Appendix A to the Review of the <u>2012 Ten-Year Site Plans</u>

For Florida's Electric Utilities

<u>Comments From</u>

State, Regional, and Local Agencies,

& Other Organizations

Florida Public Service Commission

Tallahassee, FL
December 2012

Ten-Year Site Plan Comments

State Agencies
- Florida Department of Economic Opportunity
- Florida Department of Transportation
- Fish & Wildlife Conservation Commission

Regional Planning Councils (RPCs)
- Central Florida RPC
- East Central Florida RPC
- North Central Florida RPC
- Treasure Coast RPC

Water Management Districts (WMDs)
- Southwest Florida WMD
- St. Johns River WMD

Other Organizations
- Seminole Tribe of Florida
- South Florida Wildlands Association
- Sierra Club
- Sierra Club & Earthjustice

State Agencies

Florida Department of Economic Opportunity

Rick Scott
GOVERNOR

12 JUN 27 AM 9:53

DIVISION OF
REGULATORY COMPLIANCE

FLORIDA DEPARTMENT of ECONOMIC OPPORTUNITY

Hunting F. Deutsch
EXECUTIVE DIRECTOR

June 29, 2012

Mr. Michael S. Haff
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Haff:

At your request we have reviewed the 2012 Ten-Year Site Plans of the electric utilities. The Department of Economic Opportunity's review focused on potential sites for future power generation, and the compatibility of those sites with the applicable local comprehensive plan, including the adopted future land use map, adjacent land uses, and natural resources on or adjacent to the potential sites.

Our review of the 2012 Ten-Year Site Plans addressed sixteen potential power plant sites identified in the Ten-Year Site Plans of the following utilities: Florida Power & Light Company, Gulf Power Company, and Seminole Electric Cooperative. None of the potential sites were found to be incompatible with the applicable local comprehensive plan.

Should you have any questions regarding these comments, please call Julie Evans, Planning Analyst, at (850) 717-8485.

Sincerely,

J. Thomas Beck

J. Thomas Beck, AICP
Director, Division of Community Development

JTB/je
Enclosure

Florida Department of Economic Opportunity | The Caldwell Building | 107 E. Madison Street | Tallahassee, FL | 32399-4120
866.FLA.2345 | 850.245.7105 | 850.921.3223 Fax | www.FloridaJobs.org | www.twitter.com/FLDEO | www.facebook.com/FLDEO

2012 Ten-Year Site Plan Review

Three utilities, Gulf Power, Florida Power and Light, and Seminole Electric, have identified a total of sixteen potential sites for future power generation. Potential sites are defined in Rule 25-22.070, F.A.C. as "sites within the state that an electric utility is considering for possible location of a power plant, a power plant alteration, or an addition resulting in an increase in generating capacity." These sites are discussed below.

1. Gulf Power

In its Ten-Year Site Plan, Gulf Power stated it will consider five properties as potential sites for future generating facilities. Three potential sites contain existing power plants: Plant Crist in Escambia County, Plant Smith in Bay County, and Plant Scholtz in Jackson County. Two sites, Shoal River in Walton County, and Caryville in Holmes and Washington Counties, are undeveloped.

A. Crist Site. This site, located adjacent to the Escambia River, is designated Industrial and Agriculture on the adopted Future Land Use Map (FLUM). Electric power generation facilities are an allowed use in the Industrial category, and may be allowed as a conditional use in Agriculture. The northern and eastern parts of the site are located in the coastal high hazard area, and contain wetlands and 100-year floodplain. Adjacent land uses are Industrial, Conservation, Agriculture and Mixed-Use Suburban.

For information regarding the location of the coastal high hazard area relative to the site, contact Julie Dennis with the Department of Economic Opportunity, Bureau of Comprehensive Planning, at (850) 717-8478. For wetland compatibility issues, contact the Department of Environmental Protection (DEP) Office of Submerged Lands and Environmental Resources at (850) 2456-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960

B. Smith Site. Located in Bay County, the Smith site is adjacent to the North Bay area of St. Andrews Bay. The site is located in the Category 1, 2, 3 and 4 storm surge zones. It is designated Industrial and Conservation on the adopted FLUM. Public utilities are allowed uses in both Industrial and Conservation. Adjacent land uses are Agriculture-Timber and Conservation. Wetlands and 100-year floodplains are also located onsite.

For further information regarding the location of storm surge zones relative to the site, Gulf Power should contact Julie Dennis with the Department of Economic Opportunity, Bureau of Comprehensive Planning, at (850) 717-8478. For assistance with wetland compatibility issues, contact the DEP Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960

C. Scholtz Site. This site, located in Jackson County, is adjacent to the Apalachicola River, an Outstanding Florida Water. The site is designated Agricultural-1 and Conservation. An electrical generating facility may be allowed as a conditional use in Agricultural-1; however, this use is not allowed in Conservation. Parts of the eastern and southeastern areas of the site are located in the 100-year floodplain. Wetlands are also present onsite. Gulf Power should contact the following DEP offices for further information: 1) for compatibility with OFWs, contact the Standards and Assessment section at (850) 245-8064; 2) for wetland compatibility issues, contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

D. Shoal River Site. This is a greenfield site located in Walton County. It is adjacent to the Shoal River, an Outstanding Florida Water. The site is designated Rural-Residential to the south and Agricultural to the north. Wetlands and 100-year floodplain areas are primarily located along the southern part of the site, adjacent to the Shoal River. Walton County is currently working with Eglin Air Force Base to identify Military Influence Planning Areas. While these areas have not been finalized, it is possible that the Shoal River site may be located within a future Military Influence Planning Area.

Gulf Power should contact the following DEP offices for further information regarding natural resources: 1) for compatibility with OFWs, contact the Standards and Assessment section at (850) 245-8064; 2) for wetland compatibility issues, contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960. For further information regarding compatibility issues with Eglin Air Force Base, contact Jeffrey Fanto, Community Planner, Eglin Air Force Base, at (850) 882-8036.

E. Caryville Site. Located in Holmes County, Washington County, and the City of Caryville, this site is adjacent to the Choctawhatchee River. It is designated Agriculture in Holmes County, Agriculture/Silviculture in Washington County, and Agriculture and Conservation in Caryville. In all three jurisdictions, public utilities are allowed in areas designated Agriculture. The site is surrounded by agricultural land uses. Floodplain and wetland areas exist throughout the site.

Gulf Power should contact the following DEP offices for further information: 1) for compatibility with OFWs, contact the Standards and Assessment section at (850) 245-8064; 2) for wetland compatibility issues, contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

2. Florida Power and Light. FPL has identified ten potential sites, described below.

A. Babcock Ranch, Charlotte County. This site is designated Babcock Ranch Overlay District (BROD) on the FLUM. The Development Order for the Babcock Ranch Development of Regional Impact (DRI) identifies this site as a Primary Active Greenway approved for the placement of solar generating facilities. Adjacent land uses to the east, west and south are also BROD. Land north of the site is designated Resource Conservation. The BROD is being developed under a cohesive set of policies, guided by the comprehensive plan, through the Master Incremental DRI process. No environmental or other compatibility issues have been identified for this site.

B. DeSoto Solar Expansion, DeSoto County. This site is designated Electrical Generating Facility on the adopted Future Land Use Map. The surrounding FLUM designations are Electrical Generating Facility and Rural/Agriculture. The site has been disturbed as a result of agricultural activities on the property. It is adjacent to an existing transportation corridor with roadway capacity. Demands on water facilities have already been considered in the growth projections of the Comprehensive Plan. No environmental or other compatibility issues have been identified for this site.

C. Florida Heartland Solar site, Glades County. This site is designated Agriculture/Open. An electrical generating facility is required to meet locational and siting criteria; therefore, such facility would likely have to be approved as a conditional or special use. The site is primarily surrounded by Agriculture/Open Space. There is also an adjacent area designated Transition which allows residential, non-residential and agricultural uses. No environmental or other compatibility issues have been identified for this site.

D. Hendry County site. The Hendry site, designated Agricultural on the FLUM, consists of over 3,000 acres in the southern part of the County. Utilities, including electrical generating facilities, are an allowed use in Agricultural. The site has been disturbed as a result of its use for crops and pastureland. There are scattered wetlands onsite. Significant areas in Hendry County are Florida panther habitat. FPL has offered to provide panther habitat corridors onsite and/or provide habitat mitigation if needed.

For assistance with wetland compatibility issues, FPL should contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474.

E. Manatee Plant site, Manatee County. This site is designated Public/Semipublic-2 on the adopted FLUM. Power generating facilities are an allowed use in this FLUM category. Adjacent uses are Public/Semipublic-2 and Agricultural-Rural. The site is also adjacent to Lake Parrish, which provides water to the existing power facility. Much of the property is disturbed due to agricultural activities onsite. No environmental or other compatibility issues have been identified for this site.

F. Martin County site: FPL is currently evaluating potential sites in Martin County for a future solar facility. No specific locations have been selected. The County's adopted comprehensive plan contains provisions for siting power generating facilities which use renewable energy sources. Future Land Use Policy 4.8C.1 allows alternative energy facilities in appropriate zoning districts. The policy states, "As the technology for wind, solar and other forms of power generation advance, the Land Development Regulations shall be revised to permit different forms of power generation in appropriate zoning districts." Policy 4.13A.12, which addresses the Public Utilities FLUM category, states: "electrical power facilities solely utilizing solar, wind or other renewable energy fuel or energy source may be permitted in any other Future Land Use Designation, consistent with the Land Development Regulations."

G. Northeast Okeechobee County. FP&L is considering a potential site in northeast Okeechobee County. The specific site location was not provided in the TYSP. The predominant land use designation in this area is Agriculture. Public and institutional uses, including power generation, are allowed in Agriculture. Two areas designated Rural Activity Center, and one

Resort Activity Center, also exist in northeast Okeechobee County. Wetlands and 100-year floodplain are located in the northeast County area; however, sufficient upland areas exist to support a power plant site.

For assistance with wetland compatibility issues, FPL should contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

H. Palatka Site. Located in unincorporated Putnam County, this site is designated Industrial, Agriculture, and Rural Residential. There is an existing power plant onsite. Electrical generating facilities are allowed as a principal use in the Industrial category. Surrounding land uses are Agriculture to the north and east, Industrial to the south, and the St. Johns River to the west.

I. Putnam County Site. FPL is currently evaluating potential sites in Putnam County for a future solar facility or natural gas-powered facility. No specific locations have been identified. Sites currently under investigation are approximately 2,800 acres in area. The Industrial and Community Facilities and Services land use categories allow electrical generating plants. The County's Comprehensive Plan contains policies that address compatibility and suitability of land uses, as well as directing development away from environmentally sensitive lands.

J. Space Coast Solar Expansion, Brevard County. FPL currently owns a ten-megawatt solar generating facility, known as the Space Coast Next Generation Solar Energy Center, in Brevard County at NASA's Kennedy Space Center (KSC). FPL is considering additional solar generating capacity at this site. NASA's Future Development Concept (FDC) document, which serves as the foundation for the Center Master Plan, supports solar generating facilities at KSC. The FDC states that there are several sites at KSC designated for renewable energy research and production. The sites are intended to help facilitate KSC's goal of achieving increased on-site power generation from renewable energy sources. No environmental or other compatibility issues have been identified for this site.

3. Seminole Electric.

Seminole Electric has identified one site, a 530-acre parcel located northeast of the City of Bell in Gilchrist County, as a potential power plant site. The site is designated Agricultural on the adopted Future Land Use Map. Electric generating facilities may be permitted as a special use in areas designated Agricultural. Issues that would be considered by the County through the special use review process include the amount of water projected to be used by the facility, the impact of water use on agricultural activities, and the impact of the facility on natural resources, including aquifer recharge areas and wetlands. The Gilchrist parcel is located near the Wacasassa Flats, a 50,000-acre high quality wetlands-to-uplands ecosystem located in the middle of the County. Wacasassa Flats is a perched water table system that provides significant water storage, water filtering and wildlife habitat.

For assistance with wetland compatibility issues, Seminole Electric should contact the Office of Submerged Lands and Environmental Resources at (850) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

4. Utilities With No Potential Sites Identified in the TYSP: The following utilities identified no potential sites in their TYSPs: Gainesville Regional Utilities, Progress Energy Florida, Lakeland Electric, City of Tallahassee, Florida Municipal Power Agency, Tampa Electric Company, JEA and Orlando Utilities Commission.

ENT of
UNITY

Mr. Michael S. H
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State Agencies

Florida Department of Transportation

Florida Department of Transportation

RICK SCOTT
GOVERNOR

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ANANTH PRASAD, P.E.
SECRETARY

June 21, 2012

Phillip Ellis
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Dear Mr. Ellis:

The Siting Coordination Office has reviewed the ten-year site plans and find these are suitable as planning documents. If you have any questions please feel free to call me at (850)414-4572.

Sincerely,

Connie Mitchell
Siting Coordination Office

www.dot.state.fl.us

State Agencies

Fish & Wildlife Conservation Commission

June 28, 2012

Florida Fish and Wildlife Conservation Commission

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Nick Wiley
Executive Director

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Mr. Phillip Ellis
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pellis@psc.state.fl.us

Re: Progress Energy Florida's Ten-Year Site Plan: 2012 – 2021, Multiple Counties

Dear Mr. Ellis:

The Florida Fish and Wildlife Conservation Commission (FWC) has reviewed the 2012 – 2021 Ten-Year Site Plan (Plan) submitted by Progress Energy Florida (PEF) and provides our comments, pursuant to Rule 25-22.071, Florida Administrative Code.

PEF provides electrical service to 35 counties in central and north-central Florida (Figure 1.1 in the Plan) through the use of 63 power plant units that use steam, combined-cycle, or combustion turbine technology (Table 3.1 in the Plan) for production. Electricity is then transmitted through roughly 5,000 circuit miles of transmission lines and distributed through about 18,000 circuit miles of overhead conductors and 13,000 circuit miles of underground cable (p. 1-1 of the Plan). PEF also has entered into 13 contracts for renewable and cogeneration plants and provides a number of energy conservation programs available to its customers. In addition, there are several research and development programs underway, some of which are pilot studies. The Plan consists of PEF's Base Expansion Plan, which includes resuming operations at Crystal River Unit 3, constructing and operating Levy Unit 1, and constructing a new combined-cycle facility at an as-yet undetermined location.

The FWC participated in the permitting of the Crystal River Unit 3 revisions and the new nuclear power plant in Levy County. Our input was included in the Conditions of Certification associated with each of those plants. Additionally, we encourage PEF to contact us as early as possible in the planning process for the new combined-cycle facility so we can proactively coordinate on fish and wildlife resource issues as they may relate to location, source of cooling water, and associated transmission lines.

We appreciate the opportunity to review the proposed Plan, and find that it is sufficient for planning purposes. If you need further assistance, please do not hesitate to contact Jane Chabre at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions, please contact Mary Ann Poole at (850) 488-8783 or by email at maryann.poole@myfwc.com.

Sincerely,

Bonita Gorham

Bonita Gorham
Land Use Planning Program Administrator
Office of Conservation Planning Services

bg/map
Progress Energy Florida 2012 10-year Site Plan_16168_062812
ENV 1-11-2/3

Managing fish and wildlife resources for their long-term well-being and the benefit of people.

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MyFWC.com

Florida Fish and Wildlife Conservation Commission

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June 7, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Boulevard
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pellis@psc.statea.fl.us

RE: Gulf Power 2012 10-Year Site Plan, Multi-County

Dear Mr. Ellis:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the Gulf Power 2012 10-Year Site Plan and provides the following comments and recommendations for your consideration.

Project Description

Section 186.801, Florida Statutes requires electric generating facilities to submit a ten-year site plan to the Florida Public Service Commission. Gulf Power owns and operates five plants in Northwest Florida: Plant Crist (Escambia County); Plant Lansing Smith (Bay County); Plant Sholtz (Jackson County); Pea Ridge (Santa Rosa County); and Perdido (Escambia County). Gulf Power has continued to evaluate the construction of generating facilities or the acquisition of equivalent capacity resources in coordination with other Southern Electric System (SES) operating companies. Gulf Power indicates that it has satisfied its need for firm capacity through the May 2023 time period. Any new facility construction is deferred during the 2012-2021 planning cycle. Gulf Power will consider additional capacity at its existing sites at the Plant Crist, Plant Lansing Smith, Plant Scholtz, or at the identified sites on the Shoal River property in Walton County or the Caryville property in Holmes and Washington Counties.

Potentially Affected Resources

Plant Crist (Escambia County) is located adjacent to the Escambia River, which has been designated as Critical Habitat for the Gulf Sturgeon [*Acipenser oxyrinchus desotoi* – Federal Threatened (FT)]. The undeveloped portion of the site includes mixed hardwoods/pines and mixed scrub.

Plant Lansing Smith (Bay County) is located along North Bay of the St. Andrews Bay system. The undeveloped portion of the site is predominantly pine plantation with some wetland areas. The site is adjacent to areas identified for conservation under the Bay County Sector Plan.

Plant Scholtz (Jackson County) is located adjacent to the Apalachicola River. The site consists of a mixture of pine and hardwood forests. Plant Scholtz is adjacent to the Apalachicola River, which has designated critical habitat for the Gulf Sturgeon

[*Acipenser oxyrinchus desotoi* (FT)], and critical habitat for the purple bankclimber [*Elliptoides sloatianus* (FT)] and fat three-ridge [*Amblema neislerii* - Federal Endangered (FE)].

The undeveloped Shoal River Site (Walton County) is located on the Shoal River approximately 3 miles northwest of Mossy Head, Florida. The property is predominantly in pine plantation. The site falls within a federally designated red-cockaded woodpecker consultation area; and contains primary and secondary habitat for the Florida black bear [*Ursus americanus floridanus* – State Threatened (ST)]. This site is also within close proximity to known occurrences of southern sandshell mussel (*Hamiota australis* – Federal, Candidate Endangered), blackmouth shiner [*Notropis melanostomus* – State Endangered (SE)], bluenose shiner [*Pteronotropis welaka* – State Species of Special Concern (SSC)], Eastern indigo snake [*Drymarchon couperi* – (FT)], alligator snapping turtle [*Macrochelys temminckii* (State SSC)], gopher tortoise [*Gopherus polyphemus* – (ST)], and pine barrens treefrog [*Hyla andersonii* (State SSC)].

The undeveloped Caryville Site (Holmes/Washington County) is approximately 1.5 miles northeast of Caryville, Florida. The property is predominantly in agriculture and pine plantation. The site may contain gopher tortoise [*Gopherus polyphemus* (ST)], pine barrens treefrog [*Hyla andersonii* (State SSC)], and the Eastern indigo snake [*Drymarchon couperi* (FT)]. The site is also within close proximity to the Choctawhatchee River, which contains critical habitat for the Gulf Sturgeon [*Acipenser oxyrinchus desotoi* (FT)] and known occurrences of Barbour's Map Turtle [*Graptemys barbouri* (State SSC)], Fuzzy Pigtoe (*Pleurobema strodeanum* – Federal, Candidate Endangered), and bluenose shiner [*Pteronotropis welaka* (State SSC)].

FWC appreciates the opportunity to review Gulf Power's 2012 10-year Site Plan 2012-2021 document and extends an offer to assist Gulf Power in further identifying fish and wildlife resources within their planning area. Based on our review, we have determined that there are no development plans proposed in this Gulf Power Planning document that appear to pose significant fish and wildlife resource issues or potential conflicts for this planning period. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions regarding the content of this letter, please contact Theodore Hoehn at 850-488-8792 or by email at ted.hoehn@myfwc.com.

Sincerely,

for, Scott Sanders, Director
Office of Conservation Planning Services

ss/bg/th
ENV 2-11-4/3
Gulf Power Company 2012 10-year Site Plan_16170_060712
cc: Susan Ritenour, Gulf Power, SDRITENO@southernco.com

Florida Fish and Wildlife Conservation Commission

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July 11, 2012

Mr. Phillip O. Ellis
Strategic Analysis & Government Affairs
Public Service Commission
2540 Shumard Oak Boulevard
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pellis@psc.state.fl.us

RE: 2012 Orlando Utilities Commission (OUC) 10-year Site Plan 2012-2021, Multi-County

Dear Mr. Ellis:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed OUC's 2012 10-year Site Plan and provides the following comments and recommendations for your consideration.

Project Description

Section 186.801, Florida Statutes, requires electric generating facilities to submit a ten-year site plan to the Florida Public Service Commission. The OUC reviewed its forecast of peak energy demand and existing generating resources and found that it has adequate capacity to satisfy forecast requirements through 2020. OUC forecasts indicate that 23 megawatts of reserve margin capacity will be required by summer 2021. The 10-year Site Plan reports that OUC intends to fulfill its supply requirements by adding a simple cycle combustion turbine at the Stanton Energy Center or Indian River site, both of which are existing facilities.

Potentially Affected Resources

The Stanton Energy Center site is located on S.R. 434 (S. Alafaya Trail) and north of S.R. 528 (Beachline). This facility is situated between the Big and Little Econlockhatchee Rivers and also abutts the Hal Scott Regional Preserve and Park. The electric power facility and associated solid waste disposal area comprise part of the site with the remainder of the property being mostly characterized as longleaf pine flatwoods, cypress wetlands, and dry or wet prairie. Listed species known to occur on the site include the red-cockaded woodpecker (and nest trees), bald eagle, gopher tortoise and Florida Sandhill Crane. A 2005 red-cockaded woodpecker habitat management plan is used to guide land management activities at the Stanton site and is part of the Conditions of Certification for the site.

The Indian River Plant site is located four miles south of Titusville on U.S. Highway 1 near the Indian River. The electric power facility encompasses almost the entire site; north and west of the site is the Space Coast Regional Airport. The predominant and adjacent land uses are urban in nature and contain little habitat for listed species; therefore, impacts to listed species are not anticipated.

FWC staff appreciates the opportunity to review OUC's 10-year Site Plan review the proposed planning document and finds that it is sufficient for planning purposes. We also extend an offer to assist OUC in further identifying fish and wildlife resources within their planning area. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions regarding the content of this letter, please contact Ben Shepherd at (407) 858-6170 or by email at Ben.Shepherd@MyFWC.com.

Sincerely,

Bonita Gorham
Land Use Planning Program Administrator
Office of Conservation Planning Services

bg/jdg/bs
Orlando Utilities Commission 2012 10-year Site Plan_16174_071112
ENV 2-11-4/3

July 16, 2012

Florida Fish and Wildlife Conservation Commission

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Mr. Phillip O. Ellis
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Public Service Commission
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pellis@psc.state.fl.us

RE: Multiple Utilities 2012 Ten-year Site Plans

Dear Mr. Ellis:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the 2012 Ten-year Power Plant Site Plans submitted to the Public Service Commission (PSC).

We will be providing comments on several of the site plans under separate cover; however, we are submitting no comments on the Ten-year Site Plans for the following utilities:

- City of Tallahassee
- Florida Municipal Power Agency
- JEA
- Lakeland Electric
- Seminole Electric Cooperative
- Gainesville Regional Utilities
- Tampa Electric Company

FWC appreciates the opportunity to review the Ten-year Site Plans, as submitted by the PSC. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or at FWCConservationPlanningServices@MyFWC.com.

Sincerely,

Bonita Gorham

Bonita Gorham
Land Use Planning Program Administrator
Office of Conservation Planning Services

bg/jdg
ENV 2-11-2
PSC TYSP 2012_071612

Regional Planning Councils

Central Florida RPC

CFRPC
SERVING THE COUNTIES OF • DESOTO • HARDEE • HIGHLANDS • OKEECHOBEE • POLK

July 2, 2012

Phillip Ellis
State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399

Dear Mr. Ellis,

The CFRPC reviewed ten year site plans from Lakeland Electric, Orlando Utilities Commission, Progress Energy Florida, Tampa Electric Company, and Seminole Electric Cooperative as included on the Public Service Commission's website. As requested in the latter dated April 18, 2012, a brief summary and comments related to the suitability of the above mentioned plans as planning documents is below.

Lakeland Electric:

The plan states that there are no planned facilities for the 10-year planning reporting period. There are also no upgrades of existing facilities planned.

This document is suitable for a planning document at a regional level because it provides insight on the development of areas within a portion of the region through current demand and forecast demand. It also is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts that are predicted to occur for the overall planning of the region's growth and development and protection.

This document is also written in a manner that makes it easy for non-utility planners to understand.

Orlando Utilities Commission:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. There are also no upgrades of existing facilities planned in these areas.

This document is suitable for a planning document at a regional level because it provides information as to facilities located within the region. It is somewhat less suitable as a planning document at providing insight on the development through

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current demand and forecast demand because it cannot be extrapolated to a regional or county level because Orlando Utilities Commission services so much of the State of Florida. This document would also be more helpful as a planning document with the inclusion of a service area map.

Progress Energy Florida, Inc:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. There are also no upgrades of existing facilities planned in these areas.

This document is suitable for a planning document at a regional level because it provides information as to the proposed locations of planned new facilities. It is somewhat less suitable as a planning document at providing insight on the development through current demand and forecast demand because it cannot be extrapolated to a regional or county level because Progress Energy's boundaries cover so much of the State of Florida. It is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

Tampa Electric Company:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. However, there is a planned expansion at the Polk Power Station in Polk County.

This document is suitable for a planning document at a regional level because it provides information as to the proposed locations of planned new expansions. This document is suitable for a planning document at a regional level because it provides insight on the development of areas within a portion of the region through current demand and forecast demand. It also is helpful to know what energy conservation and management programs are being utilized as well as the environmental and land impacts are predicted to occur for the overall planning of the region's growth and development and protection.

Seminole Electric Cooperative:

According to the plan, no facilities are planned within the Central Florida Regional Planning Council Region for the 10-year planning reporting period. There are also no upgrades of existing facilities planned in these areas.

This document is suitable for a planning document at a regional level because it provides information as to facilities located within the region. It is somewhat less suitable as a planning document at providing insight on the development through current demand and forecast demand because it cannot be extrapolated to a regional or county level because Seminole Electric Cooperative services so much of the State of Florida.

The proposed expansions/potential sitings as indentified in the ten year power plant plans as submitted are consistent with the Central Florida Regional Planning Council Strategic Regional Policy Plan (SRPP). Thank you for the opportunity to review these electric utility ten year site plans.

Sincerely,

M. M. B

Marisa M. Barmby, AICP
Senior Planner

Regional Planning Councils

East Central Florida RPC

East Central Florida Regional Planning Council

309 Cranes Roost Blvd. Suite 2000, Altamonte Springs, FL 32701
Phone 407.262.7772 • Fax 407.262.7788 • www.ecfrpc.org

Hugh W. Harling, Jr. P.E.
Interim Executive Director

MEMORANDUM

To: Phillip Ellis, Division of Regulatory Analysis, Florida Public Service Commission

From: Hugh W. Harling, Jr., Interim Executive Director
Tara M. McCue, AICP

Date: June 21, 2012

Subject: 2011 Ten-Year Site Plans Review
- Florida Power and Light
- Orlando Utilities Commission
- Progress Energy

The East Central Florida Regional Planning Council staff has completed a review of the 2012 Ten-Year Site Plans for the agencies listed above. Staff comments to each utility are italicized below.

Florida Power and Light (FPL)
In the East Central Florida region, FPL has identified the Space Coast Solar Expansion project in Brevard County as a potential future expansion site. This site already contains of a 10 MW PV facility and has the potential to expand by an additional 10 MW. FPL is also continuing the modernization of the Cape Canaveral Plant. The 10 Year Site Plan did not include any proposed projects or sites which conflict with the ECFRPC Regional Strategic Policy Plan. Staff finds the document to be suitable for planning purposes.

Orlando Utilities Commission (OUC)
The 10 Year Site Plan did not include any proposed projects or sites. Therefore, we find no conflicts with the ECFRPC Regional Strategic Policy Plan. Staff finds the document to be suitable for planning purposes.

Progress Energy Florida (PEF)
The 10 Year Site Plan did not include any proposed projects or sites in the East Central Florida region. Therefore, no conflicts with the ECFRPC Regional Strategic Policy Plan were identified. Staff finds the document to be suitable for planning purposes.

Council staff will provide further comments on environmental and regional impacts when new or modified units, projects or transmission lines are proposed and additional data and information are provided.

If you require any further information or comments, please contact Tara McCue, AICP at tara@ecfrpc.org or by phone at (407) 262-7772.

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12 JUN 28 AM 9:37
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REGIONAL CLEARINGHOUSE
INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 6-27-12

PROJECT DESCRIPTION

#68 Seminole Electric Cooperative, Inc., Ten Year Site Plan 2012 -2021

TO: Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
Capitol Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850

__X__ **COMMENTS ATTACHED**

___ **NO COMMENTS REGARDING THIS PROJECT**

IF YOU HAVE ANY QUESTIONS REGARDING THESE COMMENTS, PLEASE CONTACT STEVEN DOPP, SENIOR PLANNER, AT THE NORTH CENTRAL FLORIDA REGIONAL PLANNING COUNCIL AT (352) 955-2200 OR SUNCOM 625-2200, EXT 109

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2 JUN 28 AM 9:38
DIVISION OF
REGULATORY COMPLIANCE

June 27, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
Capitol Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850

RE: Regional Review of Ten Year Site Plan, 2012 - 2021
Seminole Electric Cooperative, Inc.

Dear Mr. Ellis:

Pursuant to Section 186.801, Florida Statutes, Council staff has reviewed the proposed Ten-Year Site Plan and provides the following comments.

The above-referenced ten-year site plan proposes to construct eight natural gas-powered electrical generation stations by 2021 to be located within Gilchrist County. The combined summer electrical generating capacity of the stations will be 2,010 megawatts, while the combined winter electrical generating capacity of the stations will be 2,301 megawatts. The ten-year site plan notes that 588 megawatts of the summer generating capacity and 681 megawatts of the winter generating capacity will be cooled by water using wet cooling towers with forced air draft fans.

The subject property of the Gilchrist County site is located adjacent to Waccasassa Flats, a Natural Resource of Regional Significance as identified and mapped in the North Central Florida Strategic Regional Policy Plan. Page IV-55 of the North Central Florida Strategic Regional Policy Plan notes the following regarding Waccasassa Flats.

> Occupying approximately 61,653 acres, Waccasassa Flats runs down the center of Gilchrist County. The flats are part of a larger wetland system which runs into Levy County and the Withlacoochee Regional Planning District. During the rainy season, waters in the aquifer build up sufficient pressure to spill out of the many sinkholes and ponds scattered throughout the flats to inundate the area.
>
> The area is predominantly comprised of commercial pine plantation. Pine stands are interspersed among numerous cypress ponds, depression marshes, hydric hammock, and other wetland communities. Several lakes (the largest of which is 150 acres), small areas of upland hardwood forest, sandhill, and other minor natural communities contribute to the diversity of the flats.

Applicable regional plan goals and policies include the following:

> REGIONAL GOAL 4.7. Maintain the quantity and quality of the region's surface water systems in recognition of their importance to the continued growth and development of the region.

Letter to Mr. Phillip Ellis
Page 2
June 27, 2012

> Policy 4.7.5. Use non-structural water management controls as the preferred water management approach for rivers, lakes, springs, and fresh water wetlands identified as natural resources of regional significance.
>
> Policy 4.7.6. Support the coordination of land use and water resources planning for surface water resources designated as natural resources of regional significance among the Council, local governments, and the water management districts through regional review responsibilities, participation in committees and study groups, and ongoing communication.
>
> Policy 4.7.12. Ensure that local government comprehensive plans, DRIs, and requests for federal and state funds for development activities reviewed by the Council include adequate provisions for stormwater management, including retrofit programs for known surface water runoff problem areas, and aquifer recharge protection in order to protect the quality and quantity of water contained in the Floridan Aquifer and surface water systems identified as natural resources of regional significance.
>
> Policy 4.7.13. Work with local governments, state and federal agencies, and the local water management districts in the review of local government comprehensive plans and developments of regional impact as they affect wetlands identified as natural resources of regional significance to ensure that any potential adverse impacts created by the proposed activities on wetlands are minimized to the greatest extent possible.

The proposed electrical power generation site to be located in Gilchrist County will be consistent with the regional plan provided the water consumption of the electrical generating stations does not result in significant and adverse impacts to the wetland functions of Wacassassa Flats. However, the ten-year site plan does not indicate the water source or the amount of water to be used to cool the electrical generating stations. Additionally, the ten-year site plan does not provide an analysis of environmental impacts to Wacassassa Flats of the withdrawal of groundwater used to cool the electrical generating units.

Therefore, it is recommended that the ten-year site plan include information on the water consumption of the electrical generating stations as well as an analysis of environmental impacts to Wacassassa Flats as a result of their water consumption. Finally, it is recommended that an alternative environmental impact analysis be provided whereby 100 percent of the electrical generation capacity of the site is cooled using air.

If you have any questions concerning this matter, please do not hesitate to contact Steven Dopp, Senior Planner of the Planning Council's Regional and Local Government Programs staff, at 352.955.2200, extension 109.

Sincerely,

Scott R. Koons, AICP
Executive Director

v:\chouse\responses\2011-12_68.docx

:e
3-1603

ADDRESS SERVICE
REQUESTED

Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commissic
Capitol Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399-0850
32399$0850

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REGIONAL CLEARINGHOUSE
INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 6-22-12

PROJECT DESCRIPTION

#66 - Progress Energy Florida, Inc. Ten-Year Site Plan, 2012 - 2021

TO: Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

___ **COMMENTS ATTACHED**

_X_ **NO COMMENTS REGARDING THIS PROJECT**

IF YOU HAVE ANY QUESTIONS REGARDING THESE COMMENTS, PLEASE CONTACT STEVEN DOPP, SENIOR PLANNER, AT THE NORTH CENTRAL FLORIDA REGIONAL PLANNING COUNCIL AT (352) 955-2200 OR SUNCOM 625-2200, EXT 109

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REGIONAL CLEARINGHOUSE
INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 6-22-12

PROJECT DESCRIPTION

#67 - Gainesville Regional Utilities - 2012 Ten-Year Site Plan

---

TO: Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

___ **COMMENTS ATTACHED**

_X_ **NO COMMENTS REGARDING THIS PROJECT**

IF YOU HAVE ANY QUESTIONS REGARDING THESE COMMENTS, PLEASE CONTACT STEVEN DOPP, SENIOR PLANNER, AT THE NORTH CENTRAL FLORIDA REGIONAL PLANNING COUNCIL AT (352) 955-2200 OR SUNCOM 625-2200, EXT 109

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Treasure Coast RPC

TREASURE COAST REGIONAL PLANNING COUNCIL
INDIAN RIVER – ST. LUCIE – MARTIN – PALM BEACH

June 18, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Subject: 2012 Ten Year Power Plant Site Plans

Dear Mr. Ellis:

Treasure Coast Regional Planning Council has reviewed the ten year power plant site plan prepared by Florida Power and Light Company. Council approved the comments in the attached report at a board meeting on June 15, 2012. The report concludes that the FPL Ten Year Power Plant Site Plan, 2012-2021 is inconsistent with Strategic Regional Policy Plan Goal 9.1, decreased vulnerability of the region to fuel price increases and supply interruptions; and Strategy 9.1.1, reduce the Region's reliance on fossil fuels. Council urges FPL and the State of Florida to continue developing new programs to: 1) reduce the reliance on fossil fuels as future energy sources; 2) increase conservation activities to offset the need to construct new power plants; and 3) increase the reliance on renewable energy sources to produce electricity.

Please contact me if you have any questions.

Sincerely,

Michael J. Busha, AICP
Executive Director

Attachment

cc: Nick Blount, FPL

"Regionalism One Neighborhood At A Time"- Est.1976

421 SW Camden Avenue - Stuart, Florida 34994
Phone (772) 221-4060 - Fax (772) 221-4067 - www.tcrpc.org

TREASURE COAST REGIONAL PLANNING COUNCIL

Report on the

Florida Power & Light Company Ten Year Power Plant Site Plan, 2012-2021

June 15, 2012

Introduction

Each year every electric utility in the State of Florida produces a ten year site plan that includes an estimate of future electric power generating needs, a projection of how those needs will be met, and disclosure of information pertaining to the utility's preferred and potential power plant sites. The Florida Public Service Commission (FPSC) has requested that Council review the most recent ten year site plan prepared by Florida Power & Light Company (FPL). The purpose of this report is to summarize FPL's plans for future power generation and provide comments for transmittal to the FPSC.

Summary of the Plan

The plan indicates that after FPL's demand side management efforts and significant energy efficiency contributions from the federal appliance and lighting efficiency standards are factored in, FPL will still require additional capacity from conventional power plants to meet future electrical demand. FPL is proposing to add a total of 250 megawatts (MW) of summer capacity to its system from 2012 to 2021 (Exhibit 1). FPL plans to obtain additional electricity through: 1) power purchases from qualifying facilities, utilities and other entities; 2) upgrades to existing facilities; 3) returning inactive reserve units to active status; and 4) modernization of existing facilities. Major additions of new generating capacity are as follows:

- 2013 – place in service the Cape Canaveral Next Generation Clean Energy Center (1,210 MW) in Brevard County;
- 2014 – place in service the Riviera Beach Next Generation Clean Energy Center (1,212 MW) in the City of Riviera Beach; and
- 2016 – place in service the Port Everglades Next Generation Clean Energy Center (1,277 MW) in the City of Hollywood.

Based on the projection of future resource needs, FPL has identified the following five preferred sites for future power generating facilities:

1. St. Lucie Plant site in St. Lucie County;
2. Turkey Point Plant site in Miami-Dade County;
3. Cape Canaveral Plant site in Brevard County;
4. Riviera Plant site in Palm Beach County; and
5. Port Everglades Plant site in Broward County.

Also, FPL has identified 10 potential sites for new or expanded power generating facilities. The identification of potential sites does not represent a commitment by FPL to construct new power generating facilities at these sites. The potential sites include:

1. Babcock Ranch site in Charlotte County;
2. DeSoto Solar Expansion site in DeSoto County;
3. Florida Heartland site in Glades County;
4. an undeveloped site in Hendry County;
5. Manatee Plant site in Manatee County;
6. an unidentified location in Martin County for a photovoltaic (PV) facility;
7. an unidentified location in northeast Okeechobee County;
8. Palatka site in Putnam County;
9. an unidentified location in Putnam County; and
10. Space Coast Solar Expansion site in Brevard County.

The plan describes two primary factors that are driving changes in FPL's 2012 ten year site plan compared to the 2011 ten year site plan. The first factor is that it will not be necessary to schedule planned maintenance outages for FPL's fleet of fossil-fueled generating units during all summer and winter peak load months. The second factor is changes in the load forecast, generating unit capabilities, and power purchase capabilities have combined to result in a lowering of FPL's projected resource needs through 2021. The plan also describes the following additional factors influencing FPL's resource planning work:

- Maintaining/enhancing fuel diversity in the FPL system.
- Maintaining a balance between load and generating capacity in southeastern Florida, particularly in Miami-Dade and Broward counties.
- The possibility of establishment of a Florida standard for renewable energy or clean energy.
- The issue of how best to reliably obtain additional natural gas for FPL's system.
- The extent to which FPL's reserves are projected to become increasingly dependent upon demand side management resources as opposed to generation resources.

Evaluation

One of the main purposes of preparing the ten year site plan is to disclose the general location of proposed power plant sites. The FPL ten year site plan identifies two preferred sites and one potential site for future power generating facilities in the Treasure Coast Region (Exhibit 2). The first preferred site is the St. Lucie Plant site, which is located on Hutchinson Island in St. Lucie County. This site has two nuclear-powered generating units, St. Lucie Units 1 and 2, which have been in operation since 1976 and 1983, respectively. The St. Lucie site has been selected as a preferred site for an "uprate" project to increase the capacity of the two existing nuclear generating units. FPL is modifying the two 840 MW nuclear generating units to increase their capacity by about 129 MW for Unit 1 and 115 MW for Unit 2. Council issued a report supporting this project in 2008. This uprate project has been approved by the FPSC and Florida Department of Environmental Protection (FDEP). A portion (31 MW) of the uprate capacity for St. Lucie Unit 2 has already been implemented and the remainder of the uprated capacity is projected to be in-service by the end of 2012. FPL has also been pursuing the addition of six wind turbines at the St. Lucie Plant site for a number of years. However, to date FPL has been unable to obtain the local land use approvals necessary to proceed with the process.

The second preferred site is the Riviera Plant site, which is located in the City of Riviera Beach. The previous generating capacity at this site was made up of two 300 MW oil-fired units, that have been taken out of service and dismantled in 2011. FPL is in the process of modernizing the existing Riviera Plant, which will be renamed the Riviera Beach Next Generation Clean Energy Center. FPL is replacing the existing units with a high-efficiency combined cycle natural gas-fired unit capable of producing 1,212 MW of electricity. Council issued a report supporting this project in 2009. The new facility has been approved by the FPSC and FDEP, and is expected to start commercial operation in 2014.

The only potential site identified in the Treasure Coast Region is in Martin County. The plan indicates FPL is evaluating potential sites in Martin County for a future PV facility. No specific locations have been selected at this time.

The ten year site plan also indicates that FPL is currently evaluating the possibility of serving the electrical loads of several entities (including the Cities of Vero Beach and Lake Worth). However, the load forecast presented in the ten year site plan does not include these potential loads, because these evaluations are still underway.

The ten year site plan indicates that fossil fuels will be the primary source of energy used to generate electricity by FPL during the next 10 years (Exhibit 3). The plan indicates fossil fuels will account for 76.5 percent (4.6 percent from coal, 0.9 percent from oil, and 71.0 percent from natural gas) of FPL's electric generation in 2012. The plan predicts fossil fuels will account for 74.1 percent (5.5 percent from coal, 0.5 percent from oil, and 68.1 percent from natural gas) of FPL's electric generation in 2021. During the same period, nuclear sources are predicted to change from 17.2 percent in 2012 to 20.4 percent in 2021. Solar sources are predicted to remain steady at 0.2 percent in 2012 and 0.2 percent in 2021.

Regarding solar energy, FPL has completed construction of three solar facilities: 1) a 75 MW steam generation solar thermal facility in Martin County (the Martin Next Generation Solar Energy Center); 2) a 25 MW PV electric generation facility in DeSoto County (the DeSoto Next Generation Solar Energy Center); and 3) a 10 MW PV electric generation facility in Brevard County at NASA's Kennedy Space Center (the Space Coast Next Generation Solar Energy Center). These three projects were completed in response to the 2008 Energy Bill, which was enacted to enable the development of clean, zero greenhouse gas emitting renewable generation in the State of Florida. Specifically, the bill authorized cost recovery for the first 110 MW of eligible renewable projects that had the proper land use, zoning, and transmission rights in place. Collectively, these Next Generation Solar Energy Centers are expected to produce a total of approximately 200,000 megawatt-hours of electricity each year, and at peak production provide enough energy to serve the requirements of more than 14,380 homes at current levels of average residential use.

The 2012 ten year site plan indicates that FPL is currently in the process of identifying other potential solar sites in the state in the event that a future Renewable Portfolio Standard, Clean Energy Portfolio Standard, or other legislation is enacted that enables FPL to construct and recover costs for additional renewable energy generation. Council continues to support FPL's existing solar projects and encourages FPL to develop additional projects based on renewable resources.

Conclusion

The elements of the ten year site plan that do not predict a reduction in reliance on fossil fuels and do not predict an increase in reliance on renewable energy are **inconsistent** with Strategic Regional Policy Plan Goal 9.1, decreased vulnerability of the region to fuel price increases and supply interruptions; and Strategy 9.1.1, reduce the Region's reliance on fossil fuels. Over the last ten years, Council's findings of inconsistency with the FPL ten year site plans have remained relatively unchanged, because FPL has made little progress toward addressing Council's concerns. One of the main reasons for this is because the State of Florida does not have a Renewable Portfolio Standard or other policies designed to encourage electric utilities to increase fuel diversity by adding a greater proportion of energy from renewable sources, such as solar and wind energy. Council encourages the Florida Legislature to adopt a Renewable Portfolio Standard in order to provide a mechanism to expand the use of renewable energy in Florida.

The FPL ten year site plan should predict an increase in the use of renewable energy during the next decade. Council recommends that FPL consider new strategies to expand reliance on renewable sources. FPL should develop a program to install, own, and operate PV units on the rooftops of private and public buildings. The shift to rooftop PV systems distributed throughout the area of demand could reduce the reliance on large transmission lines and reduce costs associated with owning property; purchasing fuel; and permitting, constructing, and maintaining a power plant. Another advantage of this strategy is that PV systems do not require water for cooling. The incentive for owners of buildings to participate in this strategy is they could be offered a reduced rate for purchasing electricity. The future development of ocean current technology, which is currently under investigation by the Florida Atlantic University Center for Ocean Energy Technology, may be another opportunity to expand the use of renewable energy.

Council urges FPL and the State of Florida to continue developing new programs to: 1) reduce the reliance on fossil fuels as future energy sources; 2) increase conservation activities to offset the need to construct new power plants; and 3) increase the reliance on renewable energy sources to produce electricity. The complete costs of burning fossil fuels, such as the costs to prevent environmental pollution and costs to the health of the citizens, need to be considered in evaluating these systems. State legislators should amend the regulatory framework to provide financial incentives for the power providers and the customers to increase conservation measures and to rely to a greater extent on renewable energy sources. Also, the State should reconsider the currently used test for energy efficiency and choose a test that will maximize the potential for energy efficiency and renewable energy resources. The phasing in of PV and other locally available energy sources will help Florida to achieve a sustainable future.

Attachments

EXHIBIT 1

Table III.B.1: Projected Capacity Changes for FPL

Projected Capacity Changes			
		Net Capacity Changes (MW)	
Year	Projected Capacity Changes	Winter[1]	Summer[2]
2012	Sanford Unit 5 CT Upgrade	---	19
	St. Lucie Unit 1 Uprate - Outage [5]	(853)	---
	St. Lucie Unit 1 Uprates - Completed	---	129
	Turkey Point Unit 3 Uprates - Completed	---	123
	St. Lucie Unit 2 Uprate - Outage [5]	---	(745)
	Changes to Existing Purchases [3]	375	470
	Scherer Unit 4	---	(30)
	Manatee Unit 2	---	(3)
	Inactive Reserve Units (PE Units 3 & 4) -return to active status [7]	765	761
	Manatee Unit 2 ESP - Outage [6]	(822)	---
2013	Cape Canaveral Next Generation Clean Energy Center [4]	---	1,210
	Changes to Existing Purchases [3]	(555)	(430)
	Manatee Unit 2	(3)	---
	Sanford Unit 5 CT Upgrade	19	9
	Martin Unit 8 CT Upgrade	10	10
	Sanford Unit 4 CT Upgrade	22	31
	Scherer Unit 4	(28)	---
	St. Lucie Unit 1 Uprates - Completed	129	---
	St. Lucie Unit 2 Uprates - Completed	84	84
	Turkey Point Unit 3 Uprates - Completed	123	---
	Turkey Point Unit 4 Uprates - Completed	---	123
	Turkey Point Unit 4 Uprates - Outage [5]	(717)	---
	Inactive Reserve Unit (PE Units 3 & 4) - return to inactive status [7]	(765)	(761)
	Manatee Unit 1 ESP - Outage [6]	(822)	---
	Martin Unit 1 ESP - Outage [6]	--	(826)
2014	Cape Canaveral Next Generation Clean Energy Center [4]	1,355	---
	Sanford Unit 4 CT Upgrade	16	---
	Sanford Unit 5 CT Upgrade	19	10
	Manatee Unit 3 CT Upgrade	---	19
	Turkey Point Unit 5 CT Upgrade	---	33
	Turkey Point Unit 4 Uprates - Completed	123	---
	Martin Unit 1 ESP - Outage [6]	(832)	---
	Martin Unit 2 ESP - Outage [6]	---	(826)
	Riviera Beach Next Generation Clean Energy Center [4]	---	1,212
2015	Manatee Unit 3 CT Upgrade	39	20
	Turkey Point Unit 5 CT Upgrade	33	---
	Ft. Myers Unit 2 CT Upgrade	---	51
	Riviera Beach Next Generation Clean Energy Center [4]	1,344	---
2016	Changes to Existing Purchases [3]	(858)	(858)
	Ft. Myers Unit 2 CT Upgrade	51	---
	Turkey Point Unit 1 operation changed to synchronous condenser	---	(396)
	Port Everglades Next Generation Clean Energy Center [4]	---	1,277
2017	Changes to Existing Purchases [3]	---	(375)
	Turkey Point Unit 1 operation changed to synchronous condenser	(398)	---
	Port Everglades Next Generation Clean Energy Center [4]	1,429	---
2018	Changes to Existing Purchases [3]	(383)	---
2019	---	---	---
2020	---	---	---
2021	Short Term Purchase	---	250

(1) Winter values are forecasted values for January of the year shown.
(2) Summer values are forecasted values for August of the year shown.
(3) These are firm capacity and energy contracts with QF, utilities, and other entities. See Table I.B.1 and Table I.B.2 for more details.
(4) All new unit additions are scheduled to be in-service in June of the year shown. All additions assumed to start in June are included in the Summer reserve margin calculation starting in that year and in the Winter reserve margin calculation starting with the next year.
(5) Outages for uprate work.
(6) Outages for ESP work.
(7) A number of existing FPL power plants have been removed from service and placed on Inactive Reserve status. See Chapter III for a discussion of the units on Inactive Reserves.

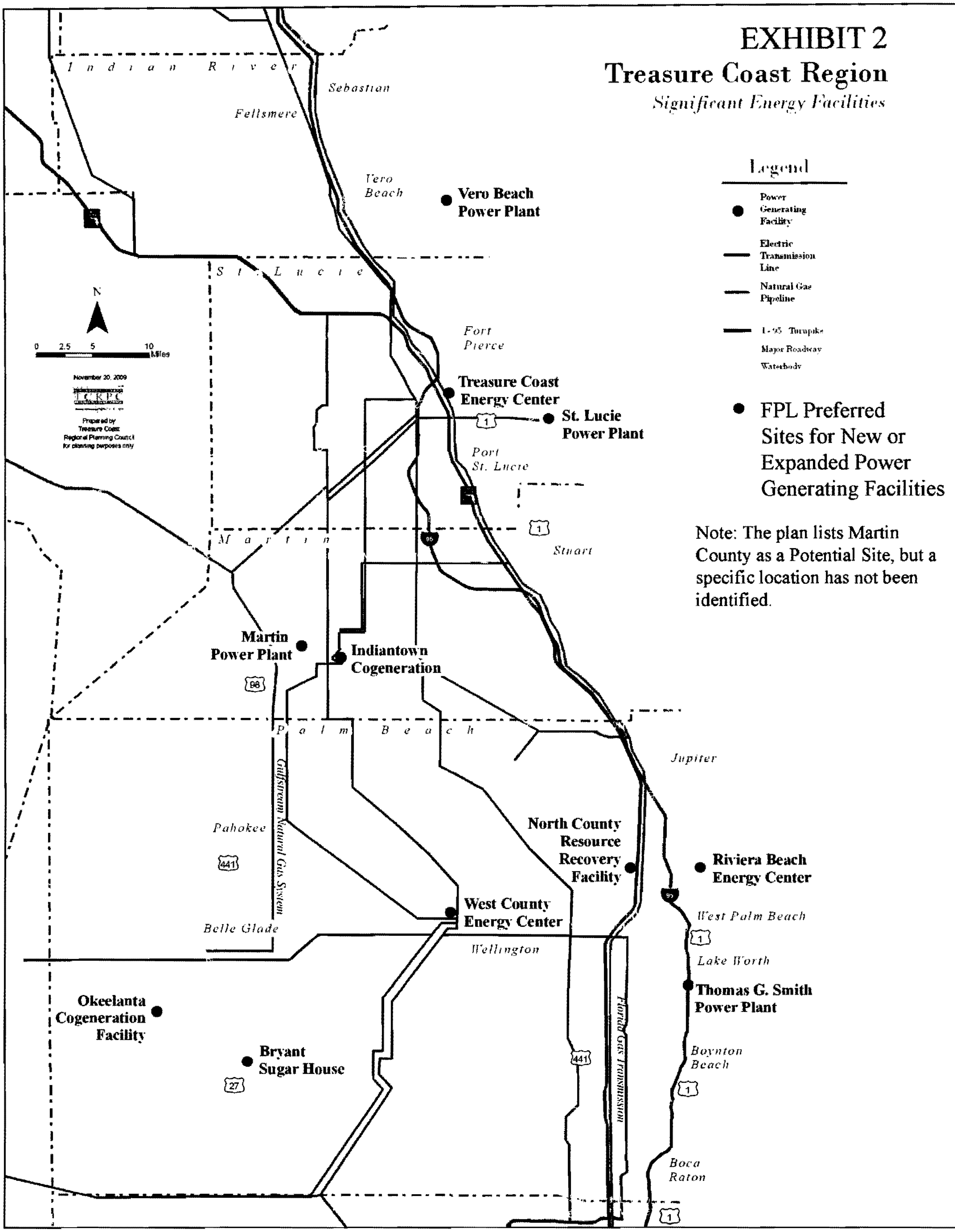

EXHIBIT 2
Treasure Coast Region
Significant Energy Facilities
Legend
Power Generating Facility
Electric Transmission Line
Natural Gas Pipeline
I-95 Turnpike
Major Roadway
Waterbody
FPL Preferred Sites for New or Expanded Power Generating Facilities
Note: The plan lists Martin County as a Potential Site, but a specific location has not been identified.
N
0 2.5 5 10 Miles
November 20, 2009
Prepared by Treasure Coast Regional Planning Council for planning purposes only
Indian River
St. Lucie
Martin
Palm Beach
Sebastian
Fellsmere
Vero Beach
Vero Beach Power Plant
Fort Pierce
Treasure Coast Energy Center
St. Lucie Power Plant
Port St. Lucie
Stuart
Martin Power Plant
Indiantown Cogeneration
Jupiter
Pahokee
Gulfstream Natural Gas System
North County Resource Recovery Facility
Riviera Beach Energy Center
West County Energy Center
West Palm Beach
Belle Glade
Wellington
Lake Worth
Thomas G. Smith Power Plant
Okeelanta Cogeneration Facility
Bryant Sugar House
Florida Gas Transmission
Boynton Beach
Boca Raton

EXHIBIT 3

Schedule 6.2
Energy Sources % by Fuel Type

Energy Source	Units	Actual 1/ 2010	Actual 1/ 2011	Forecasted 2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
(1) Annual Energy Interchange 2/	%	7.3	5.3	3.8	2.8	2.7	3.4	2.3	0.5	0.0	0.0	0.0	0.0
(2) Nuclear	%	20.0	19.1	17.2	23.6	23.8	21.8	23.1	22.8	21.6	22.2	21.9	20.4
(3) Coal	%	5.0	5.0	4.8	5.4	4.8	5.6	5.5	5.9	5.4	5.8	5.3	5.5
(4) Residual (FO6) -Total	%	3.6	0.6	0.9	0.4	0.3	0.4	0.4	0.4	0.3	0.3	0.4	0.5
(5) Steam	%	3.6	0.6	0.9	0.4	0.3	0.4	0.4	0.4	0.3	0.3	0.4	0.5
(6) Distillate (FO2) -Total	%	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CC	%	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9) CT	%	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10) Natural Gas -Total	%	58.3	66.1	71.0	65.0	65.5	64.9	64.6	66.1	68.3	67.1	67.4	68.1
(11) Steam	%	4.4	4.8	2.5	0.9	0.6	0.8	1.0	0.9	0.8	0.8	0.9	1.2
(12) CC	%	53.6	60.8	68.4	64.0	64.8	64.1	63.6	65.1	67.5	66.3	66.5	66.8
(13) CT	%	0.4	0.6	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1
(14) Solar 3/	%	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
(15) PV	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(16) Solar Thermal 4/	%	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17) Other 5/	%	5.6	3.6	2.4	2.7	2.8	3.8	4.0	4.2	4.2	4.4	4.9	5.3
		100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules
2/ The projected figures are based on estimated energy purchases from SJRPP and the Southern Companies (UPS contract).
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Estimated projected values.Solar thermal does not produce GWh, but produces steam that displaces fossil fuel-derived steam.
Its 2011 contribution to the Martin 8 CC GWh output is rolled into row (12) for reporting purposes. Its projected contributions for 2012 - 2021 are provided separately on row (16).
5/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, Independent Power Producers, net of Economy and other Power Sales.
6/ Net Energy For Load values for the years 2012 - 2021 are also shown in Col. (19) on Schedule 2.3.

Liz Gulick

From: Mike Busha <mbusha@tcrpc.org>
Sent: Monday, June 18, 2012 10:21 AM
To: lgulick@tcrpc.org
Subject: FW: Fw: FPL - Ten Year Power Plant Site Plan 2012-2021

From: RGreene@wpb.org [mailto:RGreene@wpb.org]
Sent: Friday, June 08, 2012 5:16 PM
To: mbusha@tcrpc.org
Cc: MFigueroa@wpb.org; EMitchell@wpb.org; AHansen@wpb.org
Subject: Re: Fw: FPL - Ten Year Power Plant Site Plan 2012-2021

Mike,

I hope all is well with you. Our office conducted a review of the Ten Year Power Plant Site Plan and noted a minor comment on page 142 of the report (page 150 of 248 on the file). The language incorrectly states that the Future Land Use Designation for the area in West Palm Beach immediately south of the proposed Riviera FPL Plant is Residential. The actual FLU designations for that area are Multi Family and Single Family. The same page also inaccurately identifies the Riviera FLU designations to the west as Commercial when in reality they are Utilities and Port.

Please let me know if you have any other questions.

Rick Greene, AICP
Planning Manager
Development Services Department
City of West Palm Beach
401 Clematis Street
West Palm Beach, Florida 33401
(561) 822-1455

From: Ed Mitchell/WESTPALM
To: Millie Figueroa/WESTPALM@WESTPALM
Cc: rgreene@wpb.org
Date: 05/21/2012 02:52 PM
Subject: Fw: FPL - Ten Year Power Plant Site Plan 2012-2021

t file rg
----- Forwarded by Ed Mitchell/WESTPALM on 05/21/2012 02:51 PM -----

From: "Mike Busha" <mbusha@tcrpc.org>
To: <jbaird@ircgov.com>, "Faye Outlaw" <OutlawF@stlucieco.org>, "Taryn Kryzda" <tkryzda@martin.fl.us>, "Bob Weisman" <tmlawren@pbcgov.org>, "Greg Oravec" <goravec@cityofpsl.com>, <jtitcomb@lakeparkflorida.gov>, "Lee Leffingwell" <lleffingwell@townofmangoniapark.com>, "Peter Elwell" <TownManager@townofpalmbeach.com>, "Paul Schofiled" <pschofield@wellingtonfl.gov>, "Ed Mitchell" <emitchell@wpb.org>, "Nick Mimms" <nmimms@fppwd.com>, "Ruth Jones" <rjones@rivierabch.com>
Cc: <pmerritt@tcrpc.org>
Date: 05/21/2012 02:27 PM
Subject: FPL - Ten Year Power Plant Site Plan 2012-2021

Water Management Districts

St. Johns River WMD

St. Johns River
Water Management District
Hans G. Tanzler III, Executive Director • David W. Fisk, Assistant Executive Director

4049 Reid Street • P.O. Box 1429 • Palatka, FL 32178-1429 • (386) 329-4500
On the Internet at floridaswater.com.

June 21, 2012

Mr. Philip Ellis
Division of Regulatory Analysis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Review of Florida Power and Light Company 2012 Ten-Year Site Plan

Dear Mr. Ellis:

St. Johns River Water Management District (District) staff have reviewed the Ten-Year Site Plan (TYSP) for Florida Power and Light Company (FPL) relative to its suitability as a planning document, as requested by your letter dated April 18, 2012. District staff comments are below.

1. Pursuant to subsection II, A.1.f., of the 2007 operating agreement concerning regulation between the District and the Florida Department of Environmental Protection (DEP), DEP shall review and take final action on all applications for permits for power plants and electrical distribution and transmission lines and other facilities related to the production, transmission, and distribution of electricity.

2. The TYSP for FPL did not contain information relative to projected water demand. In general, the District requires that all consumptive use permit (CUP) applications for new uses and requested increases in CUP allocations demonstrate the use of lowest-quality water source; justify the need for the requested allocation; demonstrate efficient use; and not impact springs, wetlands, water bodies, water quality, or existing legal uses. In addition, all other CUP criteria must be met. When locating or expanding a site for a power facility, FPL should consider the availability of water to meet the proposed demands of the facility and potential impacts due to facility water use, including the cumulative impacts of locating or expanding a facility at a given location.

Please note that the District's contact person for the review of TYSPs has changed and the new contact information is below.

Jeff Cole
Chief of Staff
P.O. Box 1429
Palatka, FL 32178-1429
jcole@sjrwmd.com

If you have any questions, please contact District Intergovernmental Planner Steve Fitzgibbons at (386) 312-2369 or *sfitzgib@sjrwmd.com.*

Sincerely,

Jeff Cole, Chief of Staff

cc: Richard Burklew, St. Johns River Water Management District
Patricia Renish, St. Johns River Water Management District
Jay Lawrence, St. Johns River Water Management District
Chou Fang, St. Johns River Water Management District
Susan Moor, St. Johns River Water Management District
Troy Rice, St. Johns River Water Management District

Water Management Districts

Southwest Florida WMD

Southwest Florida
Water Management District

2379 Broad Street, Brooksville, Florida 34604-6899
(352) 796-7211 or 1-800-423-1476 (FL only)
TDD only: 1-800-231-6103 (FL only)
On the Internet at *WaterMatters.org*

An Equal Opportunity Employer

Bartow Service Office
170 Century Boulevard
Bartow, Florida 33830-7700
(863) 534-1448 or
1-800-492-7862 (FL only)

Sarasota Service Office
6750 Fruitville Road
Sarasota, Florida 34240-9711
(941) 377-3722 or
1-800-320-3503 (FL only)

Tampa Service Office
7601 Highway 301 North
Tampa, Florida 33637-6759
(813) 985-7481 or
1-800-836-0797 (FL only)

June 29, 2012

Mr. Phillip Ellis
Division of Regulatory Analysis
State of Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Subject: Review of the 2012 Ten-Year Site Plans for Florida's Electric Utilities

Dear Mr. Ellis:

On April 18, 2012, the Florida Public Service Commission (FPSC) requested comments from the Southwest Florida water Management District (District) regarding selected ten-year site plans for potential electric generating plants within the District's jurisdictional boundaries. Specifically, the FPSC requested that the District *"... provide comments, along with a brief summary if possible, on their suitability as planning documents."*

It should be noted that under the current Operating Agreement between the Florida Department of Environmental Protection (FDEP) and the District, the FDEP is typically responsible for reviewing Environmental Resource Permit (ERP) applications for Electric Power Plants (reference: Section II.A.1.f of the Operating Agreement).

The following site plan reports were obtained from the FPSC's web site:

http://www.psc.state.fl.us/utilities/electricgas/10yrsiteplans.aspx

- Progress Energy, Inc.
- Tampa Electric Company

Review and Commentary for Progress Energy, Inc. (PEI):

Chapter 4 of PEI's report included a three (3) page general planning summary of their proposed Levy County Nuclear Plant which is estimated to undergo construction by 2021. This summary included two (2) 8.5"x11" figures that provided a general location of the proposed generating facilities.

PEI's report provided good information for general planning purposes in regard to the District's ERP program. The report did not contain information relating to the consumptive use of water.

Review and Commentary for Tampa Electric Company (TECO):

Chapter IV (Schedules 8.1 and 9) of TECO's report provides information on potential expansion of their existing (previously permitted) facilities within the next ten years. Chapter VI of the report provides a short location narrative of TECO's existing power plant facilities which includes three (3) supporting 8.5"x11" figures.

TECO's report provided good information for general planning purposes in regard to the District's ERP program. The report did not contain information relating to the consumptive use of water.

I hope that you will find these comments satisfy the request for review. Please do not hesitate to contact me if you have questions or need clarification at Michelle.Maxey@watermatters.org or 813-985-7481.

Sincerely,

Michelle Maxey, E.I.
Chief, Regulatory Support Bureau

cc: Hank Higginbotham, P.E.
Chaz Collins
Ralph Kerr, P.G.
Joe Oros, P.G.

Other Organizations

Seminole Tribe of Florida

Appendix A

Eric Fryson 120000-OT

From: Marilyn Lozada [mlozada@llw-law.com]

Sent: Monday, July 02, 2012 4:20 PM

To: Filings@psc.state.fl.us

Cc: Andrew Baumann; Stephen Walker

Subject: Florida Power & Light's 2012 Ten-Year Power Plant Site Plan

Attachments: Ann Cole Letter re FPL's 2012 Ten-Year Power Platn Site Plan (00109472).PDF

Attached for electronic filing with the Florida Public Service Commission is Seminole Tribe of Florida's letter addressed to Ann Cole re: FPL's 2012 Ten-Year Power Plant Site Plan.

Marilyn Ayala-Lozada
Legal Assistant to:
Kenneth G. Spillias and Andrew J. Baumann
Lewis, Longman & Walker, P.A.
515 North Flagler Drive, Suite 1500
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vCard | Website

LEWIS
LONGMAN &
WALKER | P.A.
ATTORNEYS AT LAW

Reply To: **West Palm Beach**

July 2, 2012

VIA ELECTRONIC MAIL

Ann Cole
Division of the Commission, Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Re: Florida Power & Light Company's 2012 Ten-Year Power Plant Site Plan

This Comment is submitted on behalf of the Seminole Tribe of Florida. Florida Power & Light has submitted its 2012 Ten-Year Power Plant Site Plan listed Potential Site #4 in Hendry County as a future PV and/or Natural Gas facility. Described on pages 153 and 154 of the Plan, the site is located on CR 833 on 3,127 acres of land immediately north of the Seminole Tribe's Big Cypress Reservation.

The Seminole Tribe is currently in litigation with Hendry County and Florida Power & Light concerning zoning approvals already obtained from the County. The Seminole Tribe continues to have serious concerns over the proposed site.

Given the proximity of this proposed plant to residential areas and successful ecotourism operations on the Big Cypress Reservation, the Seminole Tribe has serious concerns about the proposed potential site #4 in Hendry County. Unlike the description in the Site Plan, Florida Power & Light already identified in zoning submittals to Hendry County that it plans to build three natural gas units, with 150-foot-tall cooling towers resulting in a demand for 22.5 million gallons of cooling water per day (7.5 million gallons per unit) to be drawn from the groundwater aquifer adjacent to and beneath this property and the Seminole Big Cypress Reservation. The groundwater aquifer in this area has already been identified as having reached its maximum potential utilization. The Seminole Tribe's rights as protected by both state statute and the Water Compact between the Seminole Tribe and the State of Florida will be adversely impacted by this proposed plant. Additionally locating this plant adjacent to the Big Cypress Reservation will harm the Seminole Tribe's rights to use the Reservation for residential and business uses including agriculture and ecotourism.

Accordingly, the plan should accurately identify the size of the plant, the number of units and accurately state the source and quantity of water demanded for the site, as well as accurately describe the impact to the environment, including the Big Cypress Reservation.

Sincerely,

Andrew J. Baumann

AJB/ml

cc: Jim Shore
Craig Tepper

00109420-1

Eric Fryson

From: Matthew Schwartz [matthew3222@yahoo.com]
Sent: Monday, July 02, 2012 6:32 PM
To: Filings@psc.state.fl.us; Records Clerk
Cc: Eric Fryson
Subject: Re: FW: FW: FPL 10 Year Site Plan
Attachments: SFWA Comments on FPL 10 Year Site Plan.doc

Please see attached.

Sincerely,

Matthew Schwartz
Executive Director
South Florida Wildlands Association
P.O. Box 30211
Ft. Lauderdale, FL 33303
954-634-7173
954-993-5351 (cell)

SOUTH FLORIDA
WILDLANDS ASSOCIATION

P.O. Box 30211
Ft. Lauderdale, FL 33303

July 2, 2012

Dear Florida Public Service Commission:

South Florida Wildlands Association was recently informed that Florida Power and Light (FPL) has included the Hendry County energy center (potential site #4 - Hendry County) in its 2012 Ten Year Power Plant Site Plan submitted to the Florida Public Services Commission. on April 2, 2012.

Our organization has a longstanding objection to the location of this plant which has been brought up on numerous occasions. We objected when the proposal was first brought to the Hendry County Planning and Zoning Board in 2011. When the board transmitted their approval to the full commission, we again objected to the commission prior to their vote approving the re-zoning that would make this project possible. We also attended a meeting organized by Laurie McDonald of the Defenders of Wildlife between FPL and representatives of numerous local and national environmental organizations. We again stressed that this particular site for a 3,750 MW gas fired power plant was completely unacceptable to our organization no matter what steps the utility takes to "mitigate" the damage. We have sent action alerts to our membership on this issue (opposing the project) and our views have been covered by the news media (e.g. The Sun-Sentinel and Fox4 television in southwest Florida).

Our objections fall into the following categories:

1. According the U.S. Fish and Wildlife Service (FWS), all but 6 of the more than 3000 acres purchased by FPL for this project fall in the primary habitat zone of the critically endangered Florida panther. Panthers have been dying in record numbers as the population expands into ever shrinking habitat. Not only will this destroy and degrade a certain amount of habitat on site, but the impacts on panthers and their prey in the surrounding area from an industrial project of this magnitude are unknown (but extremely likely to be negative). FWS has provided us with GIS maps which indicate numerous instances of both roadkill and "intra-specific" aggression (panther on panther fights to the death) both in and around the FPL property (at least 3 panthers have been killed on a section of CR 833 bordering the property. Telemetry shows a great deal of panther occupancy and state FWC maps of collared panthers indicate that the property and the surrounding area is one of the most important - if not the most important - in the entire state for the species.

The former property owner, prior to selling the property to FPL, wrote a letter to the

FWS asking for help putting a conservation easement on the property. In that letter, Mr. Eddie Garcia stressed the property's importance to the panther and numerous other listed and non-listed animals on site (e.g. black bear, crested caracara, eastern indigo snake).

2. The property is currently completely rural and is surrounded by - or in a nexus of - either public lands (e.g. the Big Cypress National Preserve, Dinner Island WMA, OK Slough State Forest, etc.) or lands which have been long sought by Florida Forever for protection. The entire McDaniels Ranch was always expected to have a conservation easement on it - and was in fact included in a Florida Forever project named "Panther Glades". The McDaniels property was considered an "essential" part of that project. The FPL projected energy center will not only degrade the value of nearby public lands, but will introduce development into a still completely rural section of south Florida. Leaving the Seminole Reservation to the south - one encounters virtually no development until one arrives at either Clewiston to the north or Immokalee to the southwest. The area is completely rural. The history of development in south Florida shows that projects like this will not long stand in isolation. Development follows development. In this case - the project alone is enough to cause significant harm to the panther. Further development of the area - including widened roads and increased traffic - would simply be unacceptable.

3. The Hendry County plant would be a virtual twin of the West County Energy Center in Palm Beach County. It is completely unacceptable for a massive utility to be built in such close proximity to a location like the Big Cypress National Preserve Addition Lands (just a few miles to the south). Emissions in the form of CO_2 but also other pollutants are massive and will clearly degrade what the Big Cypress National Preserve resident botanist - Dr. Jim Burch - has referred to as the most biodiverse piece of land in the entire continental United States. Numerous other scientific papers attest to the diversity of flora and fauna nearby to the FPL Hendry County site. It should also be noted that the waters in the preserve are considered "outstanding Florida waters". That is a resource that clearly needs to be preserved in the condition it is now in.

4. In their Ten Year Plan, FPL has said that their plant will utilize up to 7.5 MGD (million gallons per day) per unit. With three units, that would a total of 22.5 MGD from water that currently makes its way not only to the Seminole Reservation, but to the Big Cypress National Preserve. This is about 7 million gallons a day more than is used by a major municipality like Pembroke Pines in Broward Count and is an unacceptably high amount of water to be drawn from this critical location.

5. There are numerous numbers of alternative sites (not far from the chosen site) for this Hendry County plant which would have far fewer ecological consequences. At the meeting with environmentalists, FPL representatives said that the fact that an existing power corridor existed on the north end of the property was a "major

consideration". However, semi-developed and already industrial sites outside the towns of Clewiston, LaBelle, or Immokalee could be easily connected by power corridor and contain available lands that contain far fewer ecological considerations. The "convenience" of a power corridor should not be an excuse for causing irrevocable damage to the one of the most important natural areas left in south Florida.

Time does not allow us to go into numerous other reasons why the FPL plant should not be built at this location. We will send additional information as time allows. Please do not hesitate with any questions or comments regarding this submission.

Thank you for your time and have a very good holiday.

Sincerely,

s/ Matthew R. Schwartz

Matthew Schwartz
Executive Director
South Florida Wildlands Association
P.O. Box 30211
Ft. Lauderdale, FL 33303
954-634-7173
954-993-5351 (cell)

Other Organizations

Sierra Club

To: Filings@psc.state.fl.us, clerk@psc.state.fl.us

Re: FPL 10 Year Power Plant Site Plan Submittal
http://www.psc.state.fl.us/library/filings/12/01983-12/01983-12.pdf

Dear Mr. Ellis and Ms. Matthews

Thank you for accepting this brief comment regarding the above-referenced ten-year plan on behalf of the Sierra Club and its many Florida members. We are writing to resolve an important ambiguity in Florida Power & Light (FP&L)'s plan.

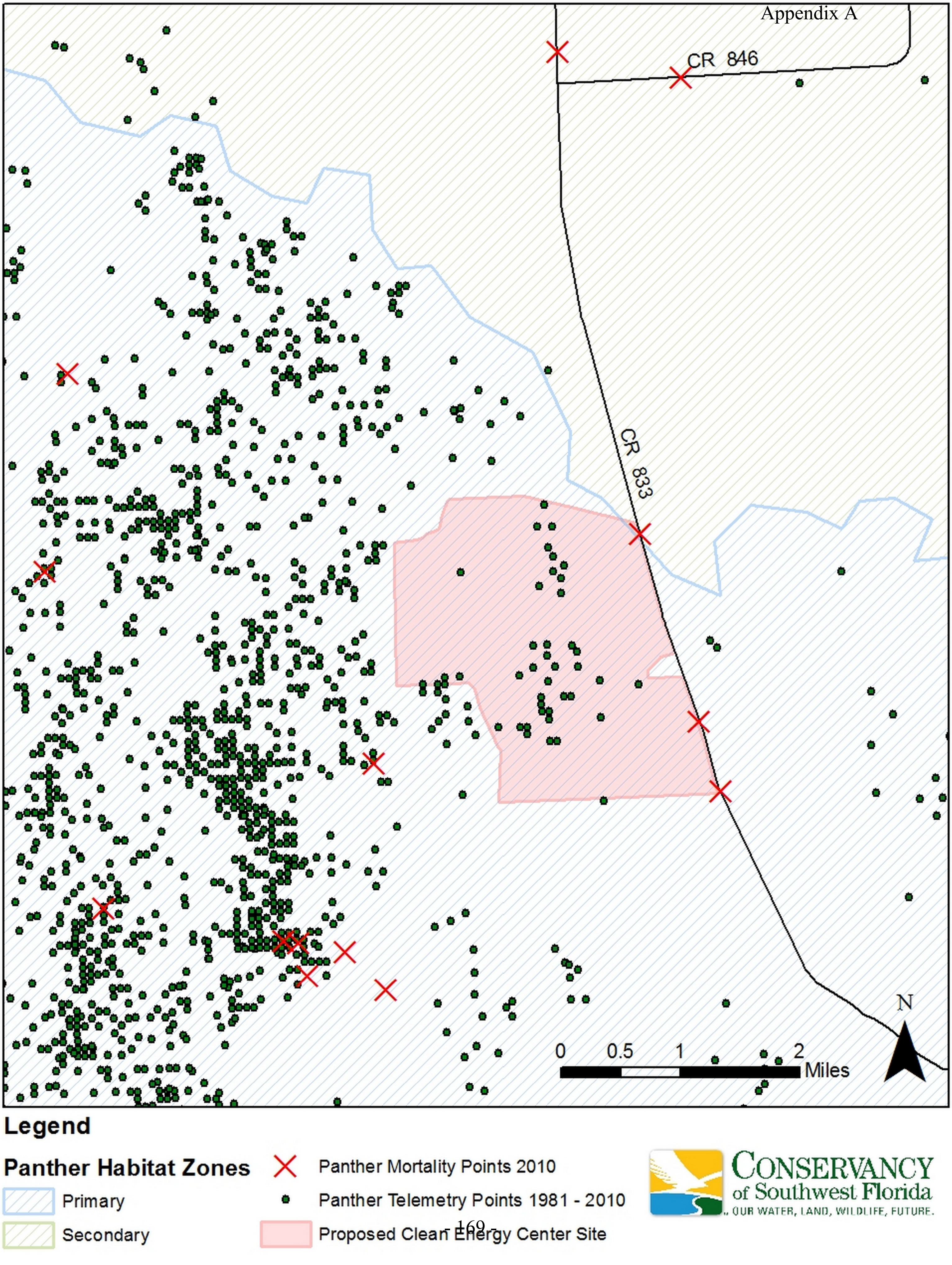
Specifically, the plan submitted by FPL lists a potential future power plant site identified as site #4 in Hendry County. The description of the Hendry County potential site does not explain whether the site would be, could be or must be used for gas, solar PV, or some mix of both, or describe what that mix would be. Further, this potential site is located in Primary Habitat for the federally and state listed endangered Florida panther, making clarifying the use of the site particularly important. See *attached diagram.*

Because ten-year plans must provide sufficient information to judge a site's "environmental impact" and its impact on "fuel diversity within the state," the likely use of this site must be clarified in the Plan, as the impacts of the site will be very different depending on how it is used, and if it is used at all. *See* F.S. 186.801. Accordingly, FP&L should identify its likely use of the site (including the types of generation contemplated for the area, identifying specific megawattage of that generation planned), or, if it cannot, it should explain how that decision will be made. Further, FP&L should specifically discuss the impacts of its plans -- whatever they may be -- upon Florida panthers and their habitat. We respectfully request that the Commission require FP&L to make these clarifications.

Sincerely,

s/ Craig Segall

Craig Segall
Sierra Club Environmental Law Program
50 F St NW, Eighth Floor
Washington, DC, 20001
202-548-4597
Craig.Segall@sierraclub.org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Legend
Panther Habitat Zones
Primary
Secondary
Panther Mortality Points 2010
Panther Telemetry Points 1981 - 2010
Proposed Clean Energy Center Site
CONSERVANCY of Southwest Florida
OUR WATER, LAND, WILDLIFE, FUTURE.

Other Organizations

Sierra Club & Earthjustice

July 2, 2012

Phillip O. Ellis
Strategic Analysis & Government Affairs
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850
pellis@psc.state.fl.us

CC: Traci Matthews
tmatthews@psc.state.fl.us

Re: Comments on Gulf Power's Ten-Year Plan Submittal

Dear Mr. Ellis and Ms Matthews:

Thank you for accepting these comments on behalf of the Sierra Club and its more than 27,000 Florida members, and on behalf of Earthjustice. We look forward to participating in the Public Service Commission (PSC)'s Ten-Year Plan review process. We are writing to help inform the Commission of serious regulatory risks which should be addressed in this Ten-Year Plan.

As you know, Ten-Year Plans are designed to provide a broad overview of a utility's "power-generating needs and the general location of its proposed power plant sites;" accordingly, plans must be "suitable" for planning purposes. F.S. § 186.801; *see also* F.A.C. §§ 25-22.070 & 25-22.071. These plans are among the many tools used by the Commission as it fulfills its statutory responsibilities to maintain "sufficient, adequate, and efficient service" and "fair and reasonable rates" for all Floridians. *See, e.g.*, F.S. § 366.03.

To do so, the Commission will have to address the implications of substantial new environmental compliance obligations at several aging coal-fired units. A recent report for state utility commissioners, primarily authored by former Colorado PSC Chair Ron Binz, puts the problem succinctly, reminding regulators that "[t]he U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence now faces tremendous challenges," including the prospect of substantial retirements of aging coal-fired power plants. *See* Ron Binz & CERES, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (2012) at 5.[1] These "retrofit or retire" decisions will lead to significant changes in the Florida coal fleet, and the PSC will be charged with managing these shifts. As Commissioner Binz writes:

> The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities

[1] Attached as Ex. 1.

> should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

Id. at 9.

These comments highlight some of these important risks. The Commission should use the Ten-Year Plan informational docket to fully investigate them. We have submitted similar comments addressing plans filed by several different utilities; this filing focuses on coal-fired power plants operated by Gulf Power.

I. Gulf Power's Plants Face Substantial Environmental Compliance Costs

Gulf Power's Lansing Smith, Crist, and Scholz plants are aging facilities lacking major pollution controls. These plants are an increasingly bad deal for ratepayers: In addition to posing a serious threat to public health, they are not economic to operate. As utilities and PSCs around the country are increasingly recognizing, rising pollution control and fuel costs make coal power an unattractive proposition, especially as energy efficiency, demand-side resources, and renewable power become ever more available and as natural gas prices continue at record lows. Multi-million dollar life-extension projects for aging coal plants are not prudent in these circumstances. Accordingly, Gulf anticipates that it is likely to retire many of its plants in the near future. Gulf Power Ten Year Plan ("Gulf Plan") at 3.

Because Gulf's plans have important implications for the "need … for electrical power" in its service territory, and for how that need is to be met, as well on "fuel diversity within the state," on the "environmental impact" of any proposed replacement power, and on the state "comprehensive plan," *see* F.S. § 186.801, the Commission should ensure that Gulf discloses its intentions in its Ten-Year Plan as fully as possible. It is particularly important to do so because Gulf will face compliance obligations within the next few years that will lead to retirement decisions. The Commission can best protect Floridians by beginning the planning process for these likely retirements now. The Plan is not suitably detailed to allow for this planning to be successful, so, at the end of these comments, we respectfully urge the PSC to require Gulf to submit critical additional information.

Gulf Power's Lansing Smith and Scholz plants are the most likely retirement targets because both plants lack "scrubbers," the flue-gas desulfurization systems required to remove SO_2, which can cause deadly respiratory damage, and other acid gases from their emissions. Scrubber systems for these plants would cost hundreds of millions of dollars. Such an investment, and the corresponding rate increase, would not be prudent when much cheaper sources of power are available. Accordingly, the Commission should work with Gulf Power to investigate retirement options for these plants.

In the discussion below, we explain the likely sources of scrubber liability for the Lansing Smith and Scholz plants, before briefly highlighting the many other environmental compliance costs which Gulf is likely to face.

A. Likely Scrubber Liability for Gulf Power Facilities

Three separate environmental and public health protection programs are likely to drive scrubber installation requirements, and hence "retire or retrofit" decisions, at the Lansing Smith and Scholz facilities: the SO_2 National Ambient Air Quality Standards ("NAAQS"), 40 C.F.R. § 50.17, the Mercury and Air Toxics Standards ("MATS"), 40 C.F.R. Subpt. UUUUU, and the Regional Haze Rule, 40 C.F.R. § 51.308.

i. The SO_2 NAAQS

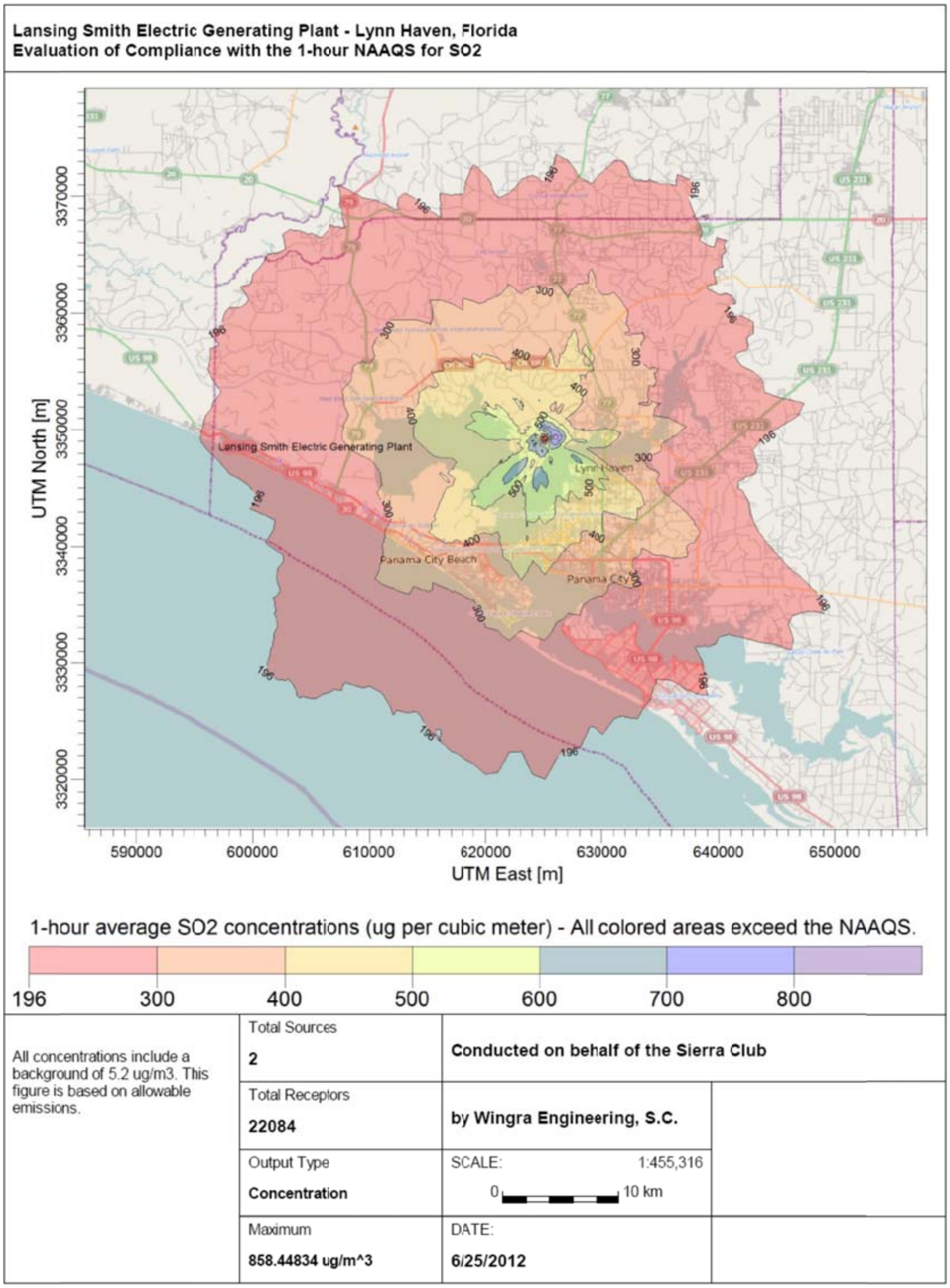
Just five minutes of exposure to SO_2 can make people sick; in fact, the causal link between this pollution and asthma attacks and other respiratory problems is the "strongest" such link which the EPA's scientific advisory board can identify. 75 Fed. Reg. 35,520, 35,525 (June 22, 2010). To protect the public from such pollutants, EPA is required to set NAAQS specifying the safe level of public exposure; states then develop state implementation plans (SIPs) to ensure that those standards are attained. *See* 42 U.S.C. §§ 7409 & 7410. EPA's decision to protect public health by lowering the NAAQS for SO_2 to a maximum allowable exposure of 75 ppb (a concentration equivalent to 196.2 $\mu g/m^3$) over an hour, *see* 75 Fed. Reg. 35,520 (June 22, 2010), thus obliges Florida to update its SIP to ensure that its citizens are protected from this dangerous air pollution.

States are generally required to submit updated SIPs "within 3 years" after EPA updates a NAAQS; because EPA finalized its NAAQS in 2010, Florida's plan is due in 2013. 42 U.S.C. § 7410(a)(1). The plan must "provide[] for implementation, maintenance, and enforcement of" the standard throughout Florida. *Id.* Although EPA's approval and review process may delay plan implementation for a year or two after submission, the Commission can reasonably expect Florida's SIP to be operating by 2015 or before.

This tight timeline is directly relevant to the Commission's review of Gulf Power's plans because the Lansing Smith plant is causing violations of the NAAQS, and so will have to install controls under any legal SIP. Sierra Club engaged an expert air modeler, Steve Klafka of Wingra Engineering, to evaluate the plant's compliance with the NAAQS, using EPA's models and methodology.[2] We modeled both the plant's allowable emissions – those authorized by its Title V Air Operation Permit, No. 0050014-018-AV – and its maximum emissions in 2011, the most recent year with complete data in EPA's Air Pollution Markets Database. Whether measured by its permit or by its most recent maximum emissions, the plant causes the pollution in the air over Panama City to reach unsafe levels, violating the NAAQS several-fold.

[2] The methodology is described in detail in the attached report, Ex. 2.

The figure below shows the SO_2 pollution plume the plant would create when operating at its permit limits. All colored areas violate the NAAQS. While the NAAQS is set at 196.2 $\mu g/m^3$, Lansing Smith's permit allows pollution levels to soar to 858.4 $\mu g/m^3$, over 400% of the safe value; even a bit further away from the plant, pollution directly over downtown Panama City reaches levels close to double the safe value.



Importantly, Lansing Smith causes NAAQS violations even when operating below its permitted maximums. Last year, Lansing Smith's highest operating hour emissions saw SO_2 concentrations reach 346.5 μg/m^3, which is nearly double the safe value. *See* Ex. 2 at Table 1.

Indeed, Lansing Smith's SO_2 emissions are so extreme that, according to the Florida Department of Environmental Protection ("FL DEP"), they even violate the far more lenient NAAQS that the new standard replaces. *See* FL DEP Permit No. 0050014-018-AV at 5. As such, FL DEP requires Gulf Power to post no trespassing signs to "protect the general public" from crossing the plant's fence line, within which the pollution is the most intense. *See id.* This is not a safe facility.

To reduce this illegal pollution, Lansing Smith would have to cut total facility emissions by 77.6% from its current permit. *Id.* at Table 3. To do so, it is highly likely to have to install a scrubber, thereby confronting hundreds of millions in control costs, which we document more fully below. Importantly, these costs will be far outweighed by public health benefits. EPA determined that the NAAQS will produce on the order of $36 billion in *net* benefits once safe levels of SO_2 have been attained. 75 Fed. Reg. at 35,588. Panama City residents will secure a substantial portion of these benefits – in the form of fewer asthma attacks, emergency room visits, and premature deaths – once Lansing Smith's pollution has been controlled.

We have not yet modeled the Scholz facility, but it is also an unscrubbed coal boiler, burning high-sulfur bituminous coal, and its permitted emissions are far higher than Lansing Smith's. While the Lansing Smith permit allows emissions of up to 4.50 lbs/MMBtu of SO_2, FL DEP Permit No. 0050014-018-AV at 8, the Scholz permit allows the facility to emit up to an astonishingly 6.17 lbs/MMBtu, FL DEP Permit No. 0630014-010-AV at 6. FL DEP candidly acknowledges that this emission rate "indicates exceedances" near the facility of even the more lenient NAAQS which EPA has since replaced, and so requires Gulf Power to take "precautions… to preclude public access." *Id.* Scholz is an even dirtier plant than Lansing Smith, and so is very likely to run afoul of the new NAAQS as well.

In short, the SO_2 NAAQS, a pollution control requirement which Gulf Power does not even acknowledge in its Ten-Year Plan, is highly likely to require the Lansing Smith and Scholz facilities to retrofit or retire. It is not the only requirement to do so, as we next discuss.

ii. MATS Requirements

In the Clean Air Act of 1990, Congress ordered EPA to investigate hazardous air pollutants emitted by power plants, and to promulgate emissions standards for these pollutants if they threatened public health. 42 U.S.C. § 7412(n)(1). Because coal power plants are dominant sources of mercury, acid gases, and other highly toxic pollutants, EPA was obligated to issue such standards, and finally did so in 2012, 22 years later. *See* 77 Fed. Reg. 9,304 (Feb. 16, 2012).

The final MATS rule issued in response to this Congressional mandate requires operators to control mercury and acid gases. A smoke stack scrubber can be required to comply with EPA's control requirements. In EPA's analysis of facility compliance options, it presumed that coal plants emitting more than 2 lbs/MMBtu of SO_2 would have to install scrubbers to comply with the standard. 77 Fed. Reg. at 9,412. As we note above, Lansing Smith emits more than twice this amount, and Scholz emits *three times* this threshold quantity. As such, scrubbers will very likely be required at these plants in order to comply with MATS.

The Clean Air Act requires that existing sources comply with MATS "as expeditiously as practicable, but in no event later than 3 years after the effective date" of the standard. 42 U.S.C. § 7412(i)(3). Because MATS was promulgated and effective on February 16, 2012, plants must comply by that date in 2015. Although limited compliance extension of up to 1-2 additional years may be available in some limited circumstances, *see id.*, these extensions are disfavored.

Accordingly, as Gulf Power recognizes, MATS "may severely restrict Gulf's coal-fired generation or completely eliminate the generation produced by Gulf's coal-fired units at Plants Smith and Scholz by as early as 2015." Gulf Plan at 3.

iii. Regional Haze Requirements

Since 1977, the Clean Air Act has required EPA and the states to make "reasonable progress" towards restoring natural visibility in Class I areas – which are essentially national parks and wildernesses. *See* 42 U.S.C. § 7491. EPA's rules to address regional haze, promulgated in 1999, are now being implemented. Florida is the process of a SIP revision intended to protect Class I areas affected by sources in the state. *See* FL DEP, *Regional Haze Plan for Florida Class I Areas* (Draft as amended May 2012).[3] Gulf Power has already determined that this rule, alone, may lead it to retire the Lansing Smith facility.

The regional haze rule requires that Florida impose controls at all sources of visibility-impairing pollutants to the extent such controls will be needed to make reasonable progress towards restoring natural visibility by 2064. *See* 40 C.F.R. § 51.308(d)(3). The Act and the Rule also require sources which were in existence by August 7, 1977, but which had not been in operation before August 7, 1962, to install "the best available retrofit technology" (BART) to control visibility-impairing pollutants. 42 U.S.C. § 7491(b)(2)(A) & 40 C.F.R. § 51.308(e). FL DEP has determined that the Crist facility is subject to reasonable progress analysis and that Lansing Smith is subject to BART. *See* FL Draft Regional Haze Plan at 98 & 102.

FL DEP had planned to rely upon a separate EPA SO_2 trading program, the Clean Air Interstate Rule ("CAIR") to address these requirements, but CAIR has been replaced with a new program which does not control SO_2 in Florida. *See* 77 Fed. Reg. 31,240, 31,248 (May 25, 2012). As such, FL DEP is reanalyzing control options and will have to consider source-specific control

[3] Available at http://www.dep.state.fl.us/air/rules/regulatory/regional_haze_imp.htm.

requirements for Crist and Lansing Smith. Scholz should also be implicated in this re-analysis because FL DEP had previously excluded relatively small facilities largely because it assumed CAIR would address most SO_2 emissions. Now that CAIR is no longer available, Scholz will have to be analyzed as well. Thus, as a result of these analyses, FL DEP will have to address SO_2 emissions, in some fashion, from all of Gulf Power's coal plants.

These controls are likely to drive scrubber requirements (and other controls or operating restrictions at scrubbed plants like Crist) because, according to FL DEP, SO_2 is the dominant source of visibility-impairing pollution in Florida. *See, e.g.*, FL Draft Regional Haze Plan at 91-92. Thus, these rules, too, are highly likely to drive scrubber requirements at the Lansing Smith facility.

Gulf Power has admitted as much to FL DEP. In a "BART Implementation Plan" submitted to DEP on May 21, 2012[4], it indicated that it will complete a BART analysis for Lansing Smith, and that it will decide, by January 1, 2015, whether to install a scrubber on the plant by 2018 (or later), "commit to retire the operation of Smith Unit 1 by January 1, 2022 and Smith Unit 2 before January 1, 2021," or to seek permit levels by 2015 reducing plant operations below BART emissions limits. Gulf BART Plan at 2. Because BART determinations will be approved within the next year, it is not at all clear how Gulf Power expects to run its plants until the early 2020s. Retirement within the next few years is the more likely option.

iv. Scrubber Costs

We have calculated the approximate cost of installing and running scrubbers (at 90% efficiency, a level which would likely be required, at a minimum, to meet the requirements of all three relevant rules) at Lansing Smith and Scholz, based upon the EPA's Integrated Planning Model and a scrubber-focused appendix developed by Sargent & Lundy.[5] This model predicts that the capital costs for fitting Lansing Smith Units 1 and 2 with scrubbers at $234 million. The incremental costs (including running costs) of these upgrades would be $43.1/MWh annually. Gulf Power would no doubt seek to pass these costs on to rate-payers if it opted to continue to run the plant, rather than to retire it.

Scrubber costs for Scholz are also very high. Using the same government modeling, we calculated that scrubbers for Scholz units 1 & 2 would cost $106 million to install, yielding a $243.5/MWh spike in incremental costs.

These figures do not include the incremental costs of effluent controls for scrubber waste. Any such additional upgrades would, of course, add to these costs, as would any additional measures required at Crist to bring that facility into compliance. The expenditures are extraordinarily high simply in order to extend the lives of these decades-old, expensive, coal-fired power plants. Gulf Power is unlikely to make them and, we submit, it would not be

[4] Attached as Ex. 3.
[5] All modeling parameters can be found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html.

appropriate for the Commission to authorize such costs where less expensive options are available.

B. Other Environmental Liabilities

As Gulf Power acknowledges, Gulf Plan at 3, scrubber costs are not the only liabilities it faces. There are also pending rules requiring upgrades to coal plant cooling water systems, *see* 76 Fed. Reg. 22,174 (Apr. 20, 2011), better handling and disposal practices for coal combustion waste, *see* 75 Fed. Reg. 35,128 (June 21, 2010), and new treatment systems for liquid effluent discharges,[6] all of which are likely to be finalized in the next two years. EPA is also updating the NAAQS for particulate matter and for ozone. Moreover, EPA has recently proposed carbon controls for new electricity generating units. *See* 77 Fed. Reg. 22,39 (Apr. 13, 2012). Once finalized, these rules will obligate EPA to extend carbon controls to existing facilities, including Gulf Power's fleet. *See* 42 U.S.C. § 7411(d). The cumulative impact of these liabilities on Gulf Power will be large. Indeed, according to Gulf, "the additional costs to comply with the final versions of EPA's proposed water quality and coal combustion by-product rules" alone "may result in total combined compliance costs that render controlled coal-fired operations uneconomical in the long term." Gulf Plan at 3.

Coal ash costs will be particularly pressing for Gulf Power. According to the Toxic Release Inventory, its Lansing Smith facility discharged 520,281 pounds of ash to its impoundment in 2006, a typical year, making Lansing Smith the 57th largest source of ash in the country and the second largest sources in Florida.[7] Highly troublingly, carcinogenic hexavalent chromium, which leaches from coal ash, has been found in groundwater wells near Lansing Smith at over 5,000 times safe levels (as determined by California for its drinking water goals), and above federal standards.[8] Clean-up costs for this contamination, including halting wet storage of ash, will be yet another substantial expense for the plants.

C. Likely Retirements

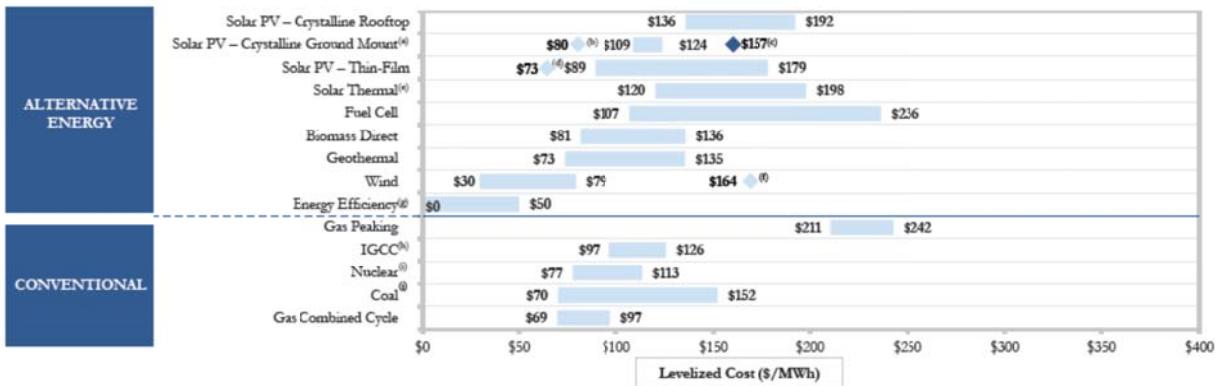
The cