CHAPTER 2

2.0 ALTERNATIVES INCLUDING THE PROPOSED ACTION

TVA considered a number of alternatives to constructing and operating BLN 1&2 in its 1974 FES, including various sources of base load generation and eight alternative plant locations. In subsequent environmental reviews, as part of the COLA process, TVA evaluated the construction and operation of AP1000 units (BLN 3&4) at the BLN site, which also included alternative sites and energy resource options. In this FSEIS, TVA discusses in detail three generation alternatives and two transmission alternatives. The nuclear generation alternatives include: Alternative A – No Action, Alternative B – Completion and Operation of a B&W Pressurized Light Water Reactor, and Alternative C – Construction and Operation of an AP1000 Advanced Passive Pressurized Light Water Reactor. These alternatives are described below in Sections 2.1, 2.2, and 2.3, respectively. The transmission alternatives, described in Section 2.6, include an Action and a No Action Alterative. All of these alternatives were considered in previous environmental reviews or reports (see Section 1.7), which are incorporated herein by reference. The project area for the nuclear generation alternatives, shown in Figures 2-1 and 2-12, is defined as the area within the BLN site where all construction activity would occur for either Alternative B or C. The project area includes the south security checkpoint on Bellefonte Road shown in the map inset of Figure 2-1.

These previous reviews also addressed alternatives to nuclear generation, including energy sources not requiring new generating capacity (i.e., power purchases; repowering, reactivating, uprating, or extending service life of existing plants; and DSM). Alternatives requiring new generating capacity (e.g., coal, natural gas, hydroelectric, and renewable sources) were also assessed, as were combinations of alternatives. A discussion of alternative energy sources considered is provided in Section 2.4. Section 2.5 describes the site screening process, identification of candidate sites, and the selection of the BLN site as the preferred site for additional nuclear generation.

Section 2.7 compares the alternatives for a single nuclear generating unit at the BLN site and summarizes the anticipated environmental impacts of the three generation alternatives and two transmission system alternatives. Mitigation measures designed to avoid or minimize impacts to resources are described in Section 2.8, and TVA staff's preferred alternative is addressed in Section 2.9.

In response to public and agency comments on the DSEIS, information was added to Chapter 2 to clarify the comparison of the two reactor technologies, explain the Detailed Scoping, Estimating, and Planning (DSEP) process, and enhance the discussion of energy alternatives.

2.1. Alternative A – No Action

Under the No Action Alternative, TVA would continue to maintain the construction permits for BLN 1&2 in deferred status. In deferred status, no construction would occur, and no power would be generated on site. TVA would continue to maintain selected plant systems and the physical plant to prevent deterioration, including major components such as the intake and discharge structures, cooling towers, and wastewater system. The switchyards and the transformer yard on site would continue to be maintained in an active state. TVA would continue to use the simulator building. TVA has refurbished the construction administration building to provide office space for personnel assigned to study the feasibility

of completing BLN 1&2, and TVA would continue to maintain facilities to house personnel. The on-site staff would total approximately 50 persons.

The existing containment, turbine, and auxiliary buildings would not be demolished. Other structures not identified as necessary would continue to be sold, dismantled, and removed from the site, or demolished. Such structures, most of which are metal and wood warehouses, are located in the western portion of the site. Any demolition wastes generated would be disposed of in appropriately permitted solid waste or other disposal facilities. Equipment identified as unnecessary would have the power disconnected and would either be reused at other TVA facilities, sold for reuse elsewhere, or abandoned in place. TVA has both agency and site processes and procedures in place to safely handle the demolition and removal of the identified equipment, structures, and fuels or lubricants in an environmentally sound manner. TVA would continue to conduct periodic site inspections to ensure that none of the equipment or materials would cause environmental, health, or safety problems. In deferred status, TVA would also perform basic maintenance of key equipment and structures.

TVA would continue regulatory compliance activities that include monitoring and maintenance of equipment used to assure compliance with NPDES and Spill Prevention Control and Countermeasures (SPCC) programs. In addition, monitoring reports, demolition permits (10-day notifications), and permits applicable to the entire site would be maintained. These measures would continue as long as TVA has ownership of the BLN site. The NPDES permit, an Air Permit for Synthetic Minor Source Operation related to diesel generators, and a RCRA permit remain active. Maintaining and complying with these existing permits and regulations would ensure the stability of the site until such time that TVA may decide if, or how, the site would be utilized. Such a future decision would be subjected to the appropriate environmental review at that time. Under the No Action Alternative, TVA would continue to pursue the BLN 3&4 licensing activities leading to the issuance of a COL in order to preserve future generation options.

2.2. Alternative B – Completion and Operation of a Single B&W Pressurized Light Water Reactor

Under Alternative B, TVA would complete and operate one B&W pressurized light water reactor, either BLN Unit 1 or Unit 2, as described in TVA's 1974 FES (TVA 1974a) and Bellefonte FSAR (TVA 1978a). The B&W facility descriptions provided in Subsection 2.2.1 are based on the contents of these documents.

2.2.1. Facility Description for Single Unit Operation

Each of the two B&W pressurized light water reactors is rated at 3,600 MWt (core thermal) with a stretch capability of 3,760 MWt, and an expected electrical output of 1,260 MW. The station operating life is expected to be at least 40 years.

The plant structures (see Figure 2-1) presently consist of two reactor containment buildings, a control building, a turbine building, an auxiliary building, a service building, a condenser circulating water pumping station, two diesel generator buildings, a river intake pumping station, two natural draft cooling towers, a transformer yard, a 500-kilovolt (kV) switchyard and a 161-kV switchyard, two spent nuclear fuel storage pools, and sewage treatment facilities. Additionally, there are office buildings to house engineering and other personnel. Entrance roads, parking lots, railroad spurs, and a helicopter landing pad are in place and are capable of supporting a construction project.

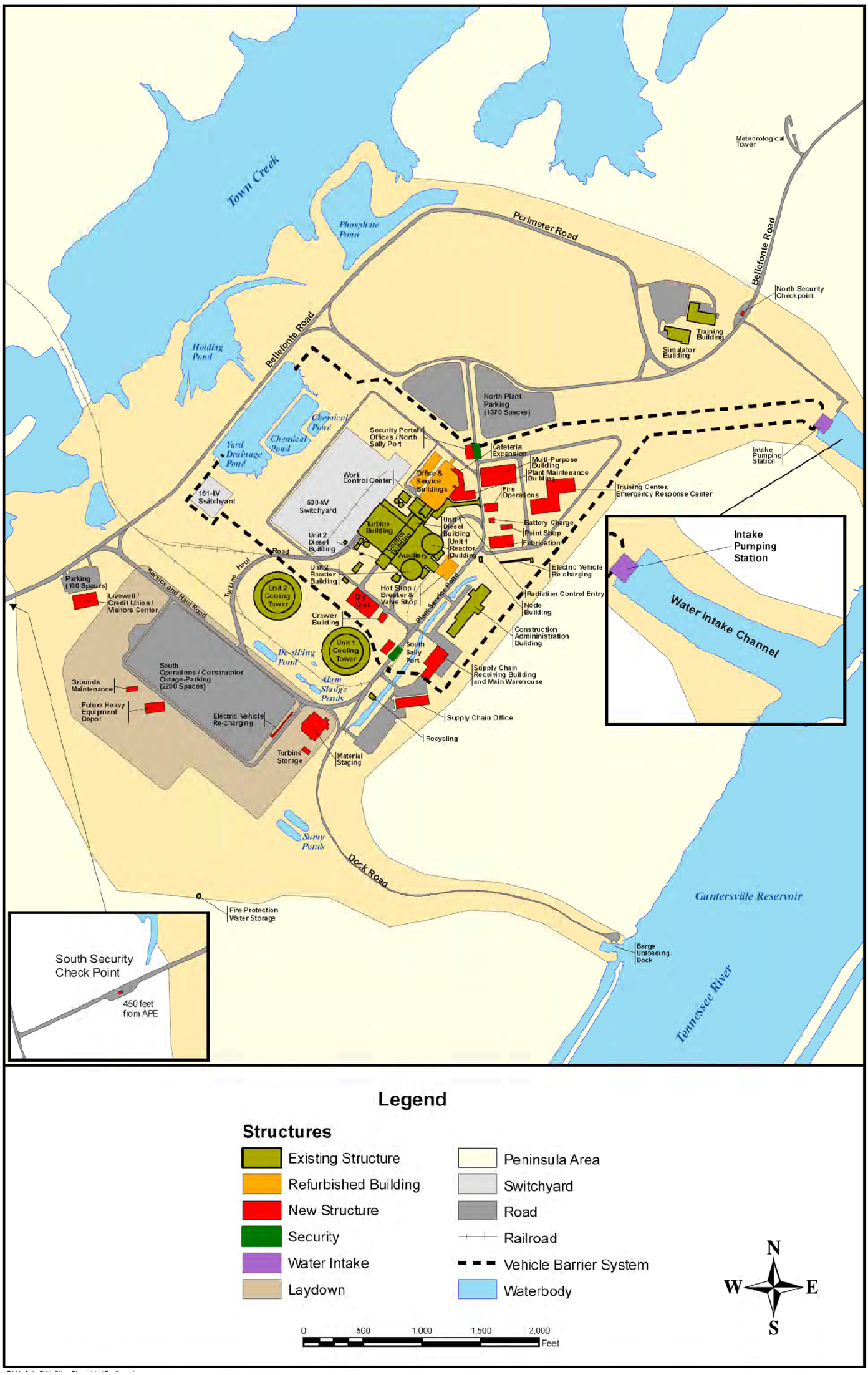

Figure 2-1. B&W Site Plan

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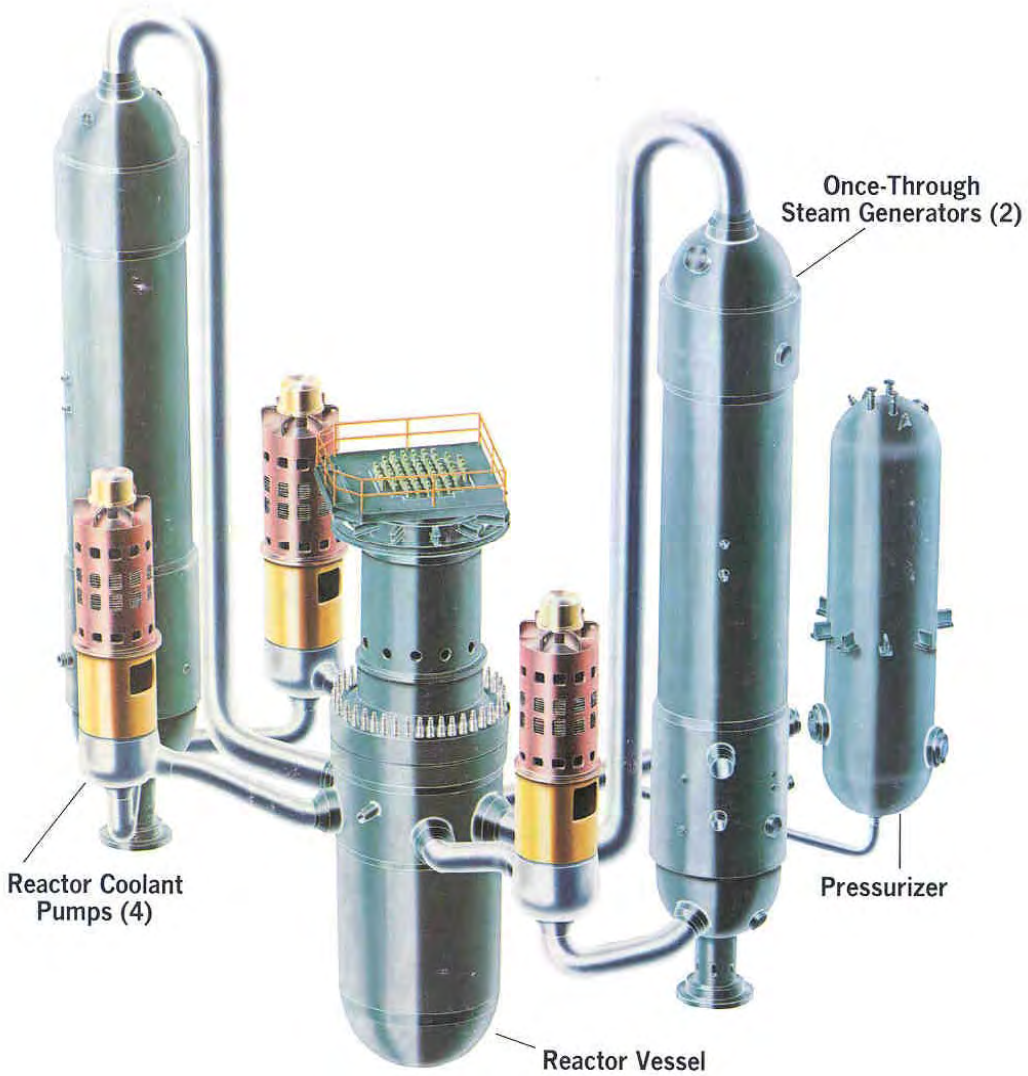
Reactor Power Conversion System and Reactor Coolant System
The nuclear steam supply system design for each unit comprises a pressurized light water reactor, the reactor coolant system, and associated auxiliary fluid systems. The reactor coolant system (see Figure 2-2) is arranged in two, closed coolant loops connected in parallel to the reactor vessel. Each loop contains two reactor coolant pumps and a once-through steam generator. An electrically heated pressurizer is connected to one of the loops.



Source: AREVA 2009a

Figure 2-2. B&W Reactor Coolant System

The reactor core consists of 205 fuel assemblies, 72 control rod assemblies, and eight axial power shaping rod assemblies. Each 12-foot fuel assembly provides for 264 fuel rods, 24 rod guide tubes, and one instrumentation tube positioned in a 17 by 17 array. The core is designed to operate approximately 18 months between refueling (DOE 1999).

The reactor and reactor coolant system have three primary safety functions. First, the system is designed to provide conditions for the reactor coolant temperature, pressure, flow, and core power that allow adequate heat removal from the fuel. This safety function maintains the integrity of the fuel cladding, which is the primary barrier to the release of radioactive fission products. Second, the reactor coolant system is designed to maintain its integrity under all operating conditions, which functions as a second barrier to the release of fission products that may escape the fuel cladding. Third, the system is able to place the reactor core in a safe shutdown condition, assuming failure of a supporting system or failure of the reactor coolant system itself. Several supporting systems aid in performing these safety functions.

The reactor building for each unit consists of a post-tensioned concrete primary containment structure and a free-standing reinforced concrete secondary containment structure. The primary containment, which houses the reactor power conversion and coolant systems, has a leak-tight 0.25-inch-thick steel liner. This primary containment is surrounded by a free-standing secondary containment composed of a reinforced concrete shell designed to maintain a slight vacuum in the annulus between the primary containment and the secondary containment to assure in-leakage into the annulus. The primary containment has a design pressure of 50 pound-force per square inch gauge (psig) and is designed to withstand the internal pressure associated with any design-basis loss-of-coolant accident. The secondary containment is designed to resist various combinations of seismic activity, wind, tornado forces, external missiles, snow loads, and external water pressure for normal and accident conditions.

The turbine generator system is designed to change the thermal energy of the steam flowing through the turbine into rotational mechanical work, which rotates a generator to provide electrical power. Each turbo-generator is a tandem compound, four-flow, two-stage reheat, 1,800 revolutions per minute (rpm) machine, manufactured by the Brown Boveri Corporation. The expected net generator electrical output is 1,260 MW at rated (licensed) power levels.

Cooling Water Systems

The component cooling water system provides cooling water for various system components and heat exchangers during both normal and accident conditions. The component cooling water system is a closed cooling system consisting of two separate cooling loops per unit and acts as an intermediate heat sink. This heat is then rejected to the essential raw cooling water. The essential raw cooling water system is designed to remove heat loads from safety-related equipment and systems. It consists of a total of eight main essential raw water cooling water pumps for both units, located in the intake pumping station to supply water from the river to the components to be cooled, and to discharge the water into the cooling tower basins. The intake pumping station is also equipped with four traveling water screens, and four screen wash pumps prevent the screens from becoming clogged with debris.

The intake channel directly connects to the main river channel at all reservoir levels, including loss of the downstream Guntersville Dam. The ultimate heat sink for the B&W units is the water source and associated routing structures, exclusive of the intake pumping station, which is used to remove waste heat from the plant under all conditions. The water source (also called the ultimate heat sink) is the Tennessee River, including the complex of TVA-controlled dams upstream of the plant intake, Guntersville Dam, and the plant intake channel. The ultimate heat sink is designed to perform the principal safety function,

throughout the plant's life, of dissipating essential equipment heat loads after an accident and during normal conditions including startup, power generation, shutdown, and refueling.

Engineered Safety Features
Engineered safety features are used to reduce the potential radiation dose to the general public from the result of a maximum hypothetical accident to below the guideline values of 10 CFR Part 100. The potential dose is reduced by immediate and automatic isolation of all reactor building fluid penetrations that are not required for limiting the consequences of the accident. This action eliminates these penetrations from becoming potential leakage paths. Long-term potential releases following the accident are minimized by reducing the reactor buildings' pressure to nearly atmospheric pressure within 24 hours, thereby reducing the driving potential for fission product escape.

In addition, the engineered safety features would cool the core, maintaining it in a coolable geometry should the worst postulated loss-of-coolant accident occur. This is accomplished by the emergency core cooling system, which includes the core flooding, high-pressure injection, and low-pressure injection systems. The core flooding system consists of two accumulator tanks directly connected to the reactor vessel via check valves. The tanks contain borated water with a nitrogen overpressure that provides automatic injection of the contained water through the check valves into the reactor vessel whenever the reactor coolant system pressure falls below the nitrogen pressure in the tank. The high-pressure injection system uses the high-pressure reactor makeup pumps to pump water from a borated water source into the cold leg reactor coolant piping near the reactor vessel inlet nozzles. The low-pressure injection system uses the decay heat removal pumps to take suction from a borated water source and pump this water through the decay heat removal heat exchangers directly into the reactor vessel through the core flood nozzles. After injection is complete, the coolant is recirculated by the low- and high-pressure injection pumps from an emergency sump below the reactor coolant system through the decay heat removal heat exchanger and back to the reactor vessel.

Each of the two nuclear units in the plant is provided with an independent electric power system to supply plant auxiliaries and provide instrumentation and control power. Each nuclear unit is provided with two diesel generators as standby power supplies in the event of a loss of all off-site power. Each diesel generator supplies power to one of the two redundant and independent Class IE power trains in each nuclear power unit. The capacity of the diesel generators would allow either one of the two generators per unit to supply safe shutdown or accident loads for its unit.

2.2.2. Use of Other Existing Structures and Systems

Natural Draft Cooling Tower
The existing cooling towers are closed-cycle, natural draft hyperbolic cooling towers. Each concrete tower is 474 feet high and has a basin with a diameter of 412 feet. This type of condenser cooling water system enables the plant to operate with a minimum thermal effect on the Tennessee River, because the system cycles cool water from the cooling towers through the condensers and discharges the warmed water back to the cooling towers in a closed system rather than discharging it to the river. As a result, closed-cycle cooling systems use substantially less water because the cooling water is continually recirculated through the main condenser and only makeup water for normal system losses is required.

Intake Channel and Pumping Station
The intake pumping station is located at the end of the intake channel extending 1,200 feet from the Guntersville Reservoir shoreline. The intake channel is centered in a natural draw on the west side of the reservoir. When constructed, the channel was excavated to rock to create a 200-foot-wide man-made channel from the reservoir to the intake pumping station. In addition, a 25-foot-wide trench was excavated into the rock along the centerline of the channel bottom and extends an additional 760 feet beyond the shoreline to the main river channel. This trench is angled to slope downward toward the intake pumping station from elevation 566.5 feet at the main river channel to elevation 565.5 feet near the intake pumping station. An intrusion barrier would be installed across the intake channel to provide security for the intake channel and pumping station. Approximately 11,100 cubic feet of dredged material would be removed from a total of 1,960 feet of intake channel (pumping station to main river channel). This proposed plant activity is described in greater detail in Subsection 2.2.4.

Blowdown Discharge Structure
The blowdown discharge system, which is designed to disperse water from the cooling tower, is discussed in greater detail in Subsection 3.1.3

Transmission Lines and Switchyards
Existing transmission lines and switchyards would be used. The transmission system is discussed in Section 2.6 and Chapter 4 of this SEIS.

Barge Unloading Dock
A barge unloading dock is located just north of the blowdown vault on the west bank of Guntersville Reservoir approximately 4,600 feet south of the intake channel. This facility was constructed with steel pilings to permit use of the facility throughout the operating life of the plant. Upgrades to the barge unloading dock are discussed in Subsection 2.2.4.

Railroad Spur
Norfolk Southern Railway Company (NSRC) owns and operates a railroad line, which runs through Scottsboro and Hollywood. TVA owns and controls a railroad spur that connects the BLN site to the NSRC mainline about 3 miles northwest of the BLN site. The rail spur would be refurbished and used to support delivery of components and equipment small enough to ship by rail.

