CHAPTER 7

7.0 ANTICIPATED ENVIRONMENTAL IMPACTS

7.1. Introduction

This chapter describes the anticipated environmental impacts of the alternative strategies and their associated portfolios. It first describes the general process TVA uses to site new power facilities. It next describes the impacts of the continued operation of TVA's generating facilities, the impacts of facilities from which TVA is purchasing power through a PPA, and the impacts of generating facilities that TVA is likely to own or purchase power from in the future. It then describes the impacts of energy efficiency and demand response (EEDR) programs and the impacts of the construction and upgrading of the transmission system necessary to support the future generating facilities.

7.2. Facility Siting and Review Processes

When planning new generating facilities, TVA uses several criteria to screen potential sites. Generating facilities are often needed in specific parts of the TVA power service area in order to support the efficient operation and reliability of the transmission system. Once a general area is defined, sites are screened by numerous engineering, environmental, and financial criteria. Specific screening criteria include regional geology and local terrain; proximity to major highways, railroads, and barge access; proximity to major natural gas pipelines; proximity to high-voltage transmission lines; land use and land ownership; regional air quality; sources of process water; the presence of floodplains, proximity to parks and recreation areas; potential impacts to endangered and threatened species, wetlands, and historic properties; and potential impacts to minority and low-income populations. Through this systematic process, TVA attempts to minimize the potential environmental impacts of the construction and operation of new generating facilities.

New transmission facilities are typically required to transmit power between two defined points or to improve transmission capacity and/or reliability in a defined area. As with generating facilities, potential transmission line routes, substation locations, and switching station locations are screened by numerous engineering, environmental, and financial criteria. Specific screening criteria include slope, the presence of highways, railroads, and airports, land use and land ownership patterns, proximity to occupied buildings, parks, and recreation areas, and potential impacts to endangered and threatened species, wetlands, and historic properties. TVA also encourages participation by potentially affected landowners in this screening process.

TVA has to date not been directly involved in the siting and operation of natural gas pipelines that may have to be built to serve new natural gas plants. It purchases natural gas service from contractors who are responsible for constructing and operating the pipeline. Construction and operation of a natural gas pipeline would be subject to various state and federal environmental requirements depending on how and where it would be constructed. If a pipeline is built specifically to serve TVA, TVA would evaluate its potential environmental impacts and take steps to ensure that any associated impacts are acceptable.

The results of the site screening process, as well as the potential impacts of the construction and operation of the generating and transmission facilities at the screened alternative locations, are described in comprehensive environmental review documents. TVA consults with the appropriate State Historic Preservation Officer on the potential impacts to historic properties and, as necessary, with the U.S. Fish and Wildlife Service on the potential impacts to endangered and threatened species during this environmental review process.

7.3. Environmental Impacts of Supply-Side Resource Options

Because the locations of most of the future generating facilities are not known, this impact assessment focuses on impact areas that are generally not location-specific. These impact areas are described below.

Air Quality - The potential impacts to air quality are described by the direct emissions of the sulfur dioxide (SO_2), nitrogen oxide (NOx), and mercury (Hg) and are quantified by the amount emitted per unit of electricity generated and the total amount emitted under each of the alternative strategies and portfolios.

Greenhouse Gases (GHG) - As recommended by CEQ (2010), GHG emissions are assessed for both the direct emissions of CO_2, from the combustion of non-renewable carbon-based fuels, and for the life-cycle GHG emissions, which include direct and indirect emissions of CO_2, methane, nitrous oxide (N_20), and other greenhouse gases. Life-cycle GHG emissions include emissions from the construction, operation, and decommissioning of generating facilities; the extraction or production, processing, and transportation of fuels; and the management of spent fuels and other wastes. Because life-cycle GHG emissions have not been determined for TVA's generating facilities, the estimates used in this assessment are based on published life-cycle assessments (e.g., Spath and Mann 2000, Odeh and Cockerill 2008). Both direct CO_2 emissions and life-cycle GHG emissions are quantified by the amount emitted per unit of electricity generated and the total amount emitted under each of the alternative strategies and portfolios.

Water Resources - The impacts of water pollutants discharged from a generating facility are highly dependent on facility-specific design features, including measures to control or eliminate the discharge of water pollutants, and are not addressed here. The impacts of the process water used and consumed by a thermal generating facility (primarily for cooling) are dependent on the characteristics of the source area of water withdrawals and of the water bodies to which process water is discharged. The quantities of process water used and consumed are indicators of the magnitude of these impacts. Facilities with open-cycle cooling systems withdraw and discharge large quantities of water. Facilities with closed-cycle cooling systems use less water but consume (typically by evaporation) a large proportion of it. Water use and consumption are quantified by the volumes used and consumed per unit of electricity generated and the total volumes used and consumed under each of the alternative strategies and portfolios.

Solid Waste - The potential for impacts from the generation and disposal of solid wastes are assessed by the quantities of coal ash, scrubber sludge (i.e., synthetic gypsum and related materials produced by flue gas desulfurization systems), low-level radioactive waste, and high-level radioactive waste (spent nuclear fuel). These are quantified by the amounts produced per unit of electricity generated and the total amounts under each of the alternative strategies and portfolios.

Fuel Consumption - The amount of fuel consumed is related to the potential impacts of the extraction or production, processing, and transportation of fuels. Fuel consumption is quantified by the amount consumed per unit of electricity generated and the amount consumed under each of the alternative strategies and portfolios. In addition to coal, coal plants equipped with scrubbers or circulating fluidized bed boilers use limestone as a reagent to reduce SO_2

emissions. The quantity of limestone consumed is a function of the quantity of coal consumed. The quarrying, processing, and transportation of limestone affect air, water, and land resources.

Land Requirements - Land requirements for the alternative strategies and portfolios are quantified by both the facility land requirements and life-cycle land requirements. These land requirements are indicators of the potential for impacts to land-based resources such as vegetation, wildlife, many endangered and threatened species, cultural resources such as archaeological sites and historic structures, land use, prime farmland, visual/aesthetic resources, and recreation. They are also related to the potential for impacts to aquatic resources resulting from runoff and sedimentation.

The facility land requirement is the land area permanently disturbed by the construction of the generating facility. It does not include adjacent lands that are part of the facility site and maintained in a natural or semi-natural state as buffers or exclusion zones. It is quantified by the total acreage permanently disturbed by the construction of new generating facilities under each of the alternative strategies and portfolios.

The life-cycle land requirement is a measure of the land area transformed during the life-cycle of a generating facility expressed in terms of units of area per amount of electricity generated. This land includes the facility site; adjacent buffer areas; lands used for fuel extraction or production, processing and transportation; and land used for managing spent fuels and other wastes. Some of the land areas, such as the facility site, are transformed for decades while others, such as some minelands, are transformed for shorter time periods. These differing time periods are considered in the assessment. The estimates used in this assessment are based on published life-cycle assessments (e.g., Fthenakis and Kim 2009).

Life-cycle land requirements can also be expressed with a land-use metric that accounts for the total surface area occupied by the materials and products used by a facility, the time the land is occupied, and the total energy generated over the life of the facility (Spitzley and Keoleian 2005, AEFPERR 2009). The rank order by energy technology reported for a sample of U.S. facilities, from the smallest to the largest land requirements, is natural gas, coal, nuclear, solar PV, wind, conventional hydroelectric, and biomass. The large land requirements for hydroelectric are due to the inclusion of the reservoirs, which typically have other uses. The biomass land requirements are based on the use of dedicated woody crops; the use of forest residues would also result in a large land requirement.

Following is a discussion of the environmental attributes of the generation options. Environmental characteristics of TVA's existing and potential new supply-side resources are listed in Tables 7-1 and 7-2, respectively. The various types of generating facilities are described in Sections 3.3 and 5.4. It is important to note that there now are comprehensive environmental laws and regulations that address almost all activities associated with the construction and operation of new industrial facilities, particularly energy generation facilities. This regulatory umbrella ensures that the environmental impacts associated with energy resources are acceptable and that in general public health and the environment are protected.

Table 7-1. Environmental characteristics of current and committed supply-side options included in alternative strategies.

	Net Capacity - MW	Capacity factor - %	Heat rate - Btu/kWh	Fuel consumption	Limestone consumption - tons/MWh	SO_2 emissions - lbs/MWh	NOx emissions - lbs/MWh
Coal-Fueled							
TVA fleet total	13,149	var.[2]	10,331	0.524 tons/MWh		6.5204	1.9232
PPA lignite	432	84	10,500	0.963 tons/MWh	0.076	1.5259	1.2288
Natural Gas-Fueled							
Combustion turbine - fleet total	5,716	5	11,486	11,184 ft^3/MWh	0	0	0.1402
Combined cycle - fleet total - TVA and PPA	4,935	40	7,150	6,998 ft^3/MWh	0	0	0.0863
Diesel-Fueled							
Fleet total - TVA and PPA	132	5	7,500	67.6 gal/MWh	0	0.5339	31.474
Nuclear							
Fleet total	7,895	95	10,136	2.2 kgU/GWh	0	0	0
Hydro							
Fleet total	4,144	var.	--	--	0	0	0
Storage[1]							
Raccoon Mountain pumped hydro	1,615	20	--	--	0	0	0
Renewable							
Wind - out of region	300	30	--	--	0	0	0
Wind - in region	29	25	--	--	0	0	0
Landfill gas - fleet total	9.6	83	13,500	27,551 ft^3/MWh	0	0.024	3.0
Solar			n/a	n/a	0	0	0

[1]Fuel requirements and emission rates exclude those of the generation used during pumping mode
[2]Varies by facility
[3]Combined with ash due to use of circulating fluidized bed boiler
[4]Facility average
[5]Estimate from life-cycle literature, see text

Table 7-1. Continued.

Hg emissions - lbs/MWh	CO_2 emissions - tons/GWh	GHG life-cycle emissions - tons CO_2-eq/GWh	Process water use gallons/MWh	Process water consumption -gallons/MWh	Solid waste - coal ash - tons/MWh	Solid waste - coal SO_2 removal byproducts toms/MWh	Low-level waste	High-level waste	Facility Land Requirement - permanently disturbed acres
Coal-Fueled									
0.0428	1059.0	1,030[5]	43,765	219.5	0.044	.0059	0	0	1,105[4]
0.0348	1141.9	unk	610.5	610.5	0.219	--[3]	0	0	320
Natural Gas-Fueled									
0	678.97	unk	0	0	0	0	0	0	68[4]
0	420.77	509[5]	978.7	831.1	0	0	0	0	80[4]
Diesel-Fueled									
0	1501.3		0	0	0	0	0	0	1
Nuclear									
0	0	22.2[5]	26,674	806	0	0			890[4]
Hydro									
0	0	--	n/a	0	0	0	0	0	--
Storage[1]									
0	see text	see text	386,470	0	0	0	0	0	1,050
Renewable									
0	0	7.10	0	0	0	0	0	0	0.59/MW
0	0	7.25	0	0	0	0	0	0	0.86/MW
0	(2,814)	--	0	0	0	0	0	0	1
0	0	72.8	0	0	0	0	0	0	var.

Table 7-2. Environmental characteristics of new supply-side options included in alternative strategies.

	Net Capacity - MW	Capacity factor - %	Heat rate - Btu/kWh	Fuel requirement	SO_2 emissions - lbs/MWh	NOx emissions - lbs/MWh	Hg emissions - lbs/MWh
Coal Fueled							
IGCC with CCS	490	82	10,533	0.534 tons/MWh	0.0898	0.5263	0.0036
Natural Gas Fueled							
Combustion turbine	686	5	9,857	9.60 ft^3/kWh	0	0.2588	0
Combustion turbine	828	5	9,857	9.60 ft^3/kWh	0	0.2588	0
Combined cycle	1,045	40	6,706	6.53 ft^3/kWh	0	0.0827	0
Nuclear							
Bellefonte Unit 1 or Unit 2	1,250	92	10,100	2.2 kgU/GWh	0	0	0
Bellefonte Unit 3 or Unit 4 (AP1000)	1,117	92	10,100	2.2 kgU/GWh	0	0	0
Storage[1]							
Pumped storage hydro	850	20	n/a	n/a	0	0	0
Renewable							
Hydro modernization	88.8[2]	--	n/a	n/a	0	0	0
Hydro - small and micro-	var.[3]	50	n/a	n/a	0	0	0
Wind - out of region	var.	var.	n/a	n/a	0	0	0
Wind - in region	var.	var.	n/a	n/a	0	0	0
Landfill gas	var.	83	13,500	27.6 ft^3/kWh			0
Biomass - cofiring	up to 169[2]	var.	12,500	see text	see text	see text	see text
Biomass - dedicated facility	50	81	12,500	1.588 tons/MWh[4]			
Biomass - coal boiler conversion	var.	var.	12,500	see text			
Solar PV	var.		n/a	n/a	0	0	0

[1]Fuel requirements and emission rates exclude those of the generation used during pumping mode
[2]System-side total
[3]Varies by facility
[4]Stoker boiler; gasification plant has lower fuel requirement

Table 7-2. Continued.

CO_2 emissions - tons/GWh	GHG life-cycle emissions - tons CO_2-eq/GWh	Process water use gallons/MWh	Process water consumption -gallons/MWh	Solid waste - ash/slag - tons/GWh	Solid waste - coal SO2 removal byproducts	Low-level waste ft^3/GWh	High level waste	Facility Land Requirement - permanently disturbed acres
Coal-Fueled								
108.0		655	655	47.31	0	0	0	200
Natural Gas-Fueled								
588.2		0	0	0	0	0	0	68
588.2		0	0	0	0	0	0	68
404.7	509	978.7	831.1	0	0	0	0	80
Nuclear								
0	39	1680	576	0	0	0.807	2.59E-06 tons uranium/MWh	400
0	39	1289	859	0	0	0.213	2.64E-06 tons uranium/MWh	450
Storage[1]								
0						0	0	750
Renewable								
0		0	0	0	0	0	0	0
0		var.	0	0	0	0	0	0.5/MW
0		0	0	0	0	0	0	0.59/MW
0		0	0	0	0	0	0	0.86/MW
		0	0		0	0		0
see text	see text	0	0			0	0	0
0	var.			31.78	0	0	0	50
0	var.			var.	0	0	0	var.
0	27.6 - 72.8	0	0	0	0	0	0	var.

7.3.1. Fossil-Fueled Generation

Coal - Existing Facilities

TVA operates 59 coal-fired generating units at 11 plant sites. Flue gas desulfurization systems (scrubbers) have been installed at 17 of these units and selective catalytic reduction (SCR) systems for NOx emissions control have been installed at 21 of these units. The plants with these scrubber and SCR systems include TVA's largest coal units and total about 8,000 MW of generating capacity. The remaining coal-fired units use other methods to reduce SO_2 and NOx emissions, and additional emission controls will likely be required for these units to comply with anticipated air quality regulations. Many of the older coal units that lack scrubbers and SCR systems are candidates or already identified for long-term idling under the alternative scenarios.

While the life-cycle GHG emissions for TVA coal plants have not been calculated, several studies have calculated these emissions for comparable coal plants. Spitzley and Keoleian (2004) found an emission rate of 1060 tons CO_2-eq/GWh for pulverized coal boilers without advanced emissions control systems. Odeh and Cockerill (2008) calculated a life-cycle GHG emission rate of 1085 tons CO_2-eq/GWh for a pulverized coal plant equipped with an electrostatic precipitator, SCR, and scrubber, comparable to Widows Creek units 7 and 8. They also calculated an emission rate of 969 tons CO_2-eq/GWh for a supercritical pulverized coal plant equipped with an electrostatic precipitator, SCR, and scrubber, comparable to Bull Run, Cumberland, and Paradise plants.

The largest source of life-cycle GHG emissions at coal plants similar to TVA's is CO_2 from the coal combustion, which typically accounts for between 80 and 90 percent of GHG emissions (Spath et al. 1999, Kim and Dale 2005, Odeh and Cockerill 2008). The next highest source is methane emissions from coal mining; these emissions are higher for underground than surface mines. Other notable GHG sources include coal preparation, coal transport, and limestone mining. GHG emissions from plant construction, decommissioning, and other process are relatively small.

All TVA coal plants, except Paradise, use open-cycle cooling and thus, have high water use rates but low water consumption rates (see Section 4.7). Paradise uses closed-cycle cooling much of the year and has lower water use and higher water consumption rates. As a result, the amount of heat discharged to the river at Paradise is relatively low.

The Red Hills plant in Mississippi burns coal from an adjacent surface mine. Relative to the average for TVA's coal plants, its SO_2, NOx, and mercury emissions rates are low and its CO_2 emission rate is high due to the lower fuel energy content. Like the TVA coal plants with scrubbers, Red Hills uses limestone to reduce SO_2 emissions. The plant occupies about 320 acres and fuel cycle disturbs about 275 acres/year, equivalent to 0.09 acre/GWh of energy generated. It uses groundwater in a closed-cycle cooling system with no discharges to receiving water bodies.

Coal - New Facilities

The only new coal plant included in the alternative strategies is an integrated gasification combined cycle (IGCC) plant with carbon capture and sequestration (CCS). The environmental impacts of constructing and operating IGCC plants with CCS have been described for the proposed FutureGen plant in USDOE (2007) and for the Kemper County,Mississippi IGCC Project in USDOE (2010). Relative to conventional coal plants, emissions of air pollutants and CO_2 are very low (Tables 7-1, 7-2). Projected life-cycle emissions for IGCC plants with CCS operating at 90 percent CO_2 capture rate have been estimated to be 0.1841 tons CO_2-eq/GWh (Odeh and Cockerill 2008) and 0.2381 tons CO_2-eq/GWh (Spath and Mann 2004).

Recently proposed commercial scale IGCC plants with CCS have closed-cycle cooling systems with zero liquid discharge. The water use and consumption rate for the Kemper County IGCC plant is 469 gallons/MWh (USDOE 2010) and for the FutureGen IGCC plant is 655 gallons/MWh (USDOE 2007). Instead of fly ash, bottom ash, and scrubber sludge, IGCC plants produce a glassy, inert slag during the gasification process. The slag production rate for the FutureGen plant, using Illinois Basin coal, is 47.3 tons/GWh (USDOE 2007).

Facility surface land requirements for IGCC plants with CCS are approximately 200 acres (DOE 2007). Life-cycle land requirements are not available and would vary with the distance from the generating facility to the carbon sequestration site.

Natural Gas - Existing Facilities

The construction and operational impacts of TVA's existing and committed (i.e., John Sevier CC plant) combustion turbine and combined cycle plants are described in several EISs and environmental assessments (e.g., TVA 2000, TVA 2008a, TVA 2010a). Natural gas-fired plants do not emit SO_2 or mercury, and direct emissions of NOx (usually controlled by steam injection and/or SCR systems) and CO_2 are low relative to other fossil plants. Life-cycle GHG emissions have not been calculated for TVA's gas-fired plants; published rates for such plants average about 509 tons CO_2-eq/GWh (Meier and Kulcinski 2000, Spath and Mann 2000, Jaramillo et al. 2007). Direct CO_2 emissions account for 85 - 90 percent of total GHGs; most of the remaining GHG emissions are from methane and CO_2 emitted during natural gas extraction, processing, and transport. Life-cycle GHG emissions from combustion turbine plants are higher due to the plant's lower efficiency. These life-cycle GHG emissions are based on the use of natural gas extracted in North America and transported by pipelines. Life-cycle GHG emissions would be greater for the use of liquefied natural gas due to the energy requirements and leakage during the additional compression, transportation, and decompression steps. Jaramillo et al. (2007) estimated life-cycle GHG emissions from generating facilities using liquefied natural gas to be about 28 percent greater than those from facilities using domestic natural gas.

Published studies of life-cycle GHG emissions from natural gas production and use are largely based on conventional non-shale onshore and offshore wells. Armendariz (2009) estimated GHG emissions from 2007 natural gas production in the Barnett Shale formation in Texas to be 22,375 tons CO_2-eq/day. Based on actual 2007 production data from RRC (RRC 2011), this equates to 1,317 tons CO_2-eq per billion cubic feet of natural gas. Wood et al. (2011) estimated GHG emissions from shale gas production ranging from 0.14 to 1.63 metric tons CO2-eq/TJ of natural gas. The Marcellus and Barnett shale gas areas were in the lower half of this range.

Combustion turbine plants require no process water. TVA's combined cycle plants use closed-cycle cooling, as do most other combined cycle plants. Facility land requirements for TVA combustion turbine plants that are not co-located with coal plants average 135 acres, about half of which are developed. Combined cycle plant sites average 119 acres, about two-thirds of which are developed.

Natural Gas - New Facilities
The alternative scenarios include two configurations of combustion turbine plants and one combined cycle plant. The environmental characteristics of these plants are similar to the existing natural gas-fueled facilities, except that the emission rates are somewhat lower due to the use of more modern components.

7.3.2. Nuclear Generation

Nuclear - Existing Facilities
The impacts of operating TVA's existing and committed (i.e., Watts Bar Unit 2) nuclear plants are described in previous EISs and other reports (e.g., TVA 2002, 2007c).

Nuclear power generation does not directly emit regulated air pollutants of GHGs. The largest variables in life-cycle GHG emissions of a nuclear plant, aside from the operating lifetime, electrical output, and capacity factor, are the uranium concentration in the ore, the type of uranium enrichment process, and the source of power for enrichment facilities. Current enrichment facilities in the U.S. use the energy-intensive gaseous diffusion process largely powered by fossil fuels. New enrichment facilities currently under construction will use much less energy-intensive processes resulting in reduced nuclear plant life-cycle emissions. The use of nuclear fuel from dismantled nuclear weapons also reduces GHG emissions. The life-cycle GHG emissions of TVA's nuclear plants have not been determined. In a recent survey of nuclear life-cycle studies, Sovacool (2008) reported a range of 1.5 to 317 tons CO_2-eq/GWh, with a mean of 73 tons CO_2-eq/GWh for plants throughout the world. Reported emissions for U.S. plants range from 17 to 61 tons CO_2-eq/GWH, with a mid-point of 39 tons CO_2-eq/GWh (White and Kulcinski 2002, Meier 2002, Fthenakis and Kim 2007, Sovacool 2008). Water use and consumption rates and radioactive waste and spent fuel production rates are listed in Table 7-2.

TVA's nuclear plants occupy an average of 1,114 acres each and about 80 percent of this area is developed. Life-cycle land metrics have not been determined for TVA's nuclear plants. Fthenakis and Kim (2009) estimated a life-cycle land transformation of 0.023 acres/GWh for nuclear power. About half of this transformed land is the power plant site. Due to the current uncertainty over the long-term disposal of spent fuel, the land required for offsite spent fuel disposal is excluded from this estimate.

Nuclear - New Generation
The impacts of constructing and operating a one- or two-unit nuclear plant at the Bellefonte site are described in previous EISs (e.g., TVA 1974, 2008c, 2010c). Because this site contains a partially built, two-unit nuclear plant, the impacts of construction of one or two nuclear units would likely not be significant. Most operational impacts are comparable to those of TVA's existing nuclear plants with the exception of water use and water consumption. Bellefonte would primarily operate with closed cycle cooling and water use is relatively low and water consumption is relatively high compared to TVA's other thermoelectric plants.

7.3.3. Renewable Generation

With the exception of upgrades to TVA's existing hydroelectric facilities, cofiring biomass at existing coal plants, and conversion of existing coal units to dedicated biomass units, increases in renewable generation are expected to be through power purchase agreements with non-TVA generators. Following is an overview of the environmental impacts of renewable generation.

Hydroelectric - Existing Facilities
Impacts of the operation of TVA's hydroelectric facilities are described in the Reservoir Operations Study (TVA 2004). Hydropower generation does not directly emit CO_2 and its life-cycle GHG emissions are among the lowest of the various types of generation. Although not studied for TVA facilities, reported life-cycle GHG emissions from other hydroelectric facilities vary greatly, primarily due to uncertainties over methane emissions from the decomposition of flooded biomass (AEFPERR 2009). These methane emissions are site-specific, and are poorly known for reservoirs in areas with temperate climates such as the TVA region. Excluding these emissions, reported life-cycle emissions include 12.1 tons CO_2/GWh for a temperate zone 10MW run-of-river plant (Hondo 2005), and 28.8 tons CO_2/GWh for the much larger Glen Canyon plant (Spitzley and Keolieian 2004). Emissions from hydro reservoirs are also offset by the multi-purpose use of the reservoirs.

Hydroelectric - New Facilities
Under all the alternatives, TVA would continue to modernize its hydroelectric units, with an eventual capacity increase of up to 89 MW from 38 units. The impacts of these upgrades have been described in environmental assessments for many facilities (e.g., TVA 2005a). While the upgrades generally do not change the volume of water used on a daily cycle, they can increase the rate of water passing through the turbines and result in small, periodic increases in downstream velocities. A potential consequence of this is increased downstream bank erosion, which TVA mitigates as necessary by protecting streambanks with riprap or other techniques. Other environmental impacts of hydro modernization are minimal and there is typically no additional long-term conversion of land.

Potential future hydroelectric generation also includes small and micro-hydro facilities. One type of small hydro generation would be the addition of turbines to existing run-of-river dams, such as old mill dams. If these continue to operate in a run-of-river mode, environmental impacts would be small. Other new small and micro-hydro projects would be run-of-river with little or no reservoirs. One class of these would divert part of the streamflow into a raceway to a downstream generator without totally blocking the stream channel. Potential environmental impacts include alterations of the streambed and streambanks, removal of riparian vegetation, and, for at least a short stretch of the stream, reduction of streamflow (EPRI 2010). Another type of project is in-stream generators mounted on the streambed or suspended from a barge or other structure. These could potentially interfere with boating and other recreational uses of the stream. At this time, their potential impacts on fish and other aquatic life is poorly known, although a few studies have suggested they are not significant. Land requirements vary with the type of facility and for this analysis are assumed to be 0.5 acres/MW.

Wind - Existing Facilities
A relatively small portion of TVA's generation portfolio is wind generation from the Cumberland Mountains of Tennessee and the upper Midwest. TVA is also in the process of acquiring more wind generation from the upper Midwest and Great Plains.

Impacts of windfarm construction include the clearing and grading of access roads and turbine sites and excavation for turbine foundations and electrical connections. Denholm et al. (2009) reported an average direct permanent impact area of 0.74 acres/MW, and a direct average temporary impact area of 1.73 acres/MW. These impact areas average somewhat smaller in mid-western croplands and somewhat larger in Great Plains grasslands/herbaceous areas and forested Appalachian ridges.

The total windfarm area tends to be much larger than the direct impact areas and nationwide averages 84 acres/MW or a capacity density of 1 MW/82 acres (Denholm et al. 2009). This density, while low relative to most other types of electrical generation, varies greatly due to different leasing practices by developers. A very small proportion of this area is directly disturbed and most land use practices can continue on the remainder of the windfarm area.

Other operational impacts include turbine noise, which can be audible for distances of a quarter mile or more, the visual impacts of the turbines which can dominate the skyline, displacement of some wildlife that avoid tall structures, and mortality of birds and bats from collision with turbines or trauma induced by air pressure changes caused by the rotating turbines (BLM 2005, Baerwald et al. 2008). The impacts of bird mortality are probably not significant in most areas, while the impacts of bat mortality are potentially significant at Appalachian windfarms (Arnett et al. 2007). Measures to mitigate bat mortality include locking the turbines in a fixed position during the late summer/early fall period of highest mortality.

Wind turbines produce no direct emissions of air pollutants or GHGs. Martinez et al. (2009) calculated a life-cycle GHG emission rate of 7.25 tons CO_2-eq/GWh for a modern 2-MW turbine operating at a 23 percent capacity factor.

Wind - New Facilities
Most of the wind energy marketed by TVA in the future under the alternative strategies will likely be purchased from windfarms outside the TVA region in the upper Midwest and Great Plains. A portion of new wind capacity, up to 360 MW (about 180 - 240 turbines), may be purchased from windfarms in the TVA region. The impacts of constructing and operating these facilities are the same as those described above. A very small portion of purchased windpower may be from small wind turbines (<100 KW). Aside from the potential visual impact of a 60-100 foot tower, these small turbines have minimal environmental impacts.

Solar - Existing Facilities
TVA operates 15 small PV installations. The environmental impacts of constructing and operating these have been negligible (TVA 2001). TVA also purchases energy generated from numerous PV facilities ranging from 2 KW to 1 MW in size.

PV facilities have the potential to cause visual impacts; this potential is both dependent on the local context and the type of installation. PV facilities produce no direct emissions of air pollutants or GHGs. Life-cycle GHG emissions from PV generation vary from about 28 - 73 tons CO_2-eq/GWh (Fthenakis and Kim 2007, Fthenakis et al. 2008). The major source of this variation is the type of PV technology; thin-film cadmium telluride panels have lower life-cycle emissions than the more common silicon-based panels which require much more energy to manufacture.

Land requirements for PV facilities vary greatly and are dependent on the type of installation. Building-mounted systems require no additional land. Ground-mounted systems may be on canopies that provide shelter and thus, do not negatively impact land use. Land requirements for stand-alone ground-mounted systems vary with the type of mounting system. Fixed systems (with panels that do not move to track the movement of the sum) require less land than those with 1- or 2-axis tracking (Denholm and Margolis 2007). The generation by tracking systems, however, is greater than from fixed systems.

Solar - New Generation
The alternative strategies include the purchase of up to 365 MW of solar capacity through PPAs. The potential impacts of the facilities generating this power vary with the facility size and type of installation.

Biomass - Existing Facilities
TVA generates electricity from biomass by cofiring methane from a sewage treatment plant at Allen Fossil Plant and by cofiring wood waste at Colbert Fossil Plant. The relative amounts of this generation are small and adverse environmental impacts are minimal. A beneficial impact is the avoidance of methane emissions and the small reduction of emissions from the displaced coal generation.

TVA also purchases electricity generated from landfill gas and wood waste. The environmental impacts of this generation are, overall, beneficial due to the avoidance of methane emissions and utilization of residues at wood and grain processing plants.

Biomass - New Generation
The alternative strategies include the purchase of energy from biomass facilities through PPAs cofiring biomass at existing TVA coal units, and converting existing TVA coal units to dedicated biomass operation. The potential environmental impacts vary with the type of facility; all of the facilities have potential beneficial impacts from the avoidance of methane emissions.

Most published studies of life-cycle GHG emissions from electrical generation with biomass fuels, including those cited below, assume that combustion of biomass does not result in the direct emission of CO_2. The combustion of biomass, however, does result in the release of the carbon stored in the biomass. For fast growing, short-rotation biomass fuels such as grasses, the released carbon is soon sequestered by regrowth. For trees, sequestering the released carbon may require many years. The effects of this on life-cycle GHG emissions varies with the characteristics of the generating plant, whether the biomass generation is replacing fossil generation, the type of fossil generation replaced, characteristics of the forest, the post-harvest management of the forest, and other factors (Walker et al. 2010).

The harvesting and transportation of woody biomass (trees) for use a fuel can result in adverse environmental impacts. These impacts are similar to those that can result from harvesting trees for other purposes, such as for wood chips for the manufacture of pulp or other forest products (TVA 1993). Potential impacts include the modification or loss of wildlife habitat, sedimentation, reduction in soil fertility, loss of old growth forest, change in forest type and understory vegetation, altered scenery, and competition with other wood-using industries. The severity of these impacts varies with the use of appropriate best management practices, the proportion or quantity of trees harvested from a stand, whether the harvested stand is a plantation, post-harvest site treatment, and other factors.

<u>Landfill Gas</u> - A small portion of future biomass generation is likely to be from landfill gas. Land requirements for landfill gas facilities are minimal as they are typically constructed on previously disturbed areas at landfills. Although the direct CO_2 emission rate from landfill gas generation is high, the net impact is an overall reduction in life-cycle GHG emissions due to the avoidance of methane emissions and the conversion of heat energy, which otherwise would have been produced by the open flaring of the methane, to electrical energy.

<u>Biomass Cofiring</u> - The alternative strategies include up to 169 MW of capacity and 1,155 GWh/year of generation from cofiring biomass at TVA coal plants. A large portion of this biomass would likely be wood waste. Cofiring requires the construction of a biomass fuel handling system and, depending on the type of plant, boiler modifications (EPRI 2010). The additional facility land requirements are small, typically one to five acres. Whether this requires new site clearing and grading depends on the configuration of the coal plant; for purposes of this impact analysis, TVA has assumed that no additional land will be disturbed. Life-cycle land requirements may increase somewhat over those of the coal plant; this is dependent on the type of biomass and its sourcing areas. Plant process water requirements remain the same or may slightly decrease due to the lower heat value of biomass fuels.

Biomass cofiring reduces emission rates of many air pollutants and may result in a reduction of GHG emissions; the percent reduction increases with the percent of coal replaced by biomass. Mann and Spath (2001) analyzed wood waste cofiring in a pulverized coal plant. At 5 percent cofiring (i.e., 5 percent of the heat input from biomass), emissions of SO_2, NOx, and CO_2 were reduced by 3, 2, and 2 percent, respectively. At 15 percent cofiring, emissions of SO_2, NOx, and CO_2 were reduced by 12, 8, and 6 percent, respectively. Although not described by Mann and Spath (2001), mercury emissions would also decrease due to the very low mercury content of wood waste. Other studies have shown small increases in NOx emissions due to the presence of nitrogen in the biomass (AEFPERR 2009). Life-cycle GHG emissions were reduced from 1,145 tons CO_2-eq/GWh to 1,106 tons CO_2-eq/GWh at 5 percent cofiring and 936 tons CO_2-eq/GWh at 15 percent cofiring (Mann and Spath 2001). These GHG emission rates are based on the assumption that the wood waste would not have otherwise been used in durable products such as building materials. Consequently, the disproportionately large reductions in GHG emissions relative to the percent cofiring are due, in part, to avoided CO_2 and methane emissions from decomposition of the wood waste.

<u>Dedicated Biomass Boiler Conversion</u> - The alternative strategies include 170 MW of capacity and 1,042 GWh/year of generation from coal boilers converted to dedicated biomass boilers. A large portion of this biomass would likely be wood waste. The conversions would require changes to the boilers, changes to or replacement of the boiler coal feed system, and construction of a biomass fuel receiving and processing facility. The land requirements for these vary and are plant-specific. Life-cycle land requirements would increase over those of a coal facility if there are multiple, dispersed fuel sourcing areas. Emission rates would likely be similar to those of a new dedicated biomass facility described below. Water use and consumption rates would be somewhat less than those of the coal unit.

<u>Dedicated Biomass Facility</u> - The alternative strategies include 117 MW of capacity and 912 GWh/year of generation from dedicated biomass facilities acquired through PPAs. The fuels for these facilities could include wood waste, forest residues, and dedicated biomass crops such as switchgrass, hybrid poplar, eastern cottonwood or sweetgum (see Section 4.17.4). Plant capacity is frequently limited due to fuel delivery constraints, and plants larger than 50 MW are uncommon (AEFPERR 2009). The amount of fuel consumed per unit of generation varies with the type of biomass and its moisture content; fuel consumption rates reported at several dedicated facilities range from 4.4 to 5.1 tons/MWh (Wiltsee 2000). Facility land requirements vary; reported values include 17 acres for a 36-MW plant, 31 acres for a 40-MW plant, 39 acres for a 50-MW plant, and 200 acres for a

100-MW plant (Wiltsee 2000, EPRI 2010). This impact analysis assumes 50 acres are required for a 50-MW plant.

While there are no net direct CO^2 emissions, GHGs are emitted during several process steps. For waste woods, as with biomass cofiring described above, the life-cycle GHG emissions may be negative; Spath and Mann (2004) calculated a rate of -452 tons CO_2-eq/GWh for a 60 MW direct-fired boiler using wood waste. For dedicated biomass crops, life-cycle GHG emissions are low but positive. Spitzley and Keoleian (2005) reported rates of 58 tons CO_2-eq/GWh for a 50-MW direct-fired boiler and 44 tons CO_2-eq/GWh for a 75-MW IGCC plant; both of these facilities were fueled with willow energy crops. Dedicated biomass facilities do not emit SO^2 or mercury; NOx emissions vary with the type of facility and NOx emission reduction systems are typically required.

7.3.4. Energy Storage

Existing Facilities

Operational impacts of the Raccoon Mountain facility are summarized in Table 7-1. Denholm and Kulcinski (2004) analyzed life-cycle GHG emissions of pumped storage facilities. The construction, operation (excluding pumping), and decommissioning of the facility produce life-cycle GHG emissions of approximately 5.5 tons of CO_2-eq/GWh of storage capacity, a small proportion of the total life-cycle GHG emissions. GHG emissions from generation are a function of the GHG intensity of the electricity used in the pumping mode. Assuming 78 percent efficiency of energy conversion (slightly lower than the 80 percent efficiency of Raccoon Mountain) and 5 percent transmission loss factor (a function of distance from the energy source and load center), GHG emissions are approximately 1.35 times the energy source emissions. At TVA's 2008 CO_2 intensity of 672 tons/GWh, the operation of Raccoon Mountain and a future pumped storage facility would be 907 tons/GWh. This emission rate will decrease with the decrease in CO_2 intensity occurring under the action alternatives. Although Raccoon Mountain uses a large volume of water, none of this water is consumed.

New Facilities

The operational impacts of the 850-MW combined cycle plant included in Alternative C are expected to be similar to those of the Raccoon Mountain plant. Construction impacts would include the construction of the upper reservoir, excavation of the tunnel connecting the upper and lower reservoirs and of the powerhouse, and construction of the discharge structure in the lower reservoir. If the lower reservoir is an existing reservoir, dredging of the discharge area and construction of an enclosure around the discharge structure would likely be required. If a new lower reservoir is required, additional impacts would result from the construction of the dam and reservoir and diversion of existing streams around or into the reservoirs. These impacts could be substantial.

7.4. Environmental Impacts of Energy Efficiency and Demand Response Programs

The sources of environmental impacts from the proposed expansion of TVA's EEDR programs under the alternative strategies include the following:

- The reduction in or avoidance of generation (collectively "reduction") resulting from energy efficiency measures. This reduction is incorporated into the alternative strategies and portfolios assessed in Section 7.6.
- The change in the type of generation due to changes from on-peak to off-peak energy use resulting from demand-response programs. This change in load shape,

and the resulting change in peak demand, is incorporated into the alternative strategies and portfolios assessed in Section 7.6. Historically, most demand response has been in emergency situations and shifted the time of electrical use with little net change in use and little environmental impact. More widespread employment of demand response is likely to result in a small net reduction in electrical use and the associated impacts from generation (Huber et al. 2011)

- The impacts of the generation of renewable electricity by end users participating in the Generation Partners, biodiesel generation, and non-renewable clean generation programs. The impacts of this generation are included in the discussion Section 7.6.
- The generation of solid waste resulting from building retrofits and the replacement of appliances, heating and air conditioning (HVAC) equipment, and other equipment to reduce energy use.

Building retrofits to reduce energy use, such as replacing windows and doors produce solid wastes which are often disposed of in landfills. The disposition of old appliances, HVAC equipment, water heaters, and other equipment varies across the region with the local availability of recycling facilities. Old refrigerators and HVAC equipment may also contain hydro chloroflourocarbon refrigerants (“freon”) whose use and disposal is regulated due to their harmful effects on stratospheric ozone (“the ozone layer”) and/or because of their high global warming potential. To reduce these harmful effects, HVAC contractors are required to reclaim and recycle these refrigerants from HVAC being replaced.

7.5. Environmental Impacts of Transmission Facility Construction and Operation

As described in Chapter 6, all of the alternatives would require the construction of new or upgraded transmission facilities. Following is a listing of generic impacts of these construction activities (Table 7-3). This listing was compiled by reviewing the EISs (e.g., TVA 2005b), environmental assessments (e.g., TVA 2010b), and other project planning documents for TVA transmission construction activities completed since 2005.

The construction activities include construction of new transmission lines, substations and switching stations; upgrades to existing transmission lines; and expansions of existing substations and switching stations.

The anticipated amount of construction of new or upgraded transmission facilities varies among the alternative strategies. All new generating facilities would require connections to the transmission system; the length of connecting transmission lines and the need for new substations and switching stations depend on the location of the facilities. Strategies C and E, with their higher amounts of coal capacity idled, would require more transmission system work to ensure system reliability is not affected by the loss of generation in parts of the TVA region. This need could be somewhat offset if new generating facilities are sited at or close to the locations of plants being laid up. Strategies C and E could also likely require more transmission system work to transmit renewable energy generated outside the TVA region. Under these scenarios TVA could participate in inter-regional project to transmit renewable energy.

Table 7-3. Generic impacts of transmission system construction activities.

	Transmission Lines	Substations and Switching Stations
Land Use Impacts		
Land requirements	Average of 12.1 acres/line mile, range 5.2 - 22.7	Average of 14.3 acres, range 1.8 - 53
Floodplain fill	0	Average of 0.02 acres, range 0 - 0.29
Prime farmland converted	0	Average of 5.1 acres, range 0 - 29.1
Land Cover Impacts		
Forest cleared	Average of 6.0 acres/line mile for new lines, range 0.4 - 11.9	Average of 0.68 acres, range 0 - 2.7
Wetland Impacts		
Area affected	Average of 0.76 acres/line mile, range 0 - 1.6	-
Forested area cleared	Average of 0.24 acres/line mile of new line, range 0 - 1.1	-
Stream Impacts		
Stream crossings	Average of 2.1 per mile of new line, range 0 - 7.1 Average of 2.3 per mile of existing line, range 0 - 17.9	n/a
Forested stream crossings	Average of 1.0 per mile of new line, range 0 - 1.8	n/a
Endangered and Threatened Species	11 of 57 projects affected federally listed endangered or threatened species, or species proposed or candidates for listing 23 of 57 projects affected state-listed endangered, threatened, or special concern species	
Historic Properties	11 of 57 projects affected historic properties	

.

7.6. Environmental Impacts of Alternative Resource Strategies and Portfolios

While the total amount of energy generated during the 2010-2029 planning period is, by design, similar across strategies for each scenario, the manner in which this energy is generated varies greatly across strategies (Figure 7-1). This is a result of the varying amounts of coal capacity idled, EEDR reductions, renewable additions, constraints on adding nuclear plants, and other factors described in Sections 2.4 and 6.2. The Strategy E portfolios consequently have smaller amounts of coal-fueled generation, larger amounts of wind and solid biomass-fueled generation, and larger amounts of energy demand met by EEDR programs. Renewable generation from sources other than solid biomass (hydroelectric modernization, new hydrogeneration, landfill gas, and solar) is not shown in Figure 7-1 due to their relatively small quantities ranging from 7,228 GWh in Strategy B to 15,704 GWh in Strategy E.

Alternative Strategies:
- B - Baseline Plan (No Action)
- C - Diversity Focused
- E - EEDR and Renewables Focused
- R - Recommended Planning Strategic Direction

Scenarios:
- 1 - Economy Recovers Dramatically
- 2 - Environmental Focus is a National Priority
- 3 - Prolonged Economic Malaise
- 7 - Reference Case: Spring 2010
- 8 - Reference Case: Great Recession Impacts Recovery

Following is a discussion of the impacts of each alternative strategy on air quality, greenhouse gas emissions and climate change, water withdrawals and water use, and land requirements.

7.6.1. Air Quality

All three alternative strategies will result in significant long-term reductions in total emissions of sulfur dioxide (SO_2), nitrogen oxides (NOx), and mercury. The trends in emissions of these three air pollutants (Figures 7-2, 7-3, and 7-4) are similar with decreases of about 60 percent between 2010 and 2015. Factors contributing to these decreases include the continued installation of emission controls necessary to comply with the Clean Air Act, including the anticipated requirements for use of maximum achievable control technology to reduce emissions of hazardous air pollutants, and reduced coal-fired generation due to the coal capacity idled and the increase in nuclear and natural gas generation. The decreases in emissions are greatest under Strategy E and least under Strategy B. Under all of these alternative strategies, there will likely be a substantial beneficial cumulative impact on regional air quality.

The reductions in SO_2, NOx, and mercury emissions will continue recent trends in emissions of these air pollutants. By 2020, TVA emissions of SO_2 will have decreased about 97 percent. This is expected to result in further decreases in regional concentrations of SO_2 and sulfate (a component of acid deposition), regional haze, and fine particulates. TVA emissions of NOx will have decreased about 95 percent since 1996. Although this continued reduction will likely result in reductions in regional NOx and ozone concentrations, the effect may be small as TVA emissions make up a relatively small proportion (11 percent) of regional NOx emissions (Figure 4-12).

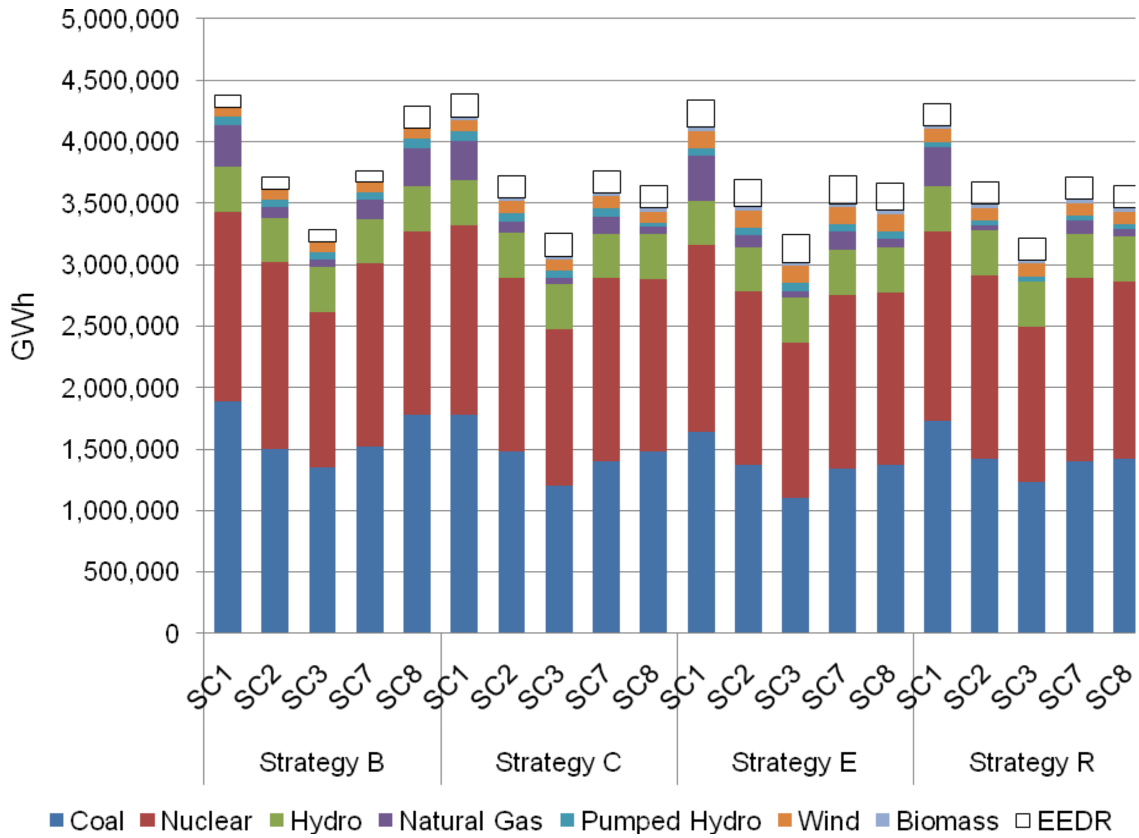

Figure 7-1. Generation (and avoided generation) by source, strategy, and scenario for the 20-year planning period. Generation by other renewable sources (hydroelectric modernization, new hydrogeneration, landfill gas, solar) is not shown because of the small quantities.

7.6.2. Greenhouse Gas Emissions and Climate Change

Total direct CO_2 emissions under the alternative strategies are highest under Strategy B and lowest under Strategy E. Compared to TVA's recent annual average direct CO_2 emissions of around 100 million tons, all of the strategies result in a decrease in CO_2 emissions (Figure 7-5). For most scenarios other than Scenario 1, and especially under strategies C, E, and R, the decrease is marked and significant. The lowest average reductions for the alternative strategies are 15.6 percent from both 2010-2020 and 2010-2028 for Strategy B (Table 7-4). The greatest reductions are 25.1 percent from 2010-2020 for Strategy R and 27.8 percent from 2010 - 2028 for Strategy E. Some strategy/scenario combinations show an increase in CO_2 emissions late in the planning period due to increased natural gas-fueled generation. The strategy/scenario combinations with the largest reductions in CO_2 emissions would approach proposed long-term GHG emissions reduction targets such as the 40 percent reduction from 2005 levels by 2030 in the recent American Clean Energy and Security Act (H.R. 2454).

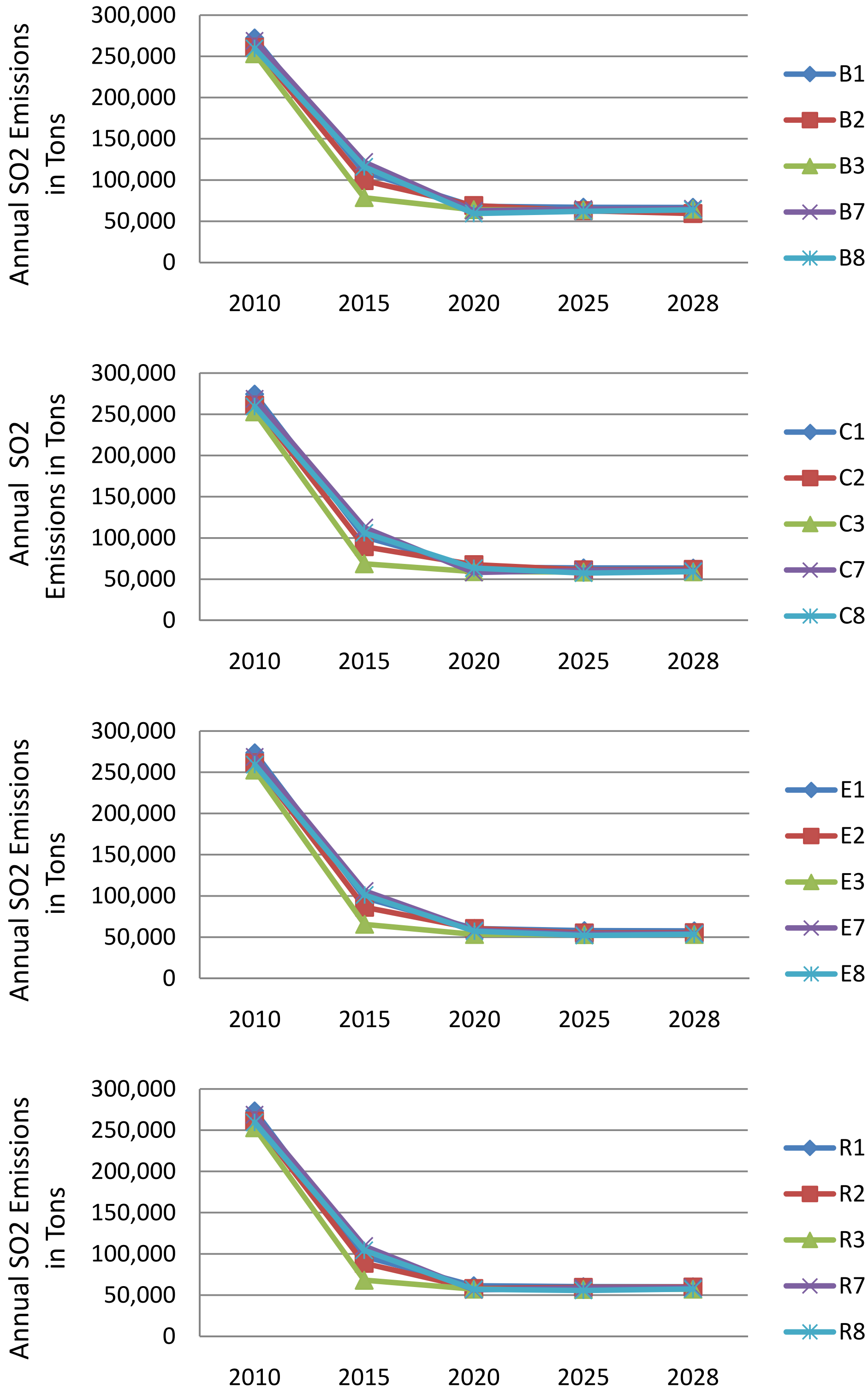

Figure 7-2. Trends in SO_2 emissions by scenario for (top to bottom) Strategies B, C, E, and R.

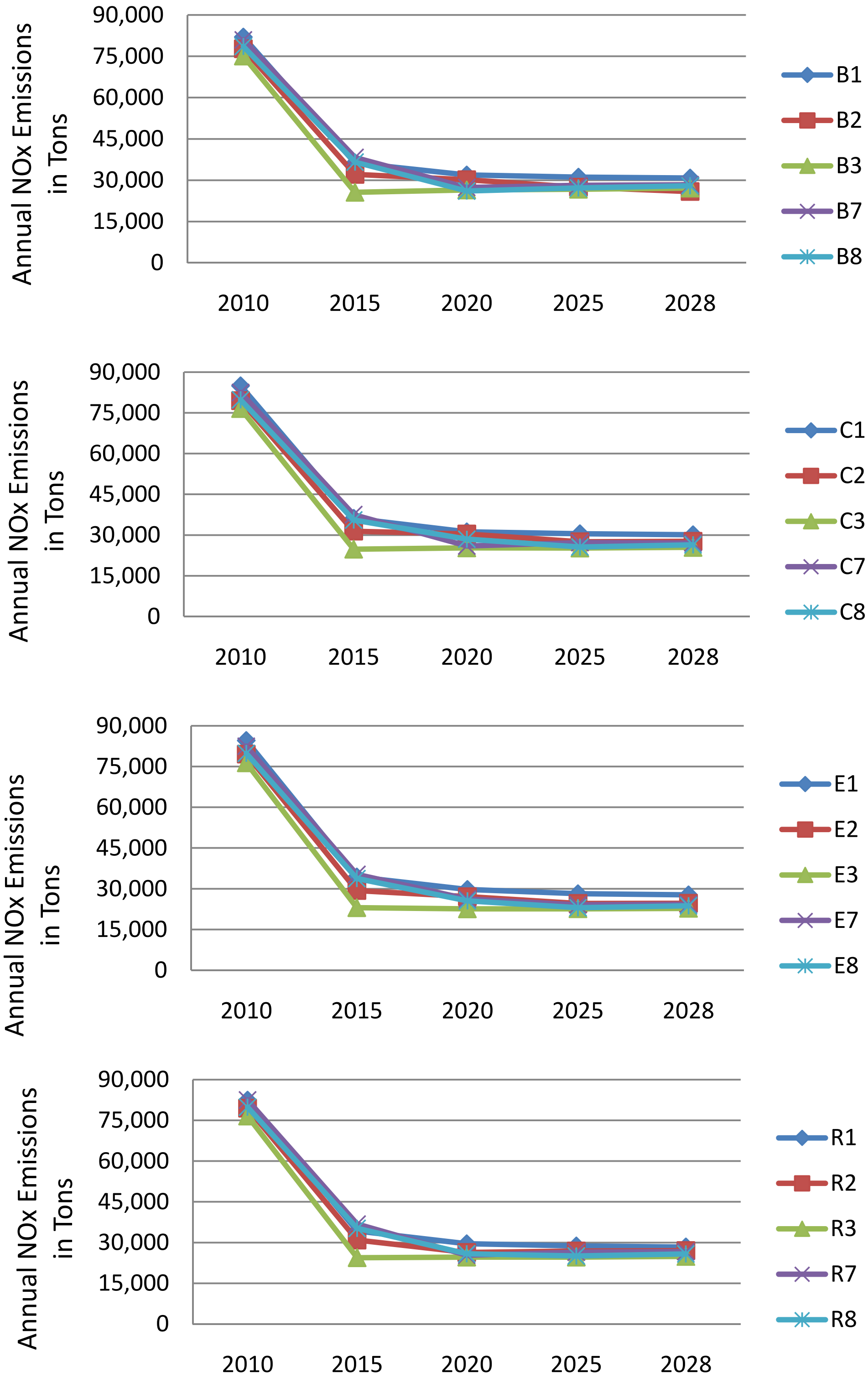

Figure 7-3. Trends in NOx emissions by scenario for (top to bottom) Strategies B, C, E, and R.

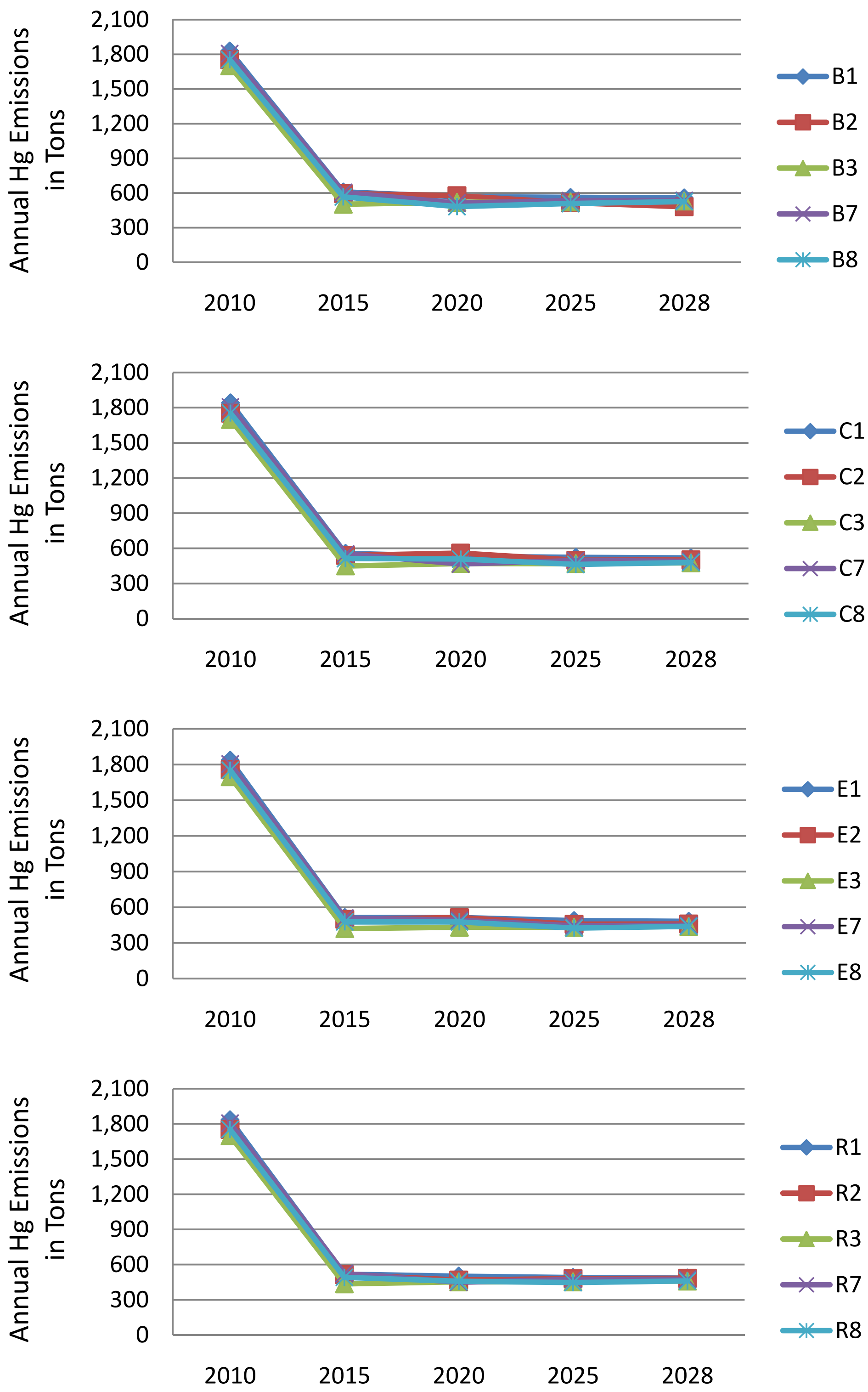

Figure 7-4. Trends in mercury (Hg) emissions by scenario for (top to bottom) Strategies B, C, E, and R.

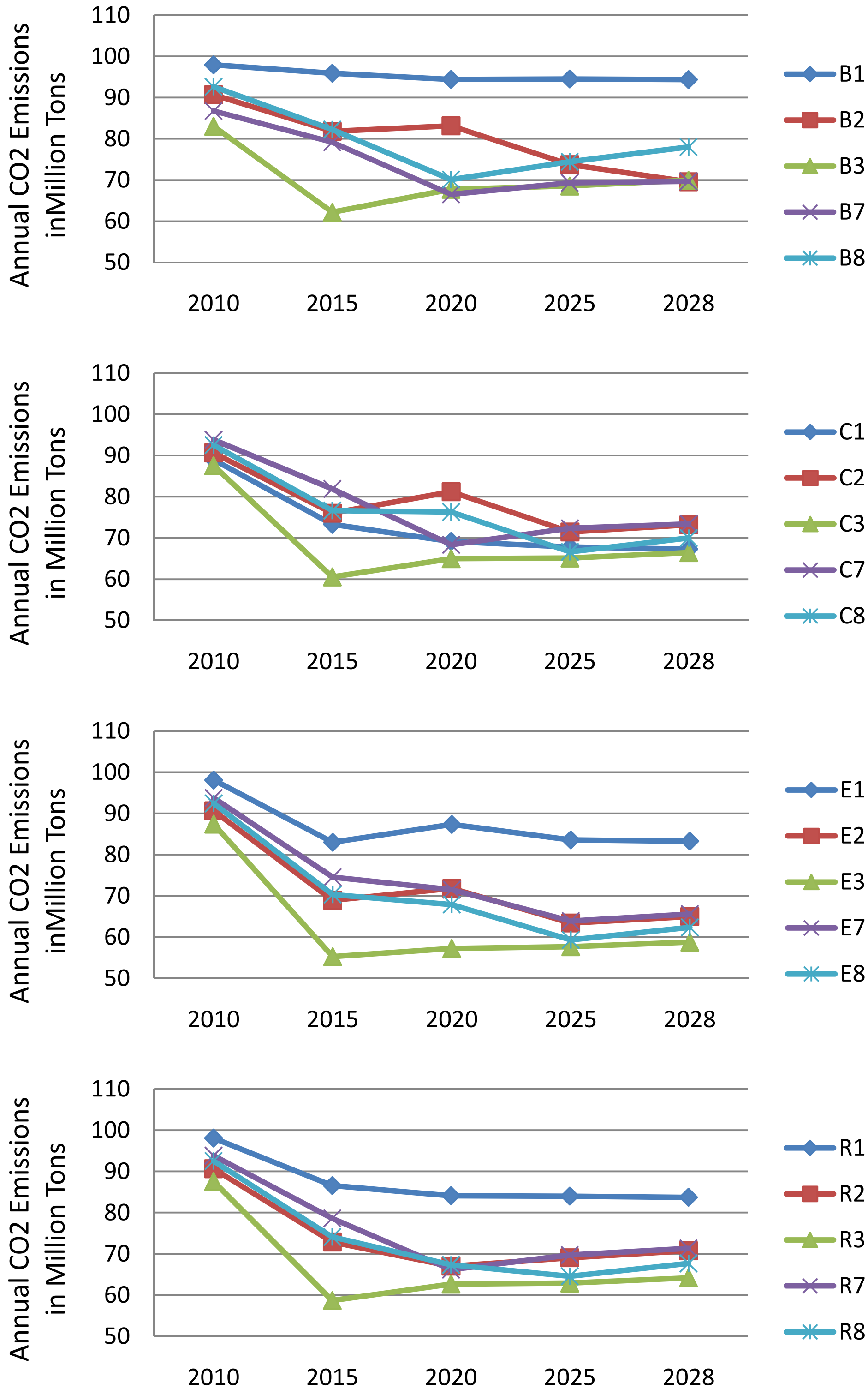

Figure 7-5. 2010-2028 trends in direct CO_2 emissions for (top to bottom) Strategies B, C, E, and R.

Table 7-4. Average percent reductions in CO_2 emissions by strategy.

	Strategy			
Years	B	C	E	R
2010 - 2020	15.6	20.6	23.3	25.1
2010 - 2028	15.6	22.8	27.8	22.8

TVA's 2005 CO_2 emissions were about 105 million tons. The CO_2 emissions rate of TVA's power generation, also known as the CO_2 intensity and expressed in terms of tons/GWh, averaged around 700 tons/GWh in recent years (Figure 4-7). It significantly decreases under the all of the alternative strategies (Figure 7-6, Table 7-5). This reduction is largely attributable to the fact that most new base-load generation will be from nuclear power, which does not have direct CO_2 emissions.

Table 7-5. Average percent reductions in CO_2 intensity by strategy.

	Strategy			
Years	B	C	E	R
2010 - 2020	25.2	28.0	27.5	31.3
2010 - 2028	29.0	33.7	36.4	30.9

For both total direct CO_2 emissions and CO_2 intensity, the reductions are greatest under Strategy E and least under Strategy B. over the planning period (Figure 7-6) are proportionately somewhat larger than the declines in direct CO_2 emissions.

The EPRI and TVA (2009) report summarizes temperature and precipitation forecasts for the TVA region based on General Circulation Model results presented in the 2007 IPCC report (Christensen et al. 2007). These forecasts are based on the A1B scenario; GHG projections associated with this scenario are in the middle of the range of the scenarios analyzed by the IPCC. The TVA region spans two model regions, the Central and Eastern North America region. Temperature forecasts for the TVA region are similar for the two model regions and predict an increase in annual mean temperatures in the TVA region of about 0.8°C (1.4°F) from 1990 to 2020 and up to 4.0°C (7.2°F) by 2100. Precipitation forecasts for the two model regions are more variable. In the central region, winter precipitation is forecast to increase by 2.6 percent from 1990 to 2020 and by 3.6 percent by 2100. Central region summer precipitation is forecast to decrease by 6.1 percent from 1990 to 2020 and by 3 percent by 2100. In the eastern region, winter precipitation is forecast to increase by 11.3 percent from 1990 to 2020 and by 13 percent by 2100. No change in eastern region summer precipitation is forecast from 1990 to 2020 or by 2100. It is important to note that these forecasts are based on coarse-scale model results; more localized downscaled analyses are required to refine the forecasts (USCCSP 2008).

The effects of the forecast climate change in the TVA region are likely to be relatively modest over the next decade and increase in magnitude by mid-century (EPRI and TVA 2009). Potential effects on water resources include increased water temperatures, increased stratification of reservoirs, reduced dissolved oxygen levels, and increased water demand for crop irrigation. Potential effects on agriculture include increased plant evapotranspiration, altered pest and pathogen regimes, changes in the types of crops grown, and increased demand for electricity by confined livestock and poultry operations.

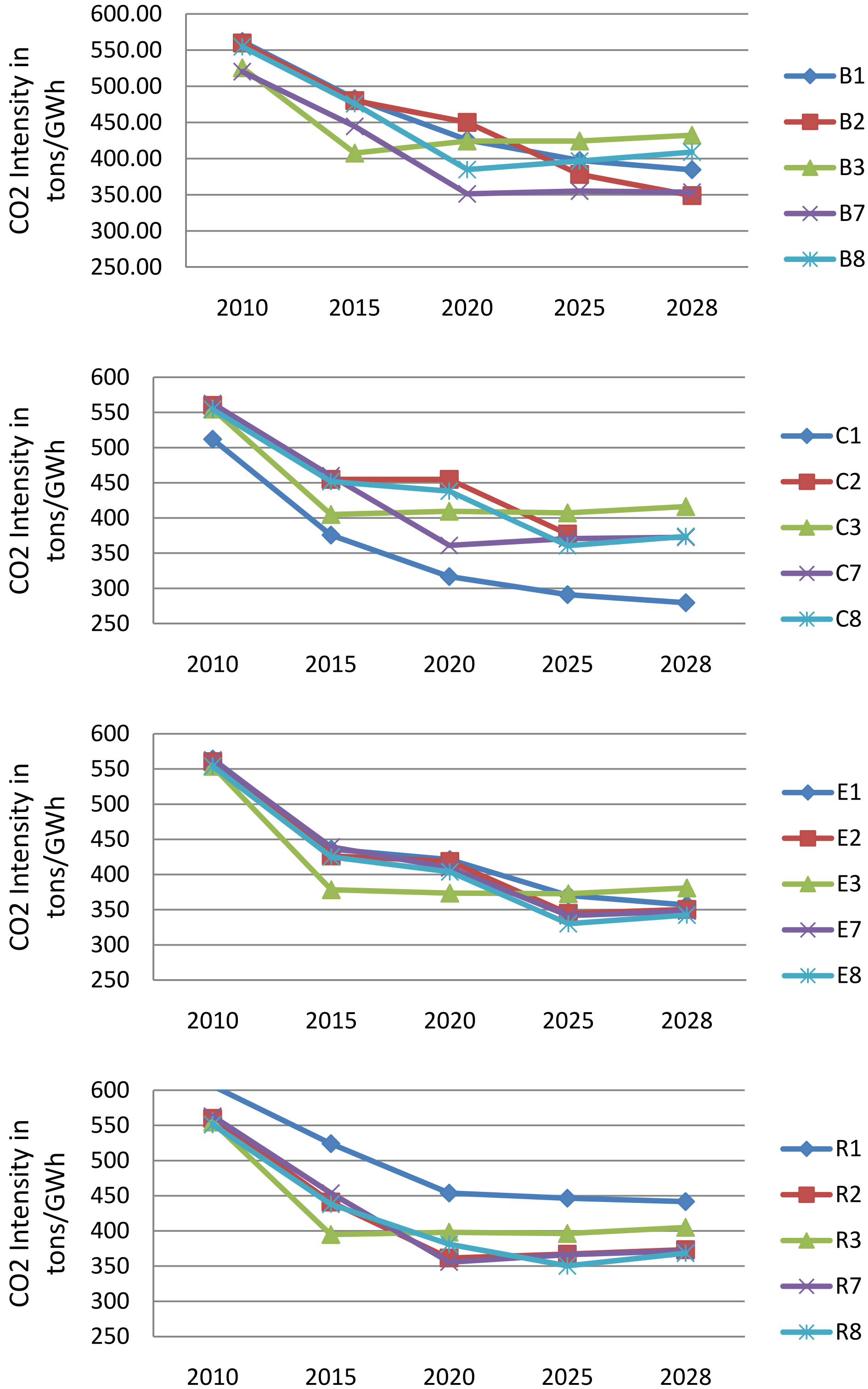

Figure 7-6. 2010-2028 trends in direct CO_2 emissions for (top to bottom) Strategies B, C, E, and R.

Potential effects on forest resources include increased tree growth, altered disturbance regimes, changes in forest community composition with declines in species currently at the southern limit of their ranges, and expansion of the oak-hickory and oak-pine forest types. Potential effects on fish and wildlife include range retractions and expansions, altered community composition, loss of cool to cold aquatic habitats and associated species such as brook trout, and increased threats to many endangered and threatened species.

The modeled higher air temperatures, the associated higher water temperatures, and the altered precipitation patterns that could result from climate change likely would affect the operation of TVA generating facilities. One likely effect is an increase in the demand for electricity. Warmer summer temperatures would result in more electricity used for air conditioning; this increase would likely be greater than the reduction in electricity used for space heating resulting from warmer winter temperatures. Most of TVA's thermal (fossil and nuclear) plants use open-cycle cooling and discharge heated water to the river system. NPDES permits, required for the discharge of cooling water into rivers and reservoirs, prescribe the maximum temperature of discharged water. The NRC also sets safety limits at nuclear plants on the maximum temperature of intake water used in essential auxiliary and emergency cooling systems. When cooling water intake temperatures are high, power plants must reduce power production (derate) or use cooling towers (if available) to reduce the temperature of the discharged water and avoid non-compliance with thermal limits. If nuclear safety intake temperatures reach their limits, NRC requires the plants to shut down. Consequently, elevated water temperatures can reduce thermal generation by causing forced deratings, additional use of cooling towers (which reduces net generation), and/or nuclear plant shutdown.

Increased air and water temperatures also influence the operation of thermal power plants with cooling towers. Increased condenser cooling water temperatures reduce the efficiency of power generation. Hotter, more humid air also reduces evaporation potential and the performance of cooling towers. A 1993 TVA study (Miller et al. 1993) analyzed the relationships between extreme air and water temperatures and power plant operations based on historical meteorological and operational data.

In the upper Tennessee River drainage, for each 1°F increase in air temperature (April through October), water temperatures increased by 0.25°F to almost 0.5°F, depending upon year and location in the TVA reservoir system. In general, air temperature effects cascaded down the reservoir system. In the Tennessee River system, for both closed- and open-cycle plants in Tennessee (on or above Chickamauga Reservoir) and in Alabama (on Wheeler Reservoir below both Chickamauga and Guntersville reservoirs), this study found that the incremental impact to operations from increased temperature were greatest during hot-dry years. Operation of most thermal power plants in the TVA power system was resilient to temperature increases during cold-wet and average meteorological years. The dominant meteorological variables affecting thermal plant performance were water temperature, and, for plants using cooling towers, humidity.

Changes in the operation of the Tennessee River system implemented in the ROS (TVA 2004) provide TVA flexibility to adapt to some climate change impacts while minimizing the effects on thermal generation. The analyses in the ROS were based on historical conditions and assume that unusually high air temperatures last a relatively short time.

Further adaptation, such as the installation of increased cooling capacity at thermal plants, may be necessary in the future given the forecast long-term increases in temperature.

7.6.3. Water Resources

Coal-fired generation would decrease and most new generating capacity would be nuclear and natural gas-fired under all of the alternative strategies. Potential impacts to water quality, with the exception of thermal discharges, are generally greater from coal-fired generation than from other types of generation due to the various liquid waste streams from coal-fired plants and the potentially adverse water quality impacts from coal mining and processing. The overall potential for water quality impacts would decrease under all alternative scenarios and this decrease would be greatest under Strategy E. Under all alternative strategies, TVA would continue to meet water quality standards through compliance with NPDES permit requirements.

All of the alternative strategies result in an increase in the volume of water used and consumed for cooling coal, natural gas, and nuclear generating facilities. As described in Section 4.7, TVA's coal and nuclear generating facilities primarily use open-cycle cooling systems. These systems withdraw large volumes of water from an adjacent reservoir or river, circulate it through condensers, and return the warmer water to the water body. Very little of the water is evaporated in the process and consequently these facilities use large volumes of water and consume a very small proportion of the water used. With closed-cycle cooling systems, water is circulated through a cooling tower where much of it evaporates; closed-cycle systems use much less water than open-cycle systems and consume a much greater proportion of the water. All of TVA's coal and nuclear plants, with the exception of Watts Bar, operate exclusively or primarily in open-cycle mode. Watts Bar Nuclear Plant Unit 1 uses a combination of open-cycle and closed-cycle cooling and thus has lower water use and higher water consumption rates than TVA's other large generating plants. TVA's combined-cycle natural gas plants, as well as the coal and combined-cycle plants from which TVA purchases power, use closed-cycle cooling. With the exception of Watts Bar Nuclear Plant Unit 2, which will operate similarly to Unit 1, all of TVA's future thermal generating plants are anticipated to use closed-cycle cooling.

Figure 7-7 shows projected trends in water use for the alternative strategies and scenarios. The major differences among the strategies and scenarios are due to the number of new nuclear units constructed during the planning period. Water use increases for all strategies between 2010 and 2015 due primarily to the completion and operation of Watts Bar Unit 2. Beyond 2015, most Strategy B and C portfolios use more water use than do most Strategy E portfolios. The overall differences, however, are relatively small and the largest increases during the planning period are 5.3 percent.

The trends in water consumption for the alternative strategies and scenarios (Figure 7-8) are similar to those for water use. The proportional increase in consumption, however, is much greater (up to a maximum of 560 percent) due to the increased proportion of energy that will be generated by thermal plants with closed-cycle cooling.

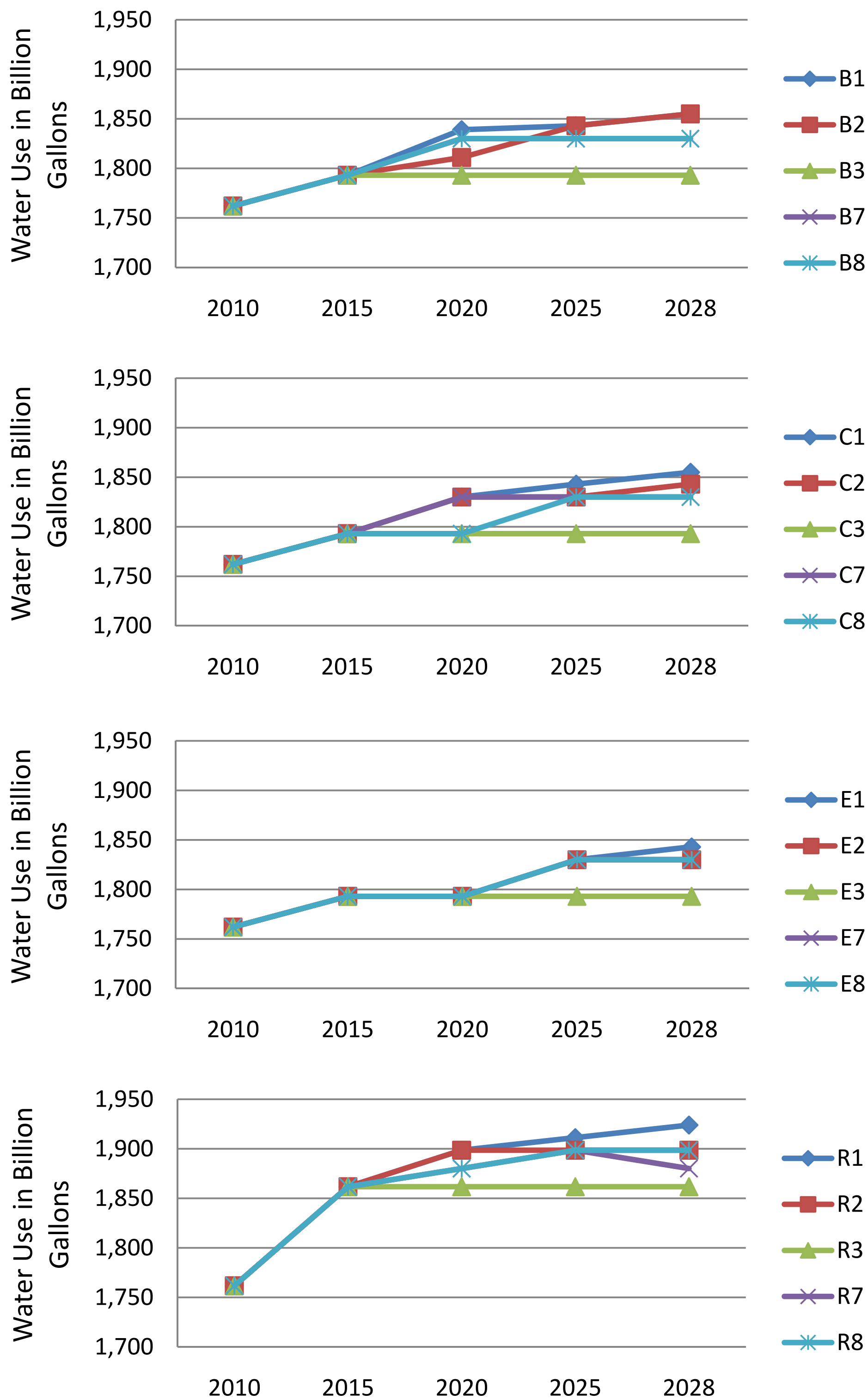

Figure 7-7. Trends in water use by coal, nuclear, and natural gas generating facilities by scenario for (top to bottom) Strategies B, C, E, and R.

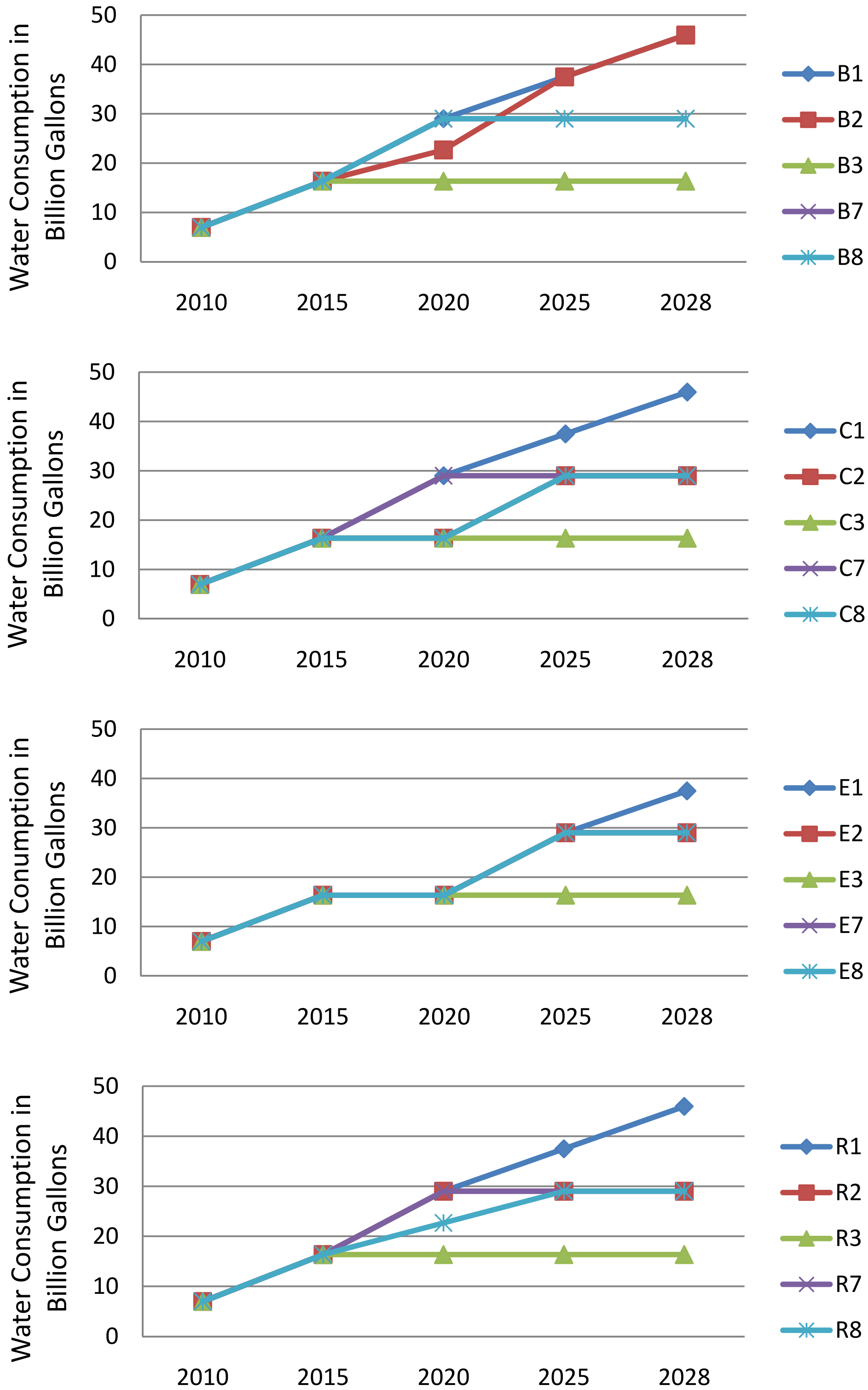

Figure 7-8. Trends in water consumption by coal, nuclear, and natural gas generating facilities by scenario for (top to bottom) Strategies B, C, E, and R.

The new nuclear units proposed in several of the strategies would consume water withdrawn from the TVA reservoir system, but would represent a very small proportion of the total water flow. The other potential combined-cycle and IGCC would likely be sited at locations across the TVA region and could consume groundwater, water withdrawn from a reservoir or river, or other source such as reclaimed wastewater. TVA would carefully assess the potential impacts of water use and water consumption during the planning process for any new generating facility.

7.6.4. Fuel Consumption

The major fuels used for generating electricity would continue to be coal, enriched uranium, and natural gas in all of the alternative strategies. The proportion of generation from coal, as well as the quantity of coal consumed (Figure 7-9), declines in the future as coal units are laid up and, except for an IGCC plant proposed under one Strategy B and one Strategy C scenario, no additional coal plants are built. The decreases in coal consumption are about 23 percent under Strategy B, 22 percent under Strategy C, and 31 percent under Strategy E. Although the future sources of coal purchased by TVA cannot be accurately predicted, the anticipated decrease in coal consumption could reduce the adverse impacts associated with coal mining, particularly with surface mining in Appalachia (EPA 2005, Palmer et al. 2010). These impacts include the loss of forests and wildlife habitat and the alteration of streams on and downstream of the mine area.

The consumption of enriched uranium increases with the startup of Watts Bar Nuclear Plant Unit 2 in 2013 under all of the alternative strategies and continues to increase as up to four additional nuclear units are added under scenarios 1, 2, and 7 (Figure 7-10). Potential impacts from producing the nuclear fuel include land disturbance, air emissions (including the release of radioactive materials), and discharge of water pollutants from uranium mining, processing, tailings disposal, and fuel fabrication. The magnitude of these impacts is difficult to predict with certainty due to the great variability in potential sources for nuclear fuel. The environmental impacts of uranium enrichment are expected to greatly decrease in the future as more energy-efficient enrichments are used in the U.S. The future use of surplus DOE highly enriched uranium would also reduce overall uranium fuel cycle impacts as this reduces the need for uranium mining and enrichment.

Natural gas consumption increases under all of the alternative strategies (Figure 7-11). Under all strategies, it remains fairly constant for Scenario 3 and increases by about 50 percent for Scenarios 2 and 3. The increase in gas consumption ranges for Scenario 1, which has the highest electrical demand, ranges from about 270 percent under Strategy B to 350 percent under Strategy E. When averaged across the five strategies, the percent increase in overall natural gas consumption is greatest under Strategy B at 87 percent and least under Strategy C at 55 percent. The increase under Strategy R is 72 percent. Much of the increase is due to increased intermediate generation and will likely displace some coal-fired generation. Overall impacts of the natural gas fuel cycle are less than those of the coal fuel cycle.

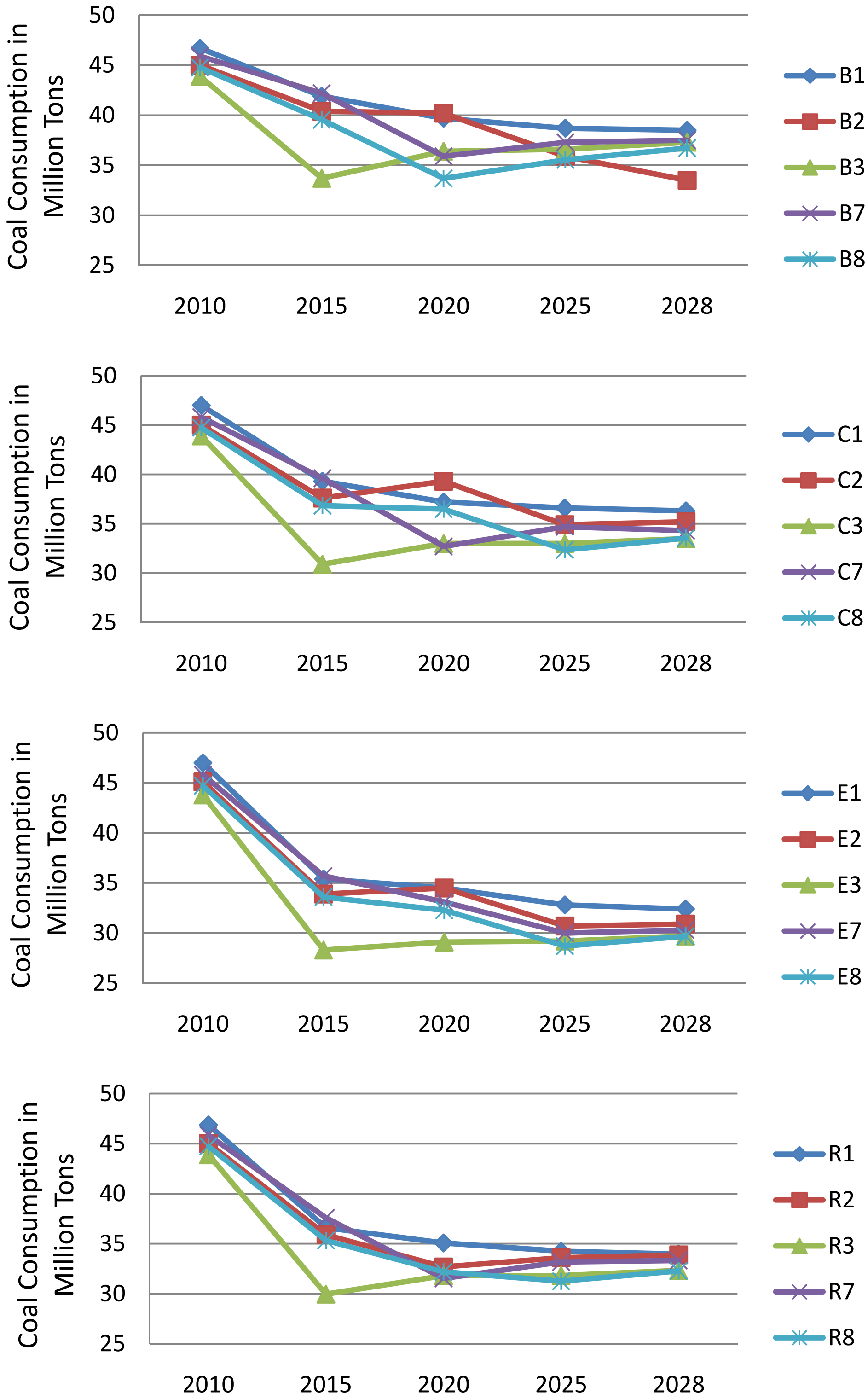

Figure 7-9. Trends in coal consumption by scenario for (top to bottom) Strategies B, C, E, and R.

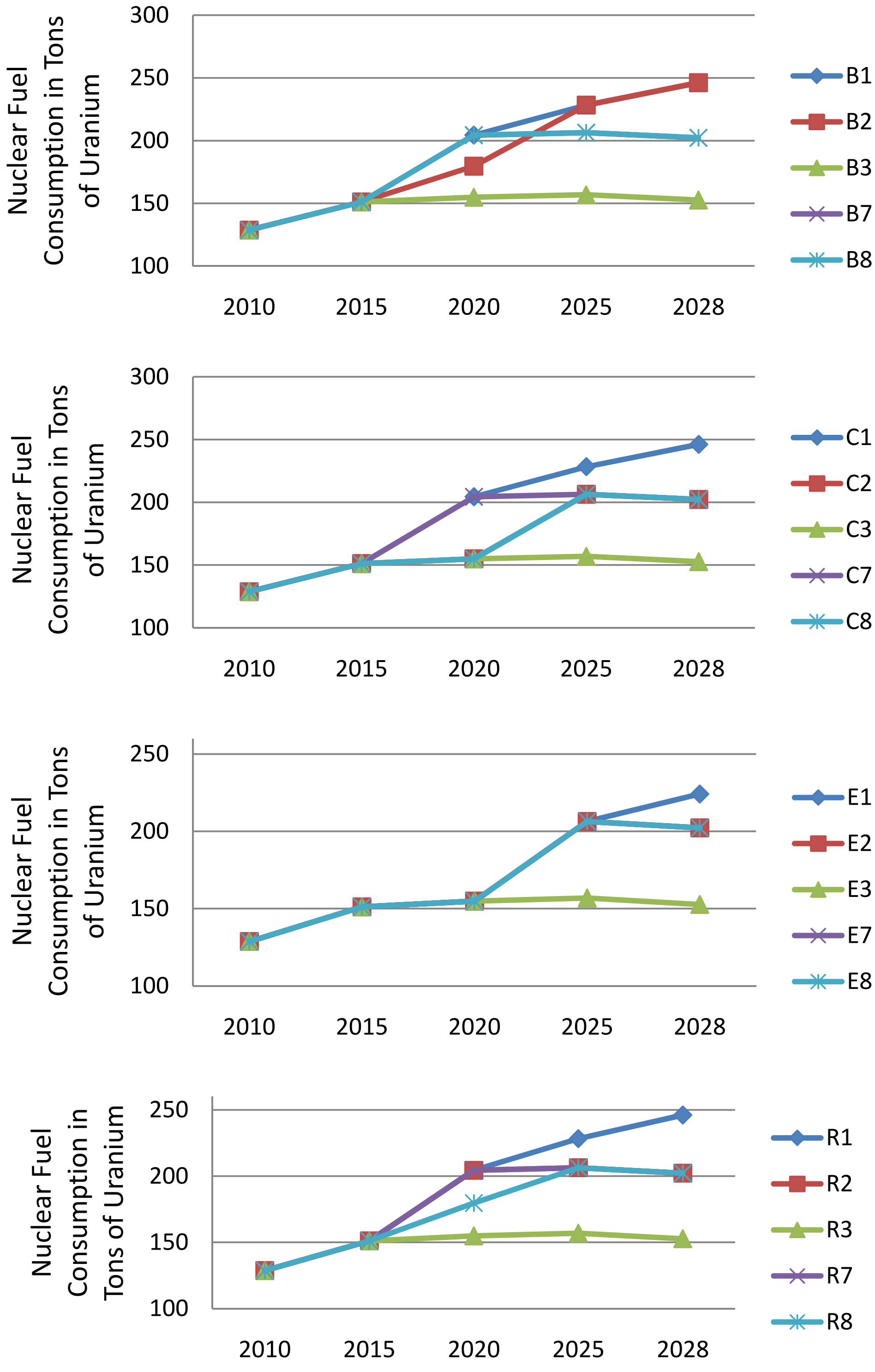

Figure 7-10. Trends in nuclear fuel consumption by scenario for (top to bottom) Strategies B, C, E, and R.

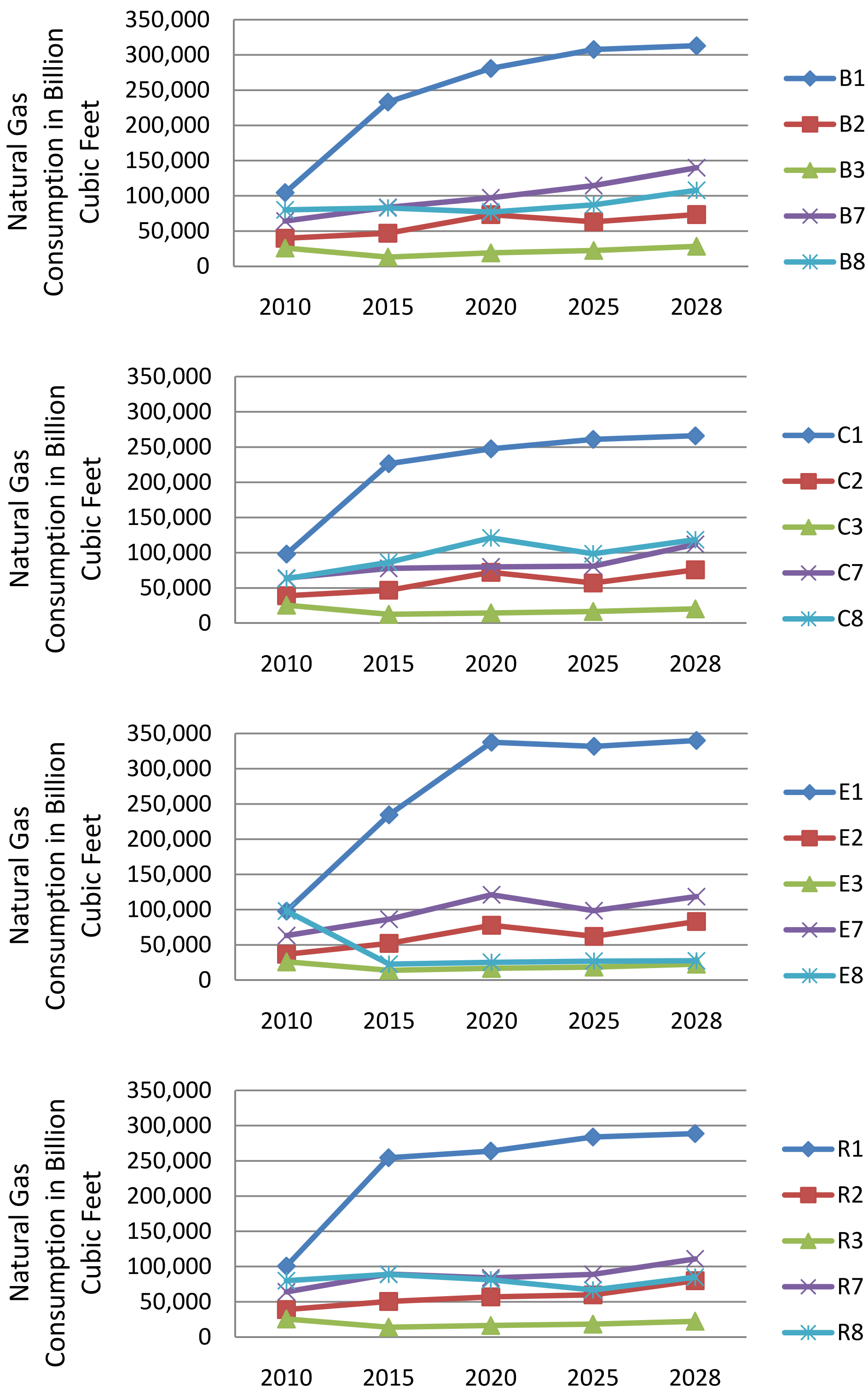

Figure 7-11. Trends in natural gas consumption by scenario for (top to bottom) Strategies B, C, E, and R. The volume is based on the heat content of 1,025 Btu/cubic foot of natural gas used by the electric power sector in 2009 (USEIA 2010b).

Based on recent trends in natural gas production, an increasing amount of natural gas is expected to be extracted from shale formations, including the Barnett Shale in Texas, the Antrim Shale in Michigan, and the Marcellus Shale in central and northern Appalachia. Producing this gas requires hydraulic fracturing, the process of injecting pressurized fluids (predominantly water with gels and chemical additives) and sand into the well borehole to fracture the gas-bearing rock formation and increase its permeability. Concerns have been expressed about the potential impacts of this "fracking" on water supplies and other environmental resources (Soeder and Kappel 2009, Kargbo et al. 2010, Zoback et al. 2010). These impacts include gas migration, groundwater, surface water, and soil contamination, the large volume of water required, seismic risks, and drillpad, road, and pipeline construction. Concerns have also been expressed over the emission of greenhouse gases from shale gas production. The magnitude of these several of these impacts, however, is poorly known and presently being investigated by EPA and others.

The consumption of biomass fuels increases under all alternative strategies and is greatest under Strategy E, which has the most biomass-fueled generation (Figure 7-1). Accurately forecasting this increase in the quantity of biomass fuels is difficult without knowing the types of biomass fuels and the types of new dedicated biomass generating facilities. For example, a dedicated stoker boiler biomass plant consumes more fuel per MWh of generation than does a biomass IGCC plant (EPRI 2010). The quantity of fuel consumed also varies with the type and the moisture content of the biomass fuel.

7.6.5. Solid Waste

Coal Combustion Solid Wastes

All three alternative strategies will result in long-term reductions in the production of ash (including related materials such as slag) from coal combustion (Figure 7-12). These reductions range from an average of about 19 percent for the Strategy B scenarios to about 42 percent for the Strategy E scenarios. These reductions are a result of the idling of coal units. The small increases in ash generation late in the planning period under some Strategies B, C, and R scenarios are due to the addition of IGCC plants . When ranked by strategy, the amount of coal ash produced would be greatest under Strategy B, followed by Strategies, C, R, and E.

In recent years, TVA has marketed between 40 and 50 percent of the annual production of ash for beneficial reuse. The remaining ash is stored in landfills and impoundments at or near coal plants. TVA is in the process of converting the wet ash collection/storage systems at six coal plants to dry storage and disposal facilities in order to reduce the potential environmental risk. TVA is also committed to increase the beneficial reuse of ash. Even with an increase in beneficial reuse, TVA will likely need additional storage areas for ash produced at many of its plants.

Unlike ash, the production of scrubber waste (synthetic gypsum) increases under all alternative strategies (Figure 7-13). Under all of the alternative strategies, the TVA coal plants with scrubbers are anticipated to continue to operate throughout the planning period, and scrubbers are anticipated to be installed on the unscrubbed coal plants that continue to operate after about 2015. Thus the increase is greatest for Strategy B which, with the fewest coal units idled, continues to rely more on coal-fired generation than do the other strategies. When ranked by strategy, the amount of scrubber waste would be greatest under Strategy B, followed by Strategies C, R, and E.

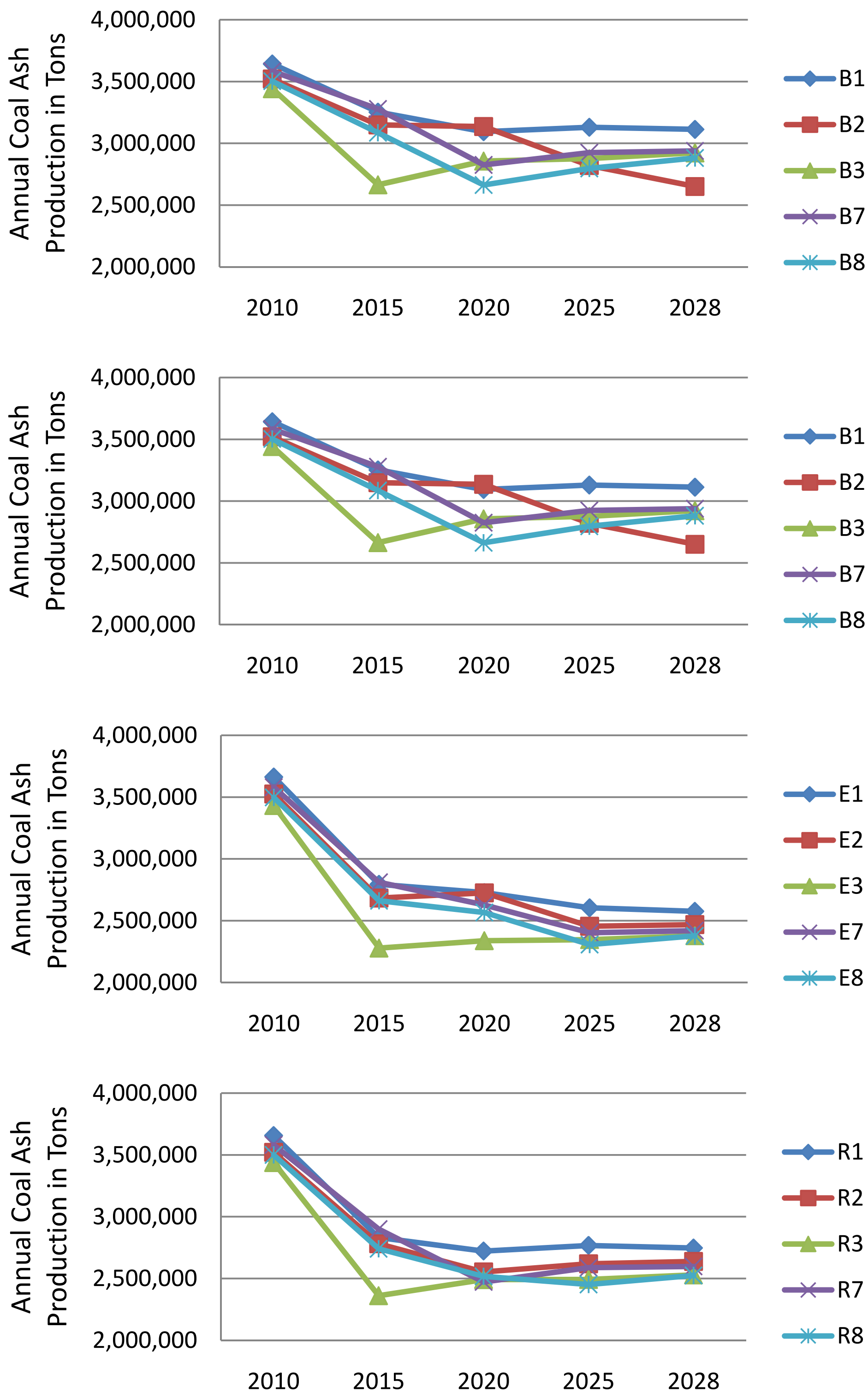

Figure 7-12. Trends in coal ash production by scenario for (top to bottom) Strategies B, C. E, and R.

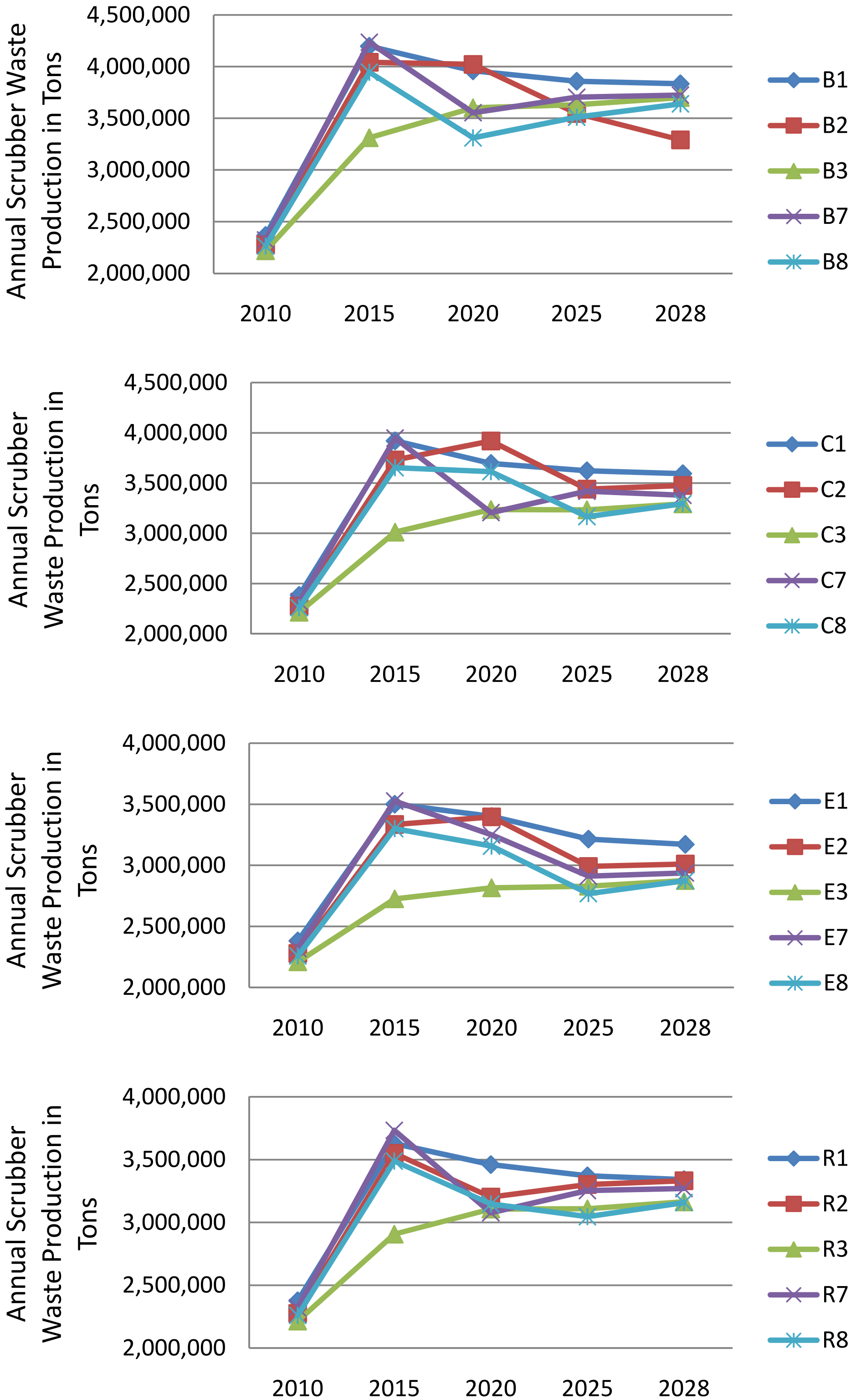

Figure 7-13. Trends in scrubber waste production by scenario for (top to bottom) Strategies B, C. E, and R.

About 30 percent of the scrubber waste produced in recent years has been marketed for beneficial use. The remaining scrubber waste is stored in landfills and impoundments at or near coal plants. As with ash, TVA has committed to converting the wet scrubber waste storage impoundments to dry storage facilities. This conversion, as well as the increased scrubber waste production, will likely require additional storage areas for scrubber waste at many plants. TVA is also committed to increase the beneficial reuse of scrubber waste.

Nuclear Wastes

The trends in the production of high-level waste (Figure 7-14), which is primarily spent nuclear fuel and other fuel assembly components, are the same as the trends in the use of nuclear fuel (Figure 7-10). The major differences among the alternative scenarios results from the number of nuclear units added under the high-growth Scenario 1 and the moderate-growth Scenario 2. When ranked by strategy, the amount of high-level waste would be greatest under Strategy B, followed by Strategies, R, C, and E. TVA anticipates continuing to store spent fuel on the nuclear plant sites until a centralized facility for long-term disposal and/or reprocessing are operating. This continued on-site storage will require the future construction of additional dry cask storage facilities.

All of the alternative strategies show a long-term increase in the production of low-level waste. The proportional increase is somewhat less than the increase in nuclear generation due to the anticipated continued development and implementation of techniques to reduce the production of low-level waste and better consolidate the low-level waste that is produced. The ranking of the strategies by amount of low-level waste is the same as their ranking by amount of high-level waste.

7.6.6. Land Requirements

TVA's existing power plant reservations have a total area of approximately 23,937 acres. This total does not include conventional hydroelectric plants, most of which are closely associated with multi-purpose dams and reservoirs, or the 1,761-acre Bellefonte site. Many of the power plant reservations have large, relatively undisturbed areas and the actual area disturbed by facility construction and operation (the "facility footprint") totals about 17,360 acres. The existing generating facilities from which TVA purchases power under long-term PPAs (> 5 years, and excluding hydroelectric plants) have facility footprints of about 600 acres.

The alternative strategies require between about 4,530 and 8,130 acres for new generating facilities (Figure 7-15). These land requirements only include those for the generating facility footprints and associated access roads. They do not include undisturbed portions of the power plant reservations or the land area needed for extraction (e.g., mining), production (e.g., biomass plantations), processing and transportation of fuels or long-term disposal of ash and other wastes. The high solar land requirements are based on the PV energy density for the TVA region described by Denholm and Margolis (2008), and adjusted to assume 40 percent of the PV is deployed on rooftops and thus has no land requirements. The remaining PV is deployed using a combination of fixed and tilting ground-based arrays. The biomass land requirements illustrated in Figure 7-16 are for dedicated biomass facilities. Biomass cofiring, conversion of coal units to dedicated biomass operation, and landfill gas are assumed not to require any land beyond that of the existing coal plant or landfill.

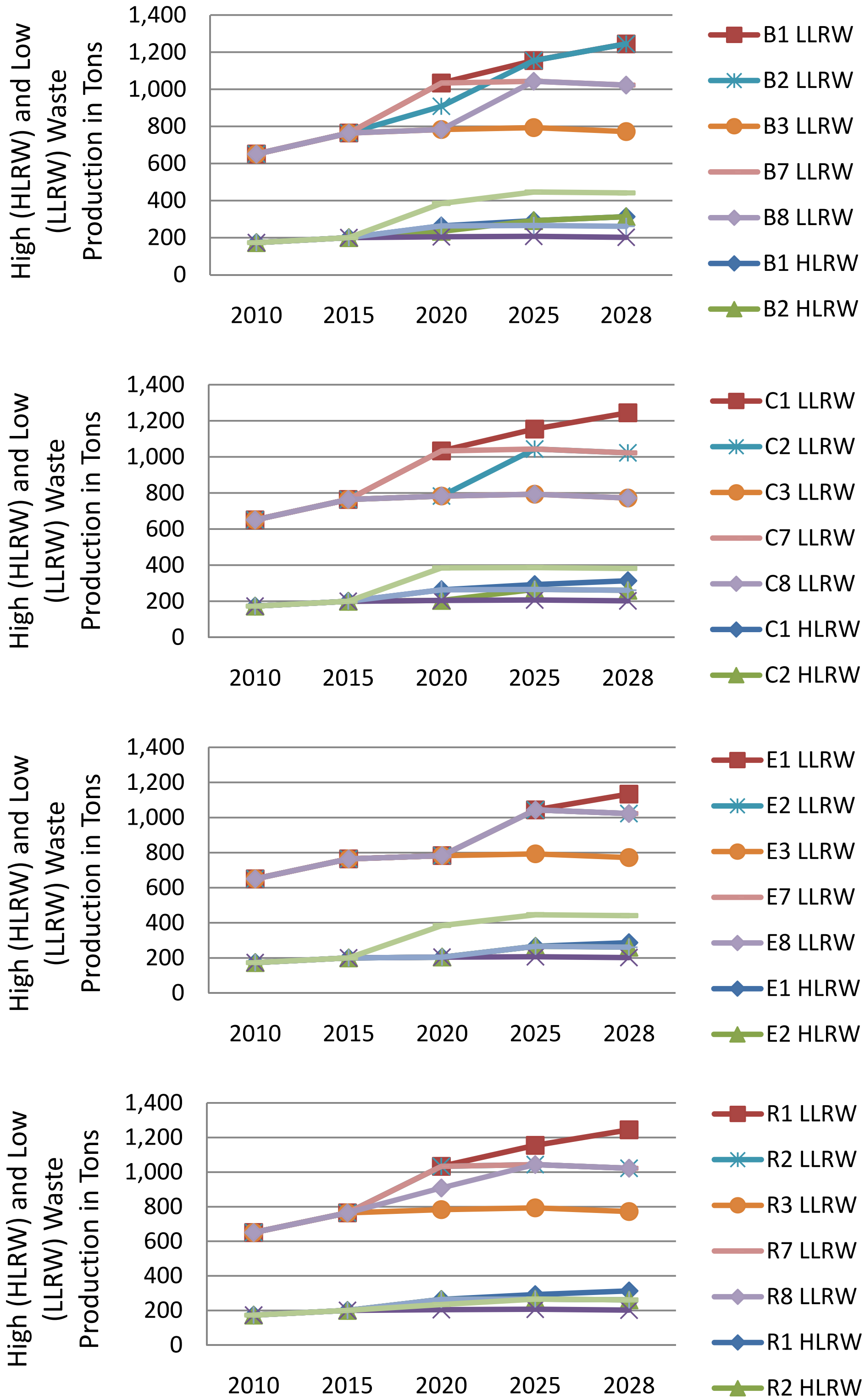

Figure 7-14. Trends in production of high and low level waste by scenario for (top to bottom) Strategies B, C. E, and R.

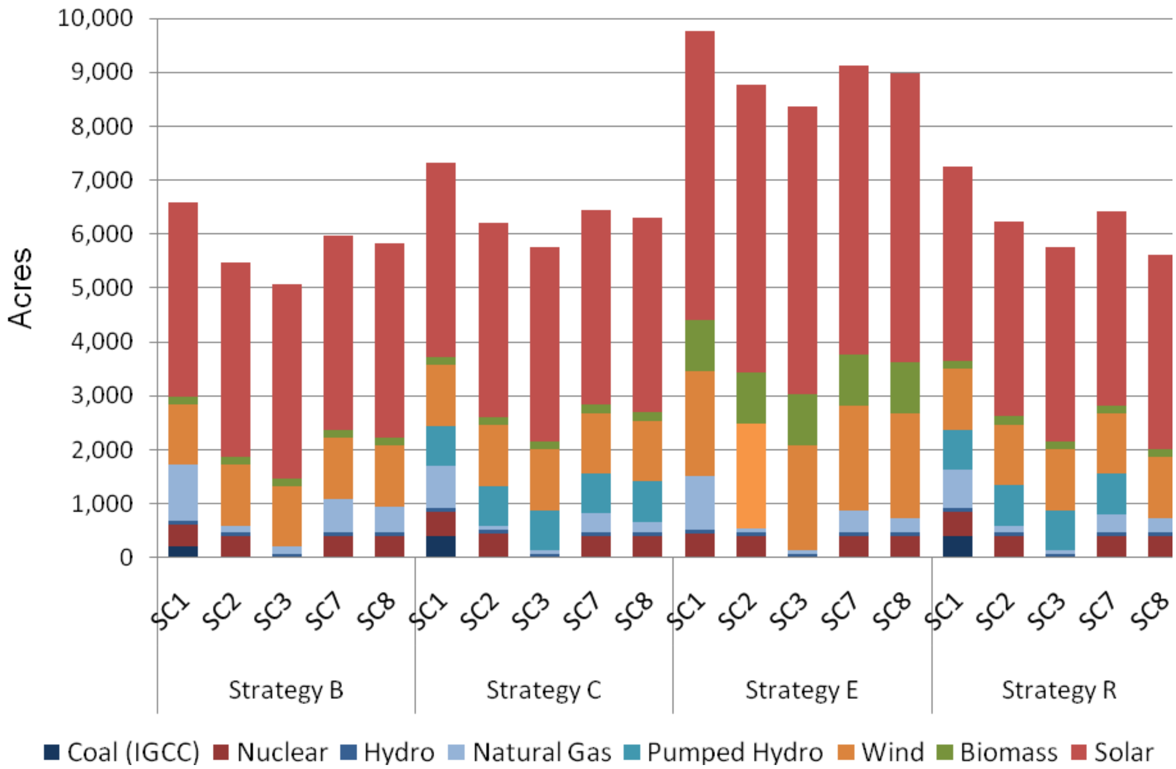

Figure 7-15. Land requirements for new generating facilities by type of generation, strategy, and scenario.

If wind and PV generation (both of which produce relatively low amounts of power per unit of area) are excluded, Strategy C has considerably larger facility land requirements for each scenario than do Strategy B and Strategy E. Strategy E has the lowest land requirements for large, central station generating facilities (average of 755 acres) and, because of its large wind and PV capacity, the largest overall land requirements (average of 9,002 acres). Average central station generating facility and overall land requirements for the other strategies are, respectively: Strategy B - 1,059 and 5,788 acres; Strategy C - 1,675 and 6,403 acres; and Strategy R - 1,525 and 6,404 acres.

Figure 7-16 shows the life-cycle land requirements for the coal, nuclear, natural gas, wind, and biomass generation components of the various alternative strategies. These land requirements are expressed in acre-years/GWh to show the land requirements over time (Spitzley and Tolle 2004, Spitzley and Keoleian 2005). It considers the amount of land occupied by a particular component of a facility life-cycle process, such as metal fabrication, coal mining, and waste disposal. For most types of generation shown in Figure 7-16 life-cycle land requirements are dominated by those associated with fuel acquisition. The biomass land requirements are based on the use of short-rotation woody crops, a biomass with large land needs and thus, present a worst-case scenario. The use of wood waste would greatly reduce life-cycle land requirements, although this is difficult to quantify without more definitive information. Life-cycle land requirements were not calculated for the other types of generation shown in Figure 7-16 because they do not greatly differ from the facility land requirements or, in the case of conventional hydroelectric generation, because of the multipurpose nature of the dams and reservoirs.

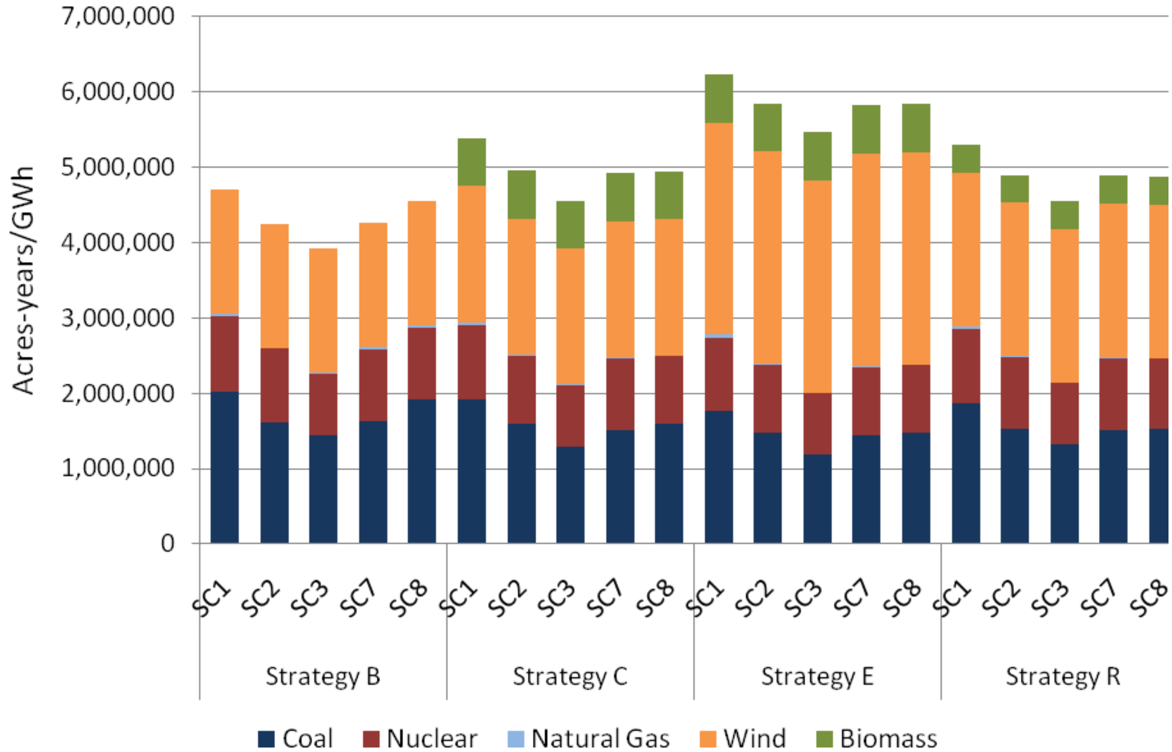

Figure 7-16. Life-cycle land requirements for generating facilities by type of generation, strategy, and scenario.

Nuclear power, because of the high power density of the fuel, has low life-cycle land requirements relative to other types of generation. Its land requirements, however, do not include those associated with the long-term disposal of spent nuclear fuel. Inclusion of spent fuel disposal would increase the land requirements because of the long life-span of a disposal area. The life-cycle land requirements for wind energy are relatively large because of the large area surrounding wind turbines on which some land uses may be restricted.

Average life-cycle land requirements are lowest for Strategy B (4,334,721 acre-years/GWh) which has the smallest renewable portfolio and highest for Strategy E (5,840,919 acre-years/GWh) which has the largest renewable portfolio. The average life-cycle land requirements for Strategies R (4,896,751 acre-years/GWh) and C (4,948,742 acre-years/GWh).

7.6.7. Socioeconomics

Potential socioeconomic impacts of the alternative strategies were assessed by comparing the economic metrics described in Sections 2.6. For each strategy, these metrics were calculated for the high-growth Scenario 1 and the low-growth Scenario 6 (Table 7-6. Although Scenario 6 is not otherwise analyzed in the retained alternative strategies, its results are very similar to the low-growth Scenario 3. Therefore, the use of scenarios 1 and 6 to define the economic development metrics encompasses the upper and lower range of impacts.

Strategy B would result in the greatest increase in total employment and in personal income growth under the high-growth Scenario 1, but would also result in the greatest decrease in both employment and income under the low-growth scenario. Strategies C and E have similar impacts, with moderate increases in both employment and income under the high-growth scenario. Under the low-growth scenario, both would have small but positive increases in employment and income. Overall, the beneficial socioeconomic impacts of strategies C, E, and R are somewhat greater than those of Strategy B across the range of scenarios.

Table 7-6. Comparison of socioeconomic impacts of alternative strategies based on the percent difference from the no-action Strategy B/Scenario 7.

		Percent Difference in			
		Total Employment		Total Personal Income	
Strategy	Scenario	Average 2011-2028	Average 2011-2015	Average 2011-2028	Average 2011-2015
B	1	1.0%	0.3%	0.8%	0.3%
	6	-0.3%	-0.4%	-0.3%	-0.3%
C	1	0.9%	0.2%	0.6%	0.2%
	6	0.2%	-0.2%	0.1%	-0.1%
E	1	0.8%	0.0%	0.6%	0.0%
	6	0.3%	-0.1%	0.2%	-0.1%
R	1	0.9%	0.2%	0.7%	0.2%
	6	0.2%	-0.2%	0.1%	-0.1%

Before implementing a specific resource option, TVA will conduct a review of its potential socioeconomic impacts. This review will, as appropriate, focus on resource- and/or site-specific socioeconomic issues such as impacts on employment rates, housing, schools, emergency services, water supply and wastewater treatment capacity, and local government revenues, as well as the potential for disproportionate impacts on minority and low-income populations.

7.7. Potential Mitigation Measures

As previously described, TVA's siting processes for generation and transmission facilities, as well as practices for processes for modifying these facilities, are designed to avoid and/or minimize potential adverse environmental impacts. Potential impacts are also reduced through pollution prevention measures and environmental controls such as air pollution control systems, wastewater treatment systems, and thermal generating plant cooling systems. Other potentially adverse impacts can be mitigated by measures such as compensatory wetlands mitigation, payments to in-lieu stream mitigation programs and related conservation initiatives, enhanced management of other properties, documentation and recovery of cultural resources, and infrastructure improvement assistance to local communities.

7.8. Unavoidable Adverse Environmental Impacts

The adoption of an alternative strategy for meeting the long-term electrical needs of the TVA region has no direct environmental impacts. The implementation of the strategy, however, would have adverse environmental impacts. The nature and potential significance of the impacts will depend on the energy resource options eventually implemented under the strategy. Resource options in each strategy have associated adverse impacts that cannot be realistically avoided.

Under every strategy, TVA would continue to operate most of its existing generating units for the duration of the 20-year planning period. The exceptions are predominantly the coal plants that would be laid up. The operation of the generating units would continue to result in the release of various air and/or water pollutants, depending on the kind of unit. As previously described, the installation of additional air emission control systems on coal units is expected to reduce the release of air pollutants.

The construction and operation of new generating facilities would unavoidably result in changes in land use unless new facilities are located at existing plant sites.

The conversion of land from a non-industrial use to an industrial use will unavoidably affect land resources such as farmland, wildlife habitat, and scenery.

7.9. Relationship Between Short-Term Uses and Long-Term Productivity of the Human Environment

The adoption and implementation of a long-term energy resource strategy would have various short- and long-term consequences. These depend, in part, on the actual energy resource options that are implemented. Option-specific and/or site-specific environmental reviews will be conducted before final implementation decisions are made to use certain energy resources and will examine potential environmental consequences in more detail.

In both the short and long term, TVA would continue to generate electrical energy to serve its customers and the public. As described in Chapter 2, the demand for electricity is forecast to grow in the future. The availability of adequate, reliable, low-priced electricity will continue to sustain the economic well-being of the TVA region and allow it to grow.

The generation of electricity has both short- and long-term environmental impacts. Short-term impacts include those associated with facility construction and operational impacts, such as the consequences of exposure to the emission of air pollutants and consequences of thermal discharges. Potential long-term impacts include land alterations for facility construction and fuel extraction, and the generation of nuclear waste that requires safe storage for an indefinite period.

7.10. Irreversible and Irretrievable Commitments of Resources

The continued generation of electricity by TVA will irreversibly consume various amounts of non-renewable fuels (coal, natural gas, diesel, fuel oil, and uranium). The continued maintenance of TVA's existing generating facilities and the construction of new generating facilities will irreversibly consume energy and materials. The siting of most new energy facilities, except for wind and PV facilities, will irretrievably commit the sites to industrial use because of the substantial alterations of the sites and the relative permanence of the structures. The continued generation of nuclear power will produce nuclear wastes; therefore, some site or sites will have to be devoted to the safe storage of these wastes. Any such site would essentially be irretrievably committed to long-term storage of nuclear waste.

The alternative strategies contain varying amounts of EEDR and renewable generation. Reliance on these resources would lessen the irreversible commitment of non-renewable fuel resources, but would still involve the irreversible commitment of materials and, depending on the type of renewable generation, the irreversible commitment of generating sites.