling systems were significant. DEIS at 9-25. Rather, the DEIS concluded that additional expenses associated with a dry cooling system rendered the technology less cost effective, but cost did not render the dry-cool infeasible. DIES at 9-25. The DEIS concluded that based on land use impacts of a dry cool system and potential noise pollution, the benefits of dry-cooling did not offset the harms imposed by a wet-cool system. DEIS at 9-25. It is not clear what data the DEIS is based on to reach its conclusion. There is no analysis provided in terms of how many dry-cool modules would be needed, at what cost or how much of a parasitic load dry-cool would require. Rather, the DEIS makes generalizations absent any apparent analysis. SNC and Cuchens asserted that 334 module ACC units would be required at the site. This is a miscalculation. See Powers Declaration ¶ 15. Mr. Powers calculates that only 230 model ACC units would be required with a 30MW parasitic fan load would be required for the same annual energy dry-cooling. *Id.* Mr. Powers points out that Mr. Cuchens identified this option, but failed to study it, instead opting to analyze a 334 module ACC. *Id.* at 14.

II. <u>SUMMARY ADJUDICATION MUST BE DENIED BECAUSE THERE ARE GENUINE ISSUES OF MATERIAL OF FACT IN DISPUTE</u>

The factual citations and argument set forth above are hereby realleged herein as applied to the legal issues. SNC is not entitled to summary adjudication as there are genuine issues of material fact in dispute. *See* 10 C.F.R. §§ 2.105 and 2.710(d)(2). SNC failed to meet its burden of demonstrating there is no genuine issue of material fact in dispute.

As outline above, there are a number of material facts in dispute. Submissions by SNC are riddled with flawed assumptions, misstatements of fact and policy misinterpretation. See Section I, "Statement of Fact (1-26)."

"Standardized" AP 1000 design is compatible with dry and wet cooling systems. Every power plant requires modifications to a generic standard design to accommodate site-specific conditions. Powers Declaration ¶9. The "standard design serves as a point of departure." *Id.* at ¶10. The standard design accommodates any cooling system, wet or dry, as long as the cooling system maintains steam turbine backpressure within the design specifications. *Id.* at ¶12.

A Dry-cooling System would not require an "entire rework" of the AP 1000 design. Moving Boiler feedwater pumps to a slightly different location and providing openings in exterior building walls to accommodate air cooled condenser (ACC) steam ducts is not an engineering challenge. Powers Declaration ¶11. With ACC system no surface condensers are used and can therefore be removed. *Id.* at ¶16. Removal of surface condensers will create adequate space for ACC steam ducts below the steam turbine outlet. *Id.* Holes would then have to be cut in the turbine building wall to allow the steam ducts to be interconnected to the ACC. *Id.* No other significant physical modifications would be required in or to the turbine building. *Id.*

SNC's ACC system size calculation is flawed. The estimated annual average efficiency penalty of using dry cooling at Plant Vogtle is approximately 1.5 percent using a 35 ^{o}F ITD ACC (see Attachment C). Powers Declaration¶ 15. The presumption used by SNC's expert in selecting a 20 ^{o}F ITD ACC for the feasibility study is flawed. *Id.* It is not necessary to maintain the same backpressure with dry cooling at peak hot summer day site conditions that would be achieved with wet cooling. *Id.* This presumption will always result in a spectacularly oversized

ACC design as seen in the feasibility study that considers 334 module ACC that costs $361 million and has a 44 MW parasitic fan load when a 230 module ACC with 30 MW parasitic fan load would result in the same annual energy penalty for the dry cooling option. *Id.*

SNC's dry cooling system efficiency analysis is flawed. Powers Declaration ¶18. There should be little or no difference in the parasitic load of the 35 ^{o}F ITD ACC and the 10 ^{o}F approach temperature wet cooling tower that Mr. Cuchens uses in his comparative analysis. *See Powers Attachment C for a comparison of the parasitic load of wet and dry cooling systems*. Pumping 600,000 gallons per minute of cooling water through the surface condensers in the standard AP1000 design requires large amounts of power. Power Declaration

SNC's statement that ACC systems are "Purely Academic," is a blatant misstatement of the facts. The largest air-cooled plant in the U.S. is the 1,650 MW Midlothian Energy natural gas combined cycle plant near Dallas, Texas. Powers Declaration ¶23. The largest coal-fired air-cooled plant in the U.S. is the 330 MW Wyodak plant in Wyoming. *Id.* The largest air-cooled coal-fired plant in the world is the 4,000 MW Matimba power plant in South Africa. Powers Attachment B.

The Applicant must do more than merely issue a statement that there is no issue of material fact to meet its burden under 10 CFR §2.1205. The Applicant must demonstrate that there is no issue of material fact in dispute. As set forth above, there are issues of material fact in dispute in this matter. Accordingly the Applicant's Motion should be denied.

III. INTERVENORS' CONTENTION 1.3 IS NOT MOOT

A. E.C. 1.3 is not a Contention of Omission

In asserting that E.C. 1.3 is a contention of omission, SNC fails to recognize the distinction between "inadequate analysis" and the "absence of analysis." As admitted by the Board, E.C. 1.3 contends that the existing analysis was "inadequate:"

> "The ER fails to satisfy 10 C.F.R. § 51.45(b)(3) because its analysis of the dry cooling alternatives is inadequate to address the appropriateness of a dry cooling system given the presence of extremely sensitive biological resources." CITE

(March 12, 2007). The Order establishes the presence of some kind of analysis on record; that this analysis did not satisfy federal requirements; and that as a result the analysis was inadequate.

A contention of omission is one that "alleges the omission of particular information or an issue from an application." *In the Matter of Duke Energy Corp.*, CLI-02-08, 56 N.R.C. 373, 383 (2002). If the information claimed lacking in the contention is later supplied, the contention is considered moot. *Id.* Here there was an alternative cooling analysis on record. E.C. 1.3 states that the "[ER's] analysis of dry cooling alternatives is inadequate…" *ASLB Order* at 47. The Contention identifies the ER as the submission on record containing the analysis and then determines that the analysis inadequate. The Contention does not state nor does it imply that an analysis of cooling alternatives is absent or missing. This contention does not omit particular information or an issue. Rather, the information provided is inadequate.

If the information claimed lacking in a contention of omission is later supplied, the contention is considered moot. *In the Matter of Duke Energy Corp.*, CLI-02-08, 56 N.R.C. 373, 383 (2002). But, because E.C. 1.3 is not a contention of omission, it cannot be mooted by the merely submitting information into the record. Here, there was already information in the record regarding dry-cooling alternatives. *See SNC ER XXX*. At issue here is not an absence of

information, but rather the inadequacy of information. E.C. 1.3, therefore can only be rendered moot with the submission of an adequate dry-cool analysis pursuant to *ASLB Order 47*.

B. The Cooling Alternative Analysis on Record is Inadequate

Determining mootness in this case requires an examination of the information contained in the record to determine its adequacy. E.C. 1.3 established that the record was not adequate as "[t]he ER fails to satisfy 10 C.F.R. § 51.45(b)(3) because it fails to address impacts to aquatic species in its discussion of alternatives. In particular, the ER's discussion of the no-action alternative and of alternative cooling technologies fails to consider environmental and economic benefits of avoiding construction of the proposed cooling system."

When the scope of an admitted contention is in question, the Board must look to the bases discussed in support of the contention. *Duke Energy,* 56 N.R.C. at 379. The NRC Staff based admission of EC 1.3 on "whether SNC has provided an adequate analysis of dry cooling as an alternative cooling system for the proposed Vogtle facilities." NRC's Memorandum and Order: Rulings on Standings and Contentions, LBP-07-03, March 12 2007 at 19. SNC generally is obligated in the ER to discuss project alternatives and emphasize those that "appear promising in terms of environmental protection." *Id.* at 19. NRC declared that "SNC should be required to conduct further analysis as to whether, considering the present sensitive species and other pertinent factors, dry cooling is appropriate for the Vogtle site." *Id.* at 20. This contention is not about a lack of discussion, but about a lack of significant and adequate analysis on dry cooling alternatives. This is not a contention of omission, and the discussion is inadequate, therefore EC 1.3 is not moot.

The analysis on record is inadequate and does not render EC 1.3 moot. . As asserted above in the "Statement of Material Facts" and in Section II(A), material facts asserted by SNC

in recent submissions are disputed do not constitute an "adequate analysis" as described by E.C.1.3. The DEIS did not analyze the dry-cooling in any detail beyond that already present in the ER. The DEIS did not identify any specific dry-cooling alternative. It did not discuss size, cost or efficiencies of dry-cooling beyond generalizations already put forward by the ER

IV. CONCLUSION

SNC's Motion for Summary Adjudication should be denied. The record shows that there are genuine issues of material fact in dispute. Assumptions and analysis put forward by SNC are flawed. SNC submissions are contradictory, misleading, and flawed. The cooling alternative analysis on record is in dispute and cannot be considered adequate without further review and clarification. Without an "adequate analysis" of cooling alternatives, E.C. 1.3 is not rendered moot. Accordingly, SNC's Motion must be dismissed.

Respectfully submitted this 13th day of November, 2007,

[Original signed by L. Sanders]

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
SOUTHERN NUCLEAR OPERATING COMPANY	)	Docket No. 52-011-ESP
	)	
	)	
(Early Site Permit for the Vogtle ESP Site)	)	

CERTIFICATE OF SERVICE

I hereby certify that copies of the foregoing **JOINT INTERVENORS ANSWER OPPOSING SOUTHERN NUCLEAR OPERATING CO.'S MOTION FOR SUMMARY DISPOSITION OF ENVIRONMENTAL CONTENTION 1.3** have been served upon the following persons by Electronic Information Exchange and/or electronic mail.

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Dated this 13th day of November, 2007

[Original signed by L. Sanders]

_____

Lawrence D. Sanders

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENCING BOARD

In the Matter of	
SOUTHERN NUCLEAR OPERATING COMPANY	Docket No. 52-011- ESP
(Early Site Permit-Vogtle Electric Generating Plant)	ASLBP No. 07-850-01-ESP-BD01

DECLARATION OF BILL POWERS

State of California

San Diego County

I, Bill Powers, do hereby declare as follows:

1. My name is Bill Powers. I am the principal of Powers Engineering, an engineering firm that consults on power generation, pollution control, and cooling technology issues and implementation. My office is located in San Diego, California. My professional and educational experience is summarized in the curriculum vitae attached to this affidavit.

2. I received a Bachelor of Science from Duke University in Mechanical Engineering and a Masters of Public Health in Environmental Sciences from the University of North Carolina. I am a registered engineer in the state of California. In 1986 I received "Engineer of the Year" award from the Naval Energy and Environment Support Activity, Port Hueneme. I also received the "Engineer of the Year" award from ENSR, Consulting and Engineering, in 1991 and "Productivity Award of Excellence" from the US Department of Defense in 1985.

3. I have over 25 years experience as a lead engineer and project manager for power generation, permitting, and emissions control projects for a number of clients. I have also served

as a power engineering expert for the cities of Carlsbad, CA, Houston, TX and Dallas, TX. I have provided expert testimony, conducted feasibility studies, and consulted on permitting regulation in a number of states including Kentucky, Georgia, Massachusetts and California.

4. In May of 2003 I co-authored and presented a paper entitled "Design Performance of Optimized Air-Cooled Condenser at Crockett Co-Generation Plant" at the EPA Symposium, Technologies Protecting Aquatic Organisms from Cooling Intake Structures. In 2005, I authored a study that examined efficiencies of Air-Cooling. See Attachment C.

5. I am familiar with SNC's application for an early site permit ("ESP") at the VEGP site. I have reviewed excerpts of NRC's Draft EIS, SNC's feasibility study on Air Cooling Condensation (ACC) system, SNC's Motion for Summary Adjudication and related documents submitted in this matter.

6. I am providing testimony in support of interveners' response to the SNC's motion for summary adjudication.

7. The analysis put forward by SNC's feasibility study and its expert, Mr. Cuchens, is flawed. Despite the absence of a cooling technology in a standard design, Mr. Cuchens asserts that a dry cool system at Plant Vogtle deviates from the AP100 "standard design." His statement claiming the plant would need to be "totally reworked" to accommodate the AAC system, is a gross mischaracterization of the simple modifications that would be required. Disregarding other nuclear plant designs incorporating dry-cooling technology in the U.S. and abroad, Mr. Cuchens and SNC incorrectly state that dry cool technologically is impossible and economically infeasible. These conclusions and assertions are incorrect.

8. The cooling component of a nuclear plant is an ancillary system that is not part of the core generating system. Use of air- cooling technology in this case has no impact on this or any

AP1000 reactor design that contains or carries radioactive substances. There is no nuclear safety risk in selecting air cooling over a wet cooling tower in this pressurized water reactor application.

9. Every power plant that is built requires numerous modifications to a generic standard design to accommodate site-specific conditions. Water availability and environmental impacts are issues at nuclear plant sites and may make modification to a standard design based on a wet cooling tower necessary. For example, Dominion Resources is currently proposing a parallel dry-wet cooling system to greatly reduce water consumption in the cooling system that will be used at the North Anna 3 and 4 nuclear reactors (Virginia). At the Palo Verde Nuclear Plant in Arizona, a plant expansion proposed in the late 1970s included the construction of two dry-cooled 1,100 MW nuclear reactors. If water availability is an issue, either to protect aquatic resources or for lack of sufficient flow, either dry cooling or parallel dry-wet cooling must be used. This is not an engineering gamble that could pose a risk to the reliable performance of the nuclear power plant. It is a necessary technical adjustment to the plant design to accommodate site-specific limitations.

10. Dry-Cool technology does not deviate from any "standard design" of the AP1000. Mr. Cuchens of Southern Company implies that the standard AP1000 design is sacrosanct and cannot be modified without ominous repercussions asserted in his June 25, 2007 analysis titled, "*Feasibility of Air-Cooled Condenser Cooling System for the Standardized AP1000 Nuclear Plant – Revision 3*." There is no engineering or technical basis for these implications, and those that are offered are not substantiated in any way.

11. A standard design serves as a point of departure for customizing the design for a specific site with specific site constraints. The engineering teams at Westinghouse Nuclear and Toshiba

that developed the standard AP1000 design have no knowledge of site constraints specific to Plant Vogtle or any other site-specific design. To imply that moving boiler feedwater pumps to a slightly different location and providing openings in building walls to accommodate air cooled condenser (ACC) steam ducts is a major engineering challenge is erroneous. These adjustments present no engineering challenge. They are simply design engineering adjustments necessary to accommodate the air-cooled system.

12. Mr. Cuchens's statements regarding cooling system within the context of a "standard design" are contradictory and misleading. Mr. Cuchens correctly states that the cooling system is part of the "balance of plant," including ancillary systems that are necessary for the plant to function, but that are not part of the core power generation system. He goes further to point out that no particular wet cooling system is identified in the standard design. It could be any wet cooling system. Mr. Cuchens is incorrect, however, in claiming that the standard design precludes dry cooling or air cooling technology. In fact, the standard design accommodates any cooling system, wet or dry, as long as the cooling system maintains steam turbine backpressure within the design limitations of the steam turbine established by Westinghouse Nuclear in its standard AP1000 design.

13. One implication of Mr. Cuchens's flawed analysis is that only a standard backpressure turbine can be used with the AP1000 design. High backpressure turbines, rated to 8 inches of mercury (Hg) backpressure or greater, are normally specified with air-cooled installations. High backpressure turbines are simpler and less expensive than standard backpressure turbines. This

means that Southern Company might save money on the steam turbine portion of the AP1000 standard design if an air-cooled system is selected.[1]

14. Mr. Cuchens identifies 35 ^{o}F ITD as the state-of-the-art level for ACC technology, and shows that 35 ^{o}F ITD ACC will maintain steam turbine backpressure within the performance envelope of the standard AP1000 steam turbine across the entire ambient temperature range at the Vogtle site. Mr. Cuchens identifies the size and cost of a 35 ^{o}F ITD ACC as 230 modules and $200 million respectively (pp. 14-15), yet he does the cooling case study using a 20 ^{o}F ITD ACC that consists of 334 modules and costs $361 million. The 20 ^{o}F ITD ACC matches the hot day performance of the wet cooling tower assumed to be a part of the standard AP1000 design. No reason is given by Mr. Cuchens explaining why the dry cooled system must match the performance of the standard wet tower system at peak hot day conditions.

15. The estimated annual average efficiency penalty of using dry cooling at Plant Vogtle is approximately 1.5 percent using a 35 ^{o}F ITD ACC (see Attachment C). The presumption used by Mr. Cuchens in selecting a 20 ^{o}F ITD ACC for the case study: that it is necessary to maintain the same backpressure with dry cooling at peak hot summer day site conditions that would be achieved with wet cooling. This presumption will always result in a spectacularly oversized ACC design. It makes no sense to build a 334 module ACC that costs $361 million and has a 44 MW parasitic fan load when a 230 module ACC with 30 MW parasitic fan load would result in the same annual energy penalty for the dry cooling option. ACC design is a balance between cost, size, and performance.

16. Contrary to Mr. Cuchens's assertion, the use of Air Cool technology would not require an entire "reworking of the turbine building." Mr. Cuchens refers to the large surface condensers

[1] Telephone communication between Charles Jones, General Electric, and Bill Powers, Powers Engineering, July 26, 2002, regarding the design and cost of a high backpressure GE D11 steam turbine for use with an air-cooled condenser.

included in the standard AP1000 design and provides an artist's rendition of the condensers (pp. 7-8). He then goes on to state, "If an ACC were to be designed for an AP1000 unit, the entire turbine building would have to be reworked. In place of the current steam surface condenser, three large ducts would have to be constructed beneath the turbine." Mr. Cuchens' assertion that the entire turbine building would have to be reworked is an inaccurate characterization. Mr. Cuchens discusses plant modifications, none of which constitute a "reworking" of the entire turbine building. As he points out, the surface condensers necessary for wet cool systems are very large. No surface condensers are used with an ACC. Removal of surface condensers will create adequate space for ACC steam ducts in the exact spot where these ducts need to be located below the steam turbine outlet. Holes will have to be cut in the turbine building wall to allow the steam ducts to be interconnected to the ACC. Cutting 20-foot diameter holes in the wall of a large industrial building in no way rises to the level of "reworking the entire turbine building." No other significant physical modifications will be required in or to the turbine building.

17. Mr. Cuchens correctly notes that the AP1000 with an air-cooled condenser would be simpler than the standard AP1000 design (p. 11). It is generally considered desirable in the power plant design engineering world to simplify complex systems wherever possibility. Simplification generally makes the system more reliable.

18. Dry cooling technology has the potential for far greater efficiency than SNC and Mr. Cuchens purport in their analysis. Mr. Cuchens examines efficiencies of 334 and 230 module dry cooling design compared to a wet cooling system. The 14 MW higher parasitic fan load of the 334 module ACC design essentially negates the higher efficiency of the 334 module design relative to the 230 module design. There should be little or no difference in the parasitic load of the 35 ^{o}F ITD ACC and the 10 ^{o}F approach temperature wet cooling tower that Mr. Cuchens uses

in his comparative analysis. See Attachment C for a comparison of the parasitic load of wet and dry cooling systems. Pumping 600,000 gallons per minute of cooling water through the surface condensers in the standard AP1000 design requires large amounts of power. The wet cooling tower also has 48 modules and the power demand of 48 large fans serving those modules.

19. Mr. Cuchens correctly states that use of this 35 ^{o}F state-of-the-art design would not require any modification to the standard steam turbine used with the AP1000 design. Use of the 35 ^{o}F ITD ACC would result in a 37 MW reduction in gross power output, a reduction from 1,193 MW to 1,156 MW, at the design ambient temperature of 95 ^{o}F (see table on p. 12). The design ambient temperature is also known as the 1 percent summertime temperature, the temperature that is reached or exceeded for 1 percent of the summertime hours. One (1) percent of summertime hours is 29 hours per year.

20. Mr. Cuchens then goes on to round the 37 MW power output differential between wet and dry cooling at peak summertime design conditions to 40 MW and to assume that this differential is maintained every hour of the year. Mr. Cuchens states (p. 11):

> "For example, assuming an average turbine backpressure 4" HgA could be achieved using an ACC in conjunction with the standard AP1000 turbine, which as noted above could not be achieved during the periods of the year in which the unit was needed most, the result would be a loss of around 40 MW out of the generator as compared to operation at the current design backpressure of 2.92" HgA."

This assumption is flawed. Peak summertime design conditions occur no more than 29 hours a year. The 37 MW differential occurs for 29 hours a year. There are 8,760 hours in a year. The average MW differential between wet and dry cooling using a 35 ^{o}F ITD ACC would fall in the range of 15 to 20 MW. See Attachment C. This MW differential can be further reduced by utilizing a parallel dry-wet cooling system, as Dominion Resources is proposing for the North Anna 3 nuclear reactor in Virginia. However, during much of the year, whenever the ambient

temperature is less than approximately 70 ^{o}F, there would be little or no differential in the MW output of the wet, dry, or parallel dry-wet AP1000 alternatives. See Attachment D.

21. Also, peak summertime load is not met by power produced by nuclear generation. Nuclear generation serves baseload power demand. When there is a peak in power demand, simple cycles gas turbines are brought online. Unlike nuclear plants, gas can be brought on and off line quickly. Peak load in most regions of the country is on the order of double the average annual load. If Southern Company considers it essential to maintain the standard wet-cooled AP1000 output on hottest day with a unit equipped with dry cooling, the most inexpensive approach would the addition of one 47 MW LM6000 peaking gas turbine at the site to address the peak day output reduction associated with use of the 35 ^{o}F ITD ACC. The equipment cost of one 47 MW LM6000 is approximately $13 million.[2] This is far less than the difference in cost of $161 million between a 20 ^{o}F ITD ACC and a 35 ^{o}F ITD ACC for the AP1000. The LM6000 is also much more thermally efficient than the AP1000. Given that the LM6000 would be used very infrequently, on the order of a few hundred hours per year at most, this approach would have almost no impact on the overall cost of the power produced at Vogtle.

22. The parasitic fan load of the ACC can also be completely eliminated by selecting a natural draft ACC. A discussion of Heller natural draft ACCs is included in Attachment E. Attachment E also includes a description of ACC spray augmentation to increase power output on hot days as well as several types of parallel dry-wet cooling system designs. Direct and indirect natural draft ACCs provided by Balcke Durr, now SPX, are described in Attachment E.

23. There are dozens of coal- and natural gas-fired plants in the U.S. that use air-cooled condensers. The largest air-cooled plant in the U.S. is the 1,650 MW Midlothian Energy natural gas combined cycle plant near Dallas, Texas. The largest coal-fired air-cooled plant in the U.S.

[2] Gas Turbine World, 2006 Gas Turbine World Handbook – Simple Cycle Prices, 2006, p. 15.

is the 330 MW Wyodak plant in Wyoming. The largest air-cooled coal-fired plant in the world is the 4,000 MW Matimba power plant in South Africa. Photographs of the Midlothian and Matimba ACCs are provided in Attachment B.

I declare under penalty of perjury that the foregoing is true and correct. Executed on November 12, 2007.

Executed in Accord with 10 C.F.R. § 2.304(d)

_____

Bill Powers, P.E.

DECLARATION OF BILL POWERS

Attachment A

Jud W. White, Ph.D.

Environmental Policy Manager
Dominion

Experience: Dr. White has been employed by Dominion since 1975 and he has served in various positions in the environmental department. These positions have included activity ranging from environmental field sampling, to regulatory/permit compliance, to public affairs, to legislative support, and to policy development. Currently, Jud oversees water policy issues at all Dominion facilities in 8 states. He has broad knowledge of state and federal environmental laws and regulations and has participated on many state/federal advisory groups in helping develop environmental policy or address an environmental issue. He is also currently an affiliate professor at VCU and is teaching a graduate course titled Business and the Environment.

Education - B.S. and M.S. in Biology - University of Richmond
Ph.D. degree (2000) in Public Policy and Administration – Virginia Commonwealth University (Dissertation Title: Accountability Issues For A Point/Nonpoint Source Effluent Trading Program in Virginia)

John D. Waddill, P.E.

Lead Civil/Mechanical Engineer for the North Anna Combined Operating License Project.
Dominion

Experience: Mr. Waddill has been involved in the design and analysis of nuclear power station systems for 29 years. His areas of concentration have been cooling water systems and thermal and hydraulic modeling. He led a project team in the development and demonstration of an on-line heat transfer monitoring system for an operating nuclear station. In 2005, Mr. Waddill joined Dominion's North Anna Early Site Permit and Combined Operating License Project as Lead Civil/Mechanical Engineer and has been the technical lead for the development of the hybrid cooling system concept for the proposed Unit 3.

Education: Mr. Waddill holds a Bachelor of Science in Mechanical Engineering from Virginia Tech and a Masters of Business Administration from Queens University in Charlotte. He is a Registered Professional Engineer in North Carolina.

Thermal Issues and a Hybrid Cooling Technology in Siting North Anna Unit 3

By

Jud White and John Waddill
Dominion Resources, Inc.

Second Thermal Ecology and Regulation Workshop
October 3, 2007

Helping Meet Our Future Energy Needs With Nuclear Power

Some Questions That We Will Address

- Why nuclear?
- Why at North Anna?
- What's the regulatory process?
- What are the environmental issues?
- What is a hybrid cooling system?
- Are there any lessons learned?

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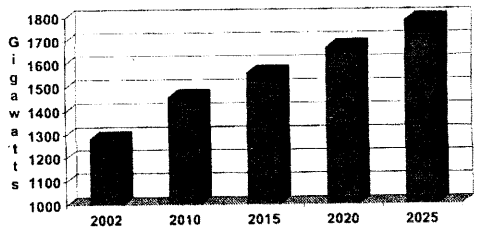
Projected U.S. Electricity Consumption



Source: EIA Annual Energy Outlook 2004 Table A2

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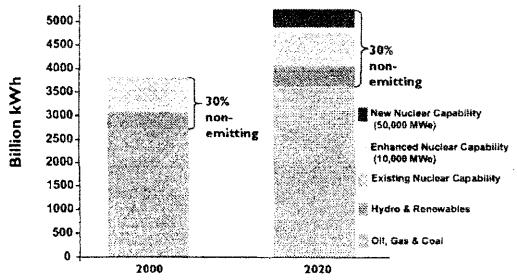
50,000 MWe of New Nuclear Needed to Maintain Existing Energy Supply Diversity



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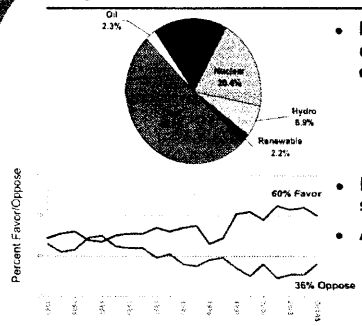
Why is Dominion Interested in New Nuclear?



- Maintain the diversity of our electricity supply
- Increased public support
- Avoided emissions

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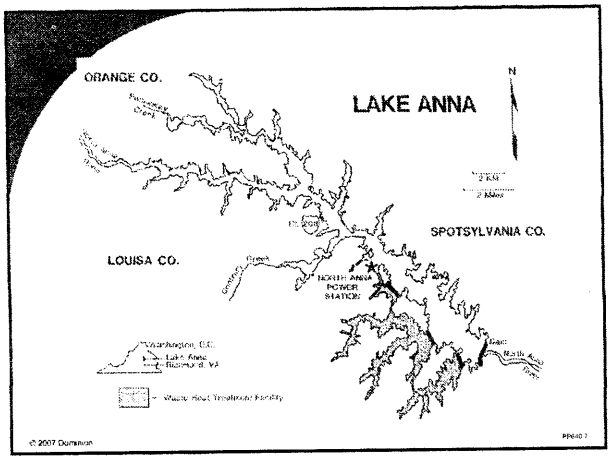
Why the North Anna Site?

- Space
- Environmentally acceptable
- No superior alternative
- Originally planned for 4 units



Overview of Nuclear Project

- NRC licensing process: Early Site Permit (ESP) for site suitability; separate Construction and Operating License (COL)
- ESP application submitted to NRC in 2003 for 2 units at 1520 MWe each
- In 2003-2006: NEPA process commenced and required state concurrence with coastal zone program of state (received in 2006)
- Unit 3 cooling system changed in 2005 from open to closed cycle due to agency and public concerns
- FEIS issued in 2006; COL application in late 2007; construction in 2010

State Requirements - CZMA

- State concurrence with our Federal Consistency Certification under the Coastal Zone Management Act (CZMA) was needed prior to issuance of ESP
- CZMA was only state authorization needed for ESP; additional permitting underway in COL process
- CZMA Question asked - Is the project consistent with enforceable policies of the Va. Coastal Resources Management Program?
- Multiple state agencies review as well as public
- State may deny, approve, or approve the certification with conditions

Lake Level Hydrograph

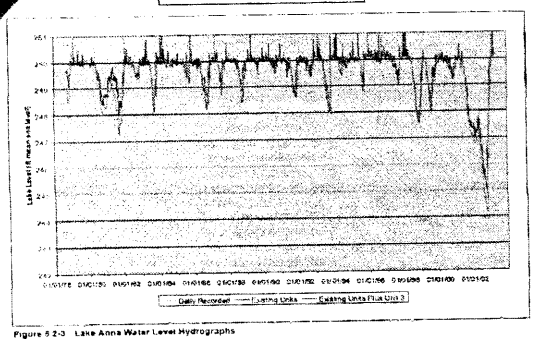


Figure 5.2-3 Lake Anna Water Level Hydrographs

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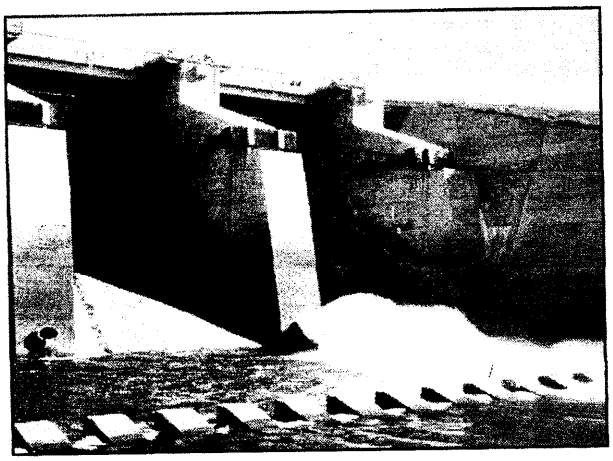
PR640.13



What is an IFIM Study?

- A widely used tool for assessing the effects of flow regulation on river habitats for fish; can also include recreational uses.
- Traditional instream flow regulatory determinations often geared to maximize habitat for single life stage of a high-profile fish species at a few isolated spots in a river.
- Current IFIM process allows for more comprehensive regulatory determinations with consideration for multiple target species.
- Expect completion in early 2008

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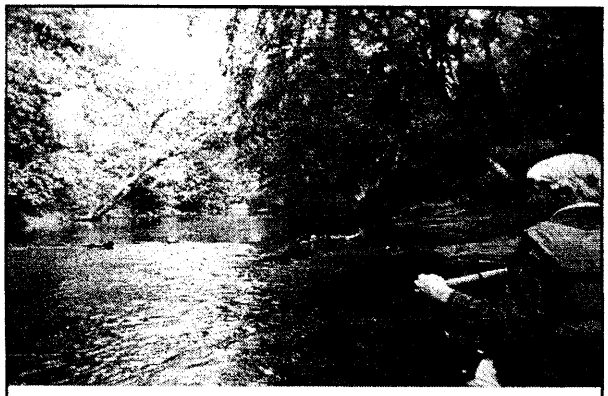

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Hybrid Cooling Technology
North Anna Unit 3

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Wet/Dry Cooling Concept/How does it work?

- Closed cycle cooling system design
  - **Dry** and water-conserving **Wet** Cooling Towers
  - Significantly reduces water consumption.
  - Unit 3's condenser water **cooled initially in Dry Towers (forced air = no water loss)**. Water **then passed through Towers (water spray = some evaporation with condensa return)**.
- Two conceptual operating modes
  - **Energy Conservation (EC)** – Dry cooling will be reduced w reliance mostly on wet towers for heat removal.
  - ***Maximum Water Conservation (MWC)*** – *Minimum* **1/3** hea removal by **Dry**, balance of heat removal by **Wet.**

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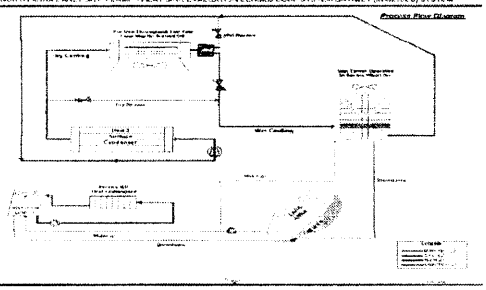
Conceptual Flow Path & Cycles



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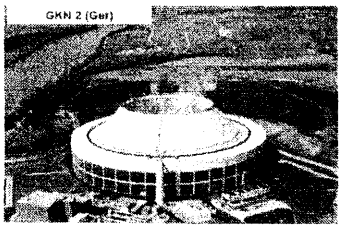
Hybrid Cooling Tower Example

The World Champion of Circular Hybrid CT's



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Looking to the Future

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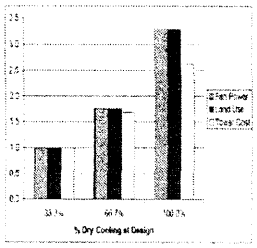
How much dry cooling?



Trade Offs

Energy to operate the system

Land Use

Cost

Cycle efficiency loss

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Resulting Performance

Bad News **– The system performs best when normally not needed → Cool weather.**

Good News **– When you *really* need it, the system can perform → Long droughts.**

- **Projected annual average evaporation reduced by more than 30% using EC/MWC operation.**
- **Projected annual average evaporation reduced by 70% using MWC only.**

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Resulting Performance

Model Prediction for Time Below Lake Low Level Elevation

Existing Units	Existing Units Plus Unit 3 with Once Through Design	Existing Units Plus Unit 3 with Hybrid Cooling
5.2%	11.6%	7.0%

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Summary and Lessons Learned

- More electricity will be needed in the future and nuclear energy will play a vital role
- New NRC licensing process allows environmental review before large investments occur
- While NRC is lead agency, the State has an important role to play in decision-making
- Ensure effective and continual communications between NRC, State, and applicant
- Sate CZMA certification process allows multiple state agencies to voice concerns about a project and it can significantly influence the outcome

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DECLARATION OF BILL POWERS

Attachment B

Attachment A: Photos of Dry-Cooled 1,650 MW Midlothian Energy and 4,000 MW Matimba

Photo 1: 1,650 MW Midlothian Energy Limited Partnership, Midlothian, Texas. Air-cooled condensers (6 sets of 15 cells each) on right, gas turbine combined-cycle units (6 total) on left.

Photo 2: 4,000 MW Matimba dry-cooled coal-fired power plant in South Africa. Plant consists of six 665 MW units. The air-cooled condensers are in the foreground of the power plant.

DECLARATION OF BILL POWERS

Attachment C

Title: Peak and Annual Average Energy Efficiency Penalty of Optimized Air-Cooled Condenser on 515 MW Fossil Fuel-Fired Utility Boiler

Author: Bill Powers, P.E., Powers Engineering

Technical Reviewer: Dr. John Maulbetsch

Abstract

This paper examines the peak (90 ^{o}F dry bulb) and annual average heat rate penalty of a 515 MW pulverized coal-fired boiler equipped with air-cooled condenser (ACC) at a north central U.S. site location, as well as the cost implications of using ACC. The basecase scenario used for the comparison is a conventional wet tower assuming a 12 ^{o}F approach temperature. The basecase wet tower is compared to ACC with no spray enhancement for three ACC cases: 1) a conservative design with "initial temperature difference – ITD" of 35 ^{o}F, 2) a mid-range design with an ITD of 40 ^{o}F, and 3) an economic design with an ITD of 44 ^{o}F. The ITD design conditions for these three cases band a condenser backpressure range from 4 inches Hg to 5 inches Hg at the site design temperature of 90 ^{o}F. The ITD design points for the three ACC cases used in this analysis reflect a representative range of ACC designs based on current bids being submitted by ACC manufacturers.

Results for the 40 ^{o}F ITD ACC case indicate that the heat rate penalty at rated boiler load at the design condition of 90 ^{o}F is approximately 3.6 percent relative to a conventional wet tower. Heat rate penalty is approximately 2 percent on an annual average basis. For the 35 ^{o}F ITD ACC case the heat rate penalty at design conditions is 2.8 percent relative to a conventional wet tower. The annual average heat rate penalty is approximately 1.5 percent. The total auxiliary power demand for the ACC options is slightly higher than the wet tower basecase at design conditions, and slightly lower on an annual average basis.

The use of a 40 ^{o}F ITD ACC in place of the least-cost wet tower basecase would increase project CAPEX by approximately 6 to 7 percent. The use of a 35 ^{o}F ITD ACC would

increase project CAPEX by approximately 7 to 8 percent. The CAPEX percentage increase is somewhat less if a plume-abated tower is necessary at the site and serves as the basecase. The use of a 40 ^{o}F ITD ACC in place of a plume-abated FRP wet tower would increase project CAPEX by approximately 4 to 6 percent.

Background - Dry Cooling and Coal-Fired Powerplants

ACCs have been used on large coal-fired power plants for over 25 years. The 330 MW Wyodak coal-fired powerplant in Wyoming has successfully operated with an ACC for over 25 years. The largest ACC-equipped coal-fired power plant in the world, the 4,000 MW Matimba plant in South Africa, has been operating successfully for nearly 15 years. The Millmerran Power Project in Australia, consisting of two ACC-equipped 420 MW pulverized coal-fired units with condenser heat rejection rates in the range of the condenser heat rejection rate of the 515 MW unit evaluated in this paper, have been operational since 2002. A 300 MW pulverized coal plant currently undergoing permitting in New Mexico, the Mustang Project, will voluntarily incorporate ACC into the plant design to minimize plant water use. A 36 MW pulverized coal unit in Iowa, Cedar Falls Utilities Streeter Station Unit 7, was retrofit with dry cooling in 1995 due to highway safety concerns caused by the wet tower plume in winter. The use of dry cooling on pulverized coal-fired power plants is well established.

Basis of Design Comparison

The proposed 515 MW (rated net output, maximum 530 MW) Weston Unit 4 supercritical pulverized coal (SCPC) project is the basis for this case study. This project was proposed in 2003 by the Wisconsin Public Service Company (WPSC) for a central Wisconsin location using a conventional wet tower cooling system. The performance characteristics of Weston Unit 4 project are detailed in the Final Environmental Impact Statement (FEIS) prepared by WPSC. This is a publicly available document accessible on the Public Service Commission of Wisconsin website.

A cooling tower consisting of twelve (12) cells and a cooling water circulation rate of 250,650 gallons per minute (gpm) is proposed for Weston Unit 4. The rated wet tower heat rejection duty is 2,177 MMBtu/hr. The design approach temperature of the wet tower is 12 ^{o}F. The tower will evaporate approximately 4,750,000 gallons per day of river water, and produce approximately 475,000 gallons per day of cooling tower blowdown, on an annual average basis.

Steam Pro™ and Steam Master™ utility boiler design software are used to carry out the comparative heat rate analysis of the wet tower basecase and ACC alternatives. Steam Pro™ changes the design of the equipment with each new input. Steam Master™ takes a selected Steam Pro™ run and "fixes" all inputs to permit analysis of off-design cases.

The initial objective was to model a basecase 530 MW (maximum net output) wet-cooled SCPC unit in Steam Pro™ that matched the characteristics and heat rate described in the FEIS for the proposed Weston Unit 4. This objective was achieved. The wet-cooled basecase unit developed in Steam Pro™, after recalculating using Steam Master™, has a calculated a net plant heat rate (HHV) of 9,741 Btu/kWh at the design ambient air temperature of 90 ^{o}F, compared to a published net plant heat rate of 9,760 Btu/kWh in the WPSC FEIS for Weston Unit 4 at 530 MW.

Case Study Goals

The goals of this case study are to: 1) determine the peak and average heat rate penalty of ACC relative to the basic wet tower design for three ACC design cases with ITDs of 35 ^{o}F, 40 ^{o}F, and 44 ^{o}F, 2) determine the change in auxiliary power demand for each option, and 3) estimate the increase in project capital cost associated with the ACC alternatives. The site averages approximately 40 hours per year at or above an ambient temperature of 90 ^{o}F. The ITD is the difference between the design ambient air temperature used for cooling, 90 ^{o}F in this case, and the steam condensation (saturation) temperature within the ACC. Specific case study goals included:

- Determine the plant heat rate penalty, number of cells, and auxiliary power demand for three ACC configurations to achieve condenser saturation temperatures of 125 ^{o}F (35 ^{o}F ITD), 130 ^{o}F (40 ^{o}F ITD), and 134 ^{o}F (44 ^{o}F ITD) at design conditions;
- Calculate heat rate penalty for each ACC case at 2/3 load across site temperature range;
- Calculate the total plant auxiliary power demand for each cooling option;
- Estimate the additional capital cost of the ACC options relative to the wet tower basecase.

Site Temperature and Wet Bulb Data

The proposed project site is located in central Wisconsin. Weather data for Madison, Wisconsin was used by the project proponent to size the wet cooling tower included in the project basecase. The wet tower was sized to achieve a 12 ^{o}F approach temperature[1] at the summer 1 percent condition of 90 ^{o}F dry bulb and 76 ^{o}F wet bulb. Madison, Wisconsin temperature data was also used to size the ACC options. The annual temperature distribution data[2] for Madison is shown in Table 1.

Table 1. Madison, Wisconsin Annual Temperature Distribution Data

Temperature (^{o}F)	Hours per year in temperature range	Percentage of total hours per year at or above temperature range (%)
$\geq$ 90	42	0.48
85-89.9	75	1.34
80-84.9	290	4.65
75-79.9	391	9.11
70-74.9	585	15.79
65-69.9	593	22.56
60-64.9	829	32.02
55-59.9	749	40.57
50-54.9	629	47.75
45-49.9	534	53.85

[1] Cooling tower approach temperature: difference between the cooling water temperature leaving the cooling tower (lowest cooling water temperature achieved) and the wet bulb air temperature.

[2] Kjelgaard, M., *Engineering Weather Data*, McGraw-Hill, 2001, p. 534.

40-44.9	449	58.97
35-39.9	709	67.07
30-34.9	911	77.47
25-29.9	589	84.19
20-24.9	380	88.53
-20 - 19.9	1,005	100.00

Heat Rate Penalty of ACC

The peak and annual average heat rate penalties calculated for the 35 ^{o}F, 40 ^{o}F, and 44 ^{o}F ITD ACC configurations analyzed in this case study are shown in Table 2. For the 40 ^{o}F ITD case, the heat rate penalty at the design ambient temperature of 90 ^{o}F at full load is 3.6 percent, while the annual average heat rate penalty is approximately 2 percent. The heat rate penalty for the 35 ^{o}F ITD case at the design ambient temperature of 90 ^{o}F at full load is 2.8 percent, while the annual average heat rate penalty is approximately 1.5 percent. Sixty (60) cells would be required to achieve an ITD of 40 ^{o}F using an ACC fan diameter of 34 feet. Fan diameter of 36 feet may also be specified. A total of 54 ACC cells would be required to achieve an ITD of 40 ^{o}F using 36-foot diameter fans.

Table 2. Calculated Peak and Annual Average ACC Heat Rate Penalties

Case	ITD (^{o}F)	Estimated annual average[a] heat rate penalty (%)	Peak heat rate penalty (%)	Fan diameter (feet)	Number of ACC cells
1	35	~1.5[b]	2.8	34 36	66 60
2	40	~2[c]	3.6	34 36	60 54
3	44	~3[d]	4.4	34 36	54 48

a) Assumes average annual load is 2/3 of rated load per EPA 316(b) TDD Chapter 3 for New Facilities, p.3-10.
b) 35 ^{o}F ITD 2/3 load heat rate penalties: 1.0% at 23 ^{o}F, 1.2% at 45 ^{o}F, 1.7% at 67 ^{o}F.
c) 40 ^{o}F ITD 2/3 load heat rate penalties: 1.4% at 23 ^{o}F, 1.7% at 45 ^{o}F, 2.2% at 67 ^{o}F.
d) 44 ^{o}F ITD 2/3 load heat rate penalties: 2.4% at 23 ^{o}F, 2.7% at 45 ^{o}F, 3.1% at 67 ^{o}F.

The annual average heat rate penalty for each ACC case was estimated as shown in Table 3. The number of annual operating hours in each of four discrete temperature ranges was calculated from the temperature data in Table 1. The annual average heat rate penalty estimate assumes that Unit 4 will typically operate at approximately two-thirds of rated load, or a capacity factor of 0.67, over the course of a year.[3] The capacity factor in the highest temperature range was assumed to be 0.85 to reflect high use during hot summertime conditions. A capacity factor of 0.60 was assumed for the three lower temperature ranges. The mean heat rate penalty for each temperature range was calculated from the Steam Pro™ heat rate curves developed for full load and two-thirds load operating scenarios. The mean between the 90 ^{o}F full load heat rate penalty (3.6 percent) and the two-thirds load penalty at 67 ^{o}F (2.2 percent), 2.9 percent, was used to represent the composite heat rate penalty for the highest temperature range. This is a reasonable assumption given the mean temperature in the highest temperature range is 74 ^{o}F, and the unit will not be operating continuously at rated load when operating in the highest temperature range. The heat rate penalty at 74 ^{o}F and full load is 3.1 percent for the 40 ^{o}F ITD case. The heat rate penalty calculated at 23 ^{o}F was used for the lowest temperature range, as 23 ^{o}F was the lowest temperature point modeled.

Table 3. Procedure Used to Estimate Annual Average Heat Rate Penalty, 40 ^{o}F ITD Case

Site temp. range (oF)	Fraction of annual hours [H]	Capacity factor (CF)	CF weighting factor [CF_w]	Mean heat rate penalty [P_m]	Heat rate penalty contribution per temp. range [$H \times CF_w \times P_m$]
67 – 90+	.20	.85	1.4	2.9[a]	0.81
45-67	.34	.60	1.0	2.0	0.68
23-45	.33	.60	1.0	1.6	0.53
< 23	.13	.60	1.0	1.4	0.18
Estimated annual average heat rate penalty for 40 ^{o}F ITD case (%)					2.20

a) The mean heat rate penalty between the full load 90 ^{o}F operating point (3.6%) and 2/3 load at 67 oF (2.2%) is 2.9%. The full load heat rate penalty at 67 ^{o}F is also 2.9%.

[3] U.S. EPA Technical Development Document (TDD) for the Proposed Section 316(b) Phase I New Facilities Rule, *Chapter 3: Energy Penalties, Air Emissions, and Cooling Tower Side-Effects*, November 2001, pg. 3-10. Coal plants have average capacity of 69 percent, therefore use 67 percent load curves to determine energy penalty values.

By way of comparison, the EPA estimates a heat rate penalty for a Chicago area coal-fired utility boiler equipped with ACC of 8.4 percent (peak) and 5.9 percent (annual average) compared to the same unit equipped with closed-cycle wet cooling.[4]
The EPA used the ITDs from a handful of existing ACC-equipped coal-fired utility boilers and plotted this data against steam condenser backpressure to establish a "representative" ACC heat rate penalty for coal-fired utility boilers.[5] The ITDs at existing ACC-equipped coal plants included in the EPA analysis are generally much higher than the ITDs being specified for new coal plants. A current state-of-the-art ITD for coal-fired units is 40 ^{o}F, based on discussions with major ACC manufacturers. New units with ITD's in the range of 35 ^{o}F ITD are becoming more common.

In addition, the EPA compared the ACC data to plants with wet towers using a 10 ^{o}F design approach. As noted by the EPA, a 10 ^{o}F approach is considered a conservative wet tower design standard. It could be argued that the approach used by the EPA is an "apples-to-oranges" comparison that accentuates the ACC heat rate penalty by comparing non-conservative ACC designs to a conservative wet tower design.

As shown in Table 2, the 40 ^{o}F ITD ACC case has a heat rate penalty of 3.6 percent at rated load and 90 ^{o}F ambient temperature. The rated output of Weston Unit 4 is 515 MW. Weston Unit 4 is designed to fire three (3) percent more fuel than necessary, equivalent to a net output of 530 MW, to produce rated output.[6] Unit 4 would be able to produce at least 512 MW of its rated output of 515 MW at the 90 ^{o}F design condition using a 40 ^{o}F ITD ACC. The 90 ^{o}F design condition is reached approximately 40 hours per year.[7] At any temperature less than 90 ^{o}F Unit 4 will produce its full rated output of 515 MW using a 40 ^{o}F ITD ACC. A 35 ^{o}F ITD ACC has a calculated heat rate penalty

[4] U.S. EPA Technical Development Document (TDD) for the Proposed Section 316(b) Phase I New Facilities Rule, *Chapter 3: Energy Penalties, Air Emissions, and Cooling Tower Side-Effects*, November 2001, p. 3-13, Tables 3-3 and 3-4.

[5] Ibid, p. 3-15.

[6] WPSC Weston Unit 4 July 2003 application, Volume II: Appendix E-1, Heat Balance

[7] Madison, Wisconsin annual temperature distribution

at the 90 ^{o}F design condition of 2.8 percent. Unit 4 would be able to produce its rated output of 515 MW at the 90 ^{o}F design condition using a 35 ^{o}F ITD ACC.

As noted, Unit 4 equipped with a 35 ^{o}F ITD ACC will maintain rated MW output across the entire spectrum of site climatic conditions. A 40 ^{o}F ITD ACC may exhibit a slight reduction in output, 512 MW versus 515 MW, at the 90 ^{o}F design condition. However, it is important to point out that the 90 ^{o}F design condition occurs for approximately 40 hours per year. There may be little financial incentive to spend additional millions on a 35 ^{o}F ITD ACC in order to produce an additional 100 to 200 MW-hr per year.

The total plant auxiliary power demand is slightly lower for any of the ACC options compared to the wet-cooled basecase on an annual average basis. At full load and the design ambient temperature of 90 ^{o}F the total plant auxiliary power demand is slightly higher, 1 to 2 percent, for the ACC options compared to the wet-cooled basecase. See Table 4. The modeled auxiliary power demand of a wet-cooled Unit 4 at rated load and 90 ^{o}F is 40.1 MW. The modeled auxiliary power demand for the wet tower basecase does not include auxiliary power demand associated with the Unit 4 raw cooling water clarifier system, as there was insufficient information in the WPSC FEIS to determine the auxiliary power demand of the system. The modeled auxiliary power demand of the 40 ^{o}F ITD ACC at the same conditions is 40.6 MW, or a 1 percent increase in the plantwide auxiliary power demand at design conditions. A comparison of the plantwide auxiliary power demand for the wet tower basecase and the three ACC options across the site temperature range is provided in Table 5.

Table 4. Comparison of Plantwide Auxiliary Power Demand for Rated Design Case, Wet-Cooled vs. 40 ^{o}F ITD ACC

Parameter	Plant Auxiliaries Power Demand (kW) at 530 MW net, 90 ^{o}F	
	Wet tower basecase	40 ^{o}F ITD ACC
Boiler primary air fan	1,537.6	1,592.8
Boiler secondary air fan	1,611.2	1,669.0
Boiler induced draft fan	6,477.2	6,708.3
Boiler gas recirculation fan	0.0	0.0
Boiler fuel delivery	6,334.5	6,562.1
Boiler forced circulation pump	0.0	0.0
Electrostatic precipitator (ESP)	2,066.5	2,140.8
Flue gas desulfurization (FGD)	4,024.9	4,238.8
Ash handling	578.6	599.4
Condenser circulation pump	5,152.5	0.0
Cooling tower fan/ACC fan	2,141.5	6,809.5
Condensate pump	1,281.0	1,330.8
Boiler feedwater booster pump(s)	0.0	0.0
Boiler feed pump	0.0	0.0
Boiler feed booster pump	577.0	597.5
FW heater drain pump(s)	286.7	276.2
Additional auxiliaries (from Steam Pro™ *Plant Equipment and Construction Estimate* software)	5,216.6	5,183.8
Miscelleneous plant auxiliaries	2,850.5	2,852.5
Constant auxiliary load	0.0	0.0
Calculated total auxiliaries	40,136.3	40,561.6

Table 5. Comparison of Wet- vs. Dry-Cooled Total Plantwide Auxiliary Power Demand Across Site Temperature Range

Design Condition	Plant Total Auxiliary Power (MW)			
	23 ^{o}F, 67% load	45 ^{o}F, 67% load	67 ^{o}F, 67% load	90 ^{o}F, 100% load
conventional wet tower	27.2	27.6	28.3	40.1
44 ^{o}F ITD	25.4	26.7	28.3	40.4
40 ^{o}F ITD	24.2	25.0	27.2	40.6
35 ^{o}F ITD	25.1	26.3	28.0	41.1

ACC Cost Implications

WPSC estimates a Weston Unit 4 project cost of $752 million using a standard wet cooling tower.[8] The cooling tower material of construction is not identified in the table listing cooling tower operating parameters in the Weston Unit 4 application.[9] For this reason the least-cost material of construction, Douglas Fir, is assumed. A 10 percent increase in wet tower cost is estimated by the EPA if a fiberglass reinforced plastic (FRP) tower is selected over the least-cost Douglas Fir alternative.[10] The $752 million cost includes the cost of a clarifier system to be added to treat river water that will be used in Unit 4, as well as the cost of modifications to an existing water intake structure increase pump capacity to meet the peak cooling water requirements.

The ACC equipment cost assumes a large ACC cell that can accommodate 34-foot or 36-foot diameter fans. The equipment cost of this cell is approximately $600,000, based on Millmerran coal-fired project in Australia.[11] The installed cost for this project, using union labor and excluding civil work, is $970,000 per cell. The total installed cost including civil work is approximately $1,000,000/cell.[12] A full noise abatement package would increase this cost by up to $100,000/cell.

The equipment cost for a 40 °F ITD ACC for Weston Unit 4, consisting of 60 cells without special noise abatement features, would be $36 million. The installed cost for the Unit 4 ACC system without special noise abatement refinements

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[8] Pre-filed direct testimony by Jerry Terrell on behalf of WPSC, April 30, 2004, Application of Wisconsin Public Service Corporation for Authority to Construct a 500MW Generating Unit at its Existing Weston Generating Station, before Public Service Commission of Wisconsin, Docket 6690-CE-187.

[9] Weston Unit 4 Certificate of Public Convenience and Necessity, filed with Public Service Commission of Wisconsin, Sept. 23, 2003. See *Cooling Tower Modeling Report*, p. 11.

[10] Economic and Engineering Analyses of the Proposed 316(b) New Facility Rule, Appendix A: Detailed Information on Technologies/Development of Unit Costs, Table A-4, Relative Cost Factors for Various Cooling Tower Types, pg. AppA-14.

[11] E-mail communication from F. Ortega, GEA PCS, May 12, 2005. Costs based on Millmerran Project, Australia.

[12] The cost of civil work was not available prior to the paper submittal deadline, though this cost is anticipated to be small relative to other ACC cost elements.

would be $60 million. The cost increment of a 35 °F ITD ACC relative to a 40 °F ITD ACC would be approximately 10 percent, or an installed cost of $66 million.

The U.S. EPA estimates the installed cost of a 204,000 gpm Douglas Fir (least-cost) conventional wet tower designed for a 10 °F approach temperature at $9 million in 1999 dollars.[13] The design cooling tower flowrate for Weston Unit 4 is 250,000 gpm. Scaling the 204,000 gpm cost estimate to the 250,000 gpm flowrate gives a projected cost for a basic wet tower of $11 million.[14]

However, the Weston Unit 4 wet tower is designed for a 12 °F approach temperature, which would result in a wet tower approximately 15 percent smaller than a unit designed for a 10 °F approach temperature.[15] The adjusted EPA installed cost estimate for a Douglas Fir wet tower with a 250,000 gpm flowrate and 12 °F approach is $10 million. Use of FRP adds 10 percent to the Douglas Fir wet tower basecase. An FRP conventional tower for Unit 4 has an estimated installed cost of $11 million.

EPA estimates a cost of $27.5 million for a 204,000 gpm plume-abated FRP wet tower designed for a 10 °F approach.[16] This is equivalent to a cost of $32 million for a 250,000 gpm plume-abated tower with a 10 °F approach, and $28 million for a 250,000 gpm flowrate and 12 °F approach (1999 dollars).

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[13] Economic and Engineering Analyses of the Proposed 316(b) New Facility Rule, Appendix A: Detailed Information on Technologies/Development of Unit Costs, Table A-7, Capital Costs of Douglas Fir Cooling Towers with Special Environmental Impact Mitigations Features (delta 10 °F) (1999 dollars), August 2000, pg. AppA-19.

[14] Ibid. EPA uses a scaling factor of ~0.8 in to estimate the cost of larger size cooling towers [$x = 0.8$, $(S_2/S_1)^x$]. The 0.8 scaling factor is used to calculate estimated cooling tower costs for the Weston Unit 4 design cooling water flowrate of 250,000 gpm (S_2) compared to the largest wet tower listed in the EPA document at 204,000 gpm (S_1).

[15] Marley, *Cooling Tower Performance – Basic Theory and Practice* (technical primer), June 1986. See Figure 6, p. 4.

[16] Economic and Engineering Analyses of the Proposed 316(b) New Facility Rule, Appendix A: Detailed Information on Technologies/Development of Unit Costs, Table A-4, Relative Cost Factors for Various Cooling Tower Types, pg. AppA-14. Mid-point cost multiplier for plume abatement tower is 2.75 relative to conventional wet tower.

Use of ACC eliminates the need for the surface condenser required in the basecase wet tower system. Steam Pro™ estimates a $3.7 million equipment cost for the surface condenser. An installed surface condenser cost of $5 million is assumed in this cost analysis. This condenser capital cost is subtracted from the CAPEX calculated for each ACC case. Table 6a summarizes the estimated CAPEX of the project depending on the cooling system specified using published EPA wet tower cost estimating methodology and ACC vendor equipment and installation cost estimates. Table 6b summarizes the Steam Pro™ CAPEX estimates for the wet tower basecase and the ACC alternatives studied.

Table 6a. Comparison of Project Cost of Wet- and Dry-Cooled Options, Using EPA Wet Tower Cost Data and ACC Vendor Cost Data to Estimate CAPEX of Options

Cooling System	Total Project Capital Expenditure - CAPEX ($ millions)	Increase in CAPEX (%)
Douglas Fir conventional wet tower	752[a]	basecase
Plume-abated FRP wet tower	770	2.4
44 ^{o}F ITD ACC	791	5.2
40 ^{o}F ITD ACC	797	6.0
35 ^{o}F ITD ACC	803	6.8

a) Project CAPEX estimated by project applicant.

Table 6b. Steam Pro™ Estimate of CAPEX for Wet- and Dry-Cooled Options

Cooling System	CAPEX ($ millions)	Cooling system equipment cost ($ millions)	Increase in CAPEX (%)
Least cost wet tower	885[a]	9[b]	basecase
Plume-abated FRP wet tower	894	12	1.0
44 ^{o}F ITD ACC	942	28	6.4
40 ^{o}F ITD ACC	948	31	7.1
35 ^{o}F ITD ACC	954	34.5	7.8

a) Wisconsin labor rates used in calculating CAPEX.
b) Cost includes surface condenser, cooling tower, condenser circulating water pump, and cold water basin.