Meteorological Tower
The existing meteorological tower was built in 2006. For a B&W unit, a taller tower may be needed to describe atmospheric transport and diffusion characteristics for operation of Unit 1 or 2. If necessary, either the height of the existing 55-meter tower would be increased or a new tower would be built that provides sufficient meteorological data. The existing instrumentation would be used on the taller tower. See Subsection 2.3.2 for additional information about the existing meteorological tower.

Exclusion Area Boundary
The exclusion area boundary (EAB) is the boundary on which limits for the release of radioactive effluents are based. The EAB is the same for both the B&W and AP1000 alternatives and is shown in Figure 2-3. This boundary was originally established as the licensing basis for BLN 1&2 and has not changed. The EAB follows the site property boundary on the land-bound side, the Tennessee River side, and the lower portion of Town Creek. The EAB extends beyond the site property boundary to the opposite shore of Town

Creek on the northwest side of the property. No residents live in this exclusion area. No unrestricted areas within the site boundary area are accessible to the public. The Town Creek portion of the EAB is controlled by TVA. The property is clearly posted and includes actions to be taken in the event of emergency conditions at the plant. The site's physical security plan contains information on actions to be taken by security personnel in the event of unauthorized persons crossing the EAB. The land and water inside the exclusion area is owned or controlled by TVA and is in the custody of TVA.

2.2.3. Current Status of Partially Constructed Facility

As described in Section 1.2, following deferral, BLN 1&2 were placed in a preventive maintenance and lay-up program to preserve plant assets. Over the years, the scope of this program was reduced when it was determined to be more economical to refurbish/replace certain plant components rather than continue the lay-up and preservation programs. The preservation maintenance and lay-up programs were continued until August 2005. Equipment maintained under this program would be evaluated to determine if it must be replaced or refurbished prior to completion and operation of a BLN unit.

In November 2005, TVA cancelled construction of BLN 1&2. TVA subsequently requested withdrawal of the construction permits from the NRC, and the NRC formally terminated the permits in 2006. After termination of the construction permits, TVA began an effort to recover sunk costs at the BLN site by disposing of plant assets. Some high value plant equipment was removed as part of these investment recovery activities. The *BLN Redress Environmental Assessment* (TVA 2006) discussed the need to remove equipment or structures not identified as necessary for other site activities. The items removed included piping, tanks, pumps, heat exchangers, valves, strainers, batteries, fans and motors, air compressors, shop equipment, and minor buildings. Other items removed included diesel generator fuel and other oils and lubricants. These buildings, equipment, fuel, and lubricants would be replaced as needed under Alternative B.

All major plant structures, including the reactor, auxiliary, control, turbine, and office and service buildings, and plant cooling towers were constructed for both Units 1&2 and remain intact. Some new construction would be required for the completion of either unit. The original power stores warehouse building has been removed and would need to be rebuilt. The auxiliary boiler building has been removed and would need to be replaced. It is expected that any new construction of buildings would occur on previously disturbed land. No new water intakes or outfalls are needed. The majority of the construction activities on plant systems and components would involve replacement or refurbishment of equipment contained within the current structures. As shown on Figure 2-1, all new construction support buildings, laydown areas, and parking areas except for the south security checkpoint would be situated on previously disturbed land within the original plant footprint.

As part of an update of the cost and schedule to complete BLN 1&2 that was completed in May 2008, TVA contracted with AREVA NP Inc. (AREVA) to assess the condition of selected plant features. AREVA conducted inspections of four mechanical systems, plant electrical systems/equipment, and plant civil/structural features in order to determine their condition. The inspections found BLN, accounting for removed equipment, was in generally good condition.

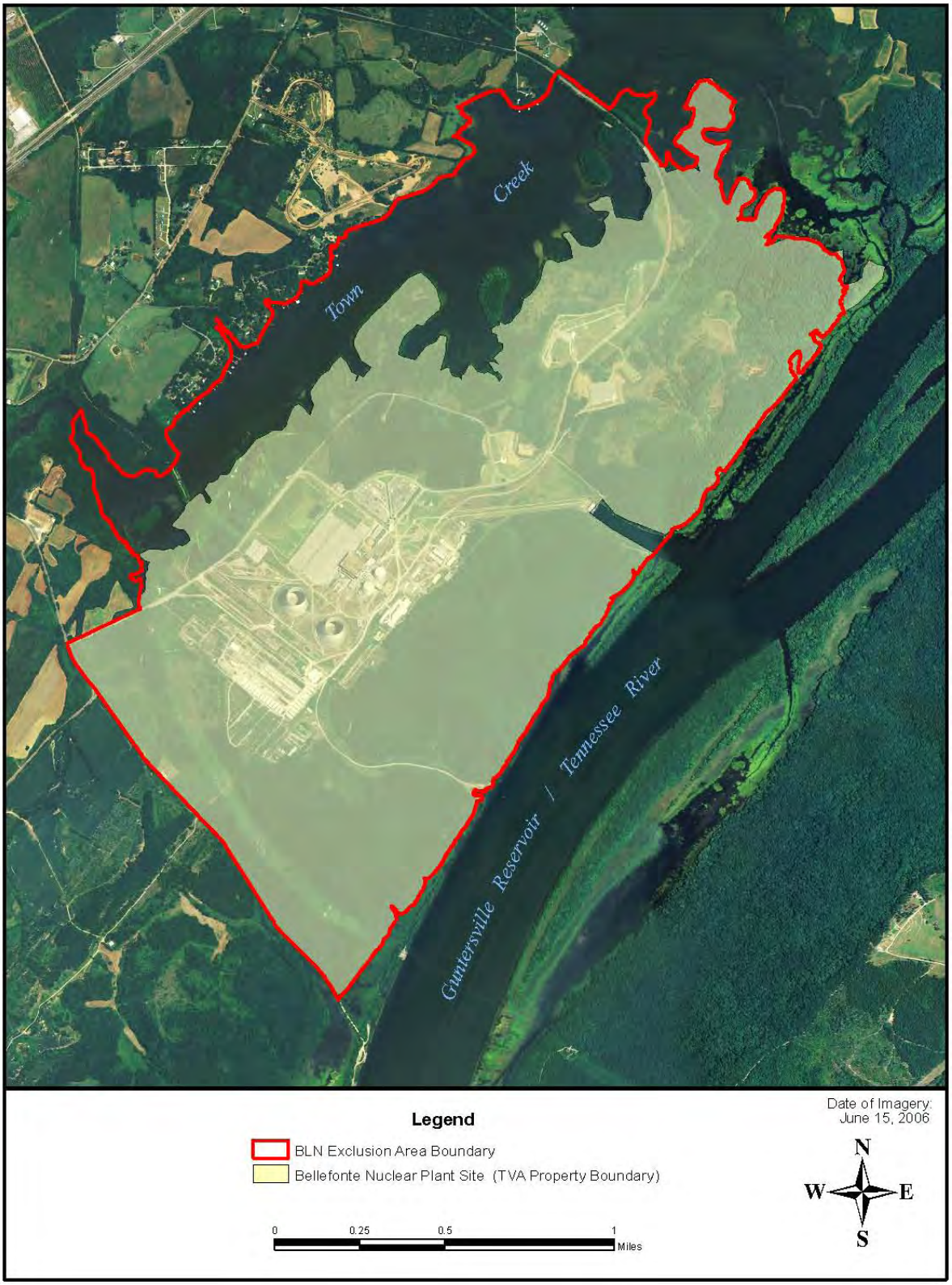


Figure 2-3. Exclusion Area Boundary for Alternatives B and C

TVA has completed a DSEP project to expand upon the AREVA effort and provide a more detailed assessment of the existing plant configuration and the requirements to complete engineering and construction. Experts in the area of construction, estimating, budgeting, and project controls have reviewed the elements to complete this project. The DSEP process was independently reviewed by a panel of experts to ensure that nothing major was overlooked. As a result of this review, refinements were made to the overall process that has resulted in a quality estimate and schedule.

The purpose of the DSEP project was to define the scope of completion, to develop licensing strategy, to determine the material condition of BLN 1&2, to define schedule and cost for completion and startup, to determine project risk, and to provide a reliable basis for decision-making. The study included physically inspecting and evaluating systems, structures, and components currently installed in the plant. It also provided a comprehensive assessment of the additional engineering, materials, components, and construction needed to complete the unit. The DSEP addresses all these factors and provides a high confidence level estimate for the cost and schedule to complete a B&W unit.

Because Bellefonte was previously estimated in detail for completion, the intent of this DSEP was to identify differences in the previous estimates with respect to investment recovery activities, withdrawal of construction permits, and subsequent suspension of the 10 CFR Part 50 Appendix B QA program, suspension of the preventive maintenance and lay-up program, and removal of environmental controls within the plant. In addition, regulatory changes and industry initiatives now require changes to the facility that were not known or included in the previous estimates. Obsolescence requires additional investigation to support long-term reliable operation of the units.

During the DSEP period that was conducted during 2009 and 2010, a detailed review of most major systems, components, and structures was conducted. This effort included over 100,000 hours of review by experts in engineering and plant systems. This allowed options to be evaluated based on current condition, including age and obsolescence of plant equipment.

A comprehensive evaluation of the reactor and other primary systems, as well as the controls for those systems, was conducted. A review was also completed on the turbine generator and the secondary plant systems, as well as, controls for those systems.

The plant utilizes a very efficient design. The secondary system will be more efficient than other operating commercial nuclear plants due to the use of once-through steam generators, a superheated steam cycle, and extensive use of reheat to limit heat loss in the secondary systems. Design features such as improved instrument and controls, steam generators, and turbine design will be modernized while still maintaining the original high efficiency.

BLN Structures

The structural condition of the existing facilities, with regard to structural integrity and safety requirements, have been evaluated. The initial engineering review performed to evaluate the potential for completing BLN 1 or 2 was conducted to determine if the existing completed seismic Category I structures could be documented to comply with the latest NRC seismic requirements. The designation of seismic Category I refers to safety-related structures, systems, and components that are designed and built to withstand the maximum potential earthquake stresses for the particular region where a nuclear plant is sited, without

loss of capability to perform their safety functions. A detailed review was performed to determine the effects of applying Bellefonte site-specific seismic criteria based on the requirements of Appendix S of 10 CFR Part 50. The results of this evaluation determined that the BLN seismic Category I safety-related structures would be able to withstand the effects of a seismic event as defined by the new criteria. These results have been reviewed by a panel of nuclear industry seismic experts who independently confirmed the results of the evaluation. The study does conclude that some internal supporting structures would require modifications, and these modifications are included in the completion estimate for the project. The original design of nonsafety-related structures, not governed by the NRC requirements, continues to meet current industrial building codes. In addition, detailed walkdowns of both the safety-related and nonsafety-related structures were performed during the DSEP to identify degradation or structural issues. No detrimental issues related to either type of structure were identified related to subsidence or settlement.

Review of the existing structures (through DSEP evaluations) to identify other structurally related considerations, including infestations, roofing integrity, and pavement structures was conducted. These evaluations considered historical water infiltration. Some water infiltration has occurred at the site mainly due to groundwater in-leakage through construction joints. A DSEP evaluation has validated the structural integrity of the affected buildings, and the project estimate carries an estimate for remediation of in-leakage sites. In addition, the existence of mold in the lowest elevations of the plant due to damp conditions has been evaluated. An industrial hygienist has evaluated the mold and provided approved methods for remediation. The structural integrity of roofing has also been evaluated, and a remediation plan is being implemented. Roofing systems for the turbine building were replaced in 2009. The project facility plan includes repair or replacement of the remaining roofing systems and is in the completion estimate.

The DSEP process evaluated plant structures for completion, including required updates associated with applicable codes and standards necessary to secure an operating license for the facility. The majority of the plant is constructed to seismic Category I requirements as set forth by the NRC. These facilities are made of high-strength concrete and steel supports that provide a robust structure for a long life. Commercial nuclear plants operating in the United States today are built to these standards, and the majority of plants have been granted a 20-year extension to the original 40-year operating life. As part of the life extension review, plants are required to address aging effects on the seismic Category I structures. In general, aging effects outside of normal maintenance practices have not been identified by the industry for these structures. Based on the extensive reviews conducted thus far, the seismic Category I structures for Bellefonte are intact and require minor maintenance to meet current requirements. As for the remainder of the plant structures outside of seismic Category I requirements, these were likewise built to stringent industrial standards, with minimal maintenance required to meet current standards.

The existing B&W structures, systems, and components have been evaluated against the current standards for terrorism threats, including impacts of large commercial aircraft. The facilities (seismic Category I structures) that contain the pressurized water reactor are complete, with minor modifications necessary to meet new regulatory requirements. Security requirements for nuclear power plants have been significantly upgraded since September 11, 2001, including the development of contingency plans to address 'beyond design basis' events. The BLN design will meet those licensing requirements and regulations, including those regarding aircraft impact, as are all currently licensed nuclear plants nationwide.

Existing Unit 1 structures are complete; seismic Category I safety-related structures comply with current NRC criteria, and nonsafety-related structures meet applicable industrial requirements. Figures 2-4, 2-5, and 2-6 provide a visual reference for the current status and condition of the existing BLN.

Figure 2-4. Bellefonte Nuclear Plant Entrance

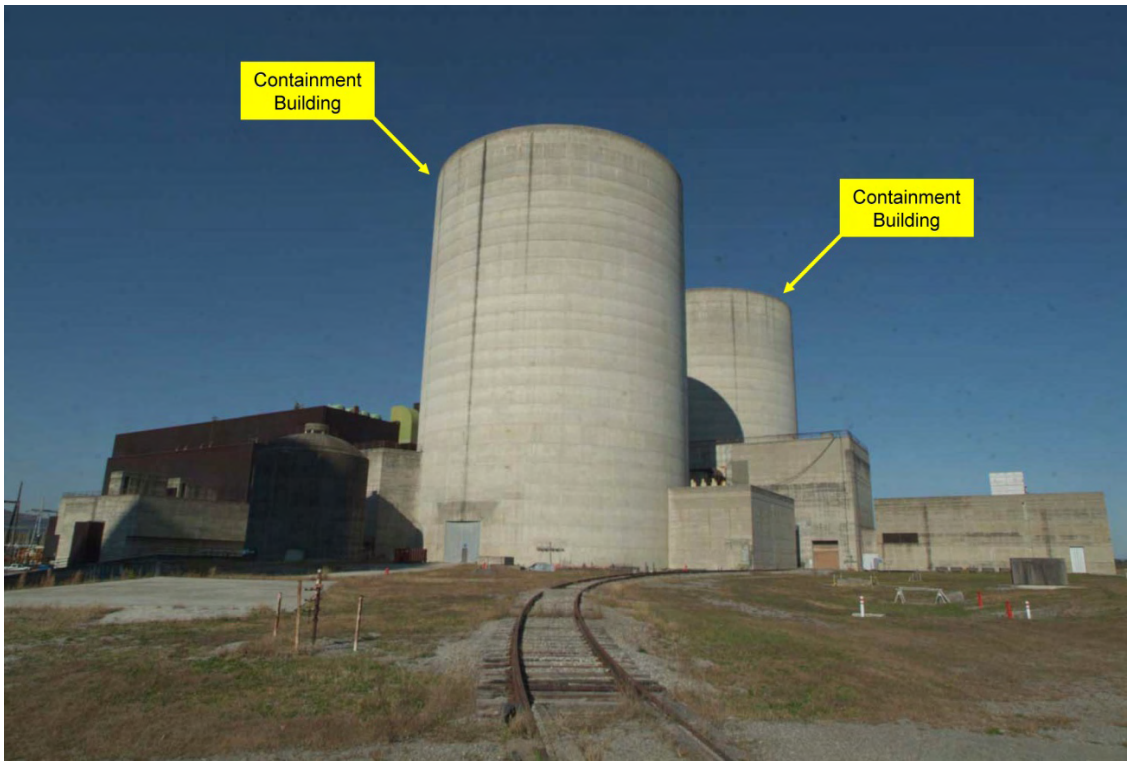


Figure 2-5. B&W Containment Buildings

Figure 2-6. View From BLN Parking Lot - Administration Building, Turbine Building, Containment Buildings, Cooling Towers, and Switchyard

B&W Systems and Components
The DSEP has developed a detailed status of the existing plant systems and components. When original construction was ceased, BLN 1&2 were substantially complete with the vast majority of plant structures, systems, and components installed and tested.

Evaluations of the existing systems and components have been performed to determine what equipment can be "used as is" and what refurbishment and replacement activities are necessary to complete the plants. Selected piping and components were salvaged during the investment recovery period in selected areas of the plant, although structures within the power plant were generally unaffected. In addition, obsolescence issues, changes in regulatory requirements, or industry best practices would require replacement of selected installed systems and components. Furthermore, refurbishment of some existing equipment would be required to ensure reliable operation in the future. As previously discussed, when construction of BLN 1&2 was halted in 1988, completion of the units was estimated at 90 percent and 58 percent, respectively. The DSEP shows that additional resources (time, manpower, and capital) will be needed to complete either unit following the investment recovery activities and to meet current construction standards. Therefore, the current completion estimate is 55 percent for Unit 1 and 35 percent for Unit 2. It should be noted that major construction is not anticipated to be required to complete the units, but the bulk of the resources will be used for internal refurbishment/modification.

Figures 2-7, 2-8, 2-9, 2-10, and 2-11 show various plant systems and components.

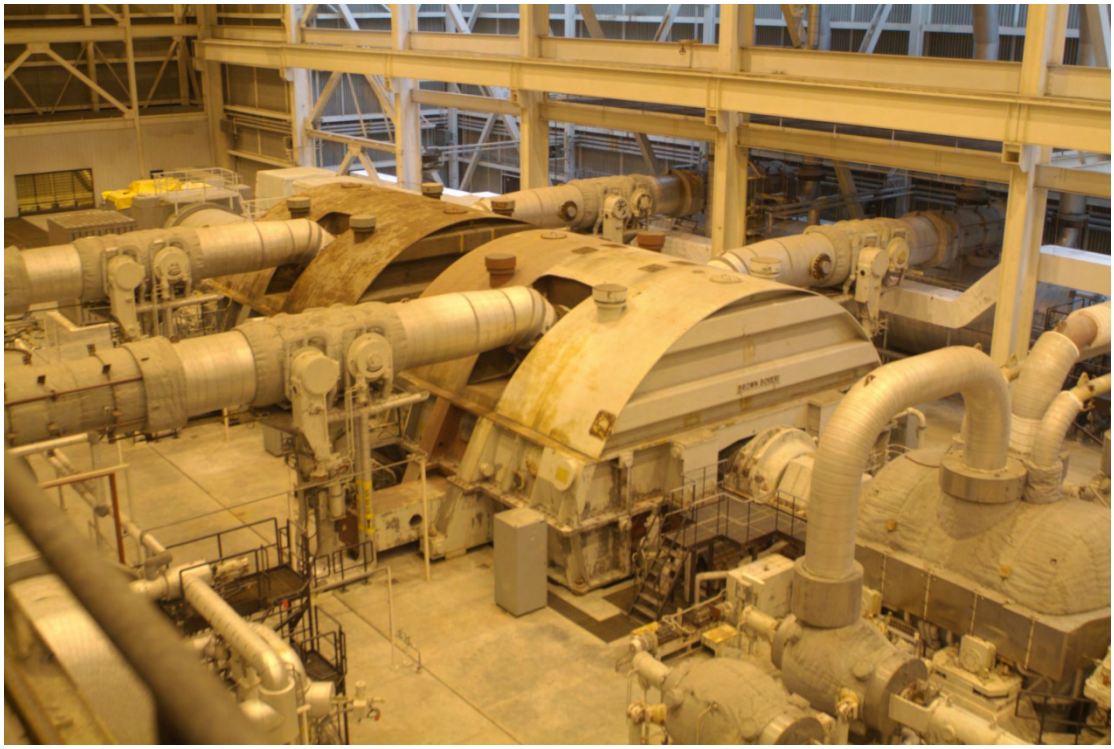


Figure 2-7. Unit 1 Turbine Generator

Figure 2-8. Unit 1 Main Control Room

Figure 2-9. Cable Spreading Room

Figure 2-10. Unit 1 Makeup High-Pressure Injection Pump

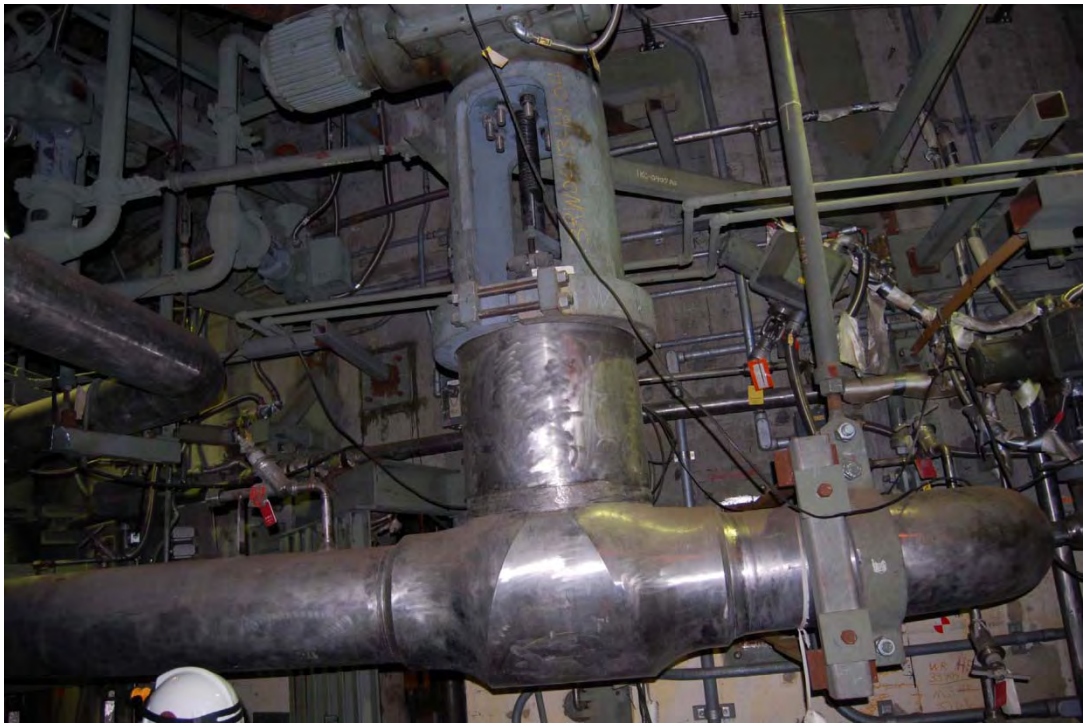


Figure 2-11. Unit 1 Large Bore Valve, Small Bore Valves, Piping

Quality Assurance Records
A total of 52,828 as-constructed drawings were prepared by the end of the original construction process. The original QA construction records have been confirmed to be available. Specific areas verified for completeness during DSEP include the American Society of Mechanical Engineers (ASME) Section III records for safety-related weld and material procurement and installation. These records were reviewed by the Authorized Inspection Agency (AIA), Hartford Steam Boiler Global Standards, and determined to be available, accessible, and maintained per the AIA's required storage quality level. NRC's December 2, 2009, *Inspection Report, Transition to Deferred Status* (see Appendix B), concluded that the QA records and the Bellefonte programs and procedures meet NRC QA requirements.

2.2.4. Proposed Plant Construction Activities

BLN Units 1&2 were being constructed on a staggered schedule, with Unit 1 scheduled for completion approximately two years before Unit 2. So, while construction of major buildings and supporting infrastructure were substantially completed for both units during the initial construction phase, in general, Unit 1 construction is further along than Unit 2. The identified major activities that would be required to complete the construction scope for BLN Unit 1 or 2, as well as planned enhancements, are listed below. Activities for either unit would be similar, but Unit 2 would require the completion of final piping structural supports, installation of instrumentation, installation of small piping and valves, insulation, and the completion of architectural features.

The following list of completion activities is based on cost and schedule information developed during the DSEP:

- Replace the two steam generators, which were affected by investment recovery activities (note: as described above, each B&W unit has two steam generators). The original steam generator tubing and shell sections were removed for salvage value and, as such, are damaged beyond repair. The replacement steam generators will be designed to incorporate industry lessons and will employ materials consistent with those used in operating plant steam generator replacement projects and new plant steam generator designs. A more complete description of the steam generator replacement process follows this list.
- Replace the existing analog and solid state instrumentation and controls systems with digital technology comparable to those utilized in new reactor designs.
- Replace the turbine rotating assemblies to ensure that the maximum energy can be extracted from the steam. This, in combination with the primary and secondary designs, would ensure one of the most efficient steam cycles in the country and would be better than new construction-type design.
- Replace major pumps, motors, heat exchangers, and tanks, and remove piping as part of investment recovery.
- Refurbish major equipment, such as reactor coolant pumps, control and instrumentation, diesel generators, and plant electrical breakers.
- Upgrade plant barge unloading dock in order to receive and unload steam generators and other major plant equipment. No dredging in the area of the barge unloading dock is required for construction of a B&W unit.

- Remove silt from the intake channel. From the pumping station to the shoreline (a distance of approximately 1,200 feet), approximately 10,000 cubic yards of dredged material would be removed. From the shoreline to the main river channel (a distance of approximately 760 feet), approximately 1,100 cubic yards of dredged material would be removed. Dredged material would be disposed of in an on-site spoils area above the 500-year flood elevation.
- Replace transmission system equipment utilized for plant operation, such as switchyard breakers.
- Upgrade a cooling tower, so that it would perform at 100 percent of original design capacity. Typical modifications of other TVA natural draft cooling towers have included (but are not limited to) modifying and extending distribution piping headers, replacing existing and adding spray nozzles, and adding or replacing fill material. Comparable modifications would be anticipated, but the exact nature of the cooling tower upgrades would be determined later.
- Update the plant control room and build a new simulator for operator training.
- Replace auxiliary boiler and auxiliary boiler building.
- Perform code inspection, documentation, and reconciliation to meet ASME standards.
- Install an intrusion barrier to provide security for the intake pumping station and intake channel.
- Construct security upgrades including addition of checkpoints and portals.
- Construct site facilities including nonplant-related administrative, maintenance, construction, fabrication, supply chain, and training buildings.

Steam Generator Replacement

The existing steam generator tubing and portions of the shell were removed for salvage value during investment recovery activities. The remainder of the old steam generators would be removed, similar to the installation of the new steam generators discussed below. The new steam generators would be transported from the fabrication facility by rail and/or barge to the BLN site. Once there, the replacement steam generators would be offloaded onto steel saddles for temporary storage. Two options for off loading could be used, based on contractor preference:

- Gantry crane. A gantry crane was used during the original BLN 1&2 construction, and the existing foundations may support the new gantry crane. However, some additional excavation may be needed for the foundation caissons.

- Barge drive off. Using this method, the barge interior cells would be filled with river water and stabilized at the height of the riverbank, and then a multiwheeled hauler vehicle would be driven onto the barge and under the steam generators. The vehicle would then rise up to lift the steam generators and drive off the barge.

The existing barge off-loading area would require some improvements, including excavation and foundation work for use with either barge off-loading system. The road leading from the barge off-loading to the BLN containment would be cleared of vegetation by grading and adding gravel to provide a level path for the multiwheeled hauler vehicle to travel.

Some steel piping on the old Unit 1 steam generator was removed from the inside, but the containment buildings are still intact. The remainder of the old steam generators would be removed as one piece, similar to the installation of new steam generator discussed below. After exiting the containment, the old steam generators would be placed on existing slabs and cut up and sold for scrap. The preferred method of old steam generator removal and installation of the new steam generators is discussed below:

- Removal of old and installation of new steam generators would use the existing equipment hatch for passage in and out of containment.
- The steel plenum of the heating, ventilation, and air conditioning (HVAC) inside containment just inside the equipment hatch would be cut to provide an opening approximately 14 feet by 14 feet. Next, a similar-size hole would be cut into the reactor pool concrete wall. This cut would either be done with chipping hammers or with the use of hydrodemolition equipment.
- A rail system would be installed from the outside of containment to the inside of the reactor pool. A multiwheeled cart would be set on the rail system to move the steam generators out and in.
- A temporary rigging device would be set on top of the polar crane girders for lifting the old steam generators from the cubicle to the multiwheeled cart. The old steam generator would be moved out of containment. An outside lift system would remove the old steam generators from the cart to a multiwheeled hauler vehicle, which would move them to a slab to be cut up and sold for scrap.
- In a reverse manner, the new steam generators would be taken from the storage slab by the multiwheeled hauler vehicle to a gantry crane outside containment, placed on the cart, rolled into containment on the rail system, upended in the reactor pool by a temporary lifting device, and placed in the steam generator cubicle.

In preparation for installation of the replacement steam generators into the containment building, some excavation and foundation work would be needed to install an outside lift system. The area next to the containment would be excavated as necessary and then backfilled back to the existing plant grade after the replacement. The steel and concrete components would be replaced to safety and engineering standards. Waste concrete would be transported to an appropriately permitted disposal site.

In general, the steam generator replacement process would entail activities and effects typical of other on-site construction activities including site reclearing, minor demolition and new construction, and equipment replacement. A hydrodemolition process, using a high-pressure water jet, could be used to remove concrete while leaving the steel reinforcement bar intact. The process would use approximately 450,000 gallons of water, likely from the local municipal source, and produce a water and concrete slurry. This wastewater would be captured, sampled, treated, and released through an approved NPDES discharge point.

2.3. Alternative C – Construction and Operation of a Westinghouse AP1000 Advanced Passive Pressurized Light Water Reactor

Under Alternative C, TVA would construct and operate a single AP1000 advanced passive pressurized light water reactor on the BLN site. The following AP1000 facility description is based on COLA FSAR Revision 1 (TVA 2009a) and COLA ER Revision 1 (TVA 2008a)

content, and *AP1000 Design Certification Document, Revision 17* (Westinghouse Electric Company [WEC] 2008). Existing main structures that would be used under Alternative C are discussed in Subsection 2.3.2.

2.3.1. Facility Description for Single Unit Operation

The nuclear steam supply system for the AP1000 is a Westinghouse-designed advanced passive pressurized light water reactor. The rated thermal power of the reactor is 3,400 MWt, with a nuclear steam supply system rating of 3,415 MWt (core plus reactor coolant pump heat), and an expected electrical output of 1,100 MW. The plant design life is 60 years.

An AP1000 power block complex is composed of five principal building structures: nuclear island, turbine building, annex building, diesel generator building, and radwaste building (see Figure 2-12). Each of these is constructed on an individual reinforced concrete foundation basemat. All safety-related structures, systems, and components are located on the nuclear island. The structures located off the nuclear island are neither safety-related nor seismic Category I.

The nuclear island is composed of the containment building, shield building, and auxiliary building. The containment building, a seismic Category I structure, is a freestanding cylindrical steel containment vessel with elliptical upper and lower heads. The containment vessel confines the release of airborne radioactivity following postulated design-basis accidents and provides shielding for the reactor core and reactor coolant system during normal operations. The containment building is surrounded by a seismic Category I reinforced shield building. In conjunction with the internal structures of the containment building, the shield building provides the required shielding for the reactor coolant system and the other radioactive systems and components housed in the containment. The shield building also protects the containment vessel and reactor coolant system from the effects of tornados and tornado-produced missiles. The auxiliary building is a seismic Category I reinforced concrete structure, which provides protection and separation for seismic Category I mechanical and electrical equipment located outside the containment building. The auxiliary building shares a common basemat with the containment building and the shield building. The nuclear island structures are designed to withstand the effects of natural phenomena such as hurricanes, floods, tornados, and earthquakes without loss of capability to perform safety functions. The nuclear island is designed to withstand the effects of postulated internal events such as fire and flooding without loss of capability to perform safety functions.

The annex building is a combination of reinforced concrete and steel-framed structure with insulated metal siding. The annex building provides the main personnel entrance to the power generation complex, includes the health physics facilities, and provides personnel and equipment access ways to and from the containment building and the rest of the radiological control area via the auxiliary building.

The diesel generator building is a single-story, steel-framed structure with insulated metal siding. The building houses two identical slide-along diesel generators separated by a three-hour firewall. The diesel generators provide backup power for plant operation if normal power sources are disrupted.

The turbine building is a steel column and beam structure that houses the main turbine, generator, and associated fluid and electrical systems. It also houses the makeup water

purification system and provides weather protection for the laydown and maintenance of major turbine/generator components.

The radwaste building includes facilities for segregated storage of various categories of waste prior to processing, for processing by mobile systems, and for storing processed waste in shipping and disposal containers. Additional plant structures include warehouses, administration/office buildings, switchyard, transmission towers, entrance roads, parking lots, and railroad spur.

The overall plant arrangement for an AP1000 unit is designed to minimize the building volumes and quantities of bulk materials (concrete, structural steel, rebar) consistent with safety, operational, maintenance, and structural needs to provide an aesthetically pleasing effect. Half of the plant would be constructed off site and transported to the site as modules. Natural features of the site would be preserved as much as possible and utilized to reduce the plant's impact on the environment. Landscaping for the site, areas adjacent to the structures, and the parking areas would blend with the natural surroundings to reduce visual impacts.

Reactor Power Conversion System and Reactor Coolant System

The major components of an AP1000 reactor are a single reactor pressure vessel, two steam generators, and four reactor coolant pumps for converting reactor thermal energy into steam. A single, high-pressure turbine and three low-pressure turbines drive a single electric generator. The steam and power conversion system is designed to remove heat energy from the reactor coolant system via the two steam generators and to convert it to electrical power in the turbine generator.

The reactor contains fuel rods assembled into 157 mechanically identical fuel assemblies, along with control and structural elements. A fuel assembly is 14 feet long in a 17 by 17 square array. The core is designed to operate approximately 18 months between refueling outages.

The AP1000 reactor coolant system (see Figure 2-13) is designed to remove or to enable the removal of heat from the reactor during all modes of operation, including shutdown and accident conditions. The system consists of two heat transfer circuits, each with a steam generator, two reactor coolant pumps, and a single hot leg and two cold legs for circulating reactor coolant. The system also includes a pressurizer, interconnecting piping, valves, and instrumentation needed for operational control and safeguards actuation. All reactor coolant system equipment is located in the reactor containment.

During operation, the reactor coolant pumps circulate pressurized water through the reactor vessel and the steam generators. The water is heated as it passes through the core to the steam generators where the heat is transferred to the steam system. The water is returned to the reactor (core) by the pumps, and the process is repeated.

The turbine generator system is designed to change the thermal energy of the steam flowing through the turbine into rotational mechanical work, which rotates a generator to provide electrical power. It consists of a double-flow, high-pressure turbine and three double-flow, low-pressure turbines. It is a six-flow, tandem compound, 1,800-rpm machine. The turbine system includes stop, control, and intercept valves directly attached to the turbine and in the steam flow path, crossover and crossunder piping between the turbine cylinders and the moisture separator reheater. The turbine generator has an expected net generator electrical output of 1,100 MW for a reactor thermal output of 3,415 MWt.

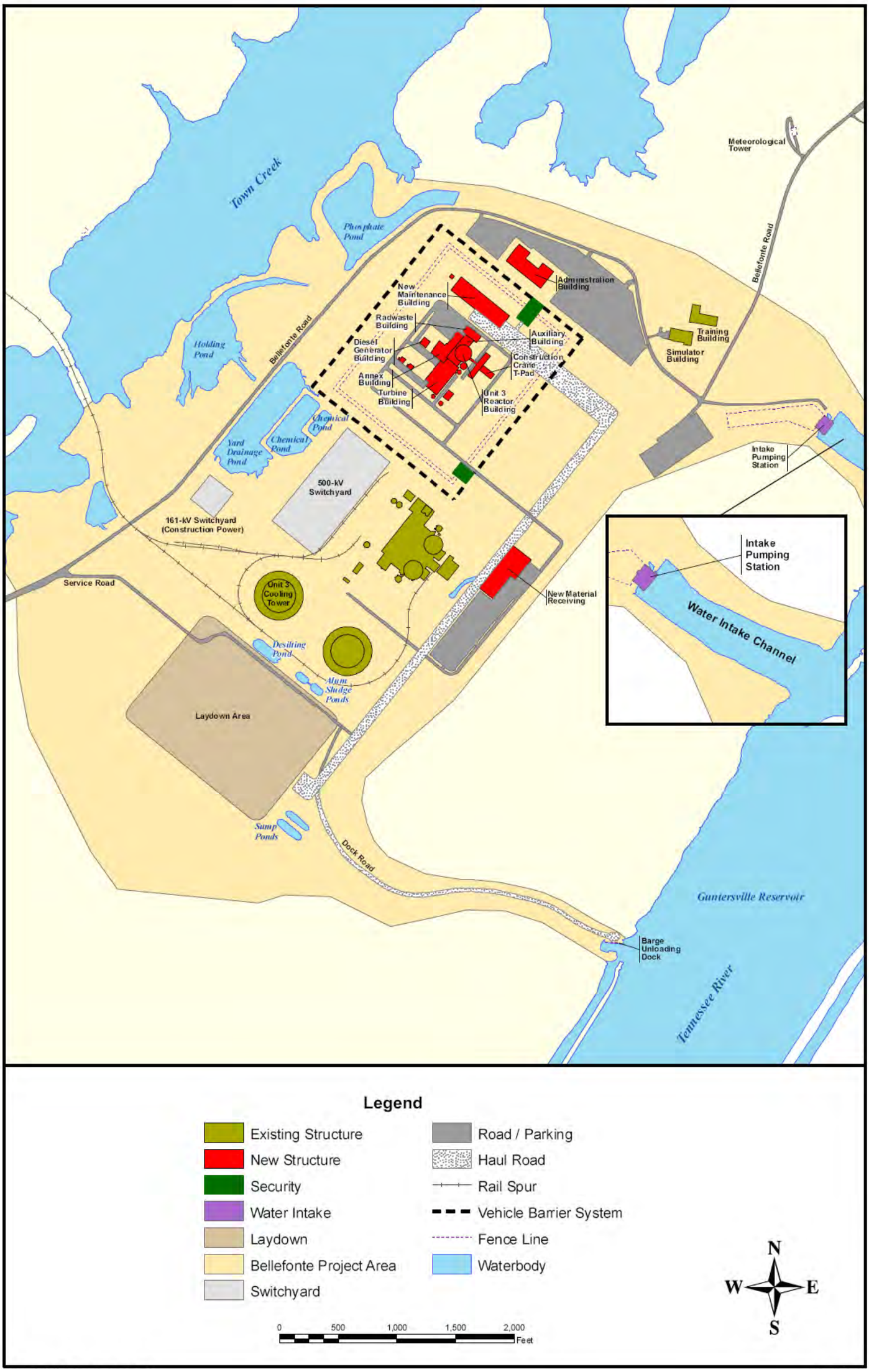


Figure 2-12. AP 1000 Site Plan

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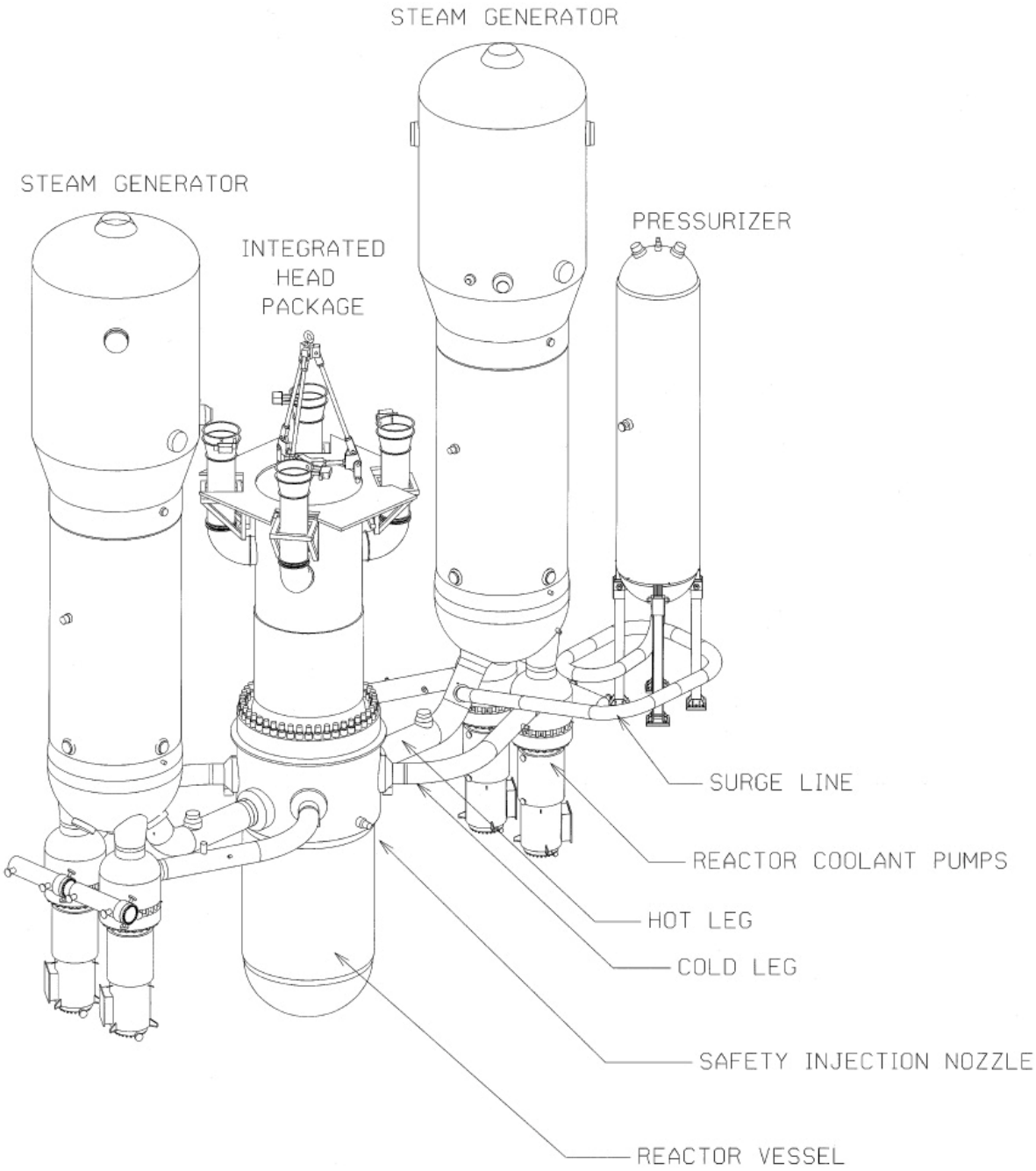


Source: WEC 2008

Figure 2-13. AP1000 Reactor Coolant System

The AP1000 unit design includes an independent electric power system. Two on-site standby diesel generators, each furnished with its own support subsystems, provide power to the selected plant nonsafety-related alternating current (AC) loads for a single AP1000 unit. Two ancillary AC diesel generators, located in the annex building, provide power for Class 1E post-accident monitoring, for control room lighting and ventilation, and for refilling the passive containment cooling system water storage tank and the spent fuel pool, when no other sources of power are available. Another on-site diesel generator provides backup power for the site technical support center.

Raw Water System

The raw water system supplies water from the intake to the circulating water system and the service water system to make up for water that has been consumed and discharged as part of the system operations. The circulating water system supplies cooling water to remove heat from the main condensers, the turbine building closed cooling water system heat exchangers, and the condenser vacuum pump seal water heat exchangers under varying conditions of power plant loading and design weather conditions. The service water system supplies cooling water to remove heat from the nonsafety-related component cooling water system heat exchangers in the turbine building. The raw water system supplies water to the circulating water system cooling tower (natural draft cooling tower) and the service water system cooling tower (mechanical draft cooling tower) to make up for water consumed as the result of evaporation, drift (water droplets swept out of the tops of the cooling towers in a moving air stream), and blowdown (water released to purge solids).

At the intake pumping station, the raw water is first strained by trash rakes and then passes through the traveling screens. Once in the raw water system, the water in each line is further strained. For the circulating water system, a back-washing feature of the strainers removes debris and sends it back to Guntersville Reservoir. A small portion of the raw water is used to supply two, 100-percent capacity screen wash pumps, and the remainder of the flow provides makeup to the circulating water system cooling tower. For the service water system, the water is then filtered to remove remaining debris and discharged to the river. The raw water then proceeds to the service water system cooling tower, where it provides the necessary makeup.

Engineered Safety Features

Engineered safety features protect the public in the event of an accidental release of radioactive fission products from the reactor coolant system. The engineered safety features function to localize, control, mitigate, and terminate such accidents and to maintain radiation exposure levels to the public below applicable limits and guidelines. The AP1000 engineered safety features are described below.

The containment vessel, an integral part of the overall containment system, confines the release of airborne radioactivity following postulated design-basis accidents and provides shielding for the reactor core and reactor coolant system during normal operations. The vessel also functions as the safety-related ultimate heat sink by safely transferring the heat associated with accident sources to the surrounding environment. The passive containment cooling system is designed to maintain the containment air temperature below a specified maximum value and to reduce the containment temperature and pressure following a postulated design-basis event. This system removes heat from the containment atmosphere and serves as the safety-related ultimate heat sink for other design-basis events and shutdowns. The passive containment cooling system limits the release of radioactive material to the environment by reducing the pressure differential between the

containment atmosphere and the external environment, which diminishes the driving force for leakage of fission products from the containment to the atmosphere.

The primary function of the containment isolation system is to allow the normal or emergency passage of fluids through the containment boundary while preserving the integrity of the containment boundary. This prevents or limits the escape of fission products, including radioactivity that may result from postulated accidents. Containment isolation provisions are designed so that fluid lines penetrating the primary containment boundary are isolated in the event of an accident.

The passive core cooling system is designed to provide emergency core cooling following postulated design-basis events. This system injects water into the reactor coolant system to provide adequate core cooling for the complete range of loss-of-coolant accident events. It also provides core decay heat removal during transients, accidents, or whenever the normal heat removal paths are lost.

The main control room emergency habitability system is designed so that the main control room remains habitable following a postulated design-basis event. With a loss of all AC power sources, the habitability system maintains an acceptable environment for continued operating staff occupancy.

Natural removal processes inside containment, the containment boundary, and the containment isolation system provide post-accident, safety-related fission product control. The natural removal processes, including various aerosol removal processes and pool scrubbing, remove airborne particulates and elemental iodine from the containment atmosphere following a postulated design-basis event.

Exclusion Area Boundary
The EAB for the AP1000 is the same as the EAB for the B&W alternative and is discussed in Subsection 2.2.1 (see Figure 2-3).

2.3.2. Use of Partially Constructed Facility

Approximately 400 acres of the 1,600-acre BLN site were previously disturbed for the partially constructed BLN 1&2 and associated plant structures. Construction of one AP1000 unit and associated structures is expected to require clearing of about 50 acres of forested land and reclearing and grading of previously disturbed ground. The existing turbine building and the office and service buildings at the BLN site would be removed under Alternative C.

Many of the other main structures from the partially completed BLN 1&2 would be used for the operation of an AP1000 reactor. These include natural draft cooling towers, intake channel and pumping station, blowdown discharge structure, transmission lines and switchyards, barge unloading dock, railroad spur, and meteorological tower (see Figure 2-12). Use of existing structures reduces the amount of additional land that would be disturbed and is cost-effective. The following is a description of these systems and how they would serve an AP1000.

Natural Draft Cooling Tower
TVA's 1974 FES considered several heat dissipation systems. Considering feasibility, environmental impact, and cost, the natural draft cooling towers represented the best balance and were selected as the best heat dissipation facilities for BLN 1&2 and were

constructed. For the same reasons identified above, TVA proposes to utilize one of the existing cooling towers to provide heat dissipation for an AP1000.

Intake Channel and Pumping Station
The intake channel and pumping station would provide makeup water to an AP1000. Removal of silt from the intake channel would be necessary. From the pumping station to the shoreline (a distance of approximately 1,200 feet), approximately 10,000 cubic yards of dredged material would be removed. Dredged material would be disposed of in an on-site spoils area above the 500-year flood elevation.

Blowdown Discharge Structure
The purpose of the existing discharge system is to disperse blowdown water from the cooling towers into the Guntersville Reservoir. Additional information about the blowdown discharge and diffuser can be found in Subsection 3.1.3. The blowdown discharge system configuration and function for an AP1000 unit would be the same as for a B&W unit.

Transmission Lines and Switchyards
A detailed discussion of the existing transmission lines and switchyards is provided in Section 2.6. No new transmission lines were proposed in the COLA ER, and none are proposed in this FSEIS.

Barge Unloading Dock
The barge unloading dock would allow the use of barges to transport heavy equipment, large reactor components (e.g., reactor vessel, steam generators, pressurizer), and construction modules too large to ship by train. With barge access, larger modules can be assembled in the factory, reducing on-site construction activity and workforce. An AP1000 unit would require an estimated total of 34 barge shipments over a three- to four-month period. These shipments of prefabricated modules would likely occur between the end of site preparation and beginning of construction commencement. Another 12 barge shipments, containing large vessels and heavy equipment, would likely be spread out over the duration of the construction period, and it is not anticipated that more than one or two barges would arrive at any particular time. Construction equipment barges would arrive as the equipment is needed, then depart as soon as the equipment is unloaded.

Dredging in the area of the barge unloading dock would be required for construction of an AP1000 unit, because the barge loads of AP1000 construction modules and components are expected to be heavier than those for a B&W unit. Approximately 240 cubic yards of dredged material would be removed. It is also likely there would be one barge for the maintenance dredging activity, with the spoils transferred to equipment that would haul it directly to the spoils area, and that barge would depart shortly after the dredging is completed. This refurbishment/maintenance activity would occur near the beginning of construction to prepare the barge unloading dock for the construction period activity. Dredged material would be disposed of in an on-site spoils area above the 500-year flood elevation.

Barge transportation would also be used to remove construction debris and other waste from the site.

Railroad Spur
The railroad spur would be refurbished to support the delivery of components and modules small enough to be shipped in a rail car (e.g., large pumps, bulk construction commodities).

Rail transportation would also be used to remove construction debris and other waste from the site.

Meteorological Tower
The existing meteorological tower was built in 2006. The meteorological facility consists of a 55-meter instrumented tower for wind and temperature measurements, a separate 10-meter tower for dewpoint measurements, a ground-based instrument for rainfall measurements, and a data collection system in an instrument building (environmental data station). The environmental data station is located west of the tower base and has been evaluated as having no adverse influence on the measurements taken at the tower. The data collected included wind speeds, wind directions, and temperatures at the 10-meter and 55-meter levels and dewpoint temperatures at the 10-meter level. The location of the meteorological tower is sufficiently removed from any plant structures or significant topographic features. This system would provide adequate data to represent on-site meteorological conditions and to describe the local and regional atmospheric transport and diffusion characteristics for operation of an AP1000 unit.

2.4. Other Energy Alternatives Considered

TVA evaluated over 100 supply-side (generation) and 60 demand-side (energy efficiency, energy conservation, etc.) resource options in its December 1995 *Energy Vision 2020* EIS. Subsequent environmental reviews, e.g., *Final Environmental Impact Statement for the Bellefonte Conversion Project* (TVA 1997), have updated these evaluations as appropriate for a number of the resource options. In general, the *Energy Vision 2020* evaluations remain adequate. However, TVA is again updating these evaluations in its ongoing IRP process. The consideration of alternatives to nuclear-powered generation at the BLN site tier from *Energy Vision 2020* and its evaluations and the updates of those evaluations in the documents identified in Section 1.7. This section addresses the merits of competing energy resource options with particular attention to those identified by commenters on the DSEIS.

The analysis of alternatives is summarized below and includes options that would not require new generating capacity (Subsection 2.4.1), those that would require new generating capacity (Subsection 2.4.2), and a combination of those alternatives (Subsection 2.4.3).

Reasonable alternatives to the construction and operation of nuclear generation at the BLN site are energy resource options, both supply-side and demand-side options, which substantially meet the purpose and need for the proposed nuclear unit at the BLN site. Supply-side resource options must be capable of delivering generation with a profile similar to that of nuclear generation. Resource options that are technically infeasible, impracticable, ineffective, substantially more expensive, or introduce greater environmental impact are not considered reasonable.

2.4.1. Alternatives Not Requiring New Generating Capacity

TVA considered several alternatives that could potentially replace new generating capacity. In reviewing these alternatives, TVA considered whether the option would provide a viable and reasonable alternative to the proposed BLN project. The alternatives below were considered but rejected for detailed consideration for the reasons discussed.

Power Purchases
TVA regularly reviews purchased power options (buying energy and/or capacity from other suppliers for use on the TVA system) and has entered into long-term contracts to obtain

firm capacity. Currently, TVA has a long-term base load purchase from the Red Hills coal-fired plant, a long-term lease of the Caledonia combustion turbine plant, a long-term hydroelectric purchase from SEPA, long-term power purchase agreements for wind energy resulting from the December 2008 Request for Proposals for Renewable Energy and/or Clean Energy Sources, and short-term purchases from the wholesale power market. Therefore, the use of purchased power is already included in TVA's current and future capacity estimates. Purchasing additional power from other generators was not addressed further because it (1) is already part of TVA's resource portfolio, (2) transfers environmental impacts to another location, and (3) involves additional potential impacts on transmission if sources are outside the TVA service area. There is also risk that purchased power will not be delivered.

Repowering Electrical Generating Plants

Repowering electrical generating plants is the process by which utilities update, change the fuel source, or change the technology of existing plants to realize gains in efficiency or output not possible at the time the plant was constructed. Power uprates would be a potential alternative source of base load electricity. NRC has approved power uprates for TVA's Browns Ferry Nuclear Plant (BFN), Sequoyah Nuclear Plant (SQN), and Watts Bar Nuclear Plant (WBN) since 1998, and TVA is seeking additional uprates for its BFN units. The need for power analysis in Section 1.4 provides more detailed information on the additional electrical generation that would be provided by approved or planned power uprates. However, power uprates are not sufficient by themselves to meet forecasted capacity needs of 7,500 MW from 2010 to 2019 (medium-load forecast). TVA continues to modernize its hydrogeneration, which increases its hydrogeneration capacity. TVA is considering converting some fossil units to biomass and studies are underway support this. Such conversions would change the operational characteristics of converted units but would not materially address TVA's base load needs. TVA is considering laying up additional coal-fired units. Such lay-ups increase the need to acquire replacement resources such as the proposed BLN unit.

Energy Conservation

Energy Efficiency and Demand Response (EEDR) programs, also sometimes called Demand Side Management (DSM) or energy conservation programs, offer potential ways to help TVA manage energy consumption and the growth in peak demand. Since the 1970s, TVA has had residential, commercial, and industrial programs to reduce peak demand and energy consumption. As currently implemented, TVA's EEDR portfolio focuses on reduction in peak demand. TVA has interruptible load contracts with industrial customers that allow TVA to reduce the flow of energy to them during high demand periods. TVA's experience to date is that successful energy conservation programs are highly dependent on the end users' recognition of the cost effectiveness of conservation.

TVA received comments on the DSEIS that energy efficiency should be used to reduce demand. TVA has reviewed the most recently published studies (Brown et al. 2009; Chandler and Brown 2009) identified by comment providers as well as reports published since the close of the comment period (Brown et al. 2010). These studies estimate the potential of EE to effectively add capacity to power systems–through energy savings–to replace or delay the construction of new generating plants through 2020 and/or 2030. For comparative purposes, TVA also reviewed a study by the Electric Power Research Institute that forecasted energy efficiency potential in southern U.S. states (EPRI 2009a).

TVA recognizes the important role conservation plays in shaping the load balance and is committed to building EEDR programs for their important resource potential. As part of the

Integrated Resource Planning process initiated in June 2009, TVA has developed program initiatives to focus on reducing energy consumption as well as decreasing peak demand. These EEDR program initiatives include the following elements:

- Residential programs for new site-built and manufactured homes, *energy right* home evaluations and in-home energy assessments, heat pump and high-efficiency air-conditioning installation and maintenance, and weatherization assistance.

- Commercial and industrial programs providing technical assistance, efficiency advice, incentives, and audits for new and existing facilities.

- Demand response programs for interruptible loads, direct load control, and conservation voltage regulation.

This FSEIS incorporates an EEDR program into the base case and all alternatives considered that reflects the energy efficiency that can result from TVA's programmatic efforts. These reductions are in addition to those energy savings that are naturally occurring due to existing legislation and policies and the independent programs of its distributors. The base case includes an EEDR program that reduces required energy needs by about 5,200 GWh in the 2018-2020 time period, averaging 0.3 percent reduction per year through 2020. This annual reduction is about 55 percent of the moderate achievable estimate of 0.5 percent annual reduction through 2020 by the Meta-Review study (Chandler and Brown 2009) and about 70 percent of the realistic achievable estimate of 0.4 percent for southern states by EPRI (2009). The Need for Power analysis in Section 1.4 shows that the base case EEDR program as well as the proposed nuclear unit and additional gas and nuclear expansion units are needed to meet the forecasted demand for power.

Each of the reports reviewed by TVA also suggest that additional savings are achievable with "transformational" policy intervention by businesses and governments. Several states and regions have developed legislation to mandate energy savings levels and regulatory mechanisms to make EE a sustainable business. Notably, TVA has found success stories in California, the Northwest and smaller states in the Northeast, where long-term application of aggressive conservation measures and existing funding mechanisms offset the need for new investment in generating facilities. The reports show that the Southern region lags far behind in developing its EE potential.

All of the reports acknowledge the technical and policy barriers to achieving the maximum potential energy reduction from aggressive energy efficiency programs. There is significant uncertainty associated with the implementation of such programs, given that widespread investment in new distribution technologies and other research is uncertain in TVA's service territory as its distributors ultimately make the decisions on most end-use technology investments. Substantial policy, legislative, and behavioral changes must occur before TVA can rely extensively on dependable capacity from conservation measures as a substitute resource for balancing generation and load.

Despite reservations about the ability of such programs to achieve such a goal, TVA constructed an enhanced case to evaluate the effect of a more extensive EEDR program on the portfolio mix and on power costs in the 2018-2020 time period. As with the base case EEDR program, the enhanced program focuses primarily on residential, commercial and industrial programs to reduce energy consumption. This is considered to be a

moderately aggressive EEDR program and would be challenging for the TVA power service area to achieve, as discussed above. The TVA Enhanced EEDR program averages 0.6 percent reduction per year through 2020. This is approximately 55-75 percent of the maximum achievable estimates of 1 percent by the Meta-Review study (Chandler and Brown 2009), 0.9 percent for southern states by EPRI (2009), 0.7 percent for Appalachia by the ARC (Brown et al. 2009), and 0.9 percent by the Energy Efficiency in the South study (Brown et al. 2010).

Figure 2-14 shows the forecasted reduction in energy consumption for both the EEDR base program and the Enhanced EEDR program.

As shown in the analysis of an Enhanced EEDR in Section 1.4, even with substantial energy replacement through conservation measures, TVA must still add new generation in the 2018-2020 time frame to balance resources with the projected load requirements. Therefore, energy conservation cannot meet the projected capacity needs in the 2018-2020 time frame and, consequently, does not meet the identified need.

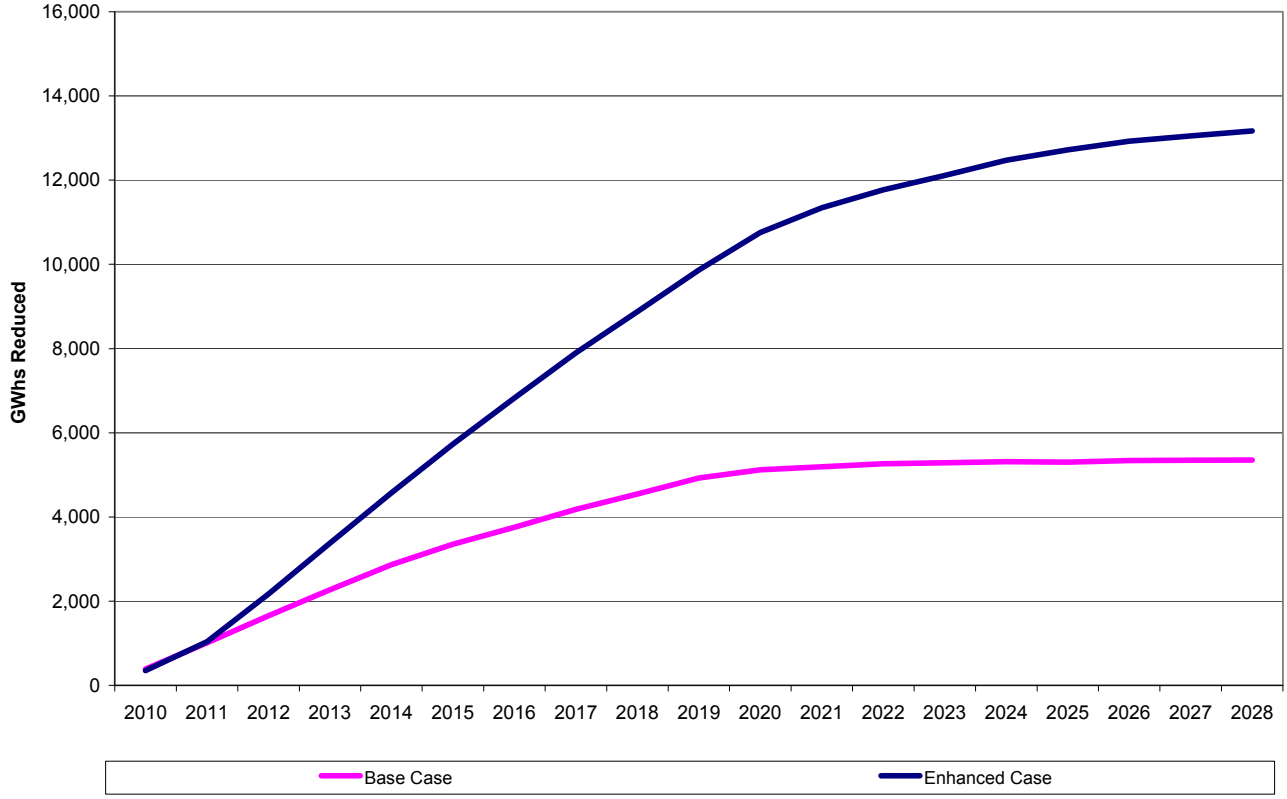


Figure 2-14. Energy Efficiency and Demand Response Scenarios

2.4.2. Alternatives Requiring New Generating Capacity

TVA also considered whether building new nonnuclear capacity would address the need for new capacity. Sources were examined alone and in combination to determine if the system capacity requirements could be met by other sources of energy.

Fossil Fuel Energy Sources

Primary fossil fuel alternatives to nuclear-powered electrical generation at the BLN site are coal-fired generation and natural gas-fired generation. In *Energy Vision 2020* and other reviews, TVA assessed several types of impacts for both sources: air quality, waste management, land use, water use and quality, human health, ecology, socioeconomics, aesthetics, historic and cultural resources, and environmental justice. The potential environmental impacts and merits of coal-fired or gas-fired generation have not materially changed since these options were evaluated in *Energy Vision 2020*. A coal-fired plant is not environmentally preferable to a nuclear plant, due primarily to impacts on air quality, waste management, and aesthetics. A natural gas-fired plant also is not environmentally preferable to a nuclear unit, due primarily to impacts on air quality. In addition, many of the construction-related environmental impacts of a nuclear unit at the BLN site have already occurred.