There is a significant difference in the CAPEX cost between the two cost approaches summarized in Tables 6a and 6b. This is not unexpected, as the Steam Pro™ model was optimized in this exercise to match the published thermal performance of Weston Unit 4. No default cost assumptions were modified, other than to specify the project location to ensure appropriate labor rate assumptions were used to calculate CAPEX. Steam Pro™

does make explicit that default cost values must be optimized using site-specific information to refine the Steam Pro™ CAPEX estimate. The principal value of the Steam Pro™ CAPEX cost estimates shown in Table 6b is to provide guidance on the relative cost increase of the project if ACC is utilized.

The Steam Pro™ model also provides cost estimates for individual pieces of equipment. The Steam Pro™ Douglas Fir wet tower equipment cost of $9 million is similar to the EPA installed cost estimate of $10 million for a Douglas Fir wet tower. The EPA also indicates that wet tower installation is assumed to be 80 percent of equipment cost.[17] Applying the EPA installation cost assumption to the Steam Pro™ wet tower equipment cost would result in a wet tower installed cost of over $16 million. Clearly the EPA wet tower cost estimate is significantly lower than the Steam Pro™ estimate.

The EPA cost methodology indicates a significantly higher cost premium for an FRP plume-abatement wet tower relative to the cost premium calculated by Steam Pro™. The FRP plume-abatement tower would add 2.4 percent to CAPEX using the EPA methodology, while Steam Pro™ estimates only a 1 percent increase in CAPEX for this upgrade.

The ACC equipment cost generated by Steam Pro™ is 10-15 percent lower than the equipment cost estimate provided by a leading ACC vendor. However, the Steam Pro™ default ACC installation cost assumptions result in a significantly higher installation cost than the cost calculated using the union labor cost estimate provided by the ACC vendor. The end result is CAPEX increments for ACC that are in relatively close agreement, 6.0 percent and 7.1 percent for the 40 ^{o}F ITD ACC, between the two cost estimating approaches summarized in Tables 6a and 6b.

[17] Ibid. Table A-5, footnote (1).

Conclusions

Results for the 40 ^{o}F ITD ACC case indicate that the heat rate penalty at rated boiler load at the design condition of 90 ^{o}F is 3.6 percent relative to a conventional wet tower. The heat rate penalty is approximately 2 percent on an annual average basis assuming an annual average load of 67 percent. For the 35 ^{o}F ITD ACC case the heat rate penalty at design conditions is 2.8 percent relative to a conventional wet tower. The annual average heat rate penalty is approximately 1.5 percent. The total auxiliary power demand and losses for the ACC options are slightly higher than the wet tower basecase at design conditions, and slightly lower on an annual average basis.

The use of a 40 ^{o}F ITD ACC in place of the least-cost wet tower basecase would increase project CAPEX by approximately 6 to 7 percent. The use of a 35 ^{o}F ITD ACC would increase project CAPEX by approximately 7 to 8 percent. The CAPEX percentage increase is somewhat less if a plume-abated tower is necessary at the site and serves as the basecase. The use of a 40 ^{o}F ITD ACC in place of a plume-abated FRP wet tower would increase project CAPEX by approximately 4 to 6 percent.

DECLARATION OF BILL POWERS

Attachment D

PAPER NO: TP03-01

CATEGORY: DRY COOLING

COOLING TECHNOLOGY INSTITUTE

WHY EVERY AIR COOLED STEAM CONDENSER NEEDS A COOLING TOWER

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WILLIAM M. WURTZ
HAMON DRY COOLING

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Presented at the 2003 Cooling Technology Institute Annual Conference
San Antonio, Texas – February 10-13, 2003

WHY EVERY AIR COOLED CONDENSER NEEDS A COOLING TOWER

By Luc De Backer and William M. Wurtz

ABSTRACT

This technical paper will review the basic types of cooling systems utilized by utility power plants, and explain the reasons why it is advantageous to include a cooling tower in many dry cooling applications.

A system where a cooling tower is used in conjunction with an air cooled steam condenser is called a parallel condensing system. This type of system utilizes three traditional types of heat exchangers: a cooling tower, an air cooled steam condenser and a surface condenser.

An optimized parallel condensing system reduces both investment costs and operational costs while using a minimum amount of water.

1. INTRODUCTION

In the steam cycle of a power plant, low-pressure water condensed in the steam condenser is pumped to high pressure before it enters the boiler or Heat Recovery Steam Generator (HRSG) where superheated steam is produced. The superheated steam is sent to the steam turbine where the steam expands to low pressure providing the energy to drive a generator. This low-pressure steam has to be condensed in a condenser in order to complete the steam cycle.

The condensation of steam requires a cooling medium. Traditionally, this has been achieved using water from a river, a stream, a pond or seawater. The cold water is pumped through a heat exchanger and the warm water is discharged back to the water source. This is called ONCE THROUGH cooling system.

A once through system is an open loop system. The need to reduce the vast amount of water requires a closed loop system. Thus the WET COOLING system came into effect, and soon after the DRY COOLING and HYBRID COOLING systems (see Table 1). In a wet cooling system, water is circulated to condense the steam in the same type of heat exchanger that is used in the once through cooling. The warm water, instead of being rejected to the water source, is cooled in a cooling tower using air as the cooling medium. Only the water carried away due to evaporation, drift and blow-down needs to be replenished by make-up water.

Cooling System	Time period
Once Through	From 1930s
Wet Cooling	From 1950s
Dry	From 1970s
Hybrid	From 1980s
Parallel	From 1990s

Table 1: Evolution of cooling systems used in power plants [R1]

2. WET COOLING SYSTEMS

The wet cooling tower system is based on the principle of evaporation. The heated cooling water coming out of the surface condenser is cooled as it flows through a cooling tower, where air is forced through the tower by either mechanical or natural draft.

In the United States, the natural draft tower, sometimes also called the hyperbolic tower because of its shape, has most often be used at nuclear plants and large coal-fired power plants. Natural draft cooling towers are primarily suited to very large cooling water quantities. The advantage of a natural draft unit is that the power required for fans is eliminated; these are very tall structures (up to 600 feet in height).

In smaller power plants, all wet cooling towers are mechanical draft cooling towers, where the air flow is accomplished by fans (see figure below).

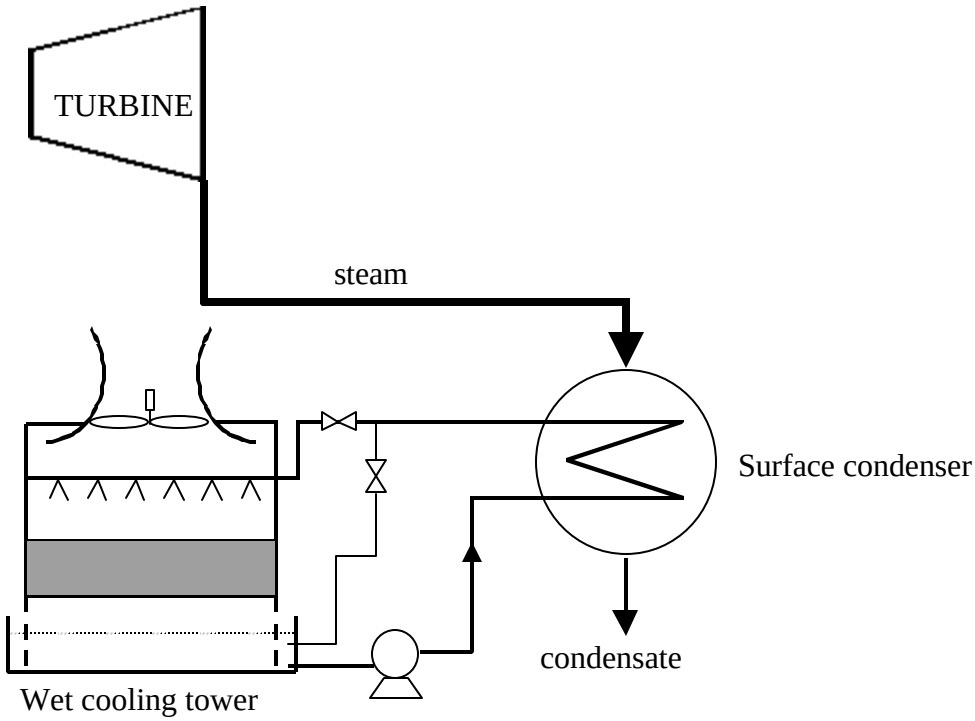

Figure 1: Indirect cooling system with a wet cooling tower and surface condenser.

The steam turbine is not directly connected to the cooling system, so this is in fact an indirect cooling system. The steam from the steam turbine is condensed at the outside of the surface condenser tubes, using cold water coming from the cooling tower. Part of the cooling water is evaporated in the cooling tower, and a continuous source of fresh water (makeup water) is required to operate a wet cooling tower.

Makeup requirements for a cooling tower consists of the summation of evaporation loss, drift loss and blow-down.

2.1 <u>Evaporation losses:</u>

Evaporation losses can be estimated using the following equation:

$$m'_{evap} = 0.00095\, m'_{cool}\, (T_{hot} - T_{cold})$$

where m'_{cool} = cooling water flow rate at the tower inlet
T_{hot} = cooling water temperature at tower inlet in °F
T_{cold} = cooling water temperature at tower outlet °F

2.2 Drift:

Drift is entrained water in the tower discharge vapors. Drift loss is a function of the drift-eliminator design, and a typical value is 0.005 % of the cooling water flow rate. New developments in eliminator design make it possible to reduce drift loss below 0.0005 %. Drift contains chemicals from circulating water.

Below a typical drift drop size spectrum is shown for a counter-flow cooling tower using a modern type of drift eliminator [R2].

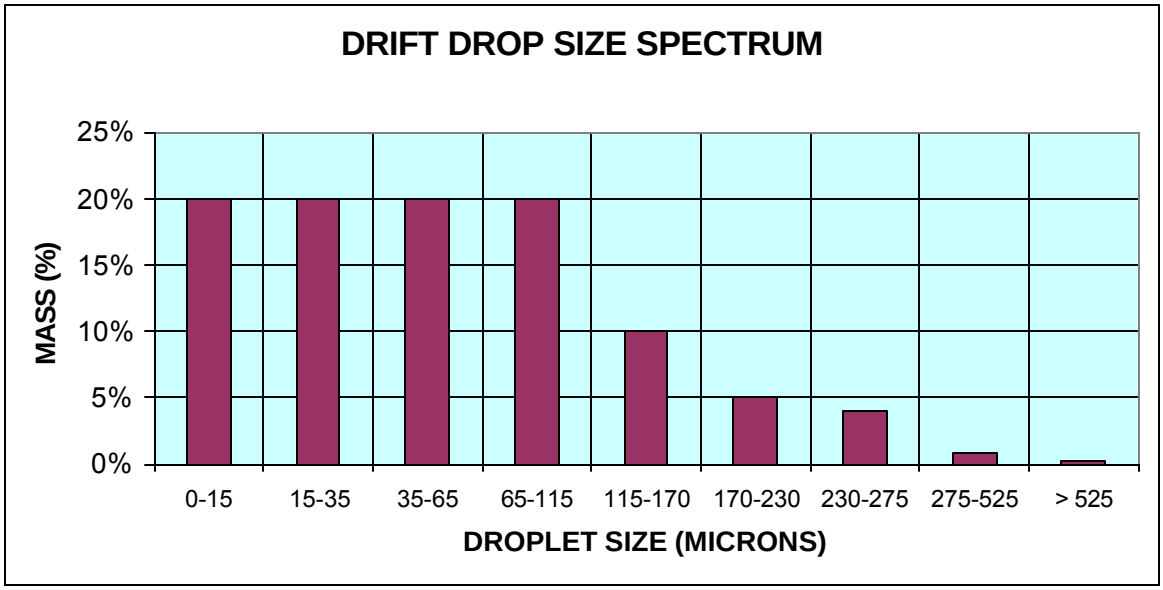

Figure 2. Cooling tower drift drop size spectrum [R2}

2.3 Blow-down:

The amount of blow-down can be calculated according to the number of cycles of concentration required to limit scale formation. Cycles of concentration are the ratio of dissolved solids in the recirculation water to dissolved solids in the makeup water. Cycles of concentration involved with cooling tower applications typically range from three to ten cycles. The amount of blow-down can be estimated from the following equation:

$$m'_{blowdown} = \frac{m'_{evap}}{(\text{cycles} - 1)}$$

2.4 Typical water consumption examples:

As an example, a 600 MW coal fired plant operating at 70 % annual capacity factor typically would require between 5 x 10^6 m^3 and 1 x 10^7 m^3 of make-up water annually [R3]. The make-up water requirements for nuclear and geothermal plants are even higher.

For a combined cycle power plant, the make-up water requirements will be generally less than half of those for a fossil-fuelled plant of comparable size, since only one third of the total electrical output is generated in the steam cycle. Below a typical example for a cooling tower in a combined cycle plant with 2 gas turbines and 1 steam turbine:

- Heat duty = 410.9 MW or 1,402 Mbtu/h
- Water flow = 36,340 m^3/h or 160,000 gpm
- Range = 9.83 K or 17.69 deg F
- Cold water temperature = 33.1 deg C or 91.5 deg F

The equations written above give the following results:

- Evaporation loss = 611 m^3/h or 2689 gpm
- Drift loss (assuming 0.005 %) = 1.82 m^3/h or 8 gpm
- Blow-down (assuming 10 cycles of concentration) = 68 m^3/h or 299 gpm
- Total make-up water required = 681 m^3/h or 2996 gpm

Fogging, icing of local roadways and drift that deposits water or minerals are some of the concerns regarding the plume. The plume is in fact the condensed water that evaporated from the cooling process. Thus, this condensed water is pure and free of chemicals and minerals, although a plume is often associated with pollution. Other environmental effects of cooling towers and technological solutions to reduce the impact on the environment have been discussed in detail elsewhere [R4].

Sometimes because of the chemical content of the make-up water the blow-down cannot be discharged outside of the boundaries of the power plant. This is the case in power plants with “zero-discharge” requirements. But complete elimination of water consumption in the cooling system can only be achieved by using dry cooling systems, or air cooled condensers.

3. DRY COOLING SYSTEMS

In a dry cooling system, heat is transferred from the process fluid, steam, to the cooling air via extended surfaces or fin tube bundles. The performance of dry cooling systems is primarily dependent on the ambient dry bulb temperature of the air. Since the ambient dry bulb temperature of the air is higher than the wet bulb temperature (wet bulb is the basis for a wet cooling tower design), dry cooling systems are less efficient. Although the capital cost of a dry cooling system is usually higher than that of a wet cooling system, the cost of providing suitable cooling water and other operational and equipment expenses may be such that the dry cooling system is more cost effective over the projected life of the power plant.

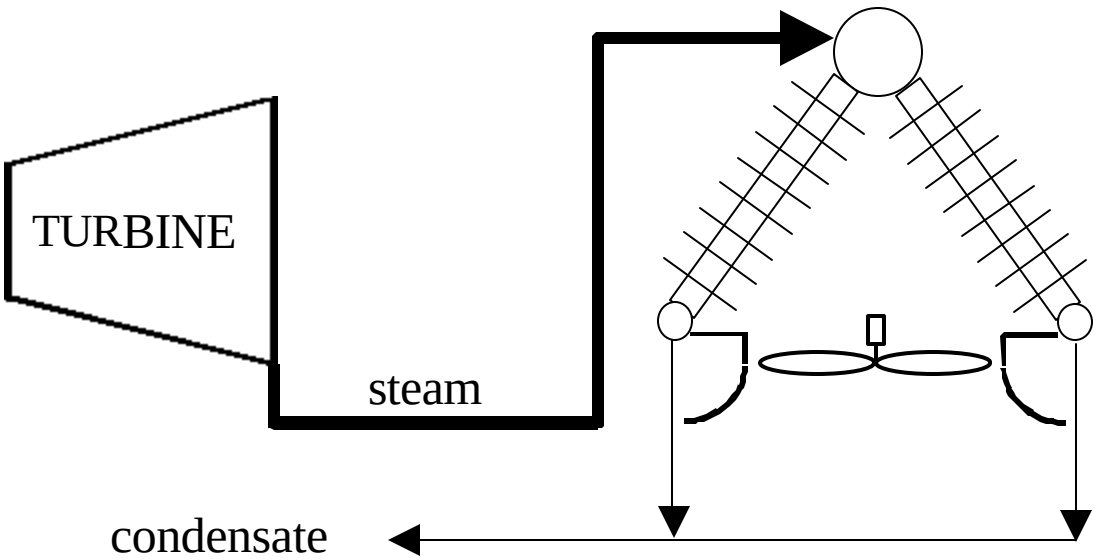

Figure 3: Dry cooling system connected to steam turbine (direct system).

In dry cooling systems, the turbine exhaust is connected directly to the air cooled steam condenser (that is why it is called a direct system) as shown in Figure 3. The steam exhaust duct has a large diameter and is usually as short as possible to reduce pressure losses. The finned tubes are arranged in the form of an A-frame to reduce the required plot area. The advantages and disadvantages of dry cooling systems are shown in table 2 below.

ADVANTAGES OF DRY COOLING	DISADVANTAGES OF DRY COOLING
Can be located at fuel source	Large plot area required
No water required	Less efficient
No plume formation	Generates more noise
No impact on environment	
Less permitting required	

Table 2: The advantages and disadvantages of dry cooling systems

Recent studies indicate that on average, one third of the new power plants permitted in North America will require a dry cooling system. This is driven by the lack of water, PM10, and EPA 316(A) and 316 (B) issues. PM10 is one of the seven air pollutants the Environmental Protection Agency (EPA) regulates under the National Ambient Air Quality Standards (NAAQS). PM10 is defined as particulate matter (PM) with a mass median diameter less than 10 micrometers. EPA standards require the PM10 concentrations (expressed in the weight of particulate matter in a cubic meter of air) to remain within certain limits.

The PM10 concentration limits (24 hour and annual allowable average) are:

- A 24 hour average not to exceed 150 micrograms per cubic meter of air more than three times in three years
- An annual arithmetic average not to exceed 50 micrograms per cubic meter of air

EPA also regulates the cooling water systems at electric generating plants and manufacturers through sections 316(a) and 316(b) of the Clean Water Act. Section 316(a) requires EPA to ensure that a cooling water system has not caused or will not cause by continuing to operate, appreciable harm to the balanced indigenous community; and allows a facility to demonstrate that thermal limitations under state quality regulations are more stringent than necessary to protect the population of shellfish, fish and wildlife in and on the body of water into which the discharge is made. Section 316(b) of the Clean Water Act requires EPA to ensure that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact.

In some areas of the US, dry cooling will be the system of choice. In the state of Massachusetts for example, air cooled condensers are used in 70 % of the recently built power plants.

4. WET/DRY OR HYBRID COOLING SYSTEMS

Wet/dry or hybrid systems designed primarily for plume abatement are essentially wet towers with just enough dry-cooling added to reduce the relative humidity of the combined effluent from the wet and dry section below the point where a visible plume will form under cool and high relative humidity conditions.

The atmospheric criteria for plume abatement are contrary to the criterion for heat rejection. In other words, the hybrid tower when operating in plume abatement mode has a lower cooling capacity compared with pure wet mode operation. However, since part of the heat rejection occurs in the “dry” section of the hybrid tower during the in plume-abatement mode, its water consumption is reduced slightly.

Generally, a hybrid tower is designed to dissipate approximately 20 to 40% of the total heat load in the “dry” section to meet the atmospheric criteria for plume-abatement, but it operates in plume-abatement mode for less than fifty percent of the time, thus reducing water consumption by 10 to 20%. On an overall basis, the reduction of water consumption in a hybrid cooling tower over the course of the year is usually limited.

5. SELECTION CRITERIA BETWEEN DRY COOLING SYSTEMS AND WET TOWERS

Since a wet tower has a lower capital cost and has a better performance in hot weather, it will be the best choice if sufficient water is available at reasonable cost. But even if enough water is available, some other factors may play a role as well. At times of high humidity and cool air temperature, a wet cooling tower is likely to produce a plume which is a visible fog exiting the tower. While the plume is environmentally safe – it is nothing but water – it can create visual problems or icing if the plant is located near a highway, residential area or airport. A power plant in Linden, New Jersey, for example went with a dry cooling system because of the twelve-lane New Jersey Turnpike next to the plant and the effect that the plume from a wet cooling tower would have on icing and fogging, which would be unacceptable [R5].

Dry cooling saves a lot of water but there is a price to pay for it; the capital cost is significantly greater and there may be plant limitations on the hottest days. Also the heat rate may be impacted on all but the coldest days. That is why dry cooling systems need a performance enhancement during hot ambient temperatures. There are different ways to enhance the performance of a 100 % dry cooling system, and one of them is spraying water at the air inlet of the fans. The purpose of this system is to reduce the dry bulb ambient temperature as close as possible to the inlet wet bulb ambient temperature during hot and dry summer days, using evaporation of the water droplets at the air inlet. However, adding a wet tower that needs only a limited use of water during summer days is probably the most attractive available solution as will be shown in this paper.

6. THE PARALLEL CONDENSING SYSTEM (PCS)

Parallel condensing systems, have been developed to save water, while avoiding the high cost of dry cooling systems and to ensure a relatively low steam turbine back pressure at high ambient conditions.

An excessive rise in steam turbine backpressure during periods of peak ambient temperatures and demand will result in a loss of efficiency of the steam turbine-generator set. In such a case, the dry section of the system may be designed to reject the total heat load at a low ambient temperature while maintaining the turbine backpressure within specified limits at high ambient temperatures using the wet part of the system. One way of sizing the wet part of a PCS cooling system is to limit the quantity of make-up water according to the local water availability.

A PCS system is a synergy of established cooling system technologies and combines some positive features of dry and wet cooling systems; the water consumption is reduced compared to a 100 % wet system, the performance is improved compared to a 100 % dry system and the capital cost decreases as the proportion of wet in the PCS system is increased.

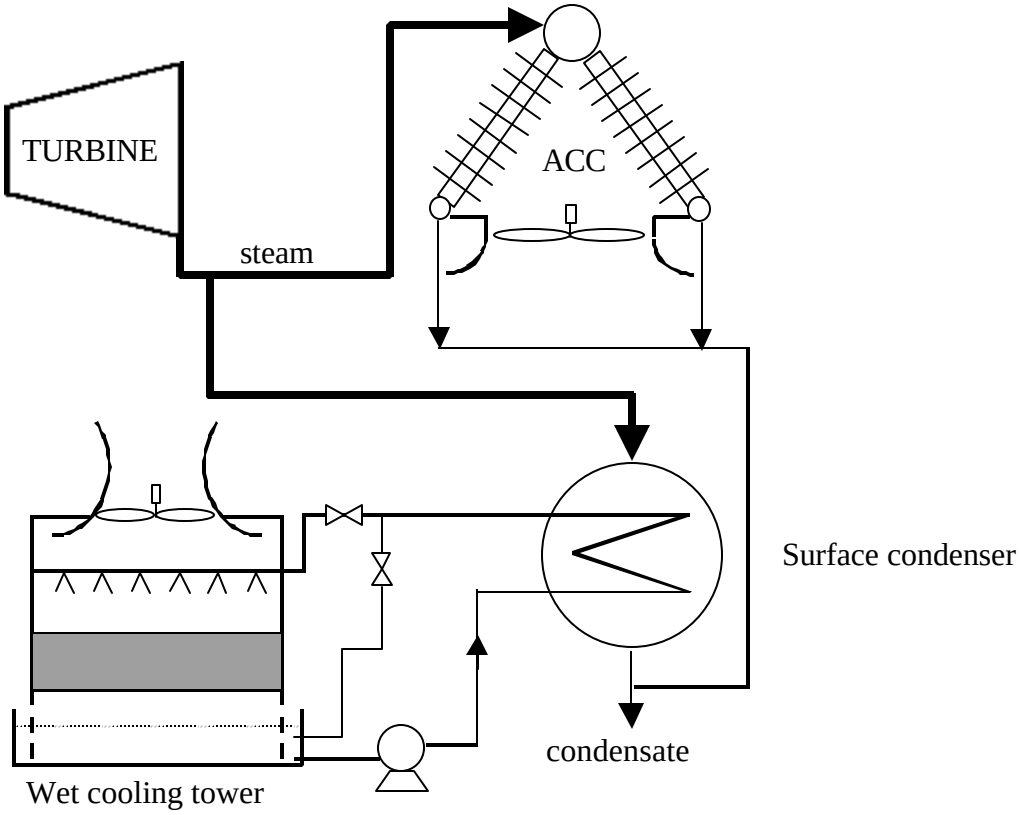

Figure 4. Parallel condensing system (Dry/wet cooling system).

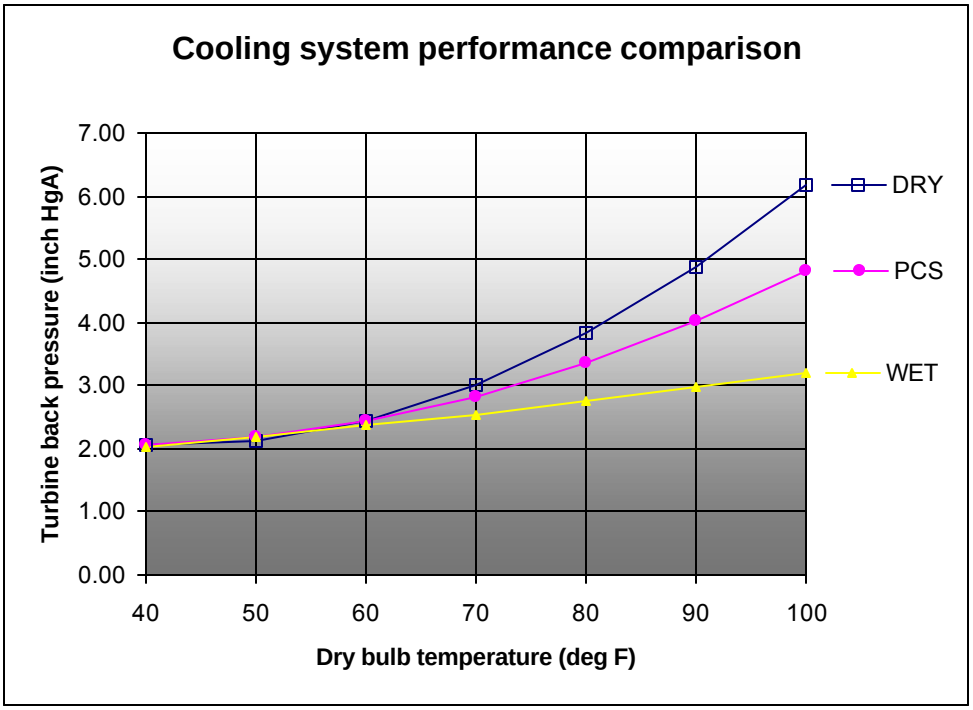

Figure 5. Dry, PCS and wet cooling systems – comparison of the performance.

A typical cooling system performance is shown in Fig 5.; the turbine back pressure is plotted as function of the dry bulb temperature. As can be noticed, all three cooling systems are similar in performance at reduced dry bulb temperatures. As the ambient temperature rises, the dry cooling system is penalized the most and will have the highest turbine back pressure.

The wet cooling system is able to maintain a much lower turbine back pressure at high ambient temperatures. The performance of the PCS system is in between the dry and wet cooling systems. The relative improvement of the PCS system with respect to the 100% dry cooling system is dependent on the amount of water that is used for wet cooling.

Another way to express the cooling system performance, however, is to evaluate the steam condensing capacity of the condenser at the maximum ambient dry bulb temperature. For simplicity, only a qualitative comparison is shown in table 3 below.

STEAM CONDENSING CAPACITY	COOLING SYSTEM
100 %	WET
Up to 100 %	PCS
Less than 100 %	DRY

Table 3. Steam condensing capacity of the wet, PCS and dry cooling systems.

The steam condensing capacity in this context can be defined as the amount of steam that can be condensed by the steam condenser in order to avoid a steam turbine trip, 100 % being full load. The advantage of the PCS system over the 100 % dry system is obvious. In a situation where the load to the steam turbine has to be reduced at high ambient temperatures with a dry cooling system, a PCS system can be designed in such a way that the steam turbine can operate at full load without risk of a steam turbine trip on a hot summer day. Under these design conditions, the air cooled condenser alone would not be able to avoid a steam turbine trip at full load and maximum ambient conditions.

In the following example we will show that by using some water for a wet cooling tower, the capital investment can be reduced significantly compared with a dry cooling system.

DESIGN CONDITIONS	VALUE in SI units	VALUE in US units
ambient dry bulb temp	40.6 deg C	105 deg F
relative humidity	16%	16%
ambient wet bulb temp	21.0 deg C	69.8 deg F
atmospheric pressure	946 mbar	27.9 inch HgA
required thermal duty	445.4 MW	1521120739 BTU/hour
turbine back pressure	< 270 mbar	< 8.0 inch HgA

Table 4. Design conditions for the air cooled condenser and PCS system.

A 100 % dry cooling system and a PCS system (using a small cooling tower) were designed for the design conditions that are shown in the table 4.

The major requirement is to avoid a turbine trip (typical value is a turbine back pressure lower than 270 mbar or 8 inch HgA) at the maximum ambient air temperature. In the following study it was decided to design the PCS system in such a way that the wet cooling tower should only operate on hot summer days (ambient dry bulb temperature above 32 deg C or 90 deg F).

In the parallel condensing system, the wet cooling tower can be shut down in spring, autumn and winter, because the dry portion of the cooling system is sufficient to handle the required thermal duty. In the graph below it can be noticed that the dry portion of the PCS system can handle the thermal duty up to an ambient temperature of about 32 degrees Celsius (90 deg F).

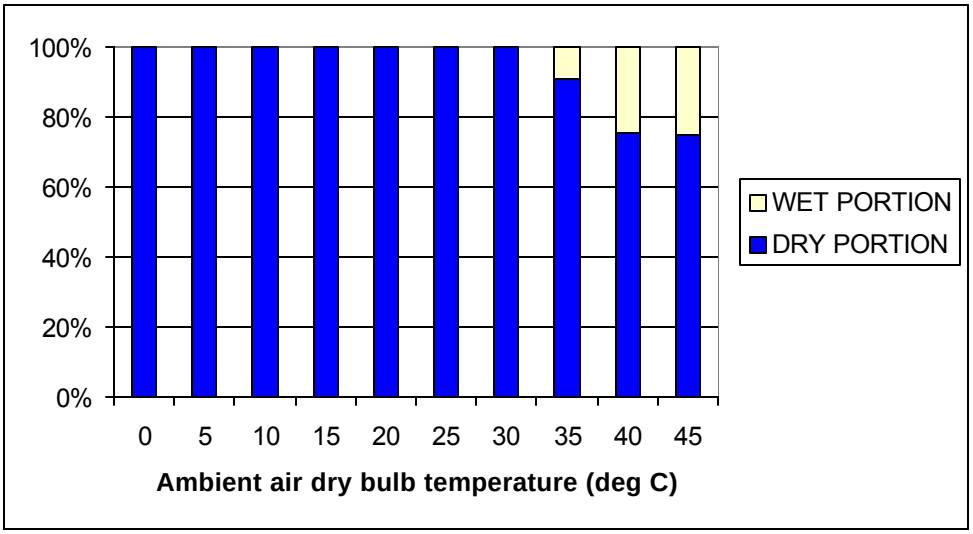

Figure 6. Wet and dry portion of the thermal duty as function of ambient dry bulb temp.

As the ambient air temperature rises, a larger portion of the duty is handled by the wet cooling tower. At the maximum ambient dry bulb temperature, the wet cooling tower rejects about 25 % of the total thermal duty.

The monthly average temperature distribution that we used in our example is given in the graph (Fig. 7). Assuming that the air cooled condenser cannot handle the thermal duty any more for ambient air temperatures exceeding 32 °C (89.6 °F), combined with the temperature distribution from Figure 7 it is assumed that the wet cooling tower will be working for only about 30 days per year, which is a reasonable design for a PCS system.

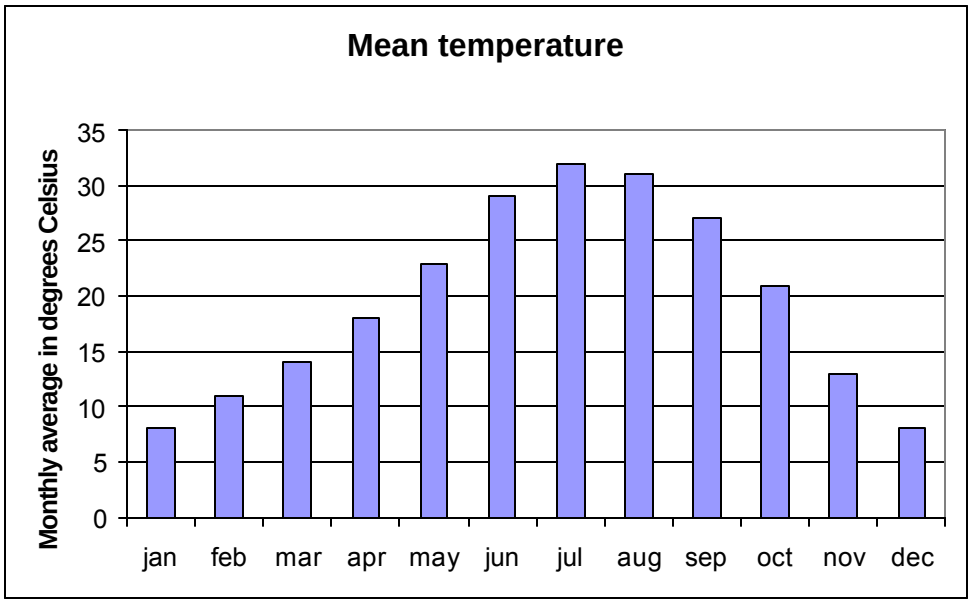

Figure 7. Monthly average temperature for the PCS system design.

Using the equations above, an estimate of the amount of make-up water that is required to operate the wet cooling tower for one month per year can be done. Assuming a drift of 0.005 % and 5 cycles of concentration for the blow-down, we arrive at a make-up flow of about 68 kg/s (1080 gallons per minute).

Considering a cost of water of $2.00 per 1000 gallons of water, the predicted yearly cost for make-up water should be about $100,000. The cost of water in an all wet system would be $3,000,000 per year (using 3000 gpm make-up during 350 days a year).

An estimation of the capital costs for the wet part of the PCS cooling system is based on the following breakdown [R6], as shown in table 5:

ELEMENT	COST
Wet cooling tower	35 - 45 % of system cost
Installation/erection	included in base price
Surface steam condenser	35 - 45 % of system cost
Tower basin	3 - 6 % of system cost
Electricals and controls	Typically $25,000 per cell
Circulating water system	5 % of system cost
Water treatment/blowdown discharg	1 % of system cost

Table 5. Capital cost breakdown for the **wet part** of the PCS cooling system.

The capital cost of the air cooled condenser (reference value = 100 % dry cooling) includes the cost for installation and erection, and is estimated at about $31.2 million for a typical 500 MW combined cycle power plant.

Table 6 compares the PCS system and an air cooled condenser (100 % dry) for capital cost, plot area and fan power consumption. The figures assume that the cooling water pumps (estimated at about 500 hp pump power) and the fans of the wet cooling tower are only operating for about one month per year.

ITEM	ALL DRY SYSTEM	PCS SYSTEM
dry fraction of heat	100	73%
capital	100	79%
fan power	100	83%
plot	100	82%

Table 6. Comparison between air cooled condenser and PCS system.

As can be noticed from table 6, the introduction of a small cooling tower (typically two cells) can reduce the capital cost by more than 20 % compared to a 100 % dry system (remark: a 100 % dry system refers to a cooling system where an air cooled condenser is responsible for one hundred percent of the total heat duty). Also the plot area and fan power consumption are more favorable for the PCS system. Operational costs are expected to be less for the PCS system in general.

7. CONCLUSION

Because of restrictions on thermal discharges to natural bodies of water, almost all power generating plants or large industries requiring cooling will require closed cycle cooling systems. Evaporative or wet cooling systems (cooling towers) generally are the most economical choice for closed cycle cooling systems where an adequate supply of suitable water is available at reasonable cost to meet the make-up requirements of these systems. If only the plume is an issue the solution may be a wet/dry cooling system (hybrid cooling towers). But although these systems may save some water, the amount of make-up water is still significant and a plume will still be present under certain atmospheric conditions, and this may be unacceptable if the power plant is close to a major highway or airport.

If only a limited amount of water is available, or the water cost is too high, most power plants tend to go for a 100 % dry system without considering the PCS system. In some cases, a dry cooling system has been selected even if water is available at reasonable cost where political or environmental considerations prevail. But by selecting a parallel cooling system that is designed to use the available water for a cooling tower on hot summer days, the performance of air cooled condensers can be enhanced and significant savings on the capital and operational costs of the cooling system can be expected. Moreover, the wet cooling tower can be shut down most of the time (except on hot summer days), so the negative effects of a plume (fogging and icing in winter months) are not an issue.

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DECLARATION OF BILL POWERS

Attachment E

Advanced HELLER System - Technical

The Advanced HELLER System

Technical Features & Characteristics

by

Andras Balogh

Zoltan Szabo

A paper for EPRI Conference on „Advanced Cooling Strategies/Technologies", June 2005, Sacramento (CA)

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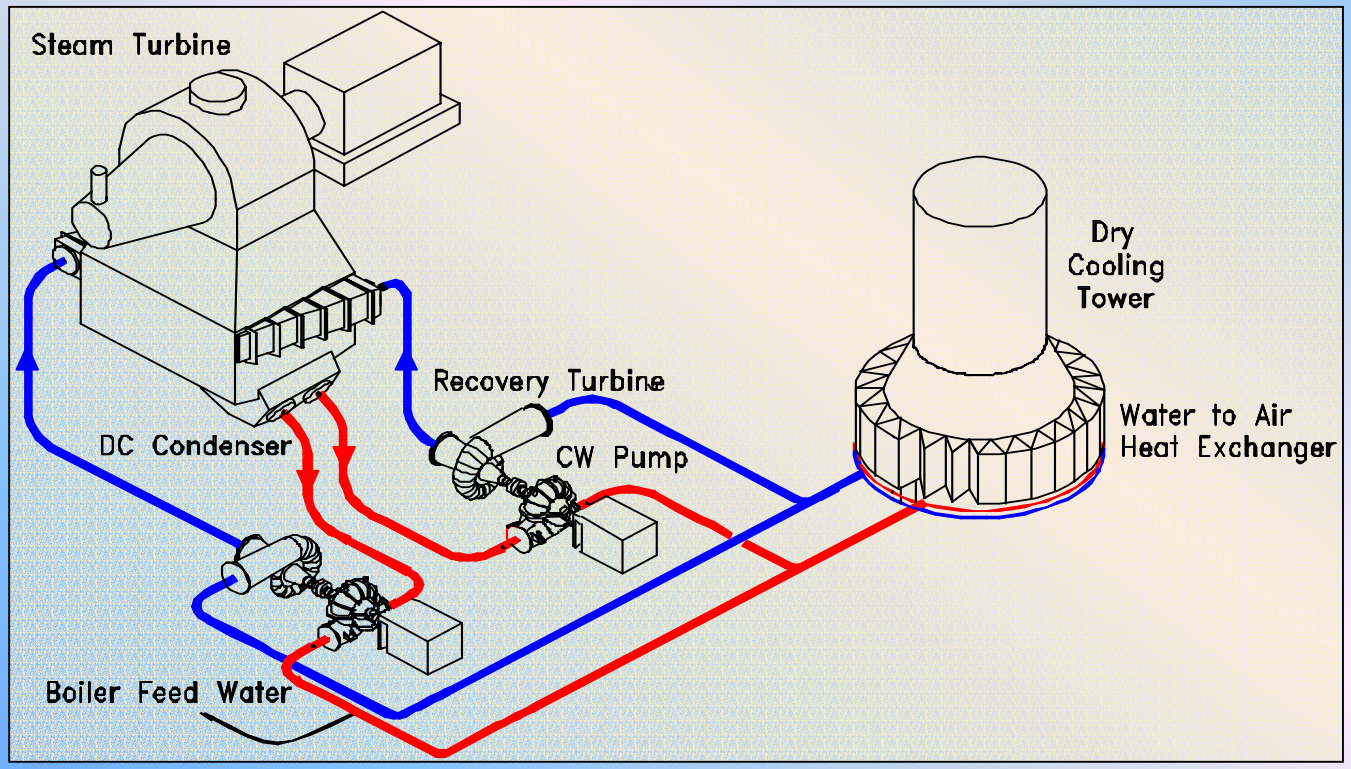
1. HELLER System: Circuitry, Technical Solutions

1.1 HELLER System Circuitry:

HELLER System is an indirect dry cooling plant. The power plant waste heat is initially exchanged in a condenser (preferably a direct contact one) to a closed cooling water circuit. The heat absorbed by the water is rejected to ambient air in fin tube type heat exchangers. [3]



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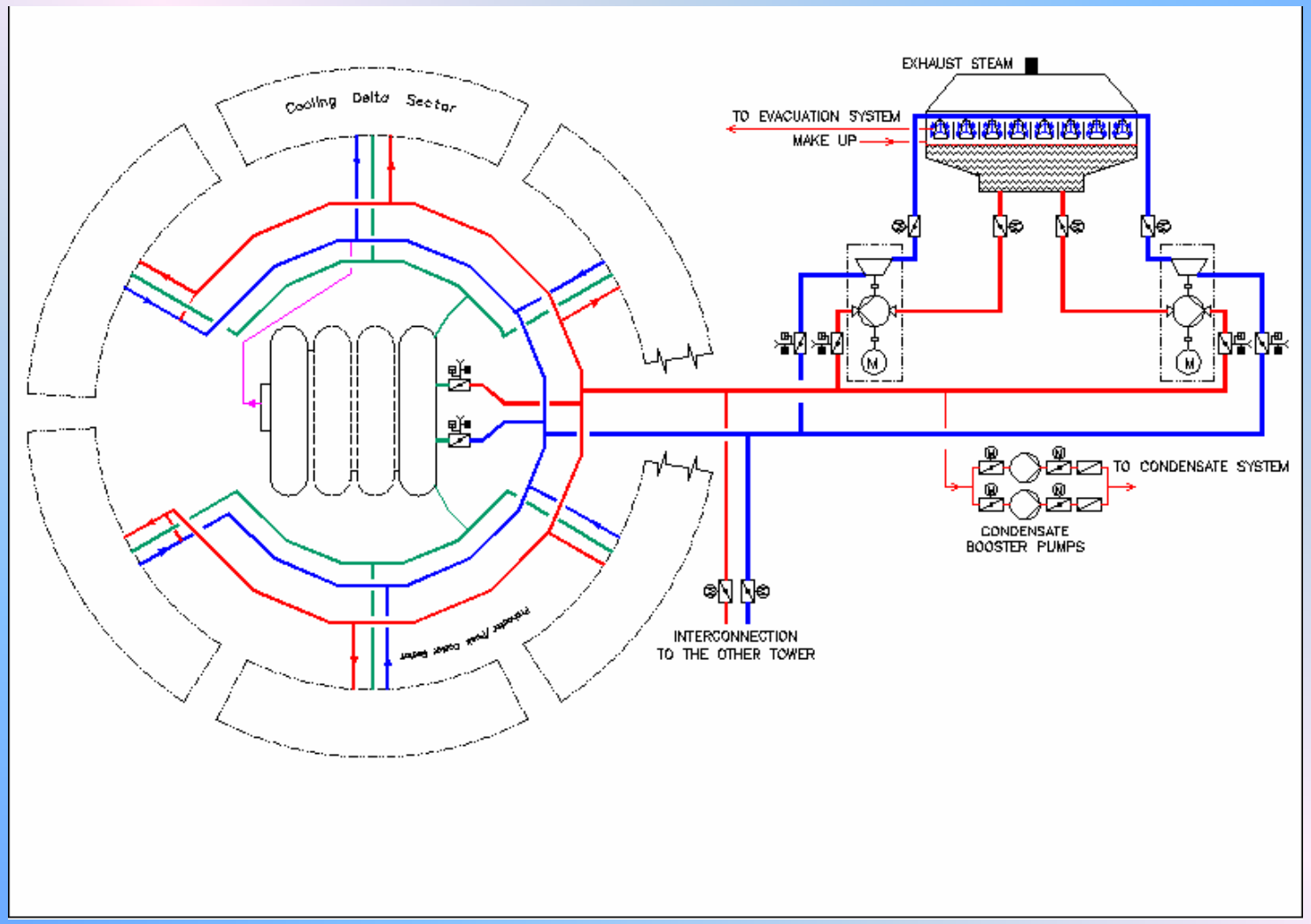
1.1 HELLER System Circuitry – cont.



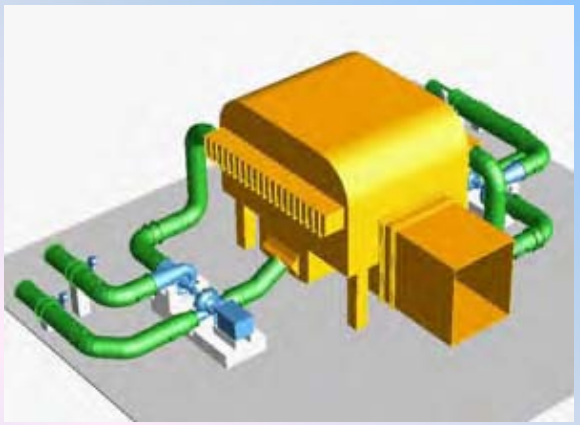
1.2 Technical Solutions - Condenser Options

- Conventional Surface Condenser TTD ~ 3-4°C (5.4-7.2°F)

- Direct Contact (DC) Jet Condenser TTD ~ 0.3°C (0.6°F)

for top entry

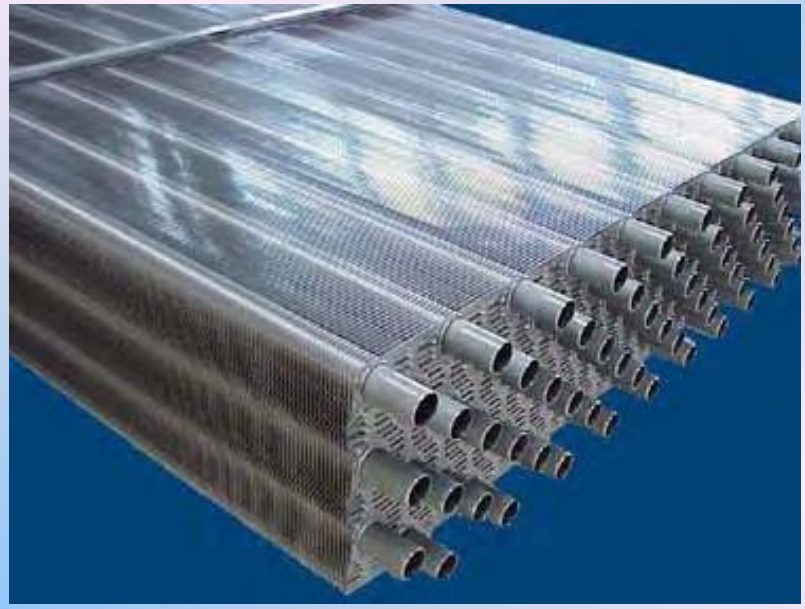
for lateral exhaust



- Combined DC & Surface Condenser

for one of EGI's novel dry/wet cooling systems

1.2 Technical Solutions – Water-to-Air Heat Exchangers



- The 5th generation FORGÓ Air Cooler, developed for power applications, is a mono-metal all aluminum heat exchanger with protective surface treatment.
- The hard plate Al-fin and normal Al-tube bond provides enduring metallic contact due to “spring effect”.
- Minimum deposition and easy cleaning (cleaning once or twice a year).

- Cooling delta washing equipment enables efficient online cleaning.

1.2 Technical Solutions – Air Moving Equipment (Draft Options)

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➢ Mechanical Draft:

– lowest investment cost among dry cooling plants

– relatively high auxiliary power consumption and noise emission

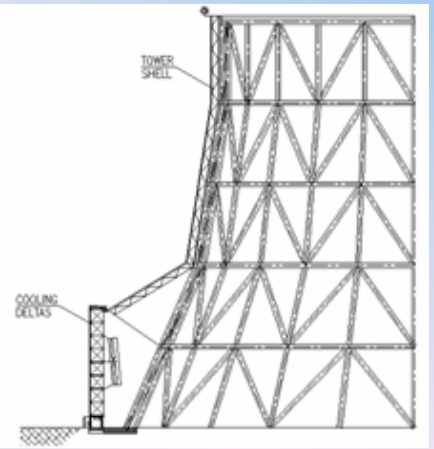
– the circular arrangement reduces noises & warm air re-circulation

➢ Fan Assisted Natural Draft

– fairly competitive for areas with limited restriction on superstructure height (allowing 50-70 m); a low noise solution

– if height limitation is very strict (< 40m), has no distinctive advantage over mechanical draft

– if height is > 60m, part of the air coolers can be without fans



1.2 Technical Solutions – Air Moving Equipment (Draft Options) – cont.

➢ **Natural Draft:**

– outstanding competitiveness, if the evaluation is based on economic life-cycle present value (extends the economic feasibility of dry cooling against wet cooling)

– improves power plant efficiency by ~2% (compared to fan draft dry cooling)

– zero noise emission

– increased availability & reliability

– low maintenance due to avoiding fan

– opportunity to exhaust flue gases via tower shell, resulting in low ground level concentration of pollutants

– the most environmental friendly solution, but its visual impact is high

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2. HELLER System References

- **More than 50 years of experience**
- **A total of 17,000 MW_e power plant capacity in service with the HELLER System**
- **EGI has reference plants in 17 countries including:**

  - units operating under extreme ambient conditions (as cold as - 62°C, or some at + 50°C)
  - the largest dry cooled Combined Cycle Plant in the world
  - the only dry-cooled nuclear power plant in the world
  - natural draft dry cooling towers through which flue gases are exhausted

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2. HELLER System References – cont.

Natural Draft Cooling Towers at the Shahid Rajai TPP (4 x 250 MW_e Iran)
Turbine cycle: by MHI; Boiler: by IHI

2. HELLER System References – cont.

EGI

In the background the cooling towers of the 4 x 200 MW_e „old" Razdan PS (Armenia)
In the foreground the cooling tower to serve the 2 x 310 MW_e Razdan Extention
(a single tower shell incorporates the air coolers of two units)

2. HELLER System References – cont.

EGI

Al Zara 3 x 220 MW_e T.P.P., Syria (commissioned in 2001)
Turn-key contractor: MHI

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2. HELLER System References – cont.

GEBZE & ADAPAZARI 3 x 777 MW_e CCPP commissioned in 2002 (Turkey)
EPC-Contractor: BECHTEL-ENKA JV, End-user: INTERGEN
The world's largest dry cooled combined cycle power plant

2. HELLER System References – cont.

EGI

3 × 777 MW_e Gebze-Adapazari CCPP

In the foreground: open-air hydraulic machines of the HELLER System

In the background: vertically arranged air coolers

2. HELLER System References – cont.

EGI

Dry/deluged Mechanical Draft HELLER System for the 150 MW_e Újpest Combined Cycle co-generation plant, Budapest, Hungary

GEA

2. HELLER System References – cont.

EGI

Kaneka Chemical Works (Japan)

Mechanical Draft HELLER Systems with optional spraying at

Sochi Cogeneration Combined Cycle (Russia)

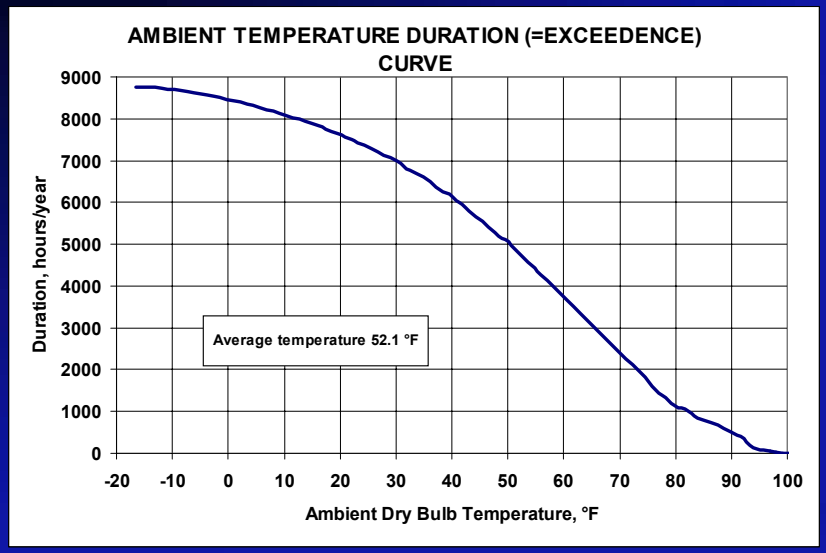
3. Cooling System Characteristics

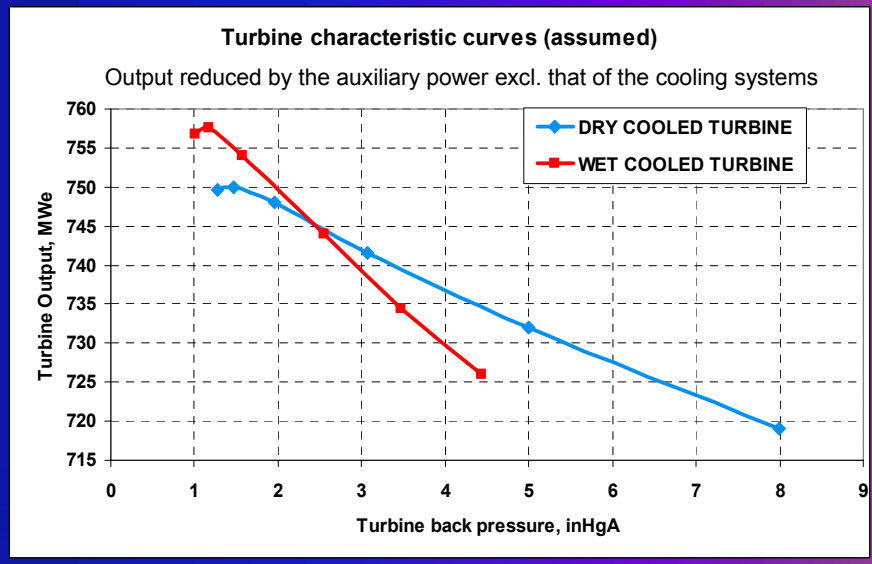
- Cooling systems are integral parts of power plants – therefore their characteristics shall also be investigated how they influence the power plant as a whole.

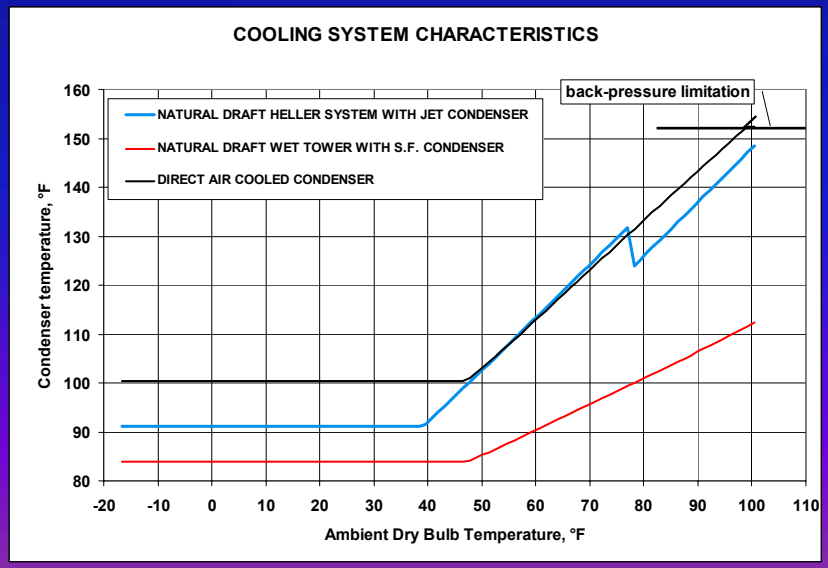
- Capability of cooling systems (especially that of the non-water solutions) heavily depend on ambient conditions. Thus it is important to determine their impact on the power output variation as well as the year-round electricity production in function of ambient temperatures. It needs to combine the cooling system and the turbine characteristic curve with the ambient temperature duration diagrams (dry bulb for dry cooling and wet bulb for evaporative one).

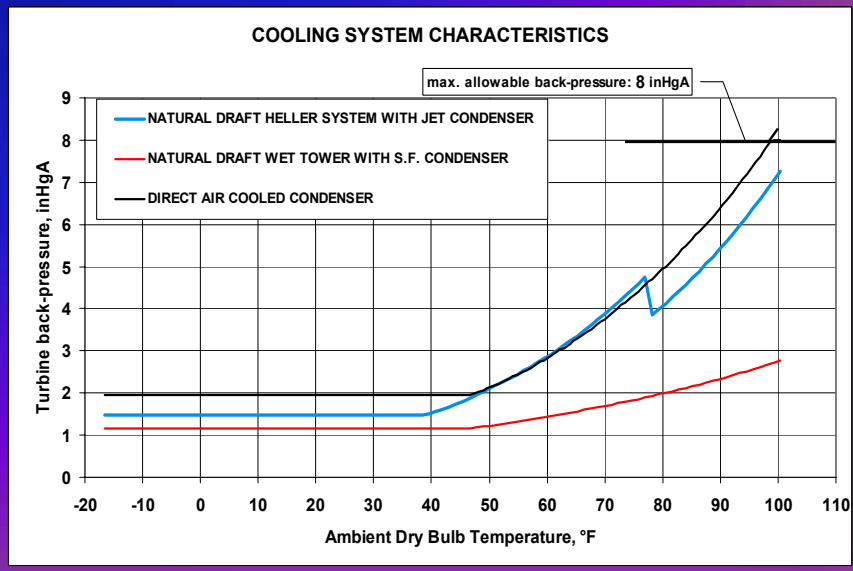
- Such evaluation process is introduced via the investigation of two power cycles:
  - an 800 MW_e coal fired supercritical power plant
  - a 500 MW_e combined cycle power plant (CCPP)

3.1 Characteristics of Cooling Options for an 800 MW_e Supercritical Cycle

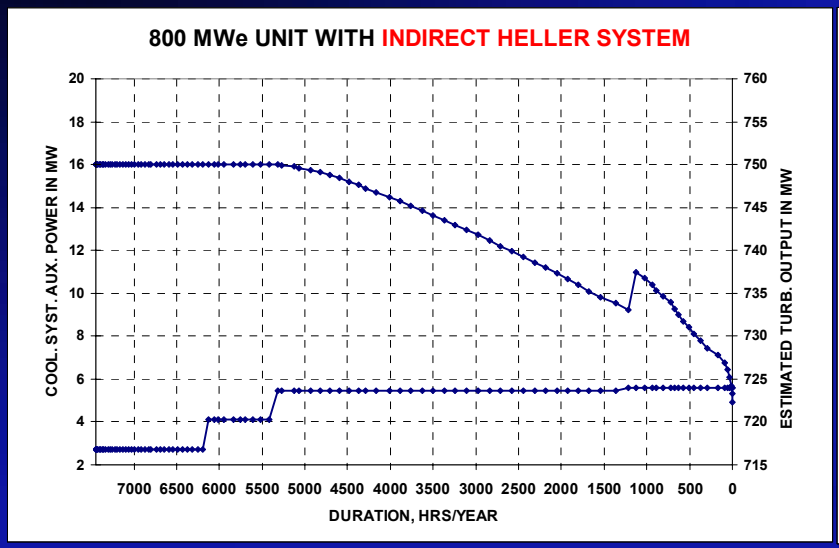


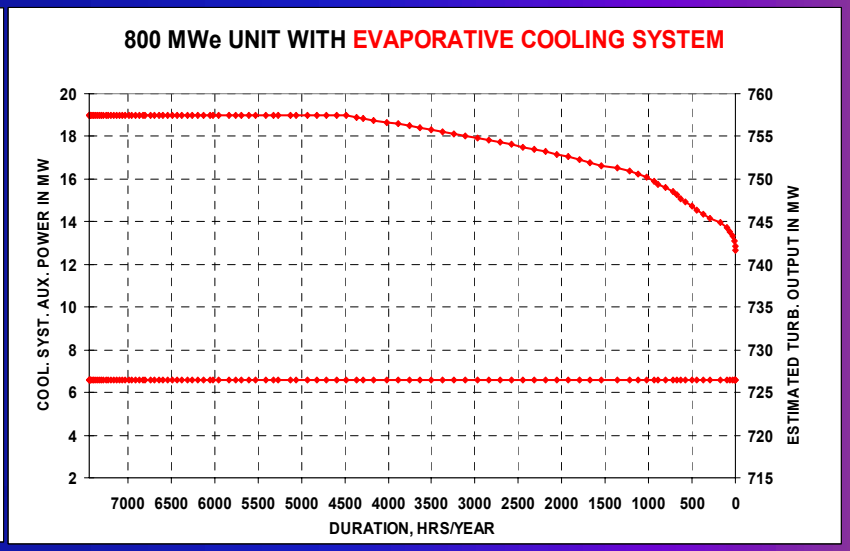




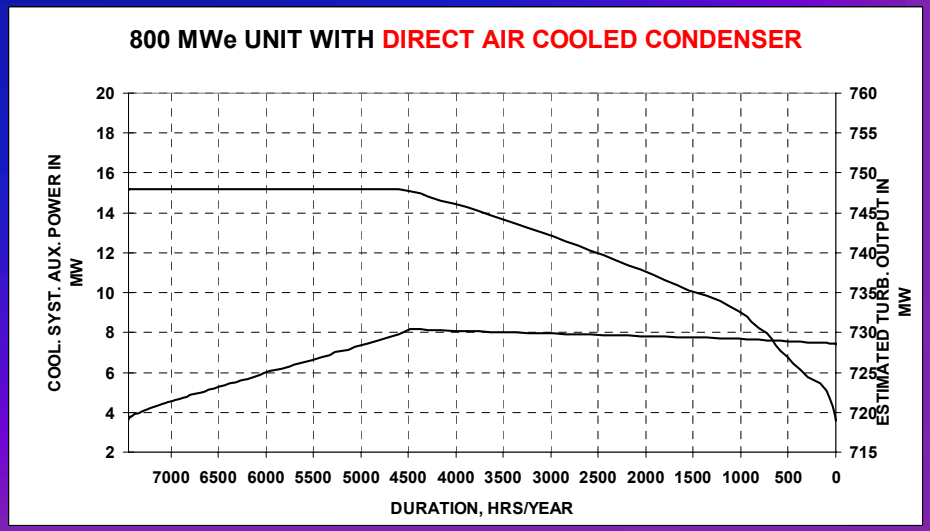


3.1 Characteristics… for an 800 MW_e Supercritical Cycle – cont.

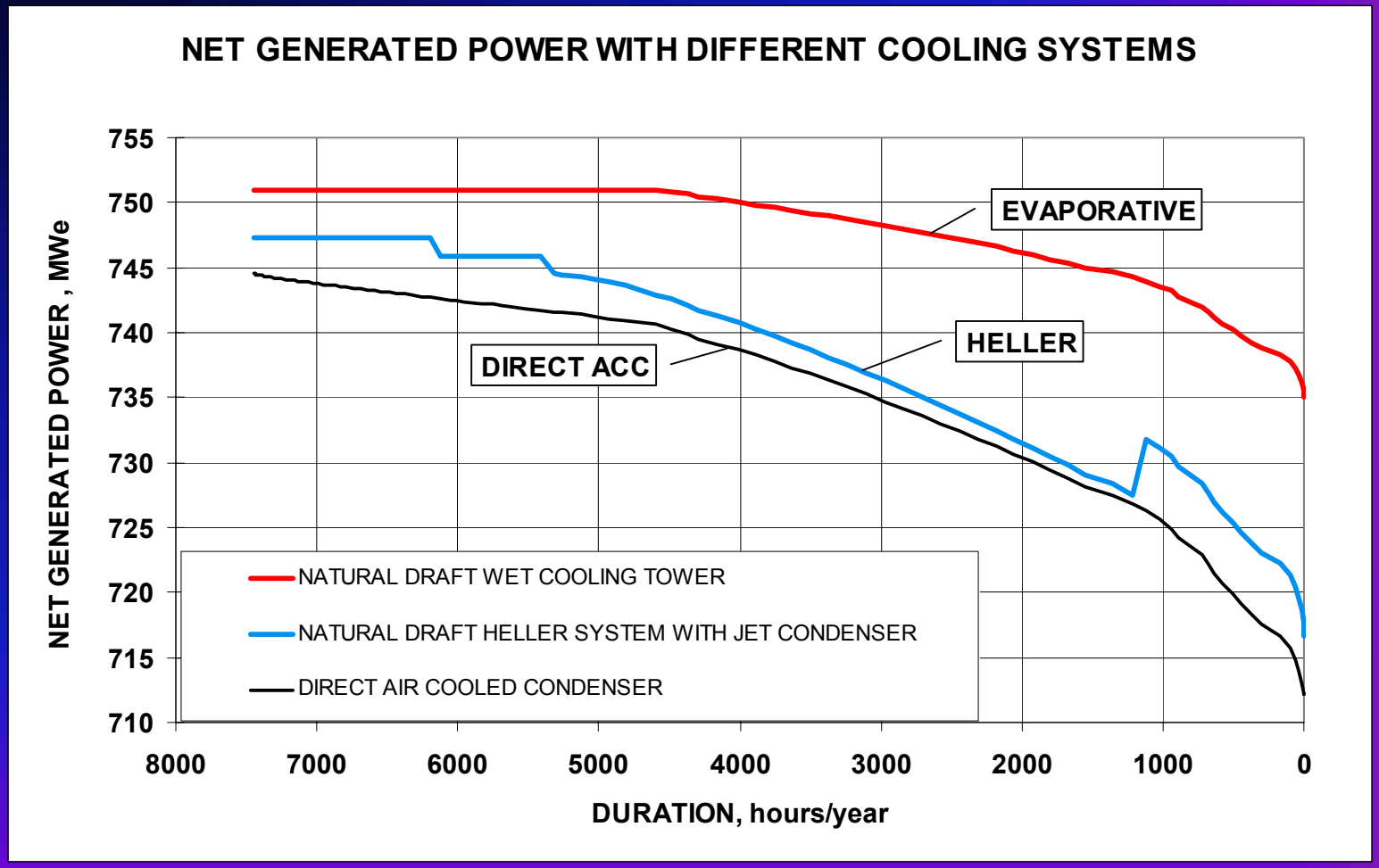




Yearly variation of steam turbine output and auxiliary power consumption versus duration in case of different cooling systems

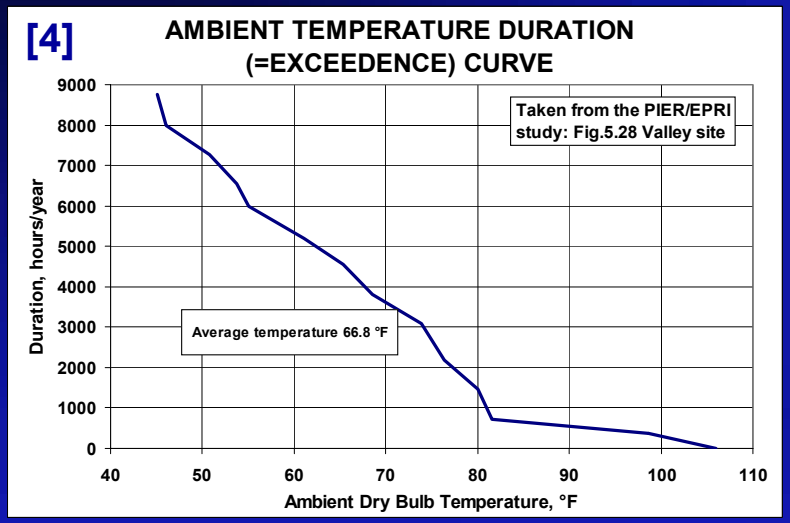


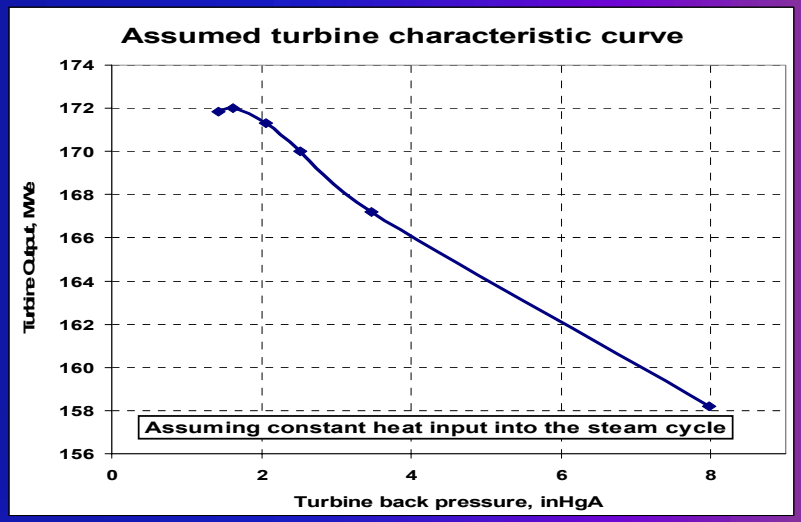
3.1 Characteristics… for an 800 MW_e Supercritical Cycle – cont.

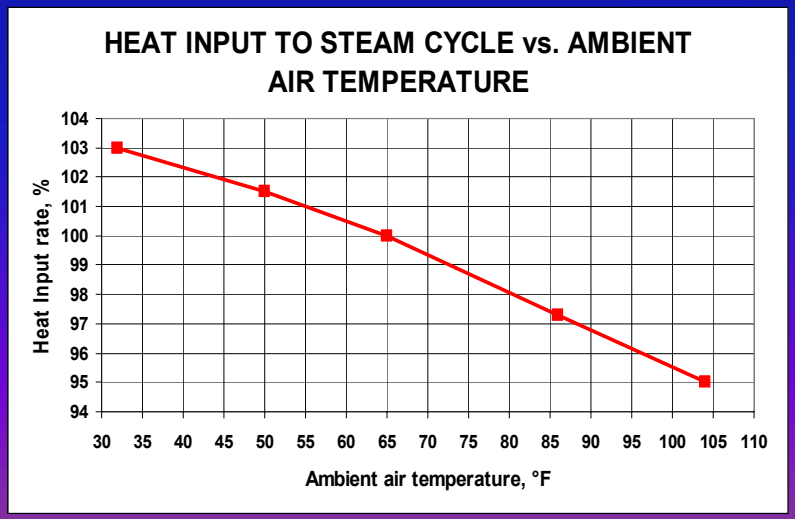


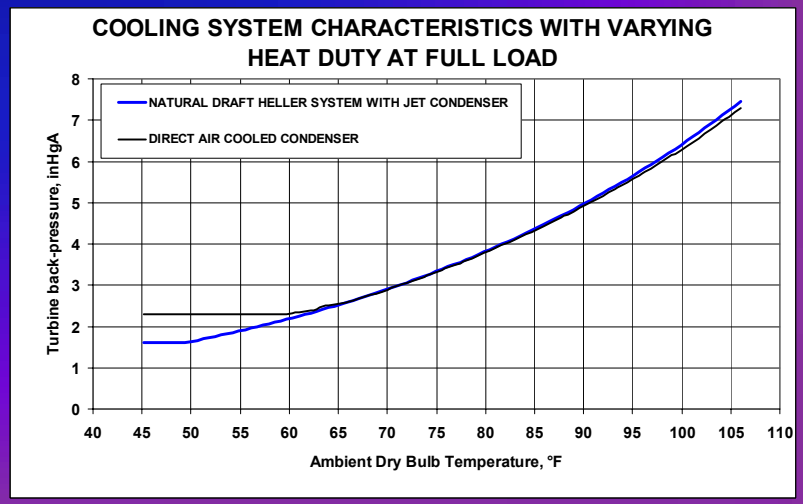
3.2 Characteristics of Dry Cooling Options for an 500 MW_e CCPP

The difference relative to conventional steam cycles is that CCPP steam cycles have a varying heat input in fuction of ambient air temperature

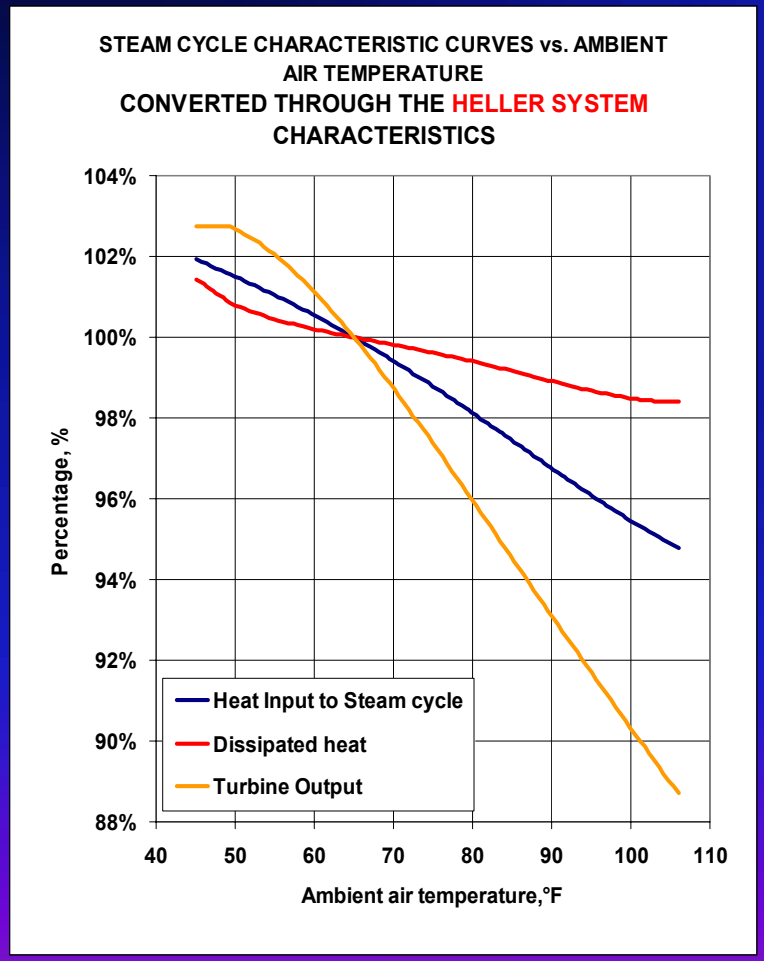


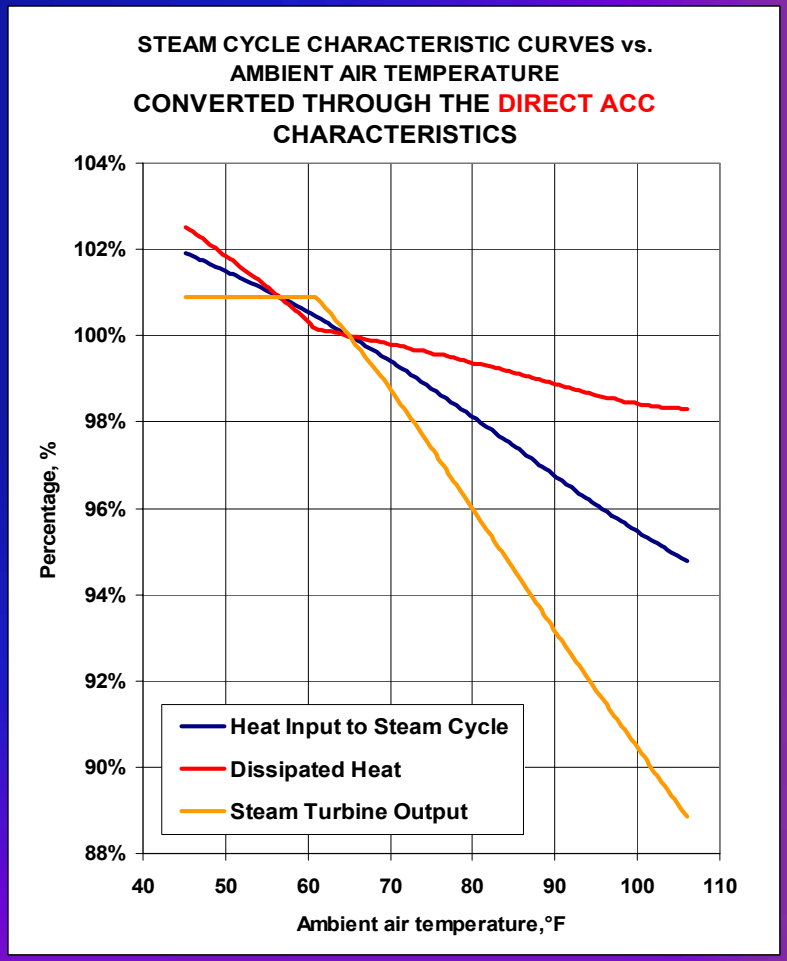




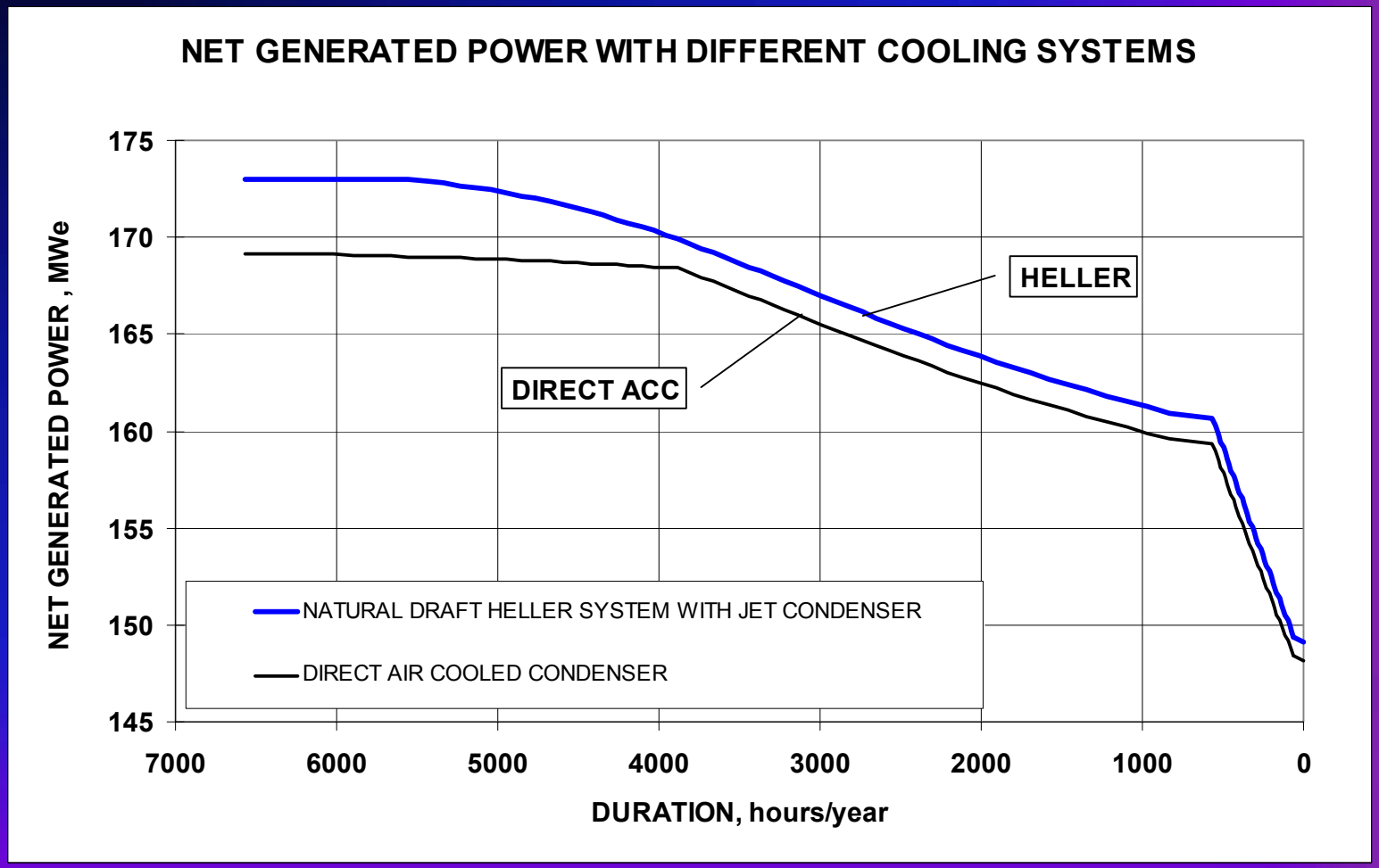


3.2 Characteristics… for an 500 MW_e CCPP - cont.





3.2 Characteristics… for an 500 MW_e CCPP - cont.



4. HELLER System Availability & Maintenance Considerations

System design concepts and equipment selection have all been refined with a view to providing HELLER System with the maximum possible availability and minimum maintenance:

- **Cooling Water Quality and CW Circuit:** The closed cooling water circuit has condensate quality water, thus precludes any deposition and fouling throughout the whole circuit (incl. the condenser) – by this eliminating the need for cleaning and excluding any external contamination to feed water cycle.

- **Condenser:** The direct contact (DC) jet condenser is a simple, maintenance-free equipment (no tubing), representing 100% availability. Vacuum – similarly to surface condensers is restricted to this space only.

- **Common Feed Water & CW Circuit:** The large condensate quality cooling water volume provides adequate buffering
  - for the power cycle water chemistry regime even in case of temporary malfunctions of water treatment plant (WTP) or condensate polishing plant (CPP),
  - and for smoothing wind gusts induced fluctuation of CW temperature, thus that of the turbine back pressure, too.

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4. HELLER System Availability & Maintenance – cont.

• **Impact on Power Unit Water Chemistry, CPP, Boiler:** HELLER System - based on the above features – relative to any other cooling systems provides ideal conditions to applying the most efficient oxygenated water treatments (CWT & NWT) and easing the sensitivity of supercritical cycles to water chemistry, resulting in

- better efficiency and reliability and less maintenance of the CPP ion exchangers (extended periods between regenerations and thus increased resin life-span);

- reduced carry-over of corrosion products to the boiler, thus maintaining the original efficiency for a longer period and requiring less major boiler cleaning.

• **Air Moving Equipment:** The natural draft tower shell represents 100% availability. There is an extreme dry air flow inside, thus no need for maintenance even if flue gases exhausted via the tower shell (no need for any painting or re-painting throughout the whole lifetime of the project).

• **Air Cooler:** The treated all aluminum matrix-type air cooler has a life-span in line with that of the power unit without performance deterioration. Air side surface can effectively be kept clean by washing once or twice a year during operation with an equipment being part of the supply. Sectionalized air cooler arrangement (e.g. 10 sectors) ensures 93% heat dissipation capacity at unchanged back-pressure even if one of the sections is disconnected, or 100% heat dissipation at a 1.7°C higher condenser temperature.

4. HELLER System Availability & Maintenance – cont.

• **Hydraulic Machinery:** The only continuously moving components of the system requiring brief maintenance during scheduled plant shut-down. If one set of hydraulic machines is out of operation, in case of the 800 MW_e supercritical cycle 92% of the original heat dissipation can be maintained at unchanged vacuum, or the heat dissipation remains 100% at 1.9 ºC higher condenser temperature. Whereas in case of the investigated 500 MW_e CCPP these figures are 81% and 4.5°C.

• **Independence from Water Availability:** Even those HELLER Systems which are equipped with supplementary spraying for enhancing heat dissipation capacity in summer peak periods, can be operated in all-dry mode, i.e. without any water, thus it is not affected by water availability.

5.1 Comparison of Effects by Dry Cooling Systems on the Environmental Impacts of a 800 MW_e CCPP

Two proven dry cooling systems (a natural draft HELLER System and a mechanical draft ACC) are compared by their influence on the environmental impact of a 800 MW_e Combined Cycle Power Plant (CCPP). First, some performance, operational and layout features are specified:

	HELLER System natural draft	Direct ACC mechanical draft
Operational & Layout Features		
Steam Turbine gross output at design point	270.1	270.1
Yearly average of steam turbine gross output	267.7 MW_e	266.3 MW_e
Cooling System Auxiliary Power Consumption - at design point - yearly average	 2400 kW 2340 kW	 4600 kW 4190 kW
Yearly average of steam turbine net output	265.34 MW_e	262.11 MW_e
Water consumption	nil	nil
Availability / Reliability	excellent	good/fair
Maintenance	low	medium
Air cooler life-span	> 30 years	> 30 years
Flexibility in site arrangement	good	fair
Plot area	∅ 121 m	70 m × 80 m
Primary wind effect	medium	medium
Warm air re-circulation	no	yes
Warm air trans-circulation	no	yes

5.1 Comparison… Environmental Impacts of an 800 MW_e CCPP – cont.

The main qualitative and quantitative environmental impacts are summarized in the following table:

	HELLER System natural draft	Direct ACC mechanical draft

Environmental Impacts & Features		
Water need and polluted water discharge	nil	nil
Effect on power cycle ground level NO_x concentration by cooling system	opportunity to reduce NO_x to 10 %	no effect
CO_2 emission - extra CO_2 emission at same electric generation	base	+ 21 million kg CO_2 per year
- or surplus electricity production at same CO_2 emission	+ 19,4 million kWh per year	base
Noise emission by cooling system	no	medium/high
Area around the 800 MW_e CCPP "occupied" by noise over 45 dB(A)	54 ha	90 ha
Visual impact	high	low

5.1 Comparison… Environmental Impacts of an 800 MW_e CCPP – cont.

➢ **Noise Emission Impacts**

Some more details are given of the noise impacts by the mentioned 800 MW_e CCPP, equipped with either a natural draft HELLER System or by a mechanical draft ACC.

- Noise impacts are best assessed in terms of the area affected by certain noise levels. In mixed industrial-residential districts the German TA-Lärm Standard specifies the allowable noise level (sound pressure) as 60 dB(A) in daytime and 45 dB(A) at night. The corresponding figures for residential-only districts are 50 dB(A) and 35 dB(A), respectively.

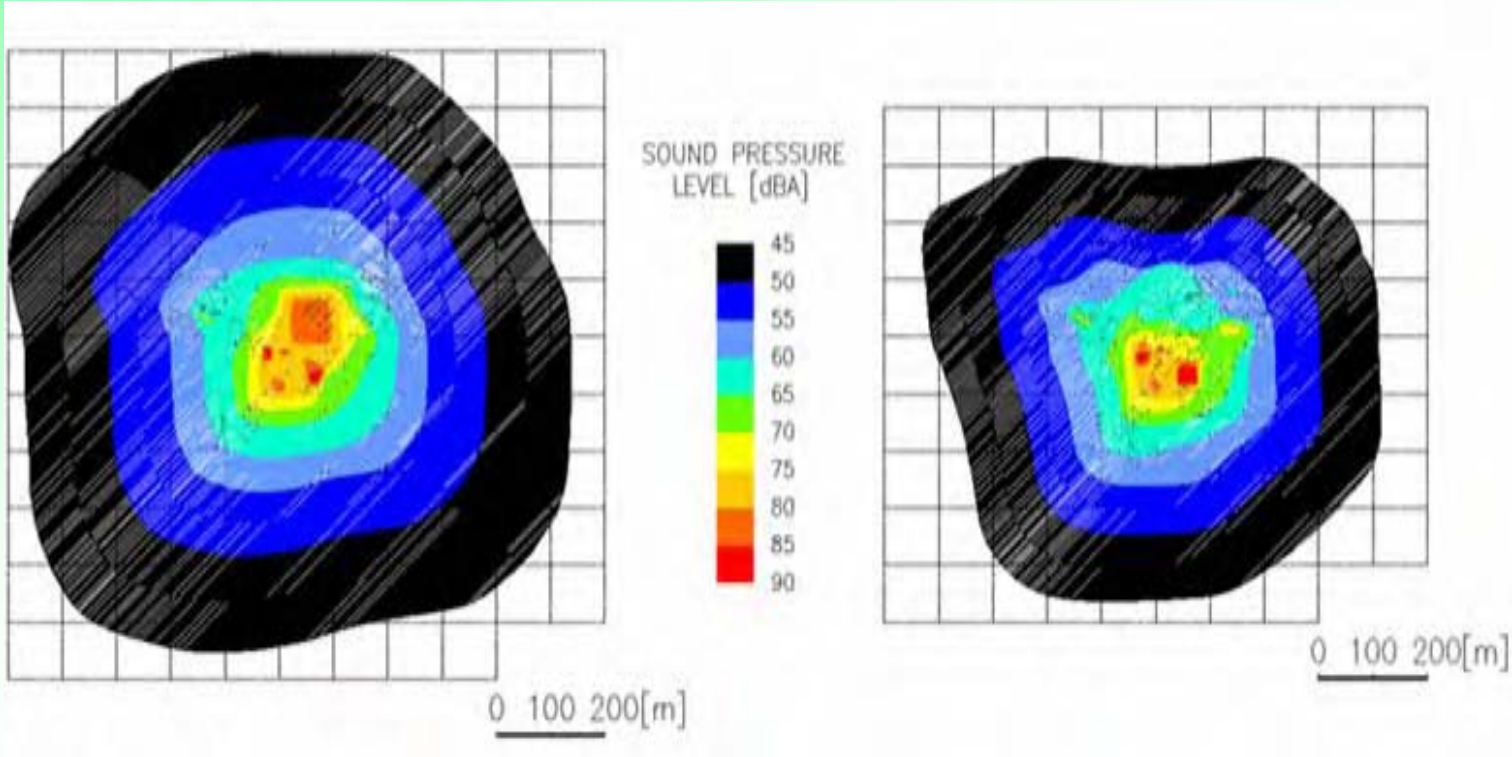
- The following slide shows how smaller area is affected by noise emission with the natural draft HELLER System version:

  - Note the area affected by noise levels higher than 45 dB (A): 54 hectares for the HELLER System variant and 90 hectares for the ACC variant.

  - Note also how the natural draft HELLER tower reduces the power plant noise level in certain directions.

5.1 Comparison… Environmental Impacts of an 800 MW_e CCPP – cont.

Sound pressure levels for an 800 MW_e combined cycle power plant equipped with functionally equivalent dry cooling systems of natural draft HELLER System and mechanical draft direct ACC:



5.1 Comparison… Environmental Impacts of an 800 MW_e CCPP – cont.

➢ Visual Impacts

- For an 800 MW_e CCGT power station, The mechanical draft direct ACC has a plot area of 70 m × 80 m and its height is about 40 m. Due to its limited height from a distance of several hundred meters it has a relatively low-key appearance and small impact on sight.

- The natural draft HELLER System needs a plot area characterized by a base diameter of 120 m, its exit diameter is about 67 m and its height is 135 m.

➢ Summary Conclusions Regarding Environmental Impacts

- In terms of noise emission, CO_2 emissions, opportunity to reduce ground level concentration of pollutants, the HELLER System is superior to the ACC.
- The visual impact of the natural draft HELLER System is greater, though as experiences suggest, it can be integrated to a CCPP site without being too obtrusive. Particularly since there would never be any vapour plume above it.

✓ *In addition, it is remarkable that for the specific application the investment cost of a state-of-the art natural draft HELLER Dry Cooling System is approximately the same as that of the mechanical draft direct ACC, however its total life-cycle cost on a present value basis is significantly lower. The difference in favor of the HELLER System is about 50 % of the investment cost.*

5.2 HELLER System to Reduce Ground Level Concentration of Pollutants

- **The stack-in-tower concept: a greener & cheaper alternative for flue gas exhausting [6] [7]**

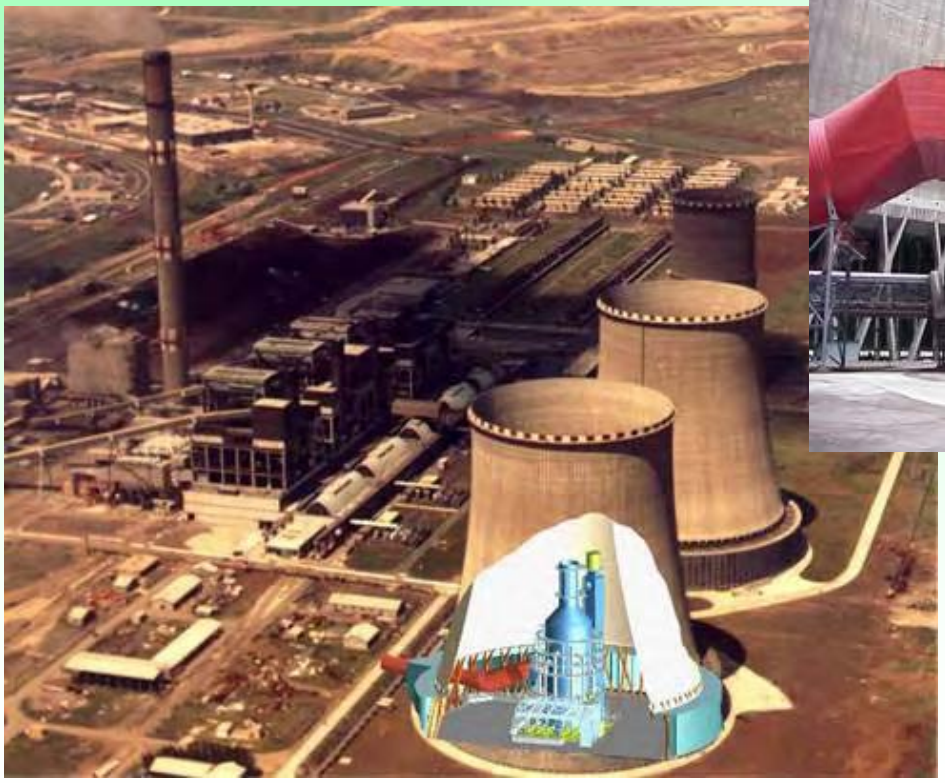
  - Natural draft towers (dry and wet towers alike) allow themselves to apply the stack-in-tower arrangement to substitute a high separate chimney with a 40-50 m high stack located inside the tower.
  - The natural draft HELLER System offers significantly more favorable conditions for the stack-in-tower concept than an evaporative cooling tower. The warmed-up (15-25°C increase to the ambient temperature) extremely dry cooling air-flow has a mass flow rate of about 50 times larger than that of the flue gas (in case of conventional steam cycles) – thus represents a tremendous up-lift momentum.
  - This solution not only reduces dramatically the ground level concentrations of pollutants and saves most of the separate high chimney's investment cost, but also eliminates the necessity of flue gas re-warming recuperator in case of wet scrubbers (FGD).

5.2 HELLER System to Reduce… Pollutants – cont.

- **EGI's references with HELLER System stack-in-tower concept**

  - **The 800 MW_e lignite fired MATRA PS (Hungary) – an RWE power plant**

    As part of the full scale retrofitting of the power station, FGD plants were implemented into the existing dry HELLER towers.



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5.2 HELLER System to Reduce… Pollutants – cont.

MATRA PS

The complete FGD plants are located inside the HELLER type dry cooling towers

5.2 HELLER System to Reduce… Pollutants – cont.

- **The 2 x 160 MW_e CFB boiler based CAN TPP (EÜAS, Turkey) – EPC contractor: ALSTOM**

  Flue gases are exhausted through a single tower shell of the HELLER System, serving both CFB boiler based steam cycles.

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5.2 HELLER System to Reduce… Pollutants – cont.

Flue gas ducts conducted to the HELLER type dry cooling tower at CAN TPP.

5.2 HELLER System to Reduce… Pollutants – cont.

➢ **Evaluation of the effects on the imission of a 800 MW_e coal fired supercritical steam cycle served by different cooling system alternatives (see also Section 3.1)**

- Natural Draft HELLER System: a 165 m high cooling tower with a 50 m stack inside
- Natural Draft Evaporative Cooling System: a 157 m high cooling tower with a 50 m stack inside
- Mechanical Draft ACC: a 250 m high separate chimney

The results of the dispersion modeling based on the VDI S/P method are given in the attachment for all 3 variants considering yearly average, daily average and hourly maximum ground level concentration values in a 16x16 km area.

The power unit with all three cooling system variants meet the allowable limit values for the ground level concentrations. The HELLER System stack-in-tower scores the best - resulting in 60% lower yearly average and 40% lower hourly maximum values than the Evaporative CS stack-in-tower. The results of Evaporative CS stack-in-tower are somewhat better than those of direct ACC with a separate chimney.

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6. Dry/Wet Combinations Derived from HELLER System

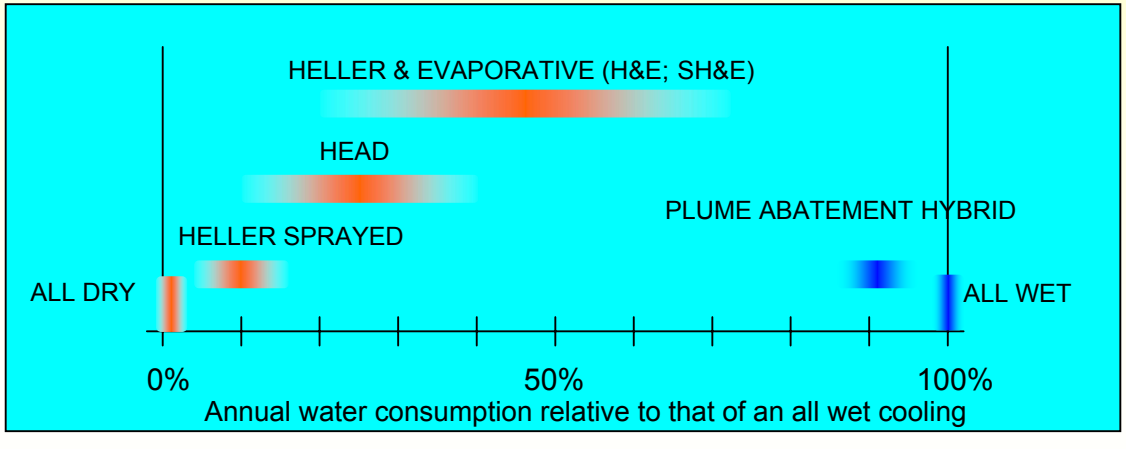
Application of dry/wet combination are to be considered if

- the available water is less than needed for an all-wet system
- the make-up water price high enough but still does not justify an all-dry system
- there is an emphasis on reducing environmental impact

EGI has developed several dry/wet combinations derived from HELLER System [1] [5] aiming at

- improving environmental compatibility and water conservation feature relative to wet cooling
- improving summertime turbine output and reducing investment costs relative to dry cooling

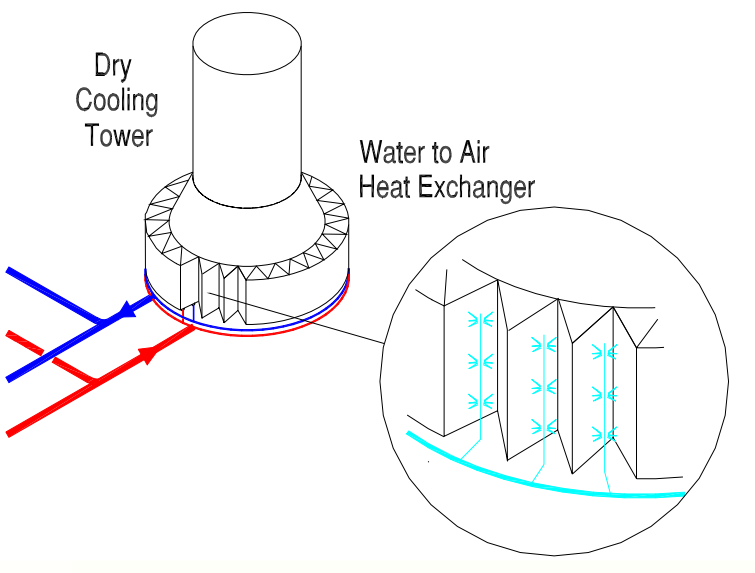
Water conservation features of different cooling systems are classified by their annual water consumption referred to that of the all-wet cooling system.



6. Dry/Wet Combinations Derived from HELLER System – cont.

- **Dry System with Water Spraying (2-10%)**

All dry HELLER Systems equipped with optional water spraying opportunities to be used for peak-shaving in the hottest summer days. Low additional investment, minimal & limited water-use (2-10%).



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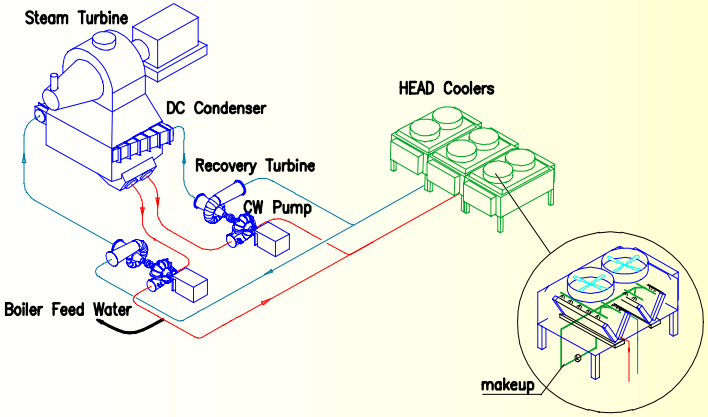
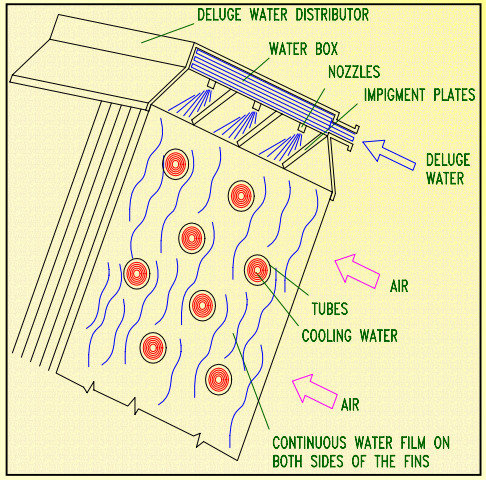
6. Dry/Wet Combinations Derived from HELLER System – cont.

HEAD Cooling System (5-35%)





- A flexible solution ideally suited to summer peaking power generators or co-generation plants with seasonally changing heat-load
- All dry operation throughout a significant part of the year
- A heat exchanger optimal for both dry & wet operation

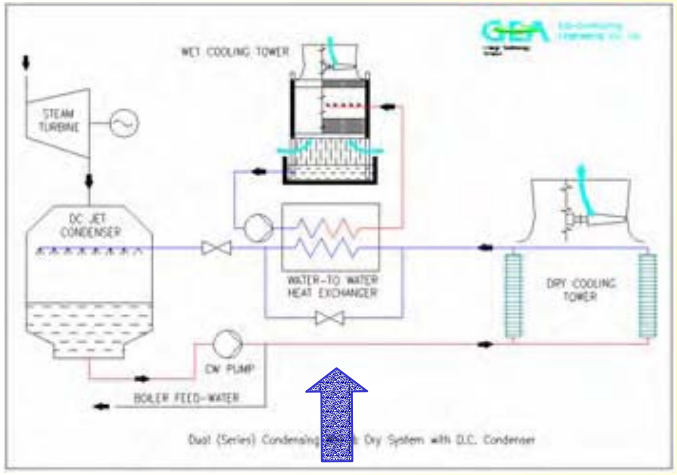
Dry Tower with delugable Peak Coolers (5-10%)

Dry/deluged Cooling System (10-35%)

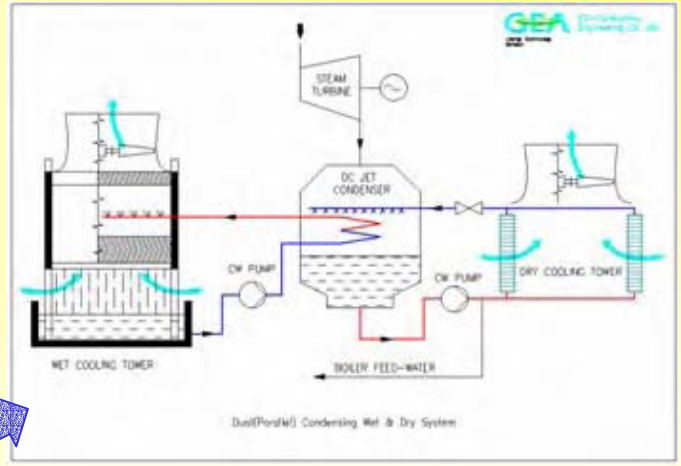
EGI

6. Dry/Wet Combinations Derived from HELLER System – cont.

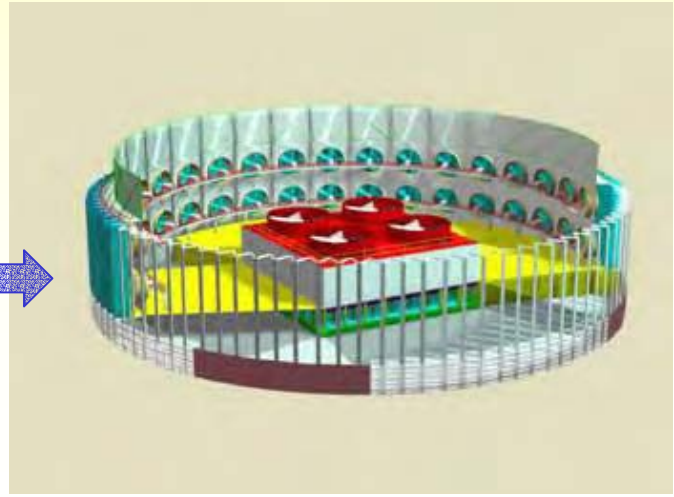
➢ **Series HELLER & Evaporative (SH&E) Cooling System (20-70%)**



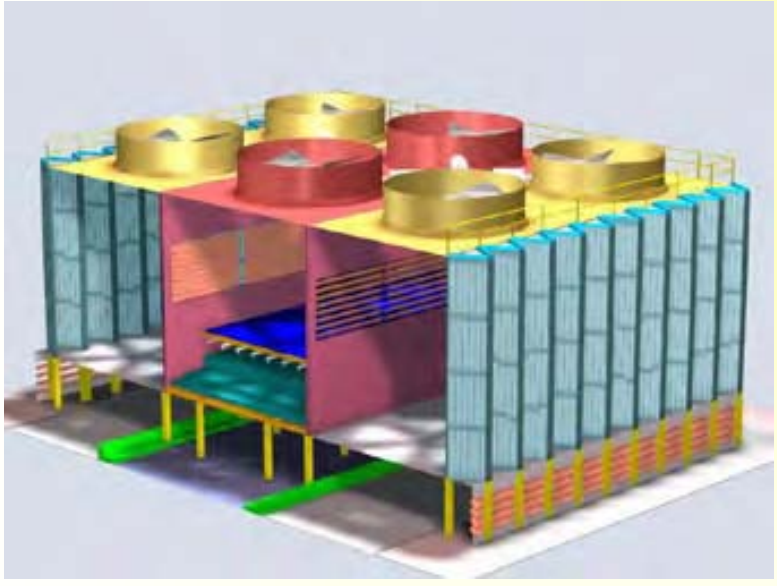
➢ **HELLER & Evaporative (H&E) Cooling System (20-70%)**



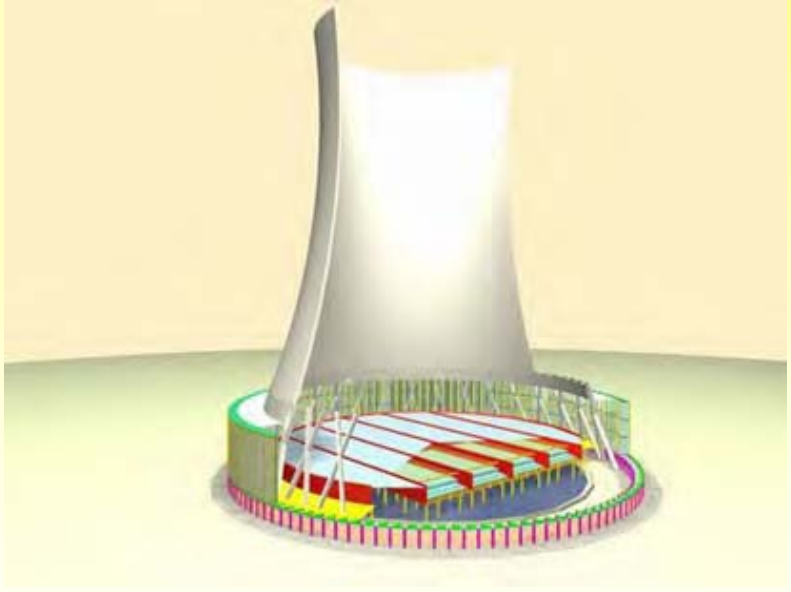
- **Both the series and parallel connection provides great flexibility in heat rejection capability and can also be used to convert existing wet cooling towers to dry/wet ones**
- **They are water conservation type dry/wet systems (water requirement 20-70% that of a wet cooling tower).**
- **They can be arranged also to provide in addition plume abatement or reduced plume.**



6. Dry/Wet Combinations Derived from HELLER System – cont.



H&E Cooling System - A rectangular arrangement for water conservation & plume abatement plus reduced noise emission



SH&E or H&E Cooling System - All natural draft - for water conservation & reduced plume and reduced noise emission

REFERENCES

[1] Szabó, Z., Tasnádi, C., Combined Dry/Wet Cooling Systems for Water Conservation, Cooling Tower Symposium of IAHR, October 1992, Karlsruhe, Germany

[2] Lees, M., The economics of wet vs. dry cooling for combined cycle, Seminar on Condensers and Cooling Towers for Combined Cycle, April 1994, London

[3] Balogh, A., Takács, Z., Developing Indirect Dry Cooling Systems for Modern Power Plants, EGI Website, 1998

[4] Maulbetsch, J.S., Comparison of Alternate Cooling Technologies for California Power Plants, a PIER/EPRI report for the California Energy Commission, February 2002, Palo Alto (CA)

[5] Szabó, Z., Water Conservation, Journal of Power & Energy 4th quarter, 2002 – Asia Pacific Development

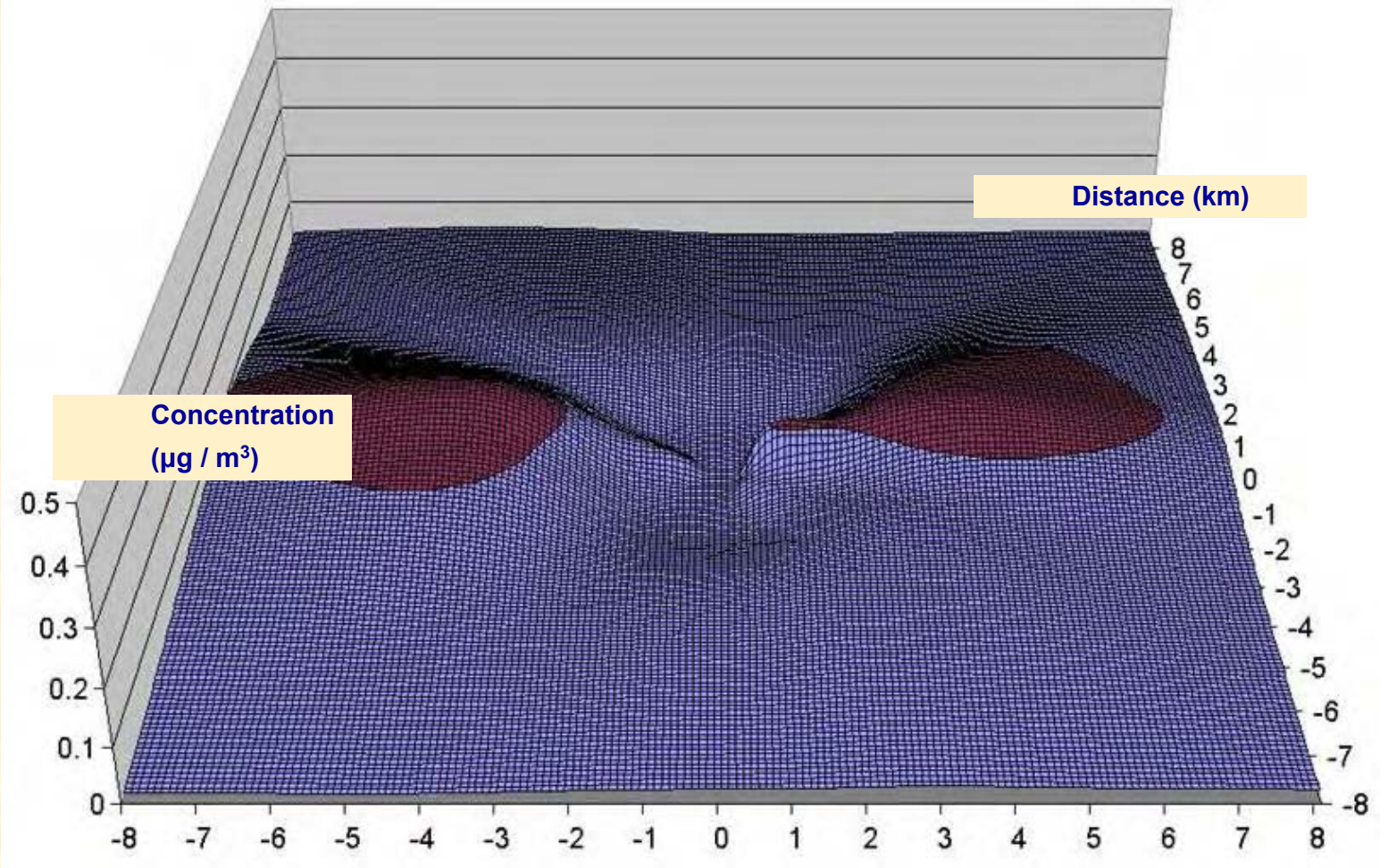
[6] Szabó, Z., Cool for Coal, Journal of Power & Energy 1st quarter, 2004 - Asia Pacific Development

[7] Takács, Z., Flue Gas Introduction - Advantages of Dry Cooling Towers, 5th Int. Symp. on Natural Draft Cooling Towers, May 2004, Istanbul

[8] Balogh, A., Szabó,Z., Advanced Heller System to Improve Economics of Power Generation, EPRI Conference on Advanced Cooling Strategies/Technologies, June 2005, Sacramento (CA)

Ground level SO_2 concentrations for an 800 MW_e Supercritical Cycle

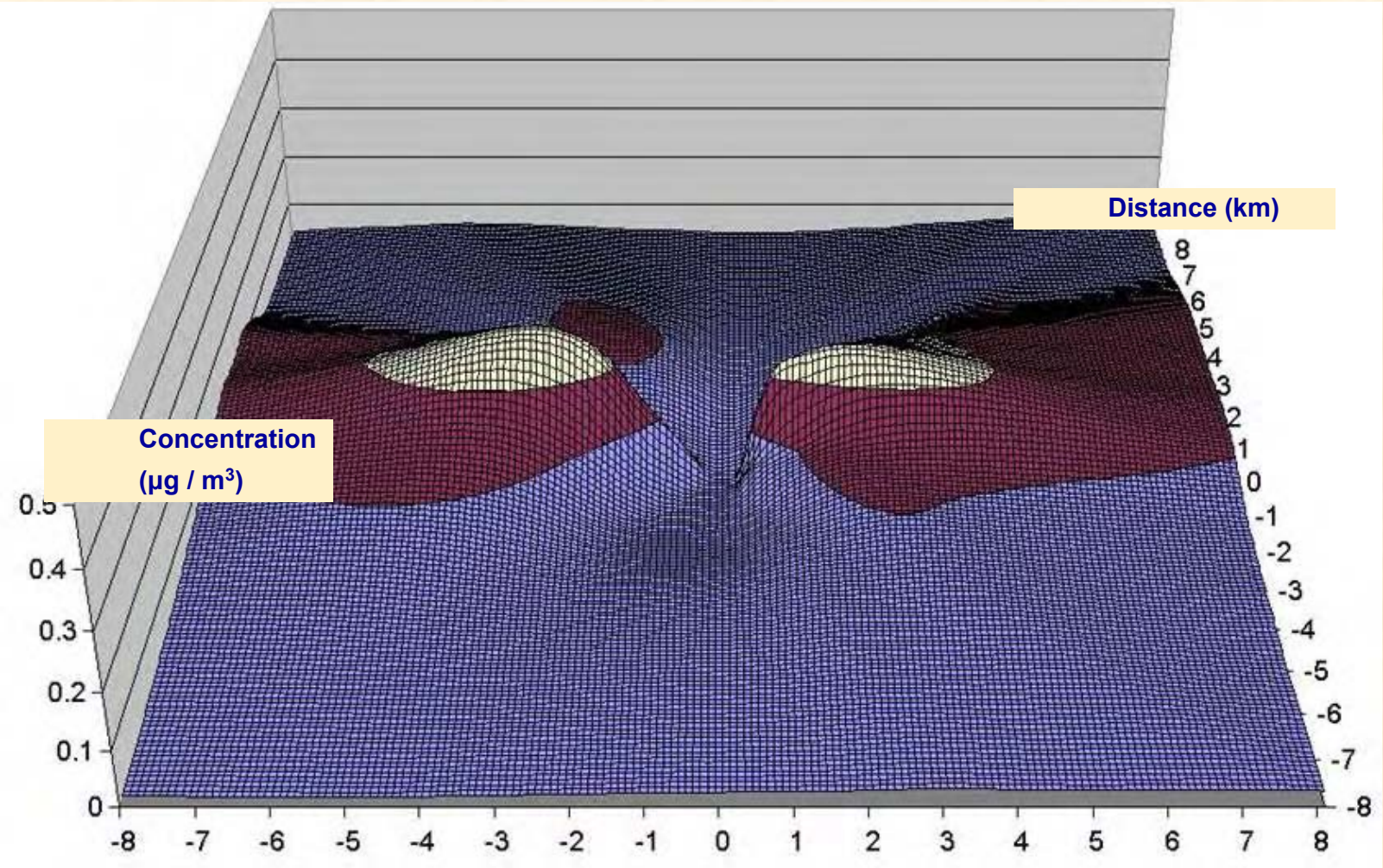
Yearly average – HELLER System with stack-in-tower (VDI S/P model)



Enclosures - Ground level SO_2 concentrations… - cont.

Advanced HELLER System - Technical

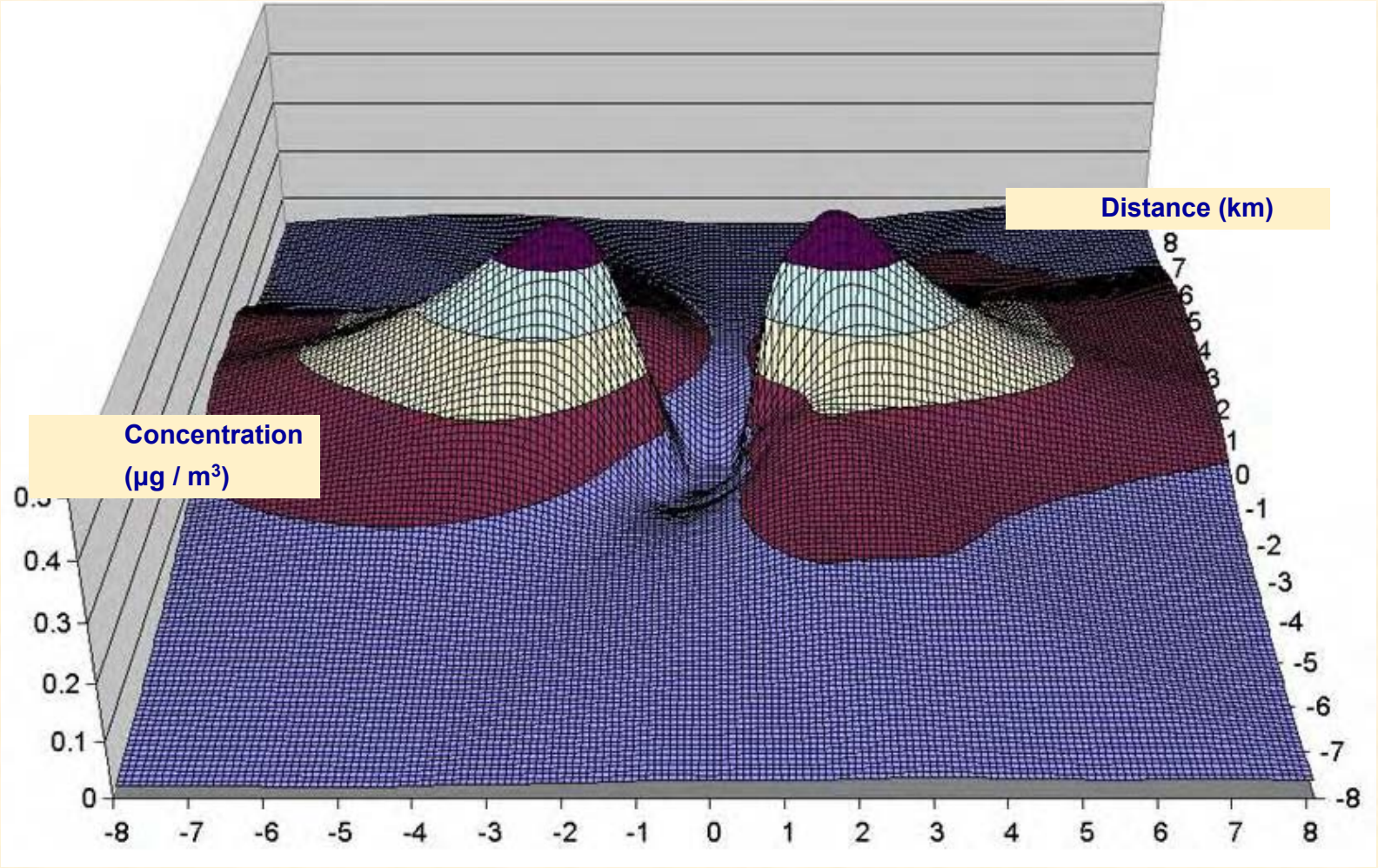
Yearly average – Evaporative CS with stack-in-tower (VDI S/P model)



Enclosures - Ground level SO_2 concentrations… – cont.

EGI

Yearly average – Direct ACC with 250 m chimney (TA Luft / VDI model)

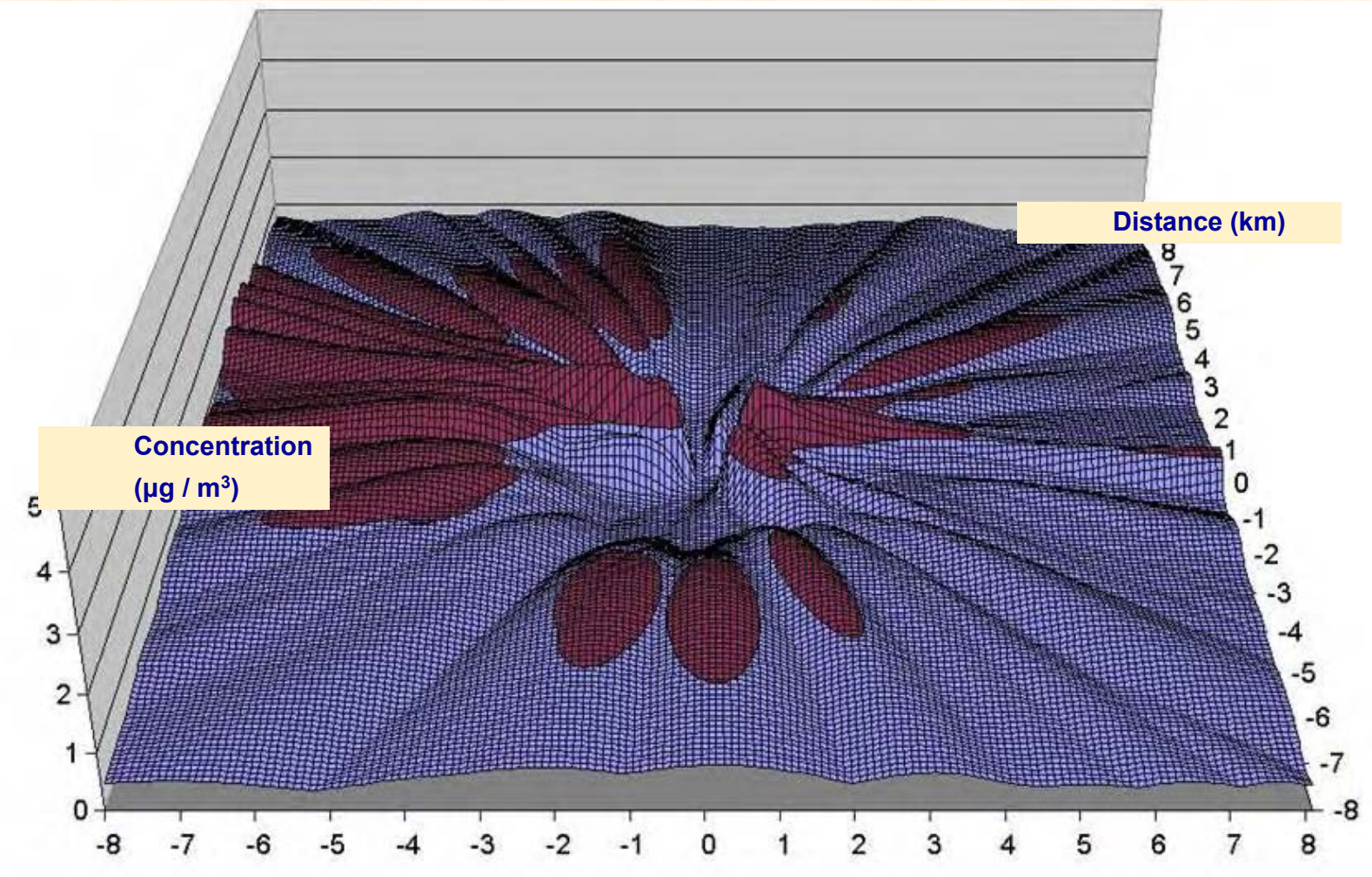


Distance (km)

Enclosures - Ground level SO_2 concentrations… – cont.

EGI

Daily average – HELLER System with stack-in-tower (VDI S/P model)



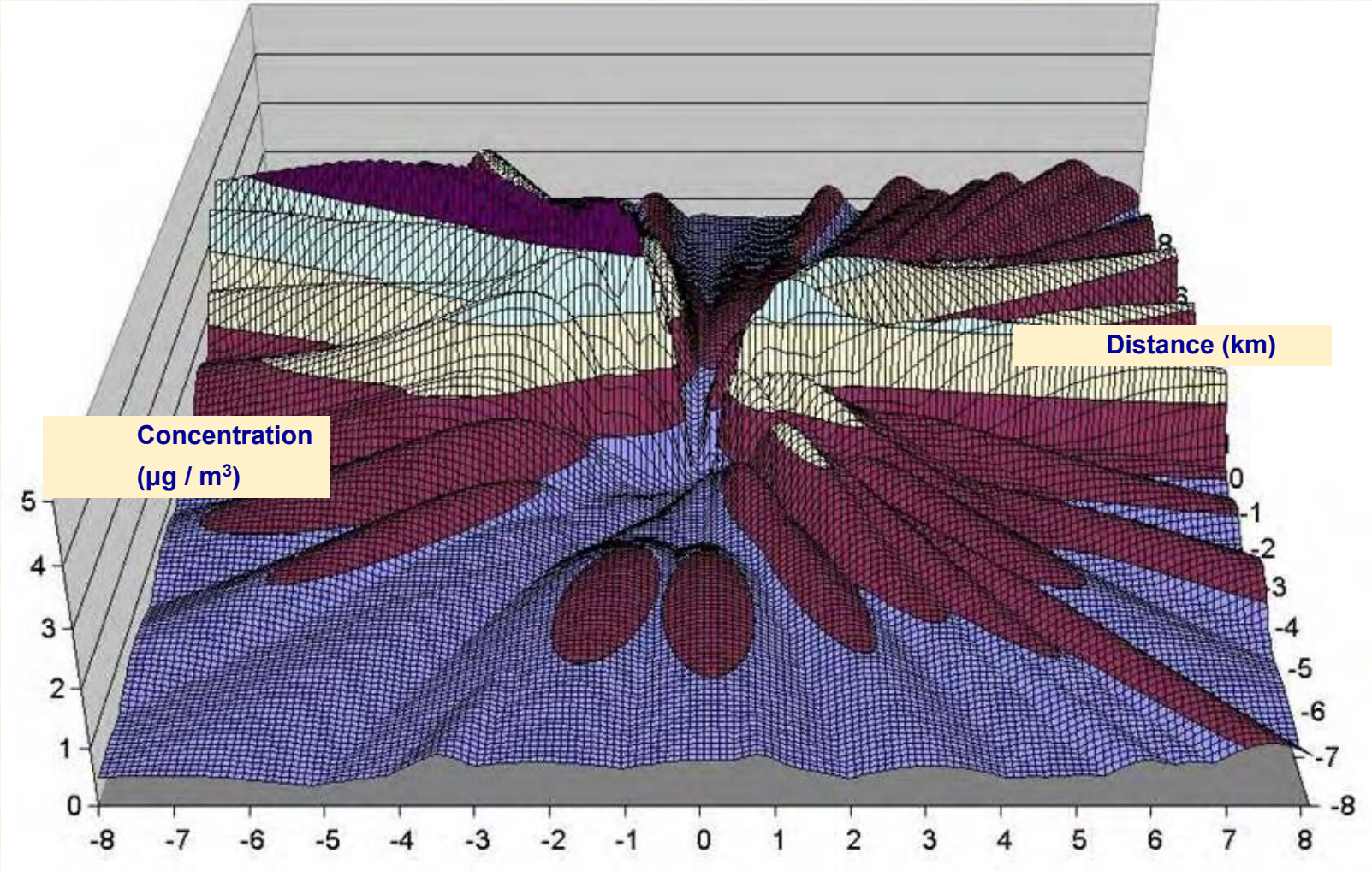
Distance (km)

Enclosures - Ground level SO_2 concentrations… – cont.

EGI

Advanced HELLER System - Technical

Daily average – Evaporative CS with stack-in-tower (VDI S/P model)

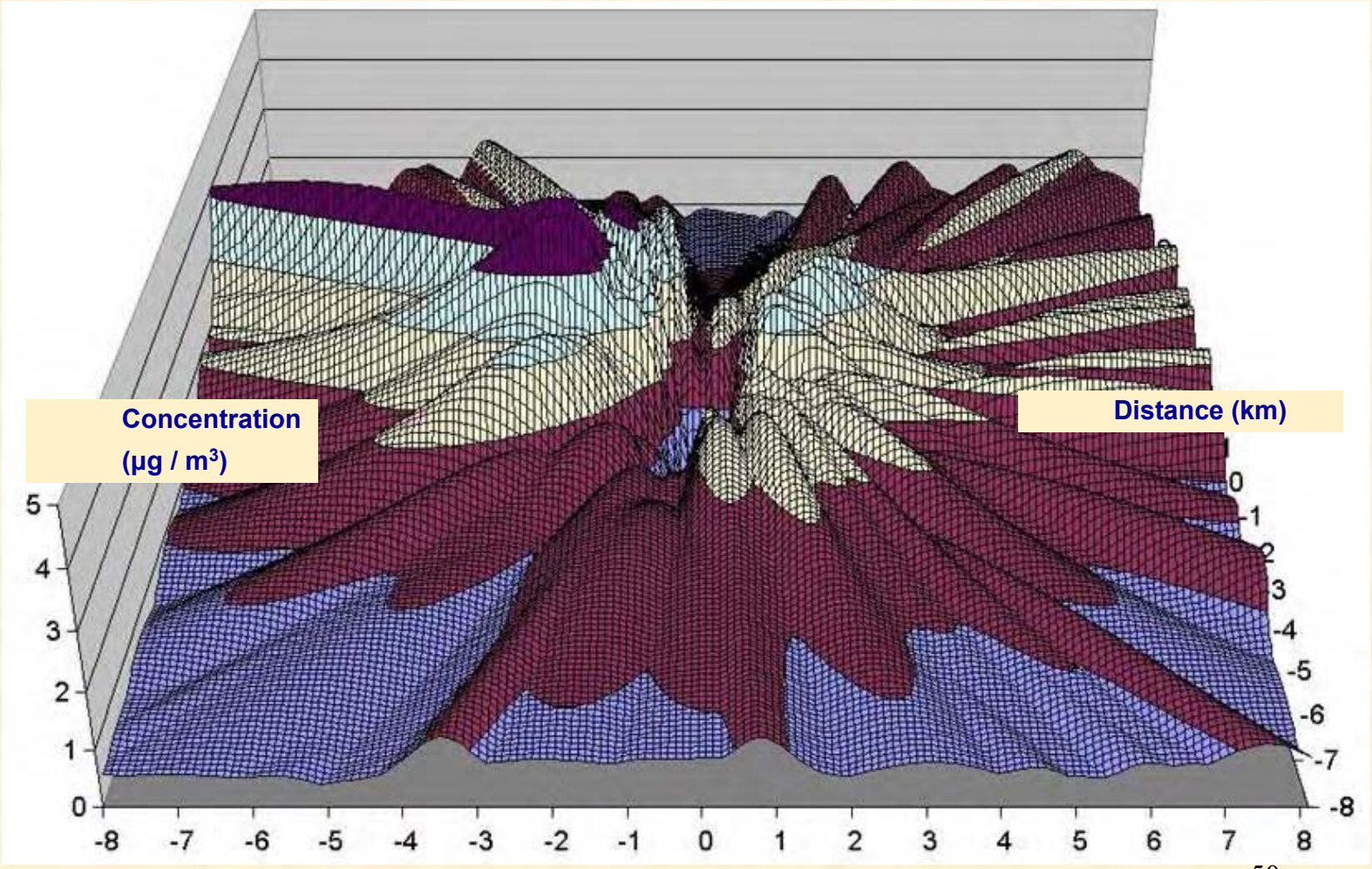


Enclosures - Ground level SO_2 concentrations… – cont.

EGI

Advanced HELLER System - Technical

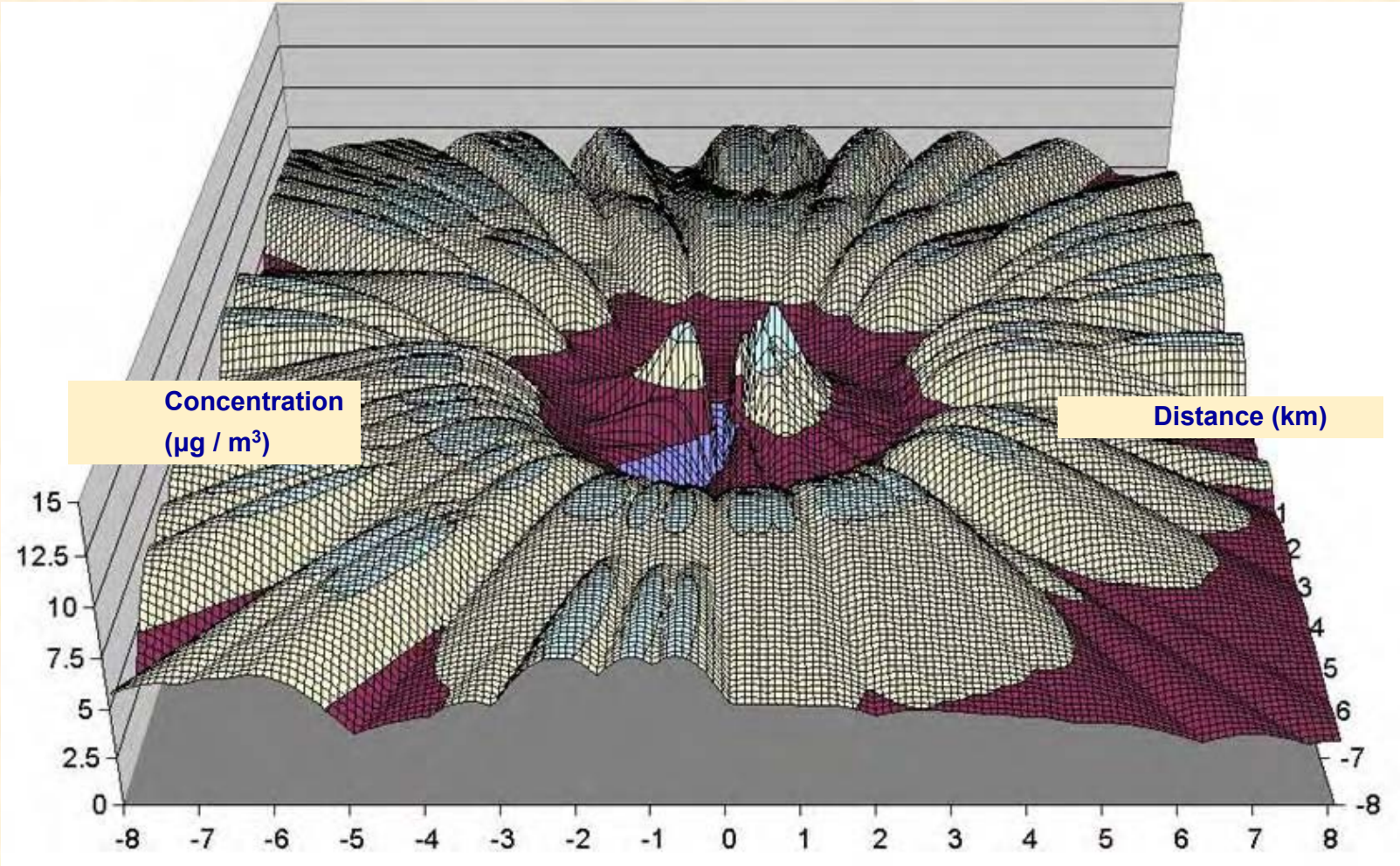
Daily average – Direct ACC with 250 m chimney (TA Luft / VDI model)



Enclosures - Ground level SO_2 concentrations… – cont.

EGI

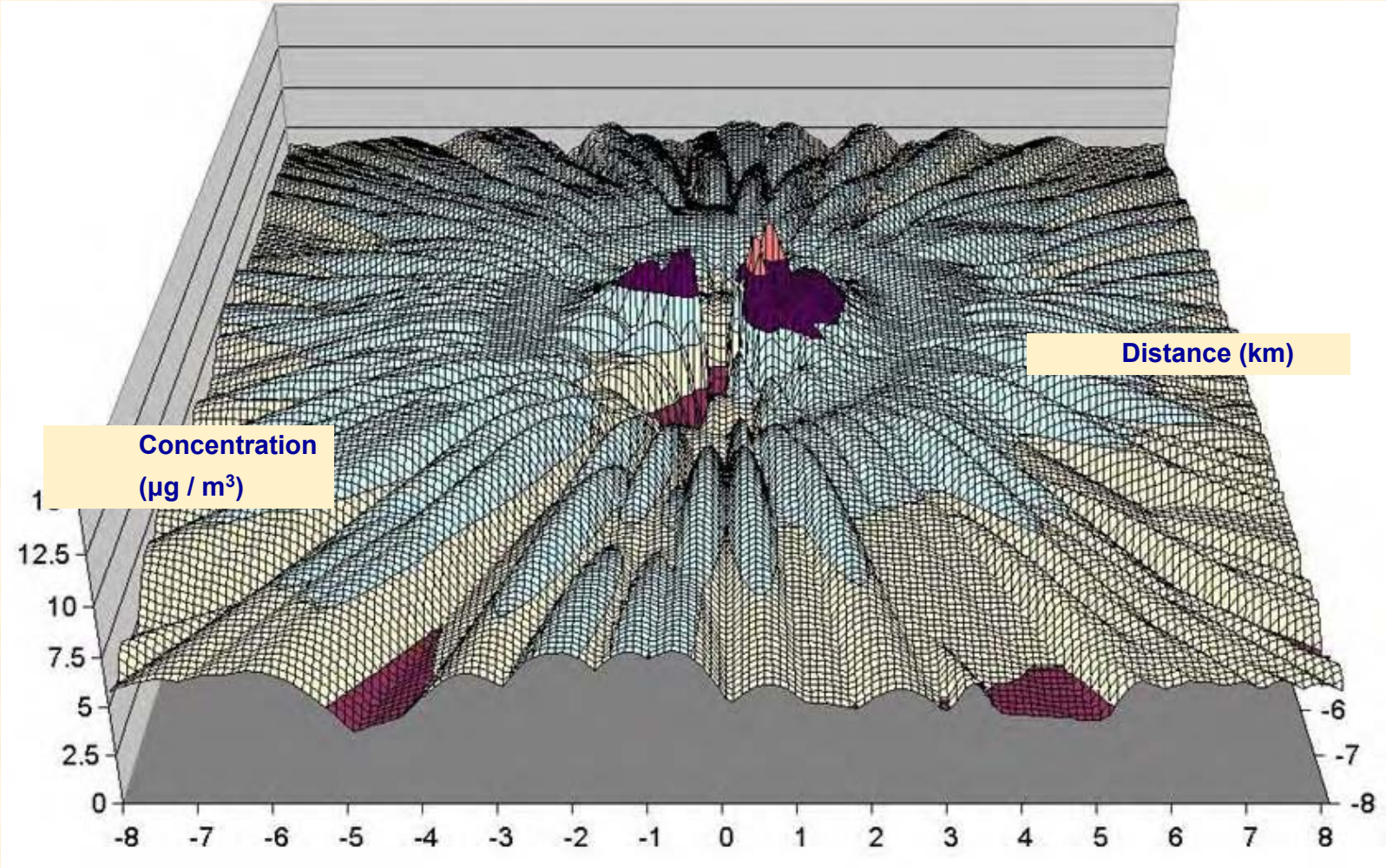
Hourly maximum – HELLER System with stack-in-tower (VDI S/P model)



Enclosures - Ground level SO_2 concentrations… – cont.

EGI

Hourly maximum – Evaporative CS with stack-in-tower (VDI S/P model)

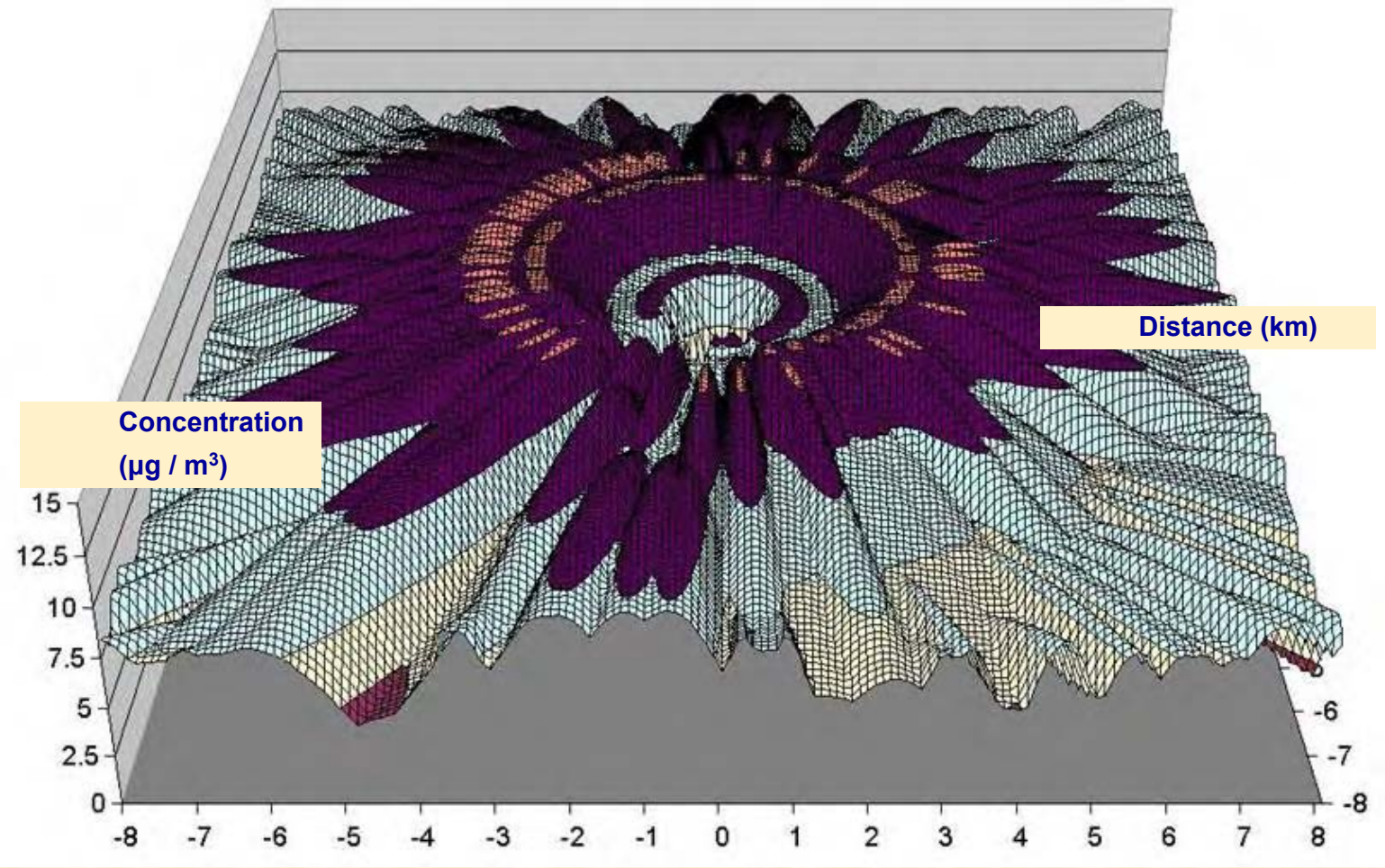


Distance (km)

Enclosures - Ground level SO_2 concentrations… – cont.

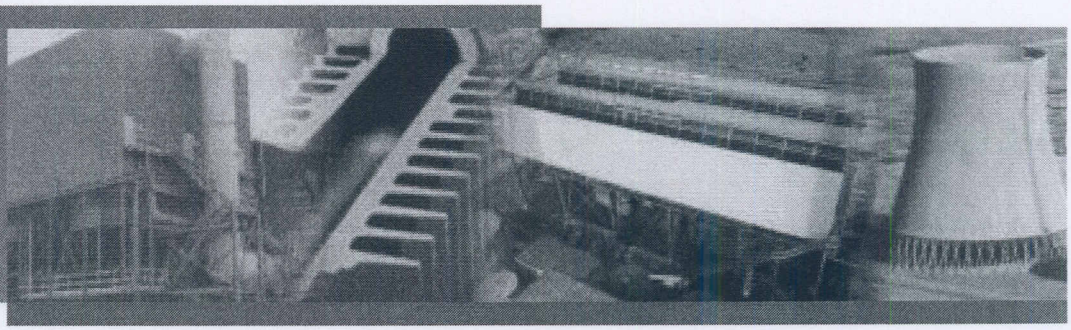
EGI

Hourly maximum – Direct ACC with 250 m chimney (TA Luft / VDI model)

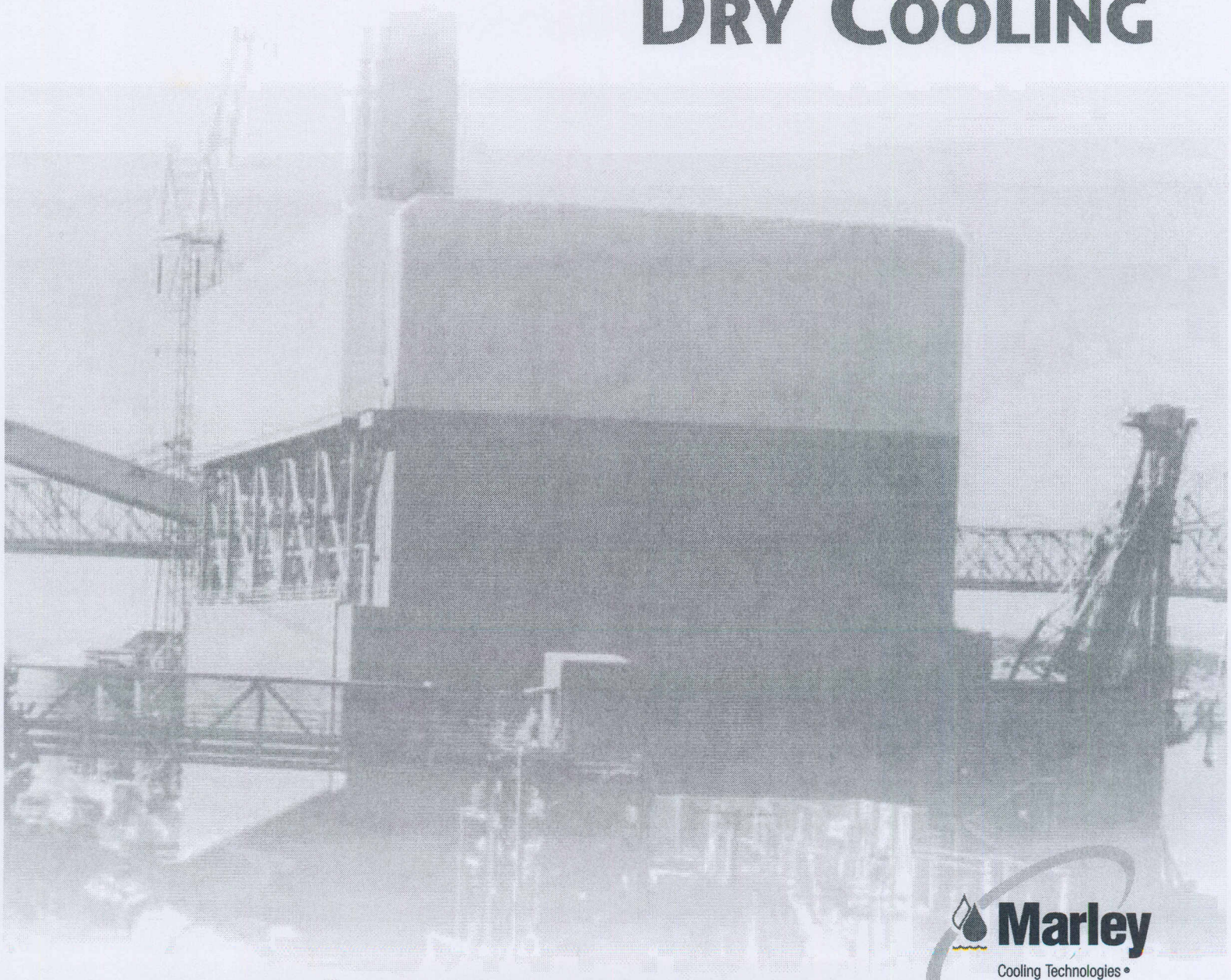


DECLARATION OF BILL POWERS

Attachment F



DRY COOLING



Marley
Cooling Technologies®

MARLEY BALCKE

DRY COOLED STEAM CONDENSING SYSTEMS

UNCONVENTIONAL ADVANTAGES

Power plant efficiency is directly affected by the efficiency with which steam is condensed and cooled.

Balcke-Dürr dry steam condensing systems offer major advantages compared to conventional wet cooling systems:

- No blow-down
- No make-up water consumption
- No visible plume
- Reduced noise levels
- No special siting requirements
- Low overall height for forced draft air-cooled condensers.

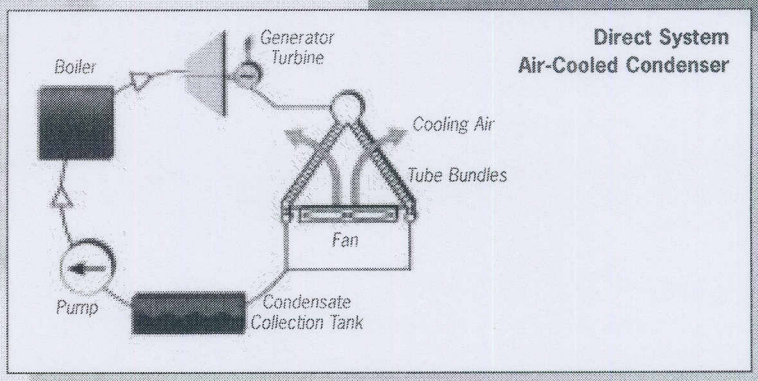
FROM CONCEPT TO SOLUTION

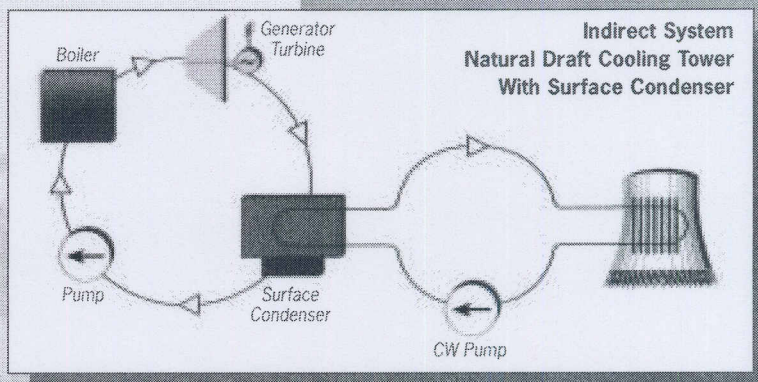
Balcke-Dürr has many decades of experience with steam condensing systems utilized in power plants. Typical systems are shown in the accompanying diagrams:

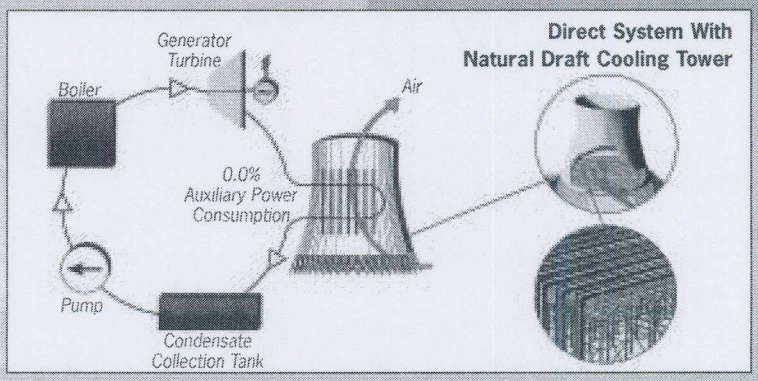
- The direct system
- The indirect system (including secondary cooling water loop)
- The parallel dry/wet system

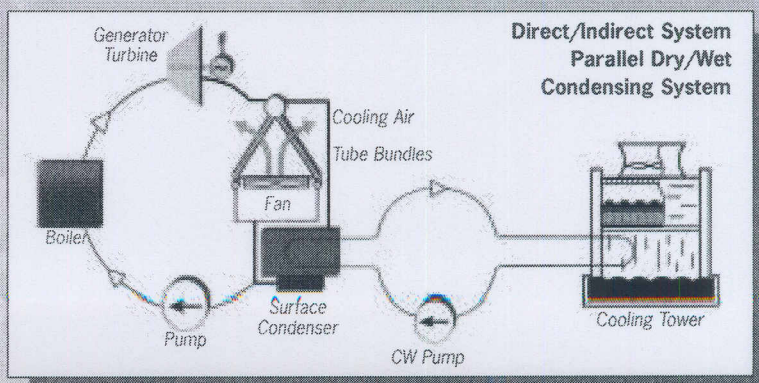
Balcke-Dürr's innovative concepts for solving the most challenging steam condensing problems are based on tubes with hot-dip galvanized steel fins of two types, elliptically-shaped and flat. Both types feature thermodynamic and hydraulic characteristics superior to those of circular fin tubes. For clients desiring conventional tubes, Balcke-Dürr also supplies circular tubes with aluminum fins for both the direct and indirect systems.

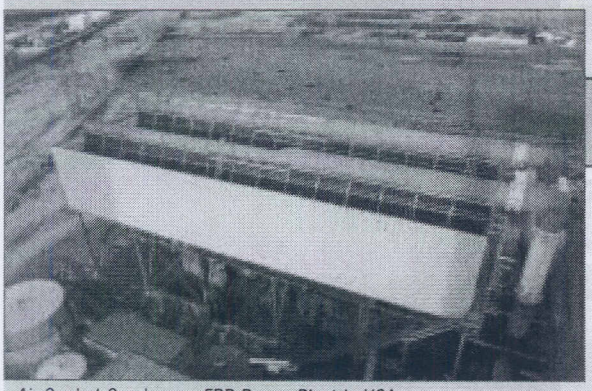
Balcke-Dürr fin tubes are manufactured at plants in Germany, Czech Republic, Republic of South Africa, and Peoples Republic of China.











Air-Cooled Condenser, FBB Power Plant in USA

Marley Balcke

Fin Tubes for Dry Cooling

Advantages Abound With Every Configuration of Balcke-Dürr Dry Cooling Fin Tube

Fin Tubes

Regardless of configuration choice, Balcke-Dürr fin tubes offer a wealth of proven performance features.

"ERS" Type

Balcke-Dürr's innovative, globally-unique single row condenser tube with high-performance galvanized steel fins:

- No cold spots, no dead zone
- No flooding in reflux condenser
- Outstanding corrosion protection
- Excellent metallic welded fin bond
- Optimal heat transfer and power consumption
- Mechanically-strong fins
- Long service life
- Steel core tube
- Minimal fouling
- Suitable for cleaning with high pressure water up to 400 bar

Elliptical Tube

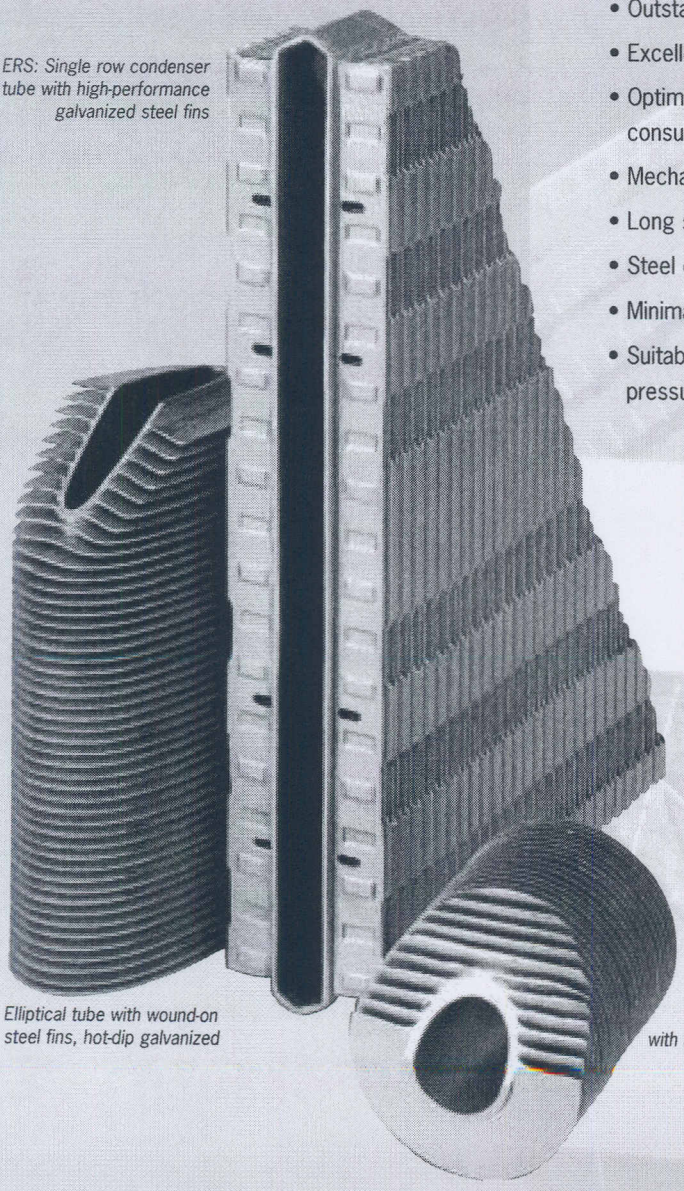
The advanced performer with wound-on steel fins, hot-dip galvanized:

- Outstanding corrosion protection
- Excellent metallic fin bond
- Optimal heat transfer and power consumption
- Mechanically-strong fins
- Long service life
- Steel core tube
- Minimal fouling
- Suitable for cleaning with high pressure water up to 400 bar

Circular Tube

Conventional with quality:

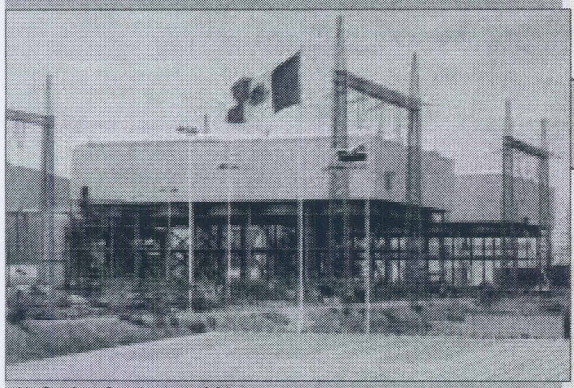
- Wound-on G-fin
- Wound-on L-fin
- Extruded fin
- Steel core tube
- Minimal fouling
- Suitable for cleaning with pressurized water or air



ERS: Single row condenser tube with high-performance galvanized steel fins

Elliptical tube with wound-on steel fins, hot-dip galvanized

Circular tube with aluminum fins



Air-Cooled Condenser, CCP plant in Mexico

Marley Balcke

Direct Dry Cooling

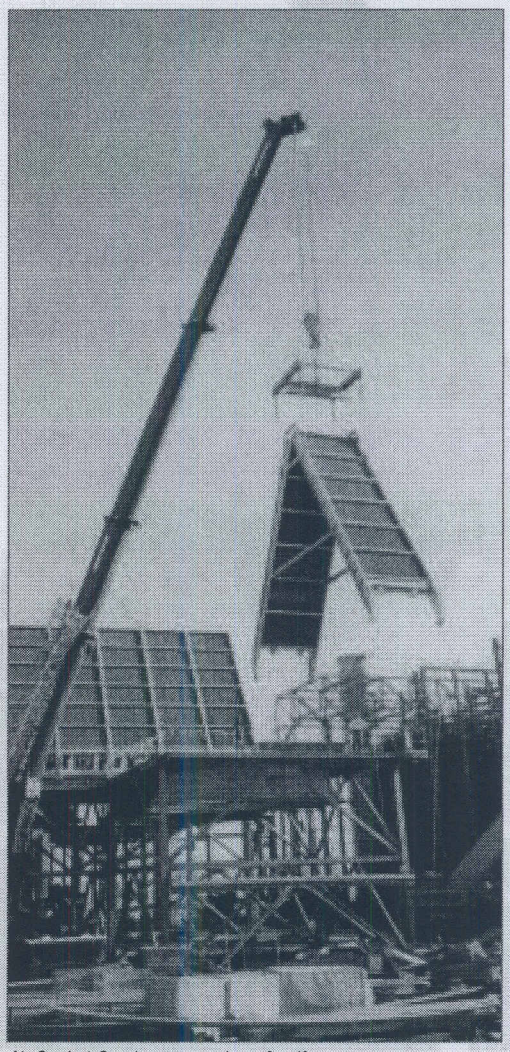
Balcke-Dürr is a Leading International Manufacturer of Air-cooled Condensers, with a Pioneering Legacy in the Field of Air-cooled Condenser Construction

Innovation in Direct Dry Cooling

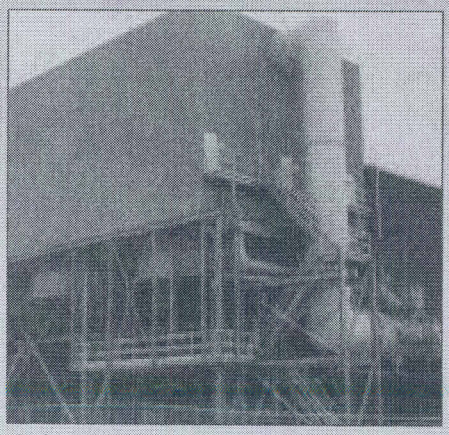
The Balcke-Dürr air-cooled condensers serve many types of industries and requirements, including:

- Power plants
- Chemical industry
- Waste incineration plants
- Steel industry
- All pressure levels with various fin tube systems
- Forced or induced draft convection

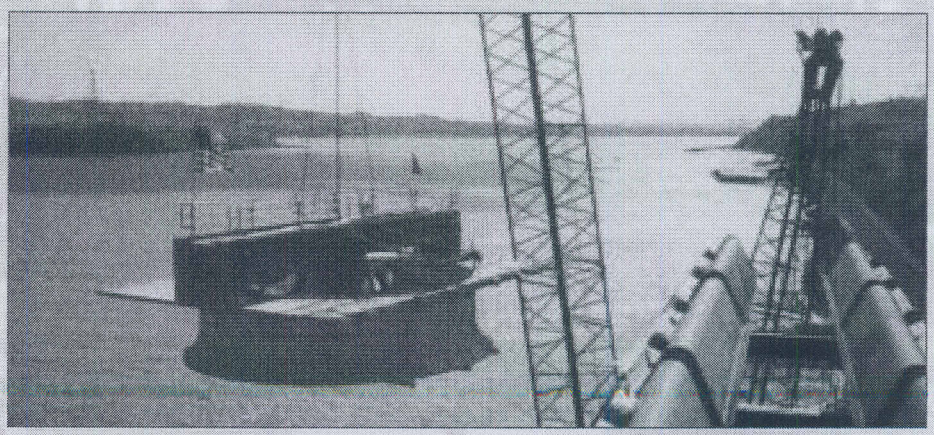
Direct-type air-cooled condensers are designed both as single-row and multi-row systems. Dead-zone formation, an undesirable characteristic of multi-row condensers, is eliminated by adjusting the fin pitch of each row and dimensioning the dephlegmator accordingly. Balcke-Dürr multi-row condensers benefit from this innovative, pragmatic engineering approach by being fully operational in cold climates. Confirming the design's merit are the many successfully functioning power stations, ranging from small waste incineration plants to large power station condensers up to 700 MW.



Air-Cooled Condenser, setting of self supporting fin tube bundles, CCP/Cogeneration Plant in Turkey



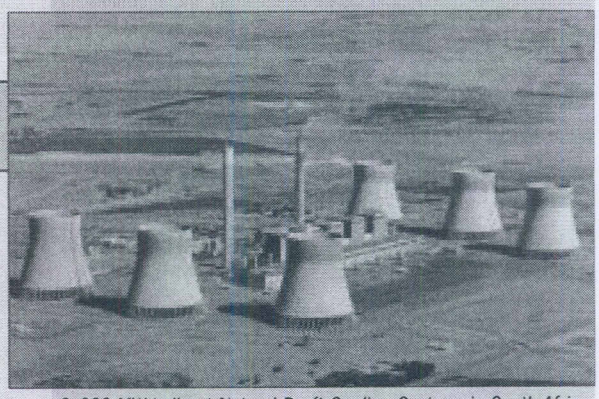
Air-Cooled Condenser, CCP/Cogeneration Plant in USA



Preassembled fan deck assembly ready for installation, CCP/Cogeneration Plant in USA

MARLEY BALCKE

INDIRECT DRY COOLING



6x680 MW Indirect Natural Draft Cooling System, in South Africa

INDIRECT DRY COOLING BEATS THE HEAT

The Balcke-Dürr indirect dry condensation system is a desirable option for arid areas lacking an adequate water supply, burdened by high make-up water costs, or charged with careful consideration of environmental protection. In such circumstances, natural draft solutions are superior to those of forced-draft because auxiliary power consumption is substantially lower. Consequently, operating costs are reduced, while noise generation and maintenance are minimized.

BALCKE-DÜRR SETS THE UNCHALLENGED STANDARD IN INDIRECT DRY COOLING TECHNOLOGY WITH THE:

- Largest dry-cooled power plant in the world
- Largest dry-cooled unit in the world

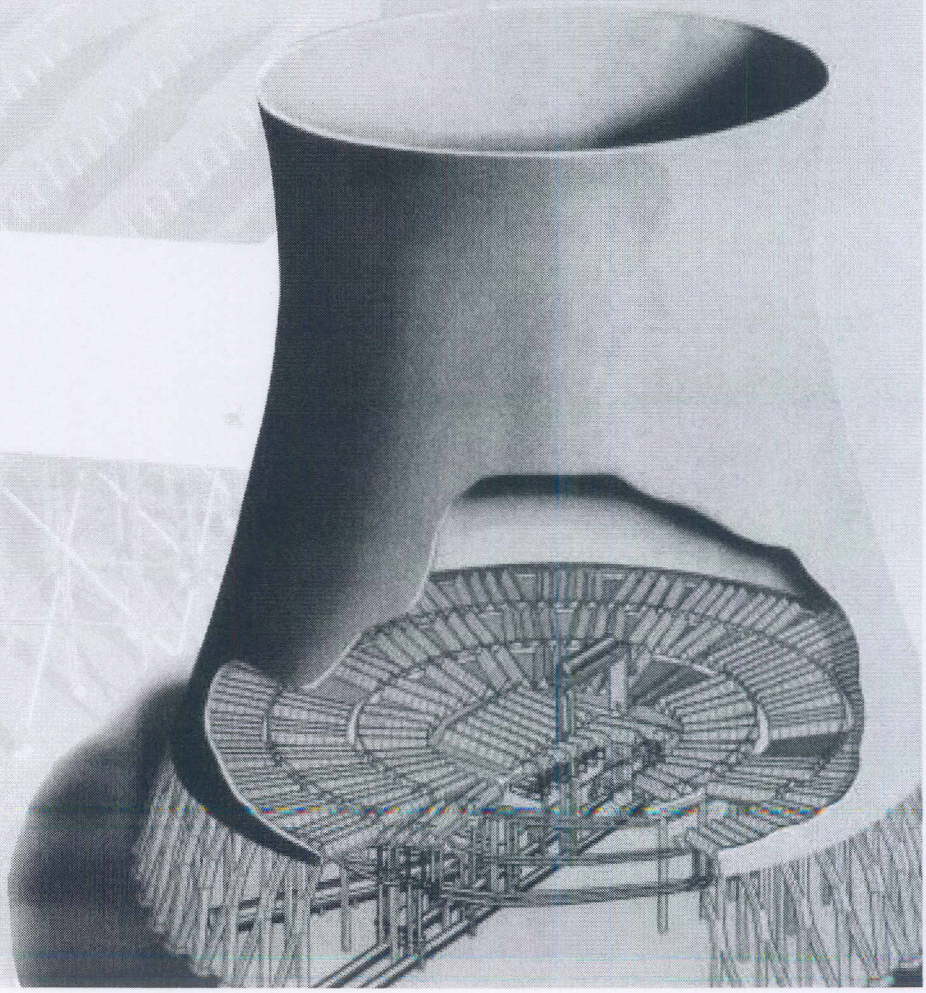
THE BALCKE-DÜRR INDIRECT DRY COOLING SYSTEM PROVIDES THE CUSTOMER WITH SEVERAL OPTIONS FOR SUPPLYING COOLING AIR:

- Natural draft cooling towers with concrete, steel or cable-net shell
- Mechanical draft
- A combination of the two

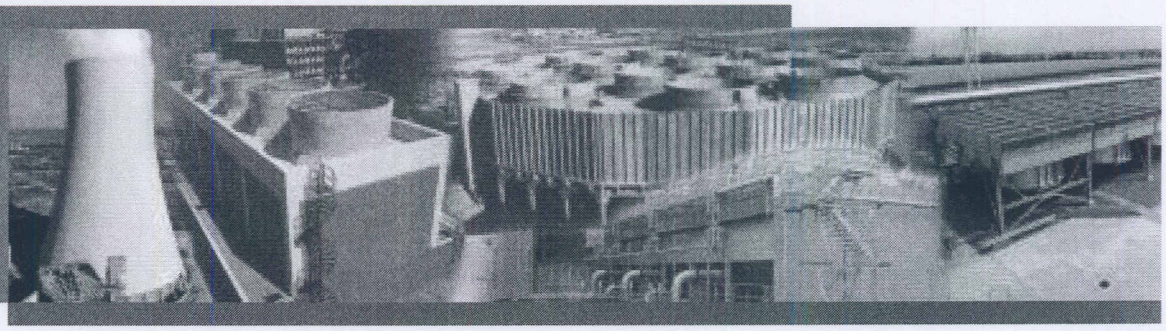
Balcke-Dürr offers the entire range of natural draft dry cooling systems, providing the customer with every required size and type, including systems with aluminum fin tubes and systems with hot-dip galvanized fin tubes.

BALCKE-DÜRR IS YOUR PREFERRED SUPPLIER OF POWER STATION "COLD END" COMPONENTS, INCLUDING:

- Cooling tower and fin tube bundles
- Surface condenser or, alternatively, spray condenser
- Pumps, ducting, control system
- Transport and mechanical erection
- Tests and inspections
- Training and instruction

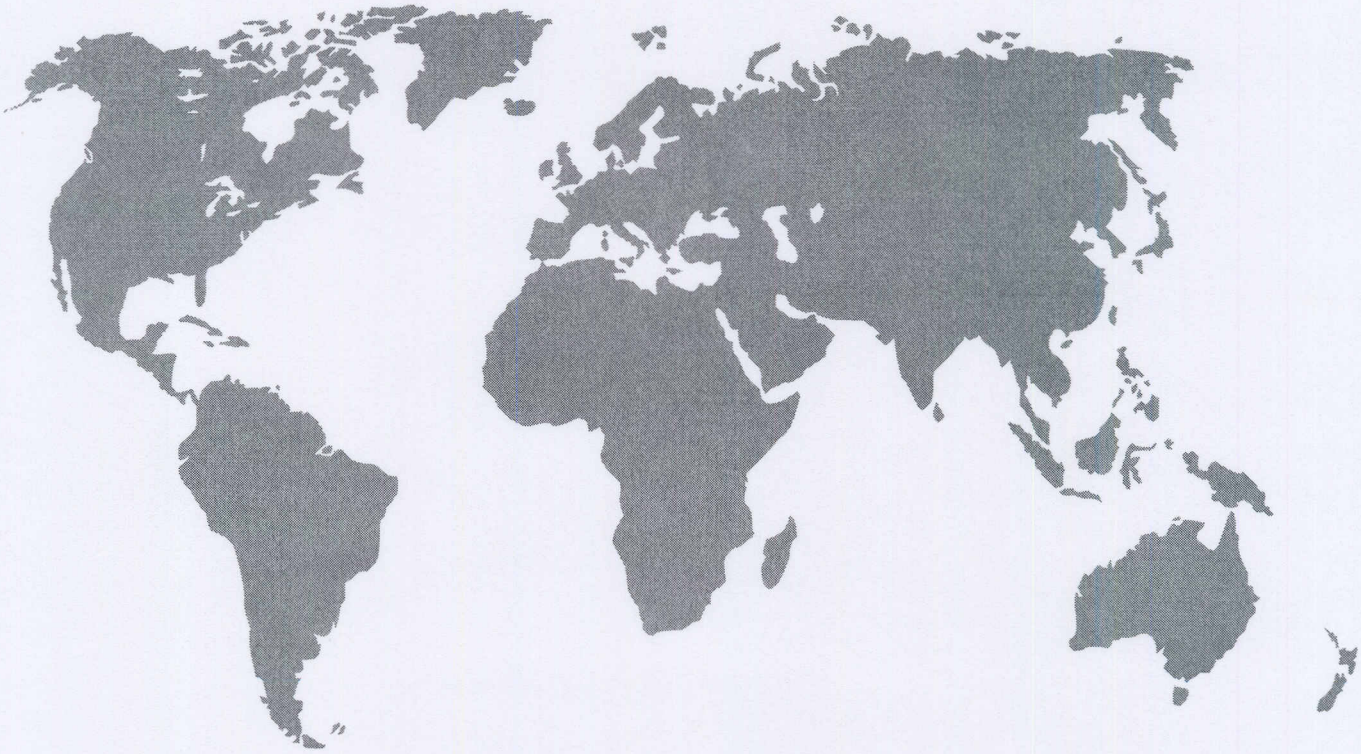


FULL RANGE OF RE-COOLING AND HEAT TRANSFER COMPONENT SYSTEMS AND SERVICES



FULL SERVICE LOCAL REPRESENTATION

Marley Cooling Technologies has the most extensive representative global network in the world with offices in over 150 locations. To find the nearest Marley sales representative log on to www.marleyct.com or call 1 800 462 7539.



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Cooling Technologies •

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DRY COOL-03