TVA has considered the conversion of the BLN site to an IGCC facility, as described in *Energy Vision 2020* and analyzed in a subsequent site-specific EIS (TVA 1997). Constructing an IGCC facility at the BLN site would not use existing assets at the BLN site to the same substantial degree as a nuclear unit, increasing environmental impacts directly and cumulatively. In addition, an IGCC facility emits CO_2, which makes it less environmentally desirable than nuclear generation. While the capture of CO_2 from an IGCC facility is technologically feasible, because CO_2 can be separated from the synthetic gas prior to combustion, further research and development is necessary to sequester the captured CO_2.

Wind

Wind turbines are commercially available today ranging from approximately 250 watts to 5 MW. The average size of wind turbines installed in the U.S. in 2008 was 1.65 MW. According to a Tennessee Wind Map and Resource Potential estimate from the DOE's Office of Energy Efficiency and Renewable Energy (DOE 2010), approximately 4 GW of wind power capacity is available at a gross capacity factor of 28 percent, based on a turbine hub height of 100 meters. This hub height is taller than most current turbine installations, which typically use between 50 to 80 meters. However, 100-meter hub heights are technically feasible with current wind turbine technology, and taller turbines help make wind power more economically feasible in low wind areas such as the TVA service area. Taking into account electrical losses, environmental factors, and wake effects (of surrounding wind turbines), the net capacity factor for the TVA service area is projected to be 24.4 percent, which is on the low end of the typical range of net capacity factors for modern utility-scale wind power projects of 25 percent to 40 percent.

Using the above-average turbine capacity and capacity factor, approximately 23 200-MW wind projects, each consisting of 121 wind turbines, would be required to generate the annual electricity equivalent to that of the proposed nuclear facility. The 23 projects in total would require an estimated 436 square miles of land, of which 5 percent would be occupied by turbines, access roads, switchyards and other equipment, and the remainder would be required for adequate spacing to minimize wake effects of surrounding turbines. The required area is more than half the size of the Great Smoky Mountains National Park.

This estimate assumes that the demand for electricity is present at the time the generation is available from the wind turbines, which is impractical to assume. Energy storage can be coupled with wind power to simulate a profile comparable to base load generation. A compressed air energy storage (CAES) facility could capture the power of the wind during low load times and utilizes it during higher load times. The wind turbines provide the power

to compress the air into a storage volume, such as an underground salt cavern or aquifer. The compressed air is discharged from the storage volume into a set of gas turbines that are fired with natural gas. The efficiency of the turbines is improved because compression of the inlet air is provided by the CAES facility instead of by the turbine itself.

The only operating CAES system in the U.S. is the McIntosh Power Plant in Alabama. Using the same operating parameters as those in the McIntosh Plant, about 2,310 wind turbines, rated at 1.65 MW each, along with over 45 million British thermal units (BTU) of natural gas consumption per year would be required to generate annual base load electricity comparable to that of the proposed nuclear facility. The land requirement for wind technology, coupled with the impacts to air quality from the combustion of natural gas, make wind power with CAES less environmentally preferable to a nuclear plant. In addition, CAES technology is still in the demonstration phase and is not technologically mature.

Solar

Generation from solar power is available in two different technologies: concentrating solar power (CSP) and photovoltaic (PV). CSP technologies (i.e., solar thermal plants using parabolic troughs, power tower, etc.) were not considered in TVA's analysis due to the low rate of delivery of solar radiation within the TVA territory. Direct solar radiation in Memphis is approximately 4.4 kilowatt-hour per square meter per day (kWh/m^2/day), which is below the minimum level of 6.75 kWh/m^2/day required for a viable CSP generating facility. Solar PV can make use of both direct solar radiation and diffuse horizontal radiation, which is one reason PV is technically feasible in more areas of the United States than CSP technologies. The average solar radiation for PV technology was estimated from National Renewable Energy Laboratory's solar radiation map for the western portion of the TVA region as 4.9 kWh/m^2/day. The solar PV capacity factor in the western portion of the TVA service region is calculated at 17 percent, which is equivalent to approximately four hours of usable solar radiation available each day. Some days have more or less solar radiation available, but this assumption is used to simulate base load operation in the discussion below.

To match the generation profile of a nuclear plant, solar PV generation is assumed to be stored in batteries that generate electricity during periods of no or low solar radiation. Battery storage systems used for energy management are those that have a deployment duration exceeding one hour. Commercially available systems come in standard unit sizes, ranging from 250 kilowatts (kW) to 2 MW. Systems of batteries are assembled to meet the needs of a particular project. Currently one of the biggest battery storage systems installed for energy management applications has 34 MW power capacity with six hours of storage capacity. A sodium sulfur (NaS) standard battery size of 2 MW with six hours of storage capacity and an electrical efficiency of 70 percent was used for the purposes of this evaluation. The battery system will be recharged from the PV modules during daylight and will be discharged when the PV power is not available. Batteries with a rating of 2 MW per battery were used. A solar to electric efficiency of 8.6 percent is typical for the complete PV panel and battery system.

The total installed land area required for commercial PV on a fixed 30-degree tilt support structure with appropriate spacing between panels for roads and to avoid shadow effects is estimated to be 5.9 acre/MW. Approximately 193 50-MW PV facilities with a total footprint of 57,000 acres (about 89 square miles) would be required to generate electricity equivalent to that of the proposed nuclear facility. The large land area requirement for such a PV system makes the option less environmentally preferable to the proposed nuclear plant.

Biomass

Biomass power plants use organic matter to generate electricity. It is one of the few renewable power options that can be operated at a relatively high capacity factor (85 percent) and is "dispatchable," meaning that its generation can be planned and scheduled much like a conventional fossil-fueled unit. TVA is currently performing biomass fuel availability surveys in the region, and a comprehensive study is underway to assess the feasibility of converting one or more coal-burning units to biomass fuel. Biomass generation was a qualifying technology in TVA's request for proposal issued in 2008 for renewable resources. However, no competitive bids sourced from biomass were received. This may suggest doubt in the market place about the sustainability of biomass generation in the TVA region at reliably competitive prices.

Agricultural and forest resources provide the most prevalent form of biomass fuel available in the TVA region. These include agricultural "crop" residues (i.e., by-products of harvest), dedicated energy crops (i.e., switchgrass on Conservation Reserve Program [CRP] lands), forest residues (i.e., waste products from logging operations) and methane gas by-products from livestock manure. Biomass resources, such as primary milling residues (i.e., by-products of commercial mills), secondary milling residues (i.e., by-products of woodworking and furniture shops), urban wood residues (i.e., waste wood products from construction, demolition, and residential), and methane gas by-products from landfills and wastewater treatment facilities are not as prevalent in less densely populated regions such as the TVA service territory.

Agricultural residues by state and county were obtained from the U.S. Department of Agriculture's National Agricultural Statistics Service. Data from 2006-2009 were averaged to estimate the typical crop production. It was assumed that 35 percent of the total gross residue is available for collection, leaving the remaining residue on the land to ensure healthy land and soil quality. Dedicated energy crops by state and county were estimated from data obtained from the Farm Service Agency (FSA) of the U.S. Department of Agriculture. The data compiled by the FSA include total CRP acreage by county. The land within the TVA service region can yield 5.0 dry tons of switchgrass per acre. Switchgrass production was calculated over the land area, assuming that 100 percent of CRP land is devoted to switchgrass.

Forest and primary milling residues by state and county were obtained from the U.S. Forest Service Southern Research Station's Timber Product Output Reports (USFS 2007). Data from 2007 were used and are the most recent available. Reported volumetric data are converted to mass using a uniform density factor of 25 pounds per cubic foot of forest product. Residues from primary wood-using mills are classified as utilized and unutilized. Most primary milling residues in the TVA region are classified as utilized and are assumed not to be available for biomass power generation. Secondary milling residues, urban wood residues, and methane gas amounts by state were obtained from a National Renewable Energy Laboratory (NREL) report (NREL 2005) and scaled to the area of each state within the TVA region.

The capacity and energy from each of the biomass fuel sources was estimated by assuming the most likely generation technology to be used. A stoker or bubbling fluidized bed technology with a heat rate of 15,000 BTU/kWh was assumed for solid fuel. For methane gas as fuel, an internal combustion engine at a heat rate of 12,500 BTU/kWh was assumed. Approximately 2,500 MW of biomass generation is estimated from agricultural and forest resources. Some 210 MW of biomass generation is estimated from unutilized

primary and secondary mill residues and urban wood residues. Another 60 MW is estimated from landfill and wastewater treatment methane sources.

Whether based on agricultural or forest resources, or population-based sources, biomass fuel is dispersed and must be collected and processed for use in biomass generating units. Consequently, the cost of collection system infrastructure and diesel fuel generally limits biomass collection to a 50-mile radius, which in turn limits plant capacity to a maximum of 30-50 MW. Biomass generating units with required emissions controls provide about the same capacity factor and environmental impacts as a small coal plant. A biomass-fired plant is not environmentally preferable to a nuclear plant due primarily to impacts on air quality, waste management, and the impacts of biomass fuel collection infrastructure.

Hydropower

The DOE EERE study (DOE 2006) was used to develop an estimate of hydropower resources that are feasible for development within the TVA region. The EERE report estimates the megawatts available for development and, of those available, how many would be feasible to develop. Available megawatts are based on those sites that are not located in zones where hydropower development is unlikely. The available megawatts are also not colocated with existing hydropower plants. The determination of availability also did not consider ownership or control of available sites. The project feasibility criteria included such factors as land use and environmental sensitivities, prior development, site access, and load and transmission proximity.

The TVA service territory encompasses much of the state of Tennessee and portions of neighboring states. The portion of available annual average hydropower in each state was determined by estimating the number of sites within the TVA coverage area for that state as compared to the number of sites in the entire state. The amount of feasible megawatts in each state was estimated to be in the same proportion as the feasible to available megawatts in that state in total. Using this approach, the total feasible hydropower capacity is 843 MWa (MWa = annual generation/annual hours). None of the feasible capacity is from large power sources (>30 MWa). Seventy percent of the feasible hydro was small hydro (1 MWa ≤Pa ≤30 MWa), and 30 percent was low power resources (<1 MWa). Low power resources include conventional technology, ultra low head and kinetic energy turbines, and micro-hydro power.

Compared to nuclear generation, new hydropower has lower capacity factors and more severe environmental impacts. Also, feasible new sites for hydroelectric facilities are limited.

2.4.3. Consideration of Other Alternatives and Combination of Alternatives

Combining alternatives could achieve an energy profile similar to base load operation. There are many possible combinations of the coal, gas, solar, wind, biomass, and hydro alternatives described above. Combinations can utilize storage technology with wind or solar technology or augment the variability of wind and solar power with the dispatchability of fossil generation (coal and gas) or biomass generation.

A storage technology other than CAES that could be combined with wind generation is pumped storage. TVA has an existing 1,600-MW pumped storage plant at Raccoon Mountain, near Chattanooga, Tennessee. Excess energy from lower cost generating resources is used to pump water from Nickajack Reservoir to the upper reservoir during periods of low power demand. The pumps are reversible and utilized as turbines to

produce power using water from the upper reservoir during periods of high demand. Additional pumped storage sites are available in the TVA region and could be developed in place of CAES to store excess wind energy from off-peak periods and produce power in periods when wind power is not available. Pumped storage plants require 2,000 to 3,000 acres for the upper pool, the generating plant, and a lower pool if another reservoir is not available. The environmental impacts associated with construction of a pumped storage plant are typical of projects of this scope and size, including recreation and scenic impacts, potential disruption of terrestrial and aquatic habitats, cultural resource impacts, and socioeconomic impacts. Operational impacts include environmental impacts of the operation of thermal plants that might be used to supply power to the plant in pumping mode.

Renewable generation also could be combined with fossil or generation instead of a storage technology to provide energy when renewable resources are not available. A natural gas-fired plant generally has fewer environmental impacts than a coal-fired plant. But the natural gas-fired facility alone has environmental impacts that are greater than nuclear, particularly those related to the emissions of air pollutants and greenhouse gases. As a result, the combination of a natural gas-fired plant and wind, solar, or hydro facilities would have environmental impacts that are equal to or greater than those of a nuclear facility.

Each of the potential combinations discussed above requires large land areas and/or has impacts to air quality due to combustion of natural gas or biomass. Therefore, the environmental impacts of combination alternatives are less preferable to those of the proposed nuclear facility.

2.4.4. Summary

TVA has concluded in Section 1.4 that new generating capacity is necessary to maintain system reliability. TVA's existing generating supply consists of a combination of existing TVA-owned resources, budgeted and approved projects (such as new plant additions and uprates to existing assets), and/or power purchase agreements. This supply includes a diverse combination of coal, nuclear, hydroelectric, natural gas and oil, market purchases, and renewable resources designed to provide reliable, low-cost power while reducing the risk of disproportionate reliance on any one type of resource.

TVA has considered alternatives to nuclear-powered generation, including those that do not require new generating capacity. Purchasing additional power from other generators was not addressed further because it is already part of TVA's portfolio of resources, transfers environmental impacts to another location, involves additional potential impacts on transmission if sources are outside the TVA service area, and has increased risk components to TVA-owned and controlled resources. Power uprates are not sufficient by themselves to meet forecasted capacity needs. Even with substantial energy replacement through conservation measures, TVA must still add new generation to balance resources with the projected load requirements.

The addition of other types of generating capacity as an alternative to nuclear capacity was also evaluated and included fossil fuel energy sources as well as renewable energy sources. In general, coal-fired and natural gas-fired power was found not to be environmentally preferable to a nuclear plant due primarily to impacts on air quality, waste management, and aesthetics.

Renewable energy sources such as wind and solar have significant land requirements to generate electricity comparable to that of a nuclear facility. Additionally, to provide generation profiles similar to a nuclear unit, they must be coupled with energy storage capacity, which increases the land requirement to compensate for additional efficiency losses or with fossil-fueled generation, which increases the impact on air quality. Biomass as a renewable fuel can be used to provide base load power provided adequate fuel supply exists; however, the air quality impacts are much greater than nuclear resources. Hydroelectric power has been concluded to be less environmentally preferable given its low capacity factors, environmental impacts, and the limited availability of feasible new sites in the TVA territory.

2.5. Alternative Sites Considered

Alternative sites and selection of the BLN site for the construction and operation of a nuclear-powered electricity generation facility (BLN 1&2) were discussed in TVA's 1974 FES (TVA 1974a). The COLA ER (TVA 2008a) most recently addressed site screening and selection, alternative sites, and selection of the BLN site for nuclear generation of electricity with AP1000 units. In addition to the COLA ER alternative site analyses, TVA submitted the following supplemental white papers to the NRC in 2008:

- "Descriptions of Existing Facilities and Infrastructure for Alternative Sites to the Selected Bellefonte Site," June 2008 (TVA 2008c).
- "Criteria and Basis for Comparative Ratings Among Alternative Brownfield and Greenfield Sites," August 2008 (TVA 2008d).
- "Site Screening Process: Information Complementary to Subsection 9.3.2 of the Bellefonte Nuclear Plant, Units 3 and 4, COLA Applicant's Environmental Report," August 2008 (TVA 2008e).

2.5.1. Identification and Screening of Potential Sites

The consideration of alternatives is required by NEPA and 10 CFR §51.45. The Electric Power Research Institute (EPRI) siting guide (EPRI 2002), the industry standard for site selection, was used as a general guideline in site selection analysis for the COLA. The EPRI guide's stated objective of site comparison is "to identify and rank a relatively small number of candidate sites for a more detailed study, with the goal of selecting a preferred site from among candidate sites."

TVA's region of interest (ROI) for the COLA ER was and remains the TVA power service area, as previously described in Section 1.4 of this FSEIS.

One of the earliest, integral, and most critical components of planning for future energy facilities has been the identification and selection of suitable locations for their construction and operation. Historically, and on an ongoing basis through the 1960s and 1970s, TVA conducted initial high-level screening assessments of more than 200 sites for electricity generation across the TVA service area. The TVA service region (ROI) was divided into five system study areas that roughly coincided with the concentration of load centers in the region. This division does not represent a real physical division in the power service area, because all these areas are strongly interconnected with transmission lines. One purpose of this approach was to identify superior sites within each area that would reduce the need for construction of additional transmission to meet load requirements. This concern remains valid today, but load growth across the TVA service area, as well as improved

transmission system characteristics and ability for load balancing, now further reduces that concern.

Four general criteria were used to guide potential site identification.

1. Potential site areas that exhibited a suitable combination of engineering, environmental, land use, cultural, and institutional characteristics for power plant siting.
2. Potential site areas of a developable size (1,000 acres or more).
3. Manageable number of potential sites.
4. Relatively even distribution of potential sites along the Tennessee River corridor and within the defined TVA service area.

Broad-based interdisciplinary TVA teams that reflected power planning, transmission, environmental, and financial interests conducted these screening efforts. These studies identified sites that warranted further detailed investigations. Of these, eventually nine sites were selected for purchase as inventory for nuclear generation sites: BLN, Yellow Creek (YCN), Hartsville (HVN), Phipps Bend (PBN), WBN, BFN, SQN, Murphy Hill (MH), and Saltillo (STO).

TVA constructed multiunit nuclear generation facilities at three of the above sites: BFN near Athens, Alabama; SQN near Chattanooga, Tennessee; and WBN near Spring City, Tennessee. In addition, TVA obtained construction permits from the NRC to build nuclear units at the BLN, YCN, HVN, and PBN sites. Site preparation and construction of nuclear units proceeded in varying degrees at each of these sites. Due to slowing demand for power, TVA subsequently halted construction at the latter three sites (HVN, PBN, and YCN) and conveyed portions of them to other governmental entities for potential industrial development. TVA has maintained the MH and STO sites as part of its inventory of potential generation sites. However, due to uncertainties regarding foundation conditions, the STO site was eliminated from consideration in the COLA ER.

The COLA ER site analysis initially considered the BLN site and the other seven potential sites for new nuclear generation: the three operating TVA nuclear sites (BFN, WBN, and SQN), three brownfield sites (HVN, PBN, and YCN), and one greenfield site (MH). These eight sites had already undergone evaluation and documentation under NEPA, and except for MH, they had also undergone licensing evaluation and documentation processes of the AEC (predecessor to the NRC). The eight potential sites considered in the COLA ER are described further in the paragraphs below.

Operating Nuclear Plants

The BFN site is situated beside Wheeler Reservoir on the Tennessee River and has three operating nuclear reactors. The BFN site has two substantive limitations regarding its potential for co-locating an additional nuclear reactor. First, the operation of an additional nuclear unit, even operating in closed-cycle mode, would increase thermal loading to Wheeler Reservoir, which could exacerbate the existing challenges to managing the three BFN units in compliance with thermal limits, especially during low flow or drought conditions. Second, because the BFN site is approximately 850 acres and already accommodates three operating nuclear reactors, the site is not large enough to accommodate an additional nuclear reactor. Additional property would have to be acquired. Because of these site issues, TVA decided that co-locating an additional nuclear reactor at

BFN is not advantageous and does not consider the BFN site a viable alternative for new nuclear generation.

The WBN site comprises approximately 1,100 acres situated on the northern end of Chickamauga Reservoir in east Tennessee and has one operating nuclear reactor, WBN Unit 1. TVA is currently completing the partially constructed WBN Unit 2. A delay in completing WBN Unit 2 would likely have resulted in overlapping construction of the AP1000 units. This overlap would have unnecessarily affected not only project management resources, but produced greater strain on plant operations, local community services, and infrastructure. It was also anticipated that once WBN Unit 2 was completed and operating, the combined total thermal discharges to the river could often approach allowable NPDES thermal limits. Therefore, co-locating an additional nuclear unit at the site would exacerbate existing thermal loading and could potentially affect the operation of WBN Units 1 and 2. Because of these site issues, TVA decided that co-locating an additional nuclear reactor at WBN is not advantageous and does not consider the WBN site a viable alternative for new nuclear capacity for the 2018-2020 time frame.

The SQN site is situated beside Chickamauga Reservoir and has two operating nuclear reactors. The SQN site has two substantive limitations for co-locating an additional nuclear reactor. First, as in the case of BFN and WBN, the SQN site has a small thermal discharge margin that would be exacerbated by co-locating an additional nuclear reactor there. Second, because the SQN site is approximately 630 acres and already accommodates two operating nuclear units, the site is not large enough to accommodate an additional reactor. Additional property would have to be acquired. Because of these site issues, TVA decided that co-locating an additional nuclear reactor at SQN is not advantageous and does not consider the SQN site a viable alternative for new nuclear capacity for the 2018-2020 time frame.

Because TVA concluded that co-location at existing nuclear sites (BFN, SQN, or WBN) is not an acceptable alternative for reasons related to thermal issues, unavailability of adequate land, the inability to make beneficial use of existing assets, and large-scale changes underway on site, the three operating nuclear plants were eliminated from further consideration in the COLA ER alternative site analysis.

Brownfield Sites

TVA selected four brownfield sites (BLN, HVN, PBN, and YCN) and one greenfield site (MH) as candidate sites in its ROI for potential siting of a new nuclear facility in the COLA ER, which also reviewed each of these sites in detail. For each of the four brownfield sites, construction permits had been obtained under the regulations and evaluation procedures of the period. The respective historical review documents are as follows:

- *Final Environmental Statement, Bellefonte Nuclear Plant Units 1 and 2* (TVA 1974a)
- *Final Environmental Statement, Hartsville Nuclear Plants* (TVA 1975a)
- *Environmental Report, Phipps Bend Nuclear Plant Units 1 and 2* (TVA 1977a)
- *Final Environmental Statement, Yellow Creek Nuclear Plant Units 1 and 2* (TVA 1978b)

The BLN site is located beside Guntersville Reservoir on the Tennessee River near the town of Hollywood and city of Scottsboro. Construction activities at BLN were deferred in 1988. The BLN site is reviewed at length in this FSEIS and the COLA ER.

The former HVN site is situated on the north shore of Old Hickory Reservoir on the Cumberland River in Smith and Trousdale counties, Tennessee. Construction permits were issued for two nuclear plants (Plants A and B) with two units each. The HVN site nuclear units were cancelled in 1983 (Plant B) and 1984 (Plant A).

The former PBN site is located on the Holston River in Hawkins County, Tennessee. Construction at PBN was cancelled in 1982.

The former YCN is located on the Yellow Creek embayment of Pickwick Reservoir (Tennessee River). Construction at YCN was cancelled in 1984.

Although nuclear plant construction was never completed at any of these sites, the brownfield sites offer some of the advantages of an operating nuclear site (e.g., existing infrastructure and facilities, prior screening and NEPA review, available site characterization information). However, because the HVN, PBN, and YCN sites, or portions thereof, were sold for industrial development, TVA would need to reacquire portions of the industrial parks. This would impact existing industrial uses on developed areas of the sites. Transportation corridors to all four of the sites were constructed to facilitate construction of the nuclear plants.

Greenfield Site

The MH site consists of approximately 1,200 acres located in northeast Marshall County, Alabama, on the southern bank of Guntersville Reservoir. Part of the site was graded for a coal gasification project. No other development has occurred on this site to date, and it is currently designated by TVA for natural resource conservation purposes. The MH greenfield site was chosen and evaluated as a site that is representative of other greenfield sites that TVA has previously evaluated. The environmental impacts of construction and operation of a nuclear power generation facility at a greenfield site would be similar to or greater than those at a brownfield or partially developed site. The greenfield site (MH) had been evaluated for a coal gasification project for which TVA prepared an FEIS. This project was cancelled after TVA had done some site grading. The respective historical review document is *Final Environmental Impact Statement, Coal Gasification Project* (TVA 1981a).

2.5.2. Review of Alternative Sites

The alternative site review compared the five candidate locations to determine whether any alternatives are obviously superior to the proposed BLN site. The analysis considered Safety Criteria (geology, cooling system suitability, plant safety, accident effects, operations effects, transportation safety); Environmental Criteria (proximity to natural areas, construction-related effects on aquatic and terrestrial ecology, and wetlands, operations-related effects on aquatic and terrestrial ecology); Socioeconomics Criteria (construction- and operations-related effects, environmental justice, land use, cultural resources); and Engineering and Cost-Related Criteria (water supply, transportation, transmission, and site preparation). Portions of the studies, data, and conclusions of the initial evaluations of each candidate site were used to support this comparison. The sites were evaluated in each area of comparison and given a numerical rating scale of 1 to 5 (least suitable to most suitable). No weighting factors were applied to these criteria. The review process is discussed in detail in the COLA ER, and in the 2008 TVA white papers cited above (TVA 2008c, TVA 2008d, and TVA 2008e).

The alternative sites analysis compared the BLN site with the four alternatives to determine if there was an obviously superior location among the candidate sites. A simultaneous

comparison considered the additional economics, technology, and institutional factors among the candidate sites to see if any was obviously superior. Based on the comparison, there were no obviously superior sites among the candidate sites. The BLN site was selected as the preferred site for additional nuclear generation for the reasons described below.

- Alternative nuclear, brownfield, and greenfield sites are not environmentally preferable to the BLN site. Construction and operation of a new nuclear plant at each of the alternative sites would entail environmental impacts that are equal to or greater than those at the BLN site.
- Existing facilities and infrastructure at the BLN site (e.g., transmission lines, intake and discharge structures, cooling towers, switchyard, barge dock, rail spur, and roads) allow TVA to maximize assets that are currently underutilized, reducing the amount of construction material needed, construction costs, and environmental impacts associated with construction of infrastructure.
- A construction permit for a B&W pressurized water reactor was previously issued for the BLN site. There is no reason to believe the BLN site would not also be suitable for an AP1000 advanced passive pressurized light water reactor.
- TVA siting program studies do not show appreciable differences in most attributes for the sites that were considered in the alternatives analysis. However, the BLN site has several advantages. The BLN site remains under TVA ownership. In addition to allowing the beneficial use of existing assets, the BLN site was rated second highest with respect to the availability of cooling water, as river flow past the BLN site is approximately three times that of PBN and more than twice the flow past HVN. Environmental data were already updated as part of the EIS for potential tritium production at the BLN site (DOE 1999).

2.6. Transmission and Construction Power Supply

The following is a description of the current transmission system associated with the BLN site, the system needs in response to the proposed action, and the types of activities these improvements would entail. This SEIS provides a programmatic-level review of the transmission lines affected by the alternatives. Prior to conducting transmission line upgrades, site-specific reviews would be conducted to further investigate potential effects to the environment. If warranted, additional NEPA documentation would be prepared.

2.6.1. Description of Current System and Needs

Transmission infrastructure, including corridors and switchyards, to support operation of a nuclear plant at the BLN site was identified, reviewed, and evaluated in the earlier environmental review documents prepared by TVA and the AEC for the original facility encompassing BLN 1&2. That review and evaluation included siting data for the potential corridors identified by TVA. The AEC subsequently approved and issued a construction license for BLN 1&2 and the supporting transmission infrastructure into and at the site. The approved transmission system was constructed before the plant entered deferred status.

The existing 500-kV switchyard constructed on the BLN site has been deenergized for a number of years. Four 500-kV transmission lines (the Widows Creek-Bellefonte #1 and #2 500-kV lines, the Bellefonte-Madison 500-kV line, and the Bellefonte-East Point 500-kV line) and two 161-kV transmission lines (the Widows Creek-Bellefonte 161-kV and the Bellefonte-Scottsboro 161-kV) now terminate in the BLN switchyard. The section of the

500-kV lines going into BLN are not energized at present but would be reconnected to the TVA system and energized if the nuclear plant is built and operated. The two 161-kV lines, which are underbuilt (i.e. lines strung on the same structures) on portions of the Bellefonte-Madison 500-kV and the Widows Creek-Bellefonte #1 500-kV lines, are energized and currently connect Widows Creek Fossil Plant (WCF) generation to the TVA transmission system. None of the power being transmitted is generated on the BLN site.

The Widows Creek-Bellefonte #1 and #2 500-kV lines would require uprating (see Subsection 2.6.4). Sections of the Bellefonte-Madison 500-kV and Bellefonte-East Point 500-kV only need to be connected and reenergized. Right-of-way (ROW) vegetation management on the deenergized 500-kV transmission line segments would be brought back to current TVA standards for energized lines. Any needed maintenance on the line would be performed, and any ROW clearing needed to meet TVA and Federal Energy Regulatory Commission (FERC) standards would be carried out. The Widows Creek-Bellefonte and the Bellefonte-Scottsboro 161-kV lines would not need to be changed to support operation of BLN.

In addition to the lines coming into the switchyard, there are six 161-kV lines and one additional 500-kV line that are located elsewhere. The proposed actions related to the transmission system are the same under Alternative B (B&W unit) and Alternative C (AP1000 unit). These lines would be reconductored and/or uprated, as described in Subsection 2.6.4.

2.6.2. Construction Power Supply

The Bellefonte Nuclear Construction Substation was constructed in 1974 as a temporary 46-4.16-kV substation to support the construction of BLN 1&2.

In 2007, TVA retired the Bellefonte Nuclear Construction 46-kV Substation. Subsequently, TVA contracted with North Alabama Electric Cooperative to provide electric service to the BLN site. A 2-mile, 13-kV three-phase circuit has been constructed by North Alabama Electric Cooperative to provide this service. No additional work is expected to be necessary to supply construction power for the proposed BLN unit.

2.6.3. Alternatives Considered

In order to accommodate the delivery of power produced from a single nuclear unit at the BLN site, an *Interconnection System Impact Study* (TVA 2009b) was carried out for the TVA transmission system. This study evaluated the incremental impact of the proposed new generation facility at the BLN site on the TVA power system during various loading conditions. Transmission network upgrades are required if overloading with the new generation is at least 3 percent more than the loading without the new unit. The study assumed operation of the new unit at full capacity and standard operational contingencies on the remainder of the transmission system.

The study projected line overloading and recommended upgrading the electrical capacity of the overloaded transmission lines. As a result, the two alternatives for the transmission line system are the No Action Alternative and the Action Alternative. No new transmission lines would be needed under these transmission alternatives, and therefore no additional ROW would be required.

No Action Alternative
Under the No Action Alternative, current maintenance status and activity would be continued. TVA routinely conducts maintenance activities on transmission lines, which includes removal of vegetation in ROWs, pole replacements, installation of lightning arrestors and counterpoise, and upgrading of existing equipment.

Transmission lines are inspected by aerial surveillance using a helicopter and by ground observation. These inspections are conducted to locate damaged conductors, insulators, and structures, and to report any abnormal conditions that might hamper the normal operation of the line or adversely impact the surrounding area. During these inspections, the condition of vegetation within the ROW, as well as vegetation immediately adjoining the ROW is noted. These observations are then used to plan corrective maintenance or routine vegetation management, which would consist of felling “danger trees” adjacent to the cleared ROW and controlling vegetation within the cleared ROW. Any trees located off the ROW that are tall enough to pass within 10 feet of a conductor or structure (if they were to fall toward the line) are designated as danger trees and would be removed.

Regular maintenance activities for vegetation control occur on a cycle of three to five years. Transmission corridors are managed to prevent woody growth from encroaching on energized transmission lines and potentially causing disruption in service or becoming a general safety hazard. This periodic vegetation management is conducted along ROWs to maintain adequate clearance between tall vegetation and transmission line conductors.

Prior to these activities, TVA biologists and cultural resource specialists conduct a Sensitive Area Review (SAR) of the transmission line area (including the ROW) to identify any resource issues that may occur. A description of the SAR process is contained in Appendix D. These reviews are conducted on a recurring basis that coincides with the maintenance cycle, to ensure that the most current information is provided to the organizations conducting maintenance on these transmission lines.

Because TVA’s transmission system comprises approximately 16,000 ROW miles, it is not possible to field survey every mile of ROW. Therefore, TVA utilizes the best tools available to determine the likelihood of any listed plant or animal inhabiting the section of line under review. TVA maintains a database of more than 30,000 occurrence records for protected plants, animals, caves, heronries, eagle nests, and natural areas for all 201 counties in the entire TVA power service area. All protected species and natural areas that are present, or are potentially present, in transmission line ROWs are taken into consideration when conducting these transmission line reviews. Wetland information maintained by TVA includes National Wetlands Inventory (NWI) wetland maps for the entire power service area. Soil survey maps are also used to identify potential wetland areas. The TVA also maintains records of known archaeological sites and routinely gathers information from the seven-state power service area.

TVA staff examines videos of the transmission line corridors to determine the kinds of habitats present in the project area. Aerial photographs, U.S. Geological Survey (USGS) topographical maps, and low-altitude flyovers are used to detect the presence of sensitive areas that meet habitat requirements for rare species of plants or animals. TVA staff then overlay the ROW with records of sensitive plants and animals, NWI maps, county soil surveys, and other available data in order to identify areas that may require alternative maintenance practices. The standard TVA criteria and guidelines are then applied to make conservative vegetation and/or land management recommendations to the maintenance project managers.

TVA is responsible for many miles of transmission lines that cross aquatic habitat and therefore has procedures in place for ROW maintenance to protect aquatic species. Aquatic biologists review county lists and database records to determine the potential presence of protected animals. Once an occurrence or likely occurrence is identified based on presence of habitat, the area is delineated on TVA maps and assigned a color and corresponding restriction class. Biologists make recommendations specific to the situation, and specialists consult as appropriate.

Management of vegetation within the cleared ROWs uses an integrated vegetation management approach designed to encourage low-growing plant species and discourage tall-growing plant species. A vegetation reclearing plan would be developed for each transmission line segment based upon the periodic inspections described above. The two principal management techniques are mechanical mowing, using tractor-mounted rotary mowers, and herbicide application. Any herbicides used would be applied in accordance with applicable state and federal laws and regulations. Only herbicides registered with the EPA would be used.

Where transmission lines cross natural areas, TVA uses geographic information system (GIS) software to draw boundaries of potentially affected areas including a 0.5-mile buffer. After reviewing available data and consulting with the area specialist or resource manager, potentially affected management areas are assigned a restriction class. Examples of restrictions include hand clearing only and selective spraying of herbicides to shrubs or tree saplings.

Activities associated with the construction, maintenance, and use of TVA transmission lines can be subject to the *National Historic Preservation Act* (NHPA) and its implementing regulations in 36 CFR Part 800. TVA cultural resources staff review the areas of maintenance activity on a case-by-case basis under the SAR process to identify whether the undertaking has any potential for adverse effects on cultural resources, such as historic structures or buried prehistoric sites. If the undertaking has potential for adverse effects, then procedures for avoidance or mitigation of the effects are put into place. Avoidance is generally feasible for transmission line maintenance projects when cultural resources are present. GIS is used to generate a map showing areas that are sensitive from the standpoint of cultural resources, and a code is applied that indicates restrictions on methods of clearing (e.g., no mechanized equipment). These maps are provided to the transmission lines crew supervisors so that crew supervisors will be aware of the necessary restrictions. Restrictions are typically required when a previously recorded cemetery, prehistoric mound, or earthwork occurs within 0.25 mile of the transmission line.

Action Alternative

Under the Action Alternative, the 500-kV switchyard and 500-kV transmission lines would be reenergized, and other existing transmission lines would be refurbished and upgraded as described in Subsection 2.6.4. If either Alternative B (B&W) or Alternative C (AP1000) were selected and implemented for the purposes of nuclear generation, the Action Alternative for the transmission system would also be selected. The scope of work for the transmission Action Alternative is the same under Alternatives B and C, and the affected transmission line ROWs are shown in Figure 2-15.

2.6.4. Proposed Refurbishments and Upgrades Under the Action Alternative

This section provides a description of the switchyard and transmission line upgrades under the Action Alternative. To accommodate the proposed nuclear unit operation, the 500-kV

switchyard would need to be refurbished. The 500-kV breakers and switches would be replaced and two additional 500-kV breakers would be added in the Widows Creek 500-kV switchyard. The generators connected to the TVA system would be equipped with a power system stabilizer (SERC Reliability Corporation [SERC] 2008) and out-of-step tripping relay for generators. Other components of the switchyard's protection and control system would be refurbished or replaced. The 161-kV switchyard would not require refurbishment.

The proposed transmission line upgrades consist of two types: uprating and reconductoring.

Uprates typically consist of retensioning or "resagging" of the existing electrical transmission line conductor. This results in a greater clearance above ground, allowing the line to operate safely at a higher temperature and, thus, increasing the current-carrying capacity of the transmission line. A total of 100.5 miles of transmission line would be uprated.

Reconductoring consists of replacing the conductor with a new conductor capable of carrying higher current levels. A total of 121.4 miles of transmission line would be reconductored.

All resagging or reconductoring activities would be confined to the existing ROWs. The following activities are typically involved in resagging or reconductoring.

- *Engineering* - Engineering analysis is conducted to determine where resagging or reconductoring is needed and to determine the nature of system changes needed to ensure optimum line sag, given the expected load, conductor temperature, diameter and stress/strain properties, and seasonal changes in the weather.

- *Equipment and Crews* - Field crews equipped with hoists, climbing gear, trucks, heavy equipment, testing and measuring equipment, safety items, communications equipment, and other necessary items are assembled on site.

- *Line Resagging* - If needed, existing conductors are disconnected from insulators, placed in stringing blocks, and then raised to the proper level, retensioned, and secured. Heavy equipment is sometimes used at each location where the conductors are "pulled" to accept the horizontal forces incurred after line disconnection. Vans and trucks for transporting ancillary equipment and workers would be used to access points along the ROW where resagging activities are required.

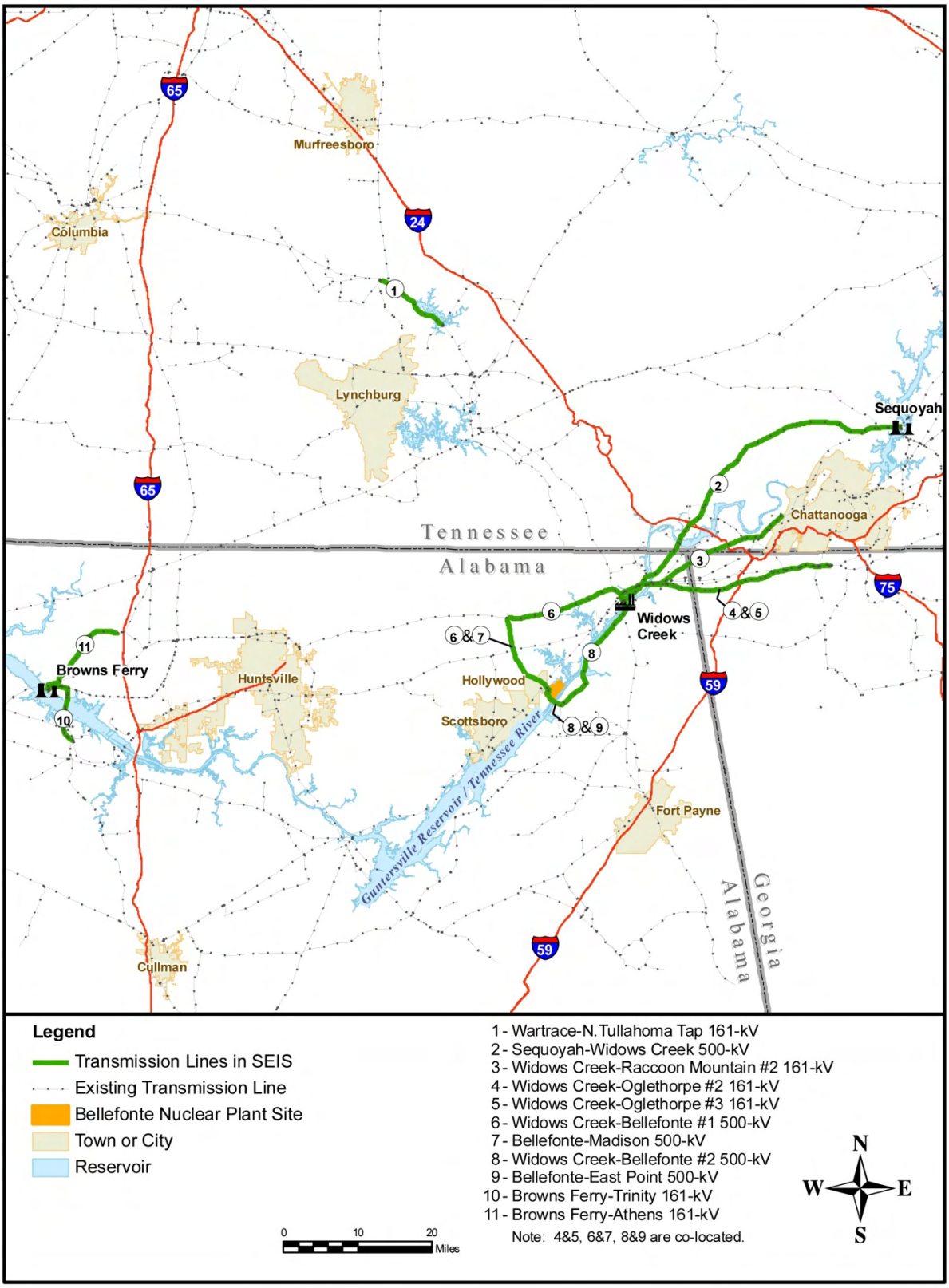


Figure 2-15. Transmission Line Rights-of-Way Affected by the Action Alternatives

- *Line Reconductoring* - If conductor replacement is needed, existing conductors are disconnected from insulators, placed in stringing blocks, and then connected to the new conductor, which is to be installed. The old conductor is then pulled onto empty conductor reels, simultaneously pulling the new conductor into place. As discussed above, heavy equipment is sometimes used at each location where the conductors are "pulled" to accept the horizontal forces incurred after line disconnection. Vans and trucks for transporting ancillary equipment and workers would be used to access points along the ROW where these activities are required. In some cases, the existing conductor could be removed to reels and the new conductor pulled into place on empty structures using ropes or cables. The retired conductor would be reused elsewhere or recycled.

- *Structure Addition/Replacement* - In the event taller structures were needed, the existing structures would be removed, and new ones would be placed along the existing ROW. Structures that have been removed would be disposed of according to TVA's Power System Operations Environmental Compliance Program. Steel from retired structures would be maintained in inventory for future use or recycled. If additional structures were needed, they would be placed where needed along the existing ROW. Holes would be excavated with digging/boring equipment, and a crane would lift the new/replacement structure into place.

- *Anchoring* - In very rare instances, bulldozers are used to accept the horizontal forces incurred with line disconnection while the structure serves as a pivot. This occurs when the structure by itself would not resist the toppling forces incurred when one of the lines is detached. However, other existing lines attached to the affected structures/towers almost always serve to sufficiently stabilize them, thereby negating the need for additional support or anchoring.

- *Logistics* - Vans, trucks, bulldozers, and other equipment would be used to access points along the ROW where resagging or reconductoring activities are required. This equipment would not, except under very rare circumstances, traverse the ROW, but instead enter from and exit to the nearest roadway using the most convenient and established ROW access point. Best management practices (BMPs) would be in place for upgrade activities, and ground surveys would take place to identify wetland areas where avoidance, minimization, or mitigation measures would be required. Movement of equipment would normally utilize access routes that are currently in place and presently being used by line maintenance crews.

- *Crews and Schedule* - The typical field crew and equipment involved in a line resagging or reconductoring operation numbers four bulldozers, four trucks, two equipment operators, and two supervisors. Actions at pulling points would be repeated until the entire line segment has been resagged. TVA construction crews would follow BMPs during the resagging or reconductoring process to minimize erosion and stream impacts and would comply with applicable TVA procedures.

The ROWs that are occupied by the transmission lines affected by this proposal have typically been kept clear of tall vegetation with the exception of portions of the Widows Creek-Bellefonte #1 and #2 500-kV, the Bellefonte-East Point 500-kV, and the Bellefonte-Madison 500-kV transmission lines. Mowing and other maintenance activities have been conducted periodically on these lines. Some of these lines were reviewed for

environmental effects prior to the time of initial construction. As a result, it is less likely that the activities associated with transmission line upgrading would impact significant resources than if new transmission lines were constructed on new ROWs. However, field studies of the transmission line ROWs to be upgraded would be carried out to better confirm if any significant environmental resources or other sensitive features are present. If these are identified, appropriate actions would be taken to avoid or minimize impacts to these resources during upgrade activities.

A total of nine transmission lines or segments of these lines would require reconductoring or uprating. Sections of two 500-kV lines need to be connected and energized. A list of the 11 TVA transmission lines that would be affected under the Action Alternative is provided in Table 2-1.

Table 2-1. Transmission Lines Affected by Proposed Operation of a Single Nuclear Unit at the BLN Site

Transmission Line		Proposed Upgrade/Action	Miles of Line Affected
Identification Number	Name		
1	Wartrace-N. Tullahoma Tap 161-kV	Reconductor to 954 aluminum conductor, steel supported (ACSS) @ 180°C (446-518 megavolt-ampere [MVA])	10.9
2	Sequoyah-Widows Creek 500-kV	Uprate to 100°C capability (2,598 MVA)	49.5
3	Widows Creek-Raccoon Mountain #2 161-kV	Reconductor to 2x956 ACSS @ 180°C (957-1,068 MVA)	25.3
4	Widows Creek-Oglethorpe #2 161-kV[1]	Reconductor to 954 ACSS @ 180°C (446-518 MVA)	30.5
5	Widows Creek-Oglethorpe #3 161-kV[1]	Reconductor to 954 ACSS @ 180°C (446-518 MVA)	30.6
6	Widows Creek-Bellefonte #1 500-kV[2]	Uprate to 100°C capability (2,598 MVA)	29.8
7	Bellefonte-Madison 500-kV[2]	Energize	12.4
8	Widows Creek-Bellefonte #2 500-kV[3]	Uprate to 100°C capability (2,598 MVA)	21.2
9	Bellefonte-East Point 500-kV[3]	Energize	3.4
10	Browns Ferry-Trinity 161-kV	Reconductor to 1,590 ACSS @ 180°C (669-734 MVA)	10.0
11	Browns Ferry-Athens 161-kV	Reconductor to 1,590 ACSS @ 180°C (669-734 MVA)	14.1

[1] The Widows Creek-Oglethorpe #2 and #3 161-kv lines are co-located.

[2] Portions of the Widows Creek-Bellefonte #1 and Bellefonte-Madison 500-kV lines share a common ROW.

[3] Portions of the Widows Creek-Bellefonte #2 and Bellefonte-East Point 500-kV lines share a common ROW.

2.7. Comparison of Alternatives

In this section, proposed actions anticipated under the three alternatives for nuclear plant completion or construction and operation are compared based upon the information and analysis provided in Sections 2.1–2.3 and Chapter 3 (Nuclear Generation Alternatives on the Bellefonte Site). Additionally, two alternatives (No Action and Action) for upgrading electric transmission lines associated with the proposed nuclear plant are compared, based upon the information and analysis in Section 2.6 and Chapter 4 (Transmission System Alternatives).

A comparison of the design, construction, operation, and cost characteristics of the generation alternatives is presented in Table 2-2. Potential environmental impacts of the three alternatives are summarized in Table 2-3. Potential environmental impacts of the transmission system alternatives are summarized in Table 2-4. Mitigation measures designed to avoid or minimize impacts of the proposed action are listed in Section 2.8.

In this review, TVA has found that few new or additional cumulative effects beyond those identified in earlier NEPA documents are expected to result from completing or constructing and operating a single nuclear unit at the Bellefonte site. As summarized in Table 2-3, only minor temporary or insignificant effects are expected for most of the resources considered. As such, these effects are not expected to contribute to cumulative impacts on most affected resources.

2.7.1. Nuclear Plant Licensing and Construction

Both the AP1000 design and the partially completed B&W design will require NRC review and approval to obtain an operating license. The licensing process for the B&W units will continue under 10 CFR Part 50 (consistent with the current construction permits and all other TVA operating units), while the AP1000 will be licensed under the newer NRC licensing regulations contained in 10 CFR Part 52. The construction permits for Units 1 and 2 have been reinstated by the NRC, and recently the NRC has confirmed that the Units 1 and 2 programs and procedures, including the QA records, successfully address the elements of the NRC's policy on deferred status, and have authorized TVA to transition BLN 1 and 2 to the deferred status. Consistent with the NRC policy, construction can be reactivated (assuming a TVA Board approval of a completion project) by issuing a letter to NRC at least 120 days before planned reactivation.

For the AP1000, licensing of both construction and operation of the facility would be accomplished in a single proceeding. Because of this, significant construction activities cannot begin until the NRC issues the COL. Issuance of the COL is predicated on successful Design Certification of the AP1000 amended design, currently under review by NRC. The Design Certification process is not under the direction of TVA, but is being accomplished independently by the design's owner. While this combined process provides additional confidence that a schedule can be met once the COL has been issued, the Design Certification process is outside of TVA's control. Consequently, the schedule for bringing a unit online using the COL process may be longer than the schedule for completing a single unit under 10 CFR Part 50.

Both designs will be reviewed in detail by the NRC to confirm that NRC regulation and guidance are met and that the health and safety of the public is protected. In addition, both designs will require a Regulatory Guide 1.200 compliant Probabilistic Risk Assessment. Both of the designs are expected to have Probabilistic Risk Assessment results that are within the NRC published safety goals (NRC Policy Statement, "Safety Goals for the Operations of Nuclear Power Plants," 51 *Federal Register* 28044, August 4, 1986).

Both of the nuclear generation Action Alternatives, Alternatives B and C, would meet the future demands for power described in Section 1.4 above. Alternative A, No Action, maintaining construction permits in a deferred status, does not address the need for power. Compared to the Action Alternatives, Alternative A would result in no new construction, no operation of a nuclear plant, and no changes to the electric transmission lines or supporting equipment. Under Alternative A, maintenance, inspections, and security functions would continue as required so long as construction permits remain valid.

Table 2-2. Summary of Generation Alternative Characteristics

Characteristics		Generation Alternative		
		A – No Action	Alternative B – B&W Unit	Alternative C – AP1000 Unit
Licensing	Regulation	Not Applicable	10 CFR Part 50	10 CFR Part 52
Plant Design	Power generation capability	Not applicable	Rated 3,600 MWt; 3,760 MWt stretch	Rated 3,400 MWt; 3,415 MWt nuclear steam rating
	Electrical output		Expected 1,260 MW	Expected 1,100 MW
	Thermal efficiency		35 percent	32.4 percent
	Number of fuel assemblies		205 - 12 Feet length	157 - 14 feet length
	Original design life		40 years	60 years
	Engineered safety features		Active shutdown and cooling system powered by AC generators	Passive core cooling system based upon gravity, natural circulation, and compressed gases
	Steam generator system		Once-through - 50º superheated steam	U-tube - saturated steam
	Cooling system		Closed-cycle	Closed-cycle
	Ultimate heat sink		Guntersville Reservoir	Atmosphere
Construction	Duration of construction	Not applicable	Approximately 4.7 years (56 months)	Approximately 6.5 years (two years site preparation and 54 months construction)
	Peak on-site workforce		Approximately 3,000	Approximately 3,000
	Previously disturbed (approximate)	400 acres	400 acres	400 acres
	Project area	Not Applicable	606 acres	606 acres
	Site clearing/grading	Negligible	Minor reclearing and grading of previously disturbed ground	Clearing of about 50 acres of forested land, blasting, reclearing, and grading of previously disturbed ground
	Completion or construction of facilities	No change – routine maintenance	Activities include: replace steam generators, refurbish or replace instrumentation and various equipment, upgrade cooling tower, construction of support buildings	Activities include: upgrade barge unloading dock, off-site construction of modules delivered to BLN via barge and completed on site, construction of support buildings, upgrade cooling tower
	Demolition	Little to none	Several support buildings demolished; no major buildings demolished	Several buildings demolished, including turbine building and administration complex
	Quantity of hazardous waste generated	Not applicable	6.3 tons solid; 56.7 tons liquid	7.25 tons solid and liquid
	Dredging	None	11,100 cubic yards dredged from 1,960 feet of intake channel	10,000 cubic yards dredged from 1,200 feet of intake channel, and 240 cubic yards from barge unloading dock

Characteristics		Generation Alternative		
		A – No Action	Alternative B – B&W Unit	Alternative C – AP1000 Unit
Operation	Typical amount of water withdrawn from Guntersville Reservoir for plant cooling	Not applicable	35,000 gallons per minute (gpm) (0.2% of average river flow)	24,000 gpm (0.14% of average river flow)
	Typical amount of water discharged to Guntersville Reservoir	approximately 400,000 gallons per quarter year	23,000 gpm (0.13% of average river flow)	8,000 gpm (0.05 % of average river flow)
	Water consumption for plant cooling	Not applicable	12,000 gpm (0.07% of average river flow)	16,000 gpm (0.10% of average river flow)
	Size of thermal mixing zone plume in Guntersville Reservoir	Not applicable	250 feet from diffuser and extending the entire depth of the reservoir	
	Temperature limits on discharged water	Not applicable	Monthly average 92°F; daily maximum 95°F; maximum in-stream temperature increase no more than 5°F above ambient water temperature	
	Frequency of maintenance dredging	Not applicable	Approximately 12-15 years as needed in intake channel	Approximately 12-15 years as needed in intake channel
	Number of on-site staff	50	Approximately 800	Approximately 650
	Quantity of nonhazardous solid waste generated	about 100 cubic yards/year (average)	500 tons/year	400 tons/year
	Quantity of hazardous waste	less than 100 kilograms (kg)/month	Approximately 1,300 pounds (lb)/year (600 kg/year)	Approximately 1,300 lb/year (600 kg/year)
	Radiological effects of normal operations	None	Doses to the public from discharge of radioactive effluents would be a small fraction of the dose considered safe by the NRC (10 CFR Part 50, Appendix I)	
	Number of months between refueling	Not applicable	18	18
	Number of refueling cycles in 40 years	None	26	26
	Number of fuel assemblies needed for 40-year operation	None	2,285	1,821
	Total spent fuel (metric tons uranium [MTU]) for 40-year operation	None	946	894 (946 MTU when normalized for the B&W generation capability--3,600 MWt)
	Spent fuel discharged (MTU/MWt)	None	0.26 MTU/MWt	0.26 MTU/MWt
Cost	Construction	Not applicable	$3,120 – $3,360/kilowatt electric (kWe)	$3,300 – $4,900/kWe
	Operation and maintenance	Not applicable	$.0131/kWh	$.0126/kWh

Table 2-3. Summary of the Environmental Impacts of the Three Alternatives Under Consideration

Resource	Attribute/Potential Effects	Alternative		
		A - No Action	B – One B&W Unit	C – One AP1000 Unit
Surface Water	Chemical or thermal degradation of surface water quality; changes to hydrology and consumptive use of surface water.	No impacts or changes anticipated.	Temporary and minor impacts from construction. No impacts are anticipated to water supply from plant water use. Near-field and far-field effects (e.g., cumulative) to water quality associated with cooling water discharge are not expected to be significant. Minor impacts from chemical discharges.	Temporary and minor effects from construction. No impacts are anticipated to water supply from plant water use. Insignificant effects on water quality similar to Alternative B, but slightly less due to smaller amount of water withdrawal and blowdown discharge. Minor impacts from chemical discharges.
Groundwater	Chemical impacts to groundwater quality; changes in use of groundwater.	No impacts expected.	No impacts expected to groundwater hydrology or groundwater use on site or locally. Insignificant impacts to groundwater quality. No cumulative effects expected.	As with Alternative B, no impacts expected to groundwater hydrology or groundwater use on site or locally. Insignificant impacts to groundwater quality. No cumulative effects expected.
Floodplain and Flood Risk	Construction or modification to the floodplain. Flooding of the plant site from the river, Town Creek, or Probable Maximum Precipitation (PMP).	No anticipated adverse impacts to the floodplain. All safety-related structures are located above the Probable Maximum Flood (PMF) and PMP drainage levels or are flood-proofed to the resulting levels.	Minor impacts from construction and dredging. All safety-related structures are located above the PMF and PMP drainage levels or are flood-proofed to the resulting levels. No cumulative effects to flood risk.	Minor impacts from construction and dredging. All safety-related structures are located above the PMF and PMP drainage levels or are flood-proofed to the resulting levels. The new administrative building would be located above the 100-year and Flood Risk Profile elevations. No cumulative effects to flood risk.

Resource	Attribute/Potential Effects	Alternative		
		A - No Action	B – One B&W Unit	C – One AP1000 Unit
Wetlands	Destruction of wetlands or degradation of wetland functions.	No impacts.	No impacts.	Impacts to 12.2 acres of wetlands with no net loss of wetland function due to in-kind mitigation within the watershed, No indirect or cumulative impacts expected.
Aquatic Ecology	Destruction of aquatic organisms; degradation or destruction of aquatic habitat.	No impacts.	Minor impacts to benthos from dredging intake channel, to aquatic communities from thermal discharge, impingement, and entrainment. No cumulative effects	Effects similar to Alternative B but slightly less dredging. Impacts from thermal discharge and impingement and entrainment minor and less than Alternative B due to smaller intake water volumes. No cumulative effects.
Terrestrial Ecology	Removal or degradation of terrestrial vegetation, wildlife habitat, and/or wildlife.	No impacts.	Insignificant impacts from minor vegetation clearing. No indirect or cumulative effects expected.	Similar to Alternative B. Minor direct impacts from removal of about 50 acres of forest and native grass. No indirect or cumulative effects expected.
Endangered and Threatened Species	Mortality, harm, or harassment of federally listed or state-listed species including impacts to their critical habitat.	No impacts.	No impacts from site construction or runoff. Adverse direct, indirect, and cumulative impacts to the pink mucket mussel from dredging and towing barges. Minor indirect effects from stress of potential mussel host fish from thermal effluent; negligible effect of impingement/entrainment of potential host fish.	No impacts from site construction or runoff. Little or no impact to Indiana bats from removal of low-quality potential roost habitat with some moderate-quality potential roost trees. Adverse direct, indirect, and cumulative impacts to the pink mucket from dredging and towing barges. Fewer individuals affected than under Alternative B. Operational impacts to pink mucket and other aquatic species same as Alternative B.

Resource	Attribute/Potential Effects	Alternative		
		A - No Action	B – One B&W Unit	C – One AP1000 Unit
Natural Areas	Degradation of the values or qualities of natural areas.	No impacts.	No direct or indirect impacts. Minor cumulative effects.	No direct or indirect impacts. Minor cumulative effects.
Recreation	Degradation or elimination of recreation facilities or opportunities.	No impacts.	Minor impacts from construction and operation, noise, and withdrawal of water. No cumulative effects.	Minor impacts from construction and operation, noise, and withdrawal of water. No cumulative effects.
Archaeology and Historic Structures	Damage to archaeological sites or historic structures.	No impacts.	No impacts. Mark and avoid site 1JA111.	No impacts. Mark and avoid site 1JA111.
Visual	Effects on scenic quality, degradation of visual resources.	No additional impact.	Minor, temporary impacts during construction. Minor impact of vapor plume. Little or no additional impacts to scenic quality. Minor cumulative impacts to regional visual setting.	Construction of new buildings offset by removal of existing buildings; construction impacts minor. Minor impact of vapor plume. Little or no additional impacts to scenic quality. Minor cumulative impacts to regional visual setting.
Noise	Generation of noise at levels causing a nuisance to the community.	No impact.	Small to moderate impacts from temporary noise during hydrodemolition and other construction. Minor impacts during operation.	Small to moderate impacts from temporary noise during blasting and other construction. Minor impacts during operation.
Socioeconomics and Environmental Justice	Changes in population, employment, income, and tax revenues. Disproportionate effects on low income and/or minority populations. Changes in availability of housing.	No impact. No impact. No impact.	No substantial change in population; no significant adverse effects; minor beneficial impacts. No disproportionate impact. Minor to potential significant adverse impacts during construction; minor impacts during operation. Potentially apply measures to mitigate demand for housing.	No substantial change in population; no significant adverse effects; minor beneficial impacts. No disproportionate impact. Minor to potential significant adverse impacts during construction; minor impacts during operation. Potentially apply measures to mitigate demand for housing.

Resource	Attribute/Potential Effects	Alternative		
		A - No Action	B – One B&W Unit	C – One AP1000 Unit
	Effects on water supply, wastewater, schools, police, fire and medical services.	No impact.	Minor and insignificant with the exception of significant increase in demand for schools during construction; moderate increase in demand for schools during operation.	Minor and insignificant with the exception of significant increase in demand for schools during construction; moderate increase in demand for schools during operation.
	Changes in land use, land acquisition, land conversion or road locations.	No impact.	No change in designated land use. Minor indirect impact from increased residential use.	No change in designated land use. Minor indirect impact from increased residential use.
	Elevated levels of traffic from construction workforce and deliveries.	No impact.	Impacts on transportation corridors from construction workforce and deliveries would be minor on all roads except for County Road 33 where temporary minor to moderate impacts are expected. Operational effects expected to be minor.	Impacts on transportation corridors from construction workforce and deliveries would be minor on all roads except for County Road 33 where temporary minor to moderate impacts are expected. Operational effects would be minor; impacts would be minor.
	Cumulative effects	No impact.	Minor impact, minor cumulative effects.	Minor impacts, minor cumulative effects.
Solid and Hazardous Waste	Generation and disposal of solid and hazardous waste.	No impact related to construction; minor indirect impact of off-site disposal in permitted facilities.	No direct or cumulative impacts; minor indirect impacts during construction and operation from off-site disposal in permitted facilities.	Quantity of construction waste greater than under Alternative B. No direct or cumulative impacts; minor indirect impacts during construction and operation from off-site disposal in permitted facilities.
Seismology	Seismic adequacy.	No change.	No adverse seismic effects anticipated.	No adverse seismic effects anticipated.

Resource	Attribute/Potential Effects	Alternative		
		A - No Action	B – One B&W Unit	C – One AP1000 Unit
Air Quality	Radiological emissions resulting in increases of air pollutants.	No impacts expected.	Small radiological doses to workers and members of the public from routine radioactive emissions during normal plant operation. Releases would be well below the regulatory limits; impacts are expected to be insignificant. Calculated impacts from design-basis accident releases would be well below the regulatory limit and therefore insignificant.	Impacts would be similar to Alternative B.
	Gasoline and diesel emissions from vehicles and equipment.	No impacts expected.	Minor impacts from vehicular and equipment emissions, controlled to meet applicable regulatory requirements.	Minor impacts from vehicular and equipment emissions, controlled to meet applicable regulatory requirements.
Radiological Effects	Effects to humans and nonhuman biota from normal radiological releases.	No impacts expected.	Annual doses to the public well within regulatory limits; no observable health impacts. Doses to nonhuman biota well below regulatory limits; no noticeable acute effects.	Annual doses to the public well within regulatory limits; no observable health impacts. Doses to nonhuman biota well below regulatory limits; no noticeable acute effects.

Table 2-4. Summary of the Environmental Impacts of the Two Transmission Upgrade Alternatives

Resource	Attribute/Potential Effects	Alternative	
		No Action	Action
Surface Water	Chemical or thermal degradation of surface water quality; changes to hydrology and surface water use.	No impacts.	Minor, temporary impacts during upgrade activities. Minor impacts during routine maintenance. No cumulative impacts.
Groundwater	Chemical impacts to groundwater quality; changes in use of groundwater.	Minor impacts to groundwater quality from ROW maintenance.	Minor impacts to groundwater quality from ROW maintenance.
Aquatic Ecology	Degradation of water quality; destruction of aquatic organisms.	Minor direct and indirect impacts from ROW maintenance. No cumulative impacts.	No impacts from ROW clearing; no additional impacts of ROW maintenance as compared to No Action.
Terrestrial Ecology	Removal or degradation of terrestrial vegetation, associated wildlife habitat, and wildlife.	No local or regional impacts.	No local or regional impacts.
Endangered and Threatened Species	Mortality, harm, or harassment of federally listed or state-listed species.	No impacts.	No effect and may affect determinations to some listed species.
Wetlands	Destruction of wetlands or degradation of wetland functions.	No impacts.	No adverse impacts.
Floodplains	Construction or modification to a floodplain.	No floodplains affected.	No adverse impacts.
Natural Areas	Degradation of the values or qualities of natural areas.	No impacts.	Minor direct impact to natural areas on ROWs, no impact to natural areas nearby.
Recreation	Degradation or elimination of recreation facilities or opportunities.	No impacts.	Minor impact from refurbishing lines and routine maintenance.
Land Use	Changes in land use and effects to uses of adjacent land.	No changes to current land use.	Minor disruption during upgrade activities.
Visual	Effects on scenic quality, degradation of visual resources.	No impacts.	Minor short-term impacts during construction and minor long-term impacts from taller structures.

Resource	Attribute/Potential Effects	Alternative	
		No Action	Action
Archaeology and Historic Structures	Damage to archaeological sites or historic structures.	No impacts.	Potential for adverse impact to archaeological sites and/or historic structures. Effects would be avoided or mitigated in accordance with memorandums of agreements (MOAs) developed in consultation with the appropriate State Historic Preservation Officers (SHPOs).
Socioeconomics	Changes, at local and regional scales, in the human population; employment, income, and tax revenues; and demand for public services and housing.	No impacts.	Minor impacts during construction.
Environmental Justice	Disproportionate effects on low income and/or minority populations.	No disproportionate effects.	No disproportionate effects.
Operational Impacts	Potential effects of electromagnetic fields (EMFs), lightning strike hazard, electric shock hazard, and generation of noises and odors.	No impacts.	No significant impacts from EMFs; no alteration of line grounding, minor noise, no odors.

Under Alternatives B and C, construction activities would incorporate existing facilities and structures and use previously disturbed ground where possible. Both a B&W and an AP1000 unit would use the existing intake channel and pumping station, cooling towers, blowdown discharge diffuser, switchyard, and transmission system. Under Alternative B, a partially constructed B&W unit would be completed on previously cleared ground, and minimal new site clearing or grading would occur. The majority of the construction activities on plant systems and components would involve replacement or refurbishment of equipment contained within the current structures.

Under Alternative C, an AP1000 unit would be constructed on a new nuclear island located on vacant ground within the BLN project area. Construction of one AP1000 unit and associated structures is expected to require clearing of about 50 acres of forested land and reclearing and grading of previously disturbed ground. Site preparation would require blasting. The existing turbine building and the office and service buildings would be removed.

Although more site preparation and construction would be necessary under Alternative C, this would be offset by the somewhat simpler design and modern modular construction techniques used to construct the AP1000 unit. Factory-built modules can be assembled at the site, significantly reducing both construction duration and construction site labor requirements. Therefore, the construction duration and site construction labor force for an AP1000 unit is comparable to the estimated duration and labor requirements to complete one of the partially constructed B&W units.

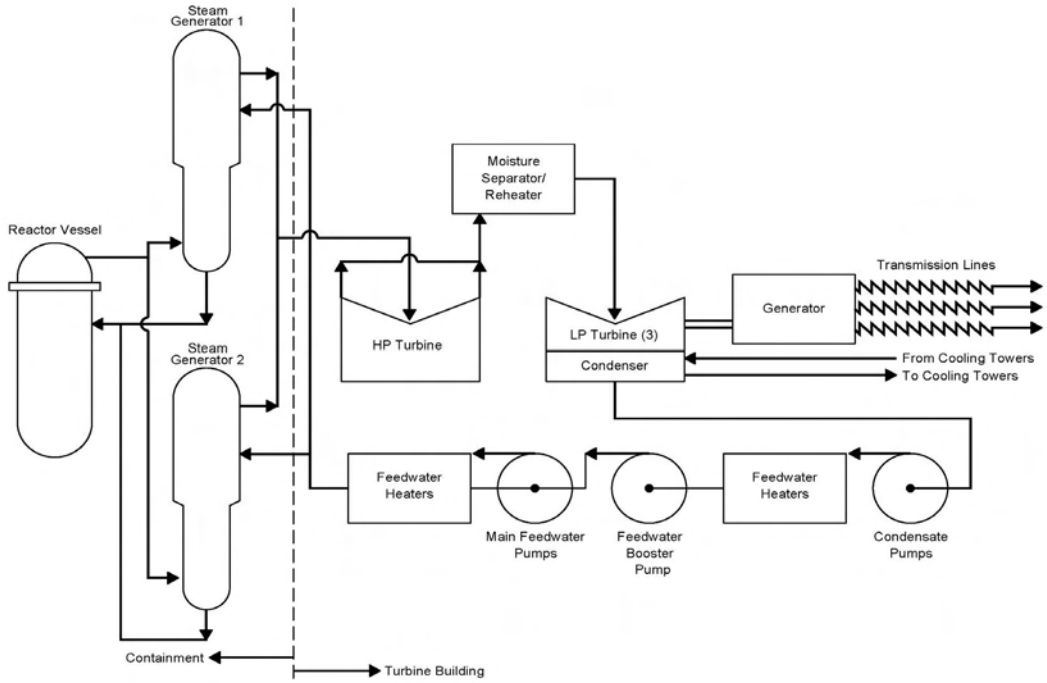
Under Alternatives B and C, initial dredging and periodic maintenance dredging would be necessary. The areas requiring dredging vary between the two alternatives. Alternative B would require the removal of about 10 percent more material from the intake channel than would Alternative C; it would also require dredging from the main river channel that would not occur under Alternative C. However, Alternative C would require dredging 240 cubic yards of material from the barge unloading area.

Potential effects to the environment from construction activities proposed under Alternatives B and C are described in Table 2-3.

2.7.2. Nuclear Plant Operation

The B&W and AP1000 alternatives are functionally very similar in that they are both pressurized light water reactors with a reactor vessel, reactor coolant pumps, a pressurizer, two steam generators, and a power conversion system consisting of high pressure and low pressure turbines, a generator, and feedwater system as illustrated in Figure 2-16. Both plants would generate comparable quantities of radioactive waste and use similar chemicals and processes for water treatment.

One of the most significant differences between these two systems is that the B&W plant utilizes once-through steam generators that produce about 50 degrees of superheated steam, whereas the AP1000 uses a U-tube steam generator system that produces saturated steam. By utilizing a superheat design, working steam is supplied well above saturation points and can deliver working energy more efficiently. Therefore, a superheat cycle plant would, in general, provide more energy for useful work (turning a generator) than a comparable nonsuperheat cycle design. The ability to create superheated steam makes the B&W unit thermally more efficient. The efficiency of the B&W plant is 35 percent compared to 32.4 percent for the AP1000.



Source: TVA 2008a

Figure 2-16. Typical Pressurized Light Water Reactor - Reactor Power Conversion System and Reactor Coolant System

Both the B&W and AP1000 would use closed-cycle cooling systems, discharging cooling tower blowdown via a diffuser in Guntersville Reservoir, requiring only a small amount of water compared both to the average flow and the minimum expected drought flow in the Guntersville Reservoir. The two plant designs differ in volumes of operating water flows (see Table 2-5). For a single B&W unit, intake water would make up 12,000 gallons per minute (gpm) for evaporation, plus about 23,000 gpm of cooling tower blowdown, resulting in a typical withdrawal from Guntersville Reservoir of 35,000 gpm (or 0.21 percent of the average flow through Guntersville Reservoir). For a single AP1000 unit, intake water would make up for 16,000 gpm for evaporation plus about 8,000 gpm cooling tower blowdown, resulting in a typical withdrawal from Guntersville Reservoir of 24,000 gpm (or about 0.14 percent of the average flow through Guntersville Reservoir). Both plants would meet the same specifications for temperature of discharged water. The larger makeup and blowdown volumes for the B&W design would be partly offset by the lower evaporative losses and the expected 160 MWe increase in electrical production.

Table 2-5. B&W and AP1000 Water Use

	B&W[1]	Percent Average River Flow[2]	AP1000[3]	Percent Average River Flow[2]
Condenser Circulating Water Flow Rate (Closed Cycle)	420,000 gpm	N/A	500,000 gpm	N/A
Evaporation (Consumption)	12,000 gpm	0.07%	16,000 gpm	0.10%
Blowdown (Discharge)	23,000 gpm	0.13%	8,000 gpm	0.05%
Makeup (Withdrawal)	35,000 gpm	0.21%	24,000 gpm	0.14%

[1]B&W operating water flow rates source: TVA 1976; T. Spink, TVA, personal communication, March 2010.
[2]Average River Flow at Bellefonte is 37,300 cubic feet per second (approximately 16,700,000 gpm). Source: P. Hopping, TVA, personal communication, February 2010.
[3]AP1000 operating water flow rates source: TVA 2008a

A comparison of spent fuel production for the B&W and AP1000 is provided in Table 2-6. A comparison based on the number of fuel assemblies discharged over the 40-year lifetime can be misleading because of different fuel assembly length (B&W - 12 feet versus AP1000 - 14 feet) and power level (3,600 MW versus 3,400 MW). Fuel is limited in its burnup to approximately 62,000 megawatt-days (MWD)/metric tons uranium (MTU). Allowing for power peaking factors, the average discharge burnup is expected to be approximately 50,000 MWD/MTU for both the AP1000 and the B&W BLN plant designs. Because this fuel characteristic parameter is expected to be the same for both fuel designs, this indicates that the expected amount of fuel to be discharged is proportional to the amount of energy produced.

Table 2-6. Spent Fuel Quantity Determination for BLN Single Unit Operation

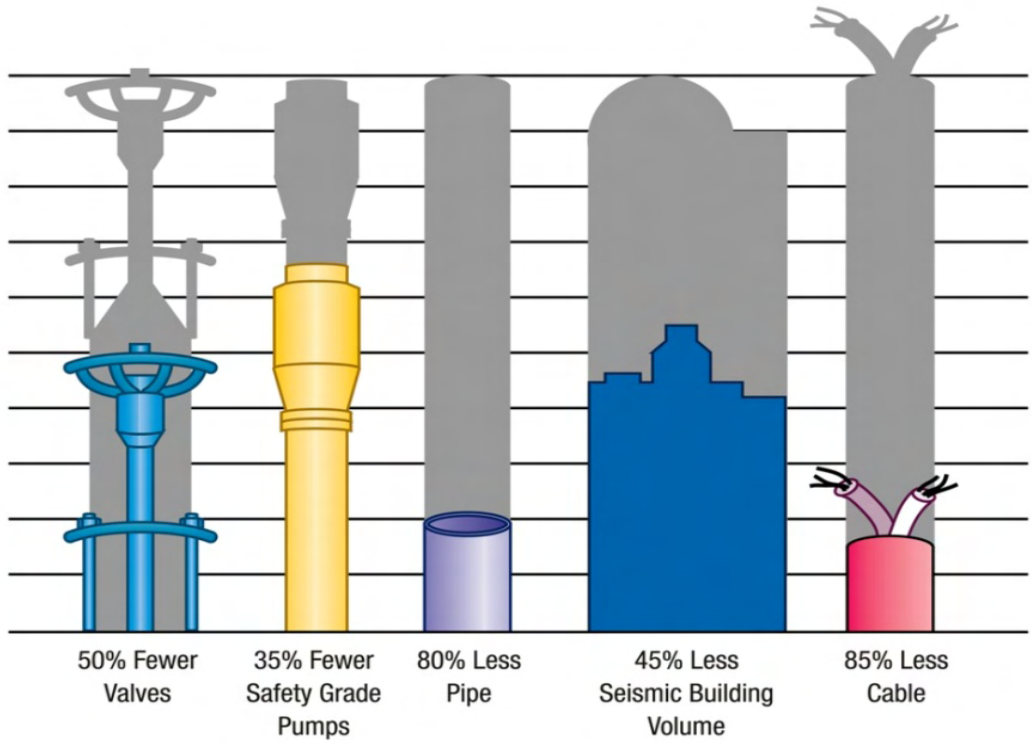
Data Parameter	BLN B&W	BLN AP1000	BLN AP1000 Normalized for Power
Core thermal power, MWt	3,600	3,400	3,600
Operating cycle length	18 months	18 months	N/A
Number of assemblies in the core	205[1]	157[2]	N/A
Number of fresh fuel assemblies per refueling cycle	80[3]	64[4]	N/A
Height of active fuel, feet	12	14	14
Number of refueling cycles in 40 years[5]	26	26	N/A
Number of fuel assemblies for 40-year operation[6]	2,285	1,821	N/A
Total Spent Fuel (MTU) for 40-year operation	946	894	946

[1] (TVA 1978a)
[2] (TVA 2008a)
[3] (T A Keys, TVA, personal communication, September 3, 2009)
[4] (TVA 2008a)
[5] Forty years of operation covers 26 refueling cycles and 27 operating cycles. Spent fuel is discharged a total of 27 times from each unit, which includes the last cycle discharge of the entire core.
[6] Number includes assemblies from 26 refueling cycles, plus assemblies in the core.

Another significant difference between the B&W and the AP1000 designs is that the AP1000 works on the concept that, in the event of a design-basis accident (such as a coolant pipe break), the plant is designed to achieve and maintain safe shutdown condition without any operator action and without the need for AC power or pumps. Instead of relying on active components such as diesel generators and pumps, the AP1000 relies on the natural forces of gravity, natural circulation, and compressed gases to keep the core and containment from overheating. The ultimate heat sink for the AP1000 is the atmosphere, whereas the ultimate heat sink for the B&W is the river. These passive design concepts greatly simplify the design and construction of the AP1000 plant and reduce its overall footprint. For example, the AP1000 uses far less equipment than a typical nuclear plant, as illustrated in Figure 2-17.

The B&W 205 unit is an evolution of the existing operating B&W 177 units. The design incorporates improved safety features to address lessons learned and NRC requirements resulting from the Three Mile Island event. In addition, both the B&W and the AP1000 designs require a detailed Probabilistic Risk Assessment, and both of the designs are expected to have Probabilistic Risk Assessment results that are within the NRC published

safety goals (NRC Policy Statement, "Safety Goals for the Operations of Nuclear Power Plants," 51 *Federal Register* 28044, August 4, 1986).



Source: WEC 2009

Figure 2-17. AP1000 Simplified Design - Fewer Components

As a result of the AP1000's design simplicity and significant reduction in safety-related systems and equipment, operations and maintenance costs for the AP1000 should be slightly lower than for the B&W unit, although partially offset by the B&W unit's higher thermal efficiency and generating capacity.

2.7.3. Transmission System

Should a nuclear plant at the Bellefonte site become operational, electricity generated by the new plant would overload the existing transmission infrastructure. To address the projected overloading, TVA evaluated potential effects of implementing two alternatives; this evaluation is summarized in Table 2-4.

2.8. Identification of Mitigation Measures

Mitigation of potential environmental impacts includes measures to avoid, minimize, rectify, reduce, or compensate for adverse impacts. Mitigation measures have been identified in TVA's 1974 FES and subsequent environmental reviews. Those measures would be implemented as described. The AEC's 1974 FES (AEC 1974) includes a list of seven conditions for the protection of the environment during construction and operation of BLN 1&2. After reviewing these conditions, TVA has concluded that these conditions either have been met during plant construction or will be addressed by required permits and

authorizations. This supplemental document identifies mitigation measures to address impacts beyond those discussed in the earlier reviews. TVA will identify specific mitigations and commitments selected for implementation in the ROD for this project.

TVA has identified the following measures that could be implemented during construction or operation of a single nuclear unit at the Bellefonte site to address those potential impacts.

Completion of Construction and Operation of a Nuclear Unit
If Alternative B or C were adopted, TVA would avoid disturbing archaeological site 1JA111. The site would be fenced off and its location would be marked on BLN drawings. Prior to the adoption of any future modification to current project plans having potential to affect this site, site 1JA111 would be subjected to further testing to determine the extent and nature of adverse effects.

If either Action Alternative were implemented, TVA would review the availability of housing, traffic congestion, and impacts to schools during the construction phase to assess whether efforts to mitigate such impacts in Jackson County are needed. Such efforts could include housing assistance for employees, transportation assistance for commuting employees, or remote parking areas with shuttles.

If either Action Alternative were implemented, in accord with the results of formal Section 7 consultation under the *Endangered Species Act* (ESA) of 1973, TVA would provide a total of $30,000 to be used for research and recovery of pink mucket

If Alternative C were selected and implemented, TVA would conduct a survey to further investigate the presence of Indiana bats prior to clearing forest on the BLN site. The need for measures designed to avoid or minimize impacts to Indiana bats would be determined based upon results of the survey and in coordination with the USFWS.

If Alternative C were selected for implementation, TVA would compensate for wetland impacts caused by construction activities by purchasing wetland mitigation credits at Robinson Spring Wetland Mitigation Bank, which is located within the same watershed as the proposed impacts. TVA would determine the exact extent of wetland fill required and would obtain and comply with a Section 404/401 permit.

If Alternative C were adopted, preparation for the construction of an AP1000 unit would also require blasting, which would cause temporary noise impacts. Potential mitigation measures include, but are not limited to, the use of blasting blankets, notification of the surrounding receptors prior to blasting, and limiting blasting activities to daylight hours.

Transmission System Impacts
Should TVA select Alternative B or C, the following mitigation measures could be implemented to address the potential impacts of the proposed transmission upgrades.

Federally listed and state-listed plant species have been previously documented along small portions of the transmission ROWs. Prior to implementing any ground-disturbing work on transmission ROWs, appropriately timed botanical surveys would be conducted to examine all sites where listed plant species have been previously reported to confirm whether the rare species are still present and the full extent of the plants in the ROWs. If survey results indicate listed plants are present in the project area, the following mitigation measures would be used to reduce or eliminate impacts to the species:

- Locations of areas with federally listed plant species would be noted in the transmission line and access road engineering design specification drawings used during the design and construction of the upgrades. TVA botanists would help fence these areas to ensure construction crews would avoid the sites. Depending on the species present, construction may be timed so work takes place during the dormant season when plants are less likely to be harmed by construction. Any new structures would be placed to avoid impacting these areas. Additionally, access roads and the associated vehicle traffic would be excluded from these areas.

- Areas where state-listed species occur in the project area would be avoided unless there is no practical alternative. Avoidance measures would be comparable to those used for federally listed plants.

Prior to implementing any proposed upgrade activities, TVA would conduct a ground survey to confirm the exact extent of any wetland areas located within the corridors proposed for upgrade. Pending this review, specific commitments may be placed on wetland areas to ensure no significant impacts or loss of wetland function occurs as a result of the transmission line upgrade activities. These commitments would result in avoidance strategies, minimization measures, or mitigation measures should wetland functions be compromised. Mitigation would be provided for any other activity that reduces the functional capacity of a specific wetland. BMPs would be in place for upgrade activities, and ground surveys would take place to identify wetland areas where avoidance, minimization, or mitigation measures would be required. No significant impacts to potential wetland areas within the ROW would be anticipated from the transmission line upgrade.

TVA would also evaluate the presence of historic structures and archaeological sites in areas to be disturbed. This evaluation would be guided by the memorandums of agreement (MOAs) with Georgia (executed April 29, 2010) and Alabama (pending) for identification and evaluation of historic properties. Instead of an MOA in Tennessee, TVA would use the phased identification and evaluation of historic properties pursuant to 36 CFR Part 800.4(b)(2). TVA would, in consultation with the SHPO (for which the property is located) and other consulting parties, develop and evaluate alternatives or modifications, that would avoid, minimize, or mitigate any adverse effects to historic properties. Mitigation measures requiring data recovery for an archaeological site(s) would require a separate MOA developed in consultation with the SHPO and consulting parties pursuant 36 CFR Part 800.6.

2.9. Preferred Alternative

On the basis of TVA's integrated assessment of the two alternatives (completing a B&W unit or constructing an AP1000), completing Bellefonte Unit 1 (a B&W unit) has been identifed as TVA's preferred alternative. The assessments conclude that from financial, schedule, and risk-minimization perspectives, this is the preferred generation option. In support of the preferred alternative, the transmission system also would be upgraded.

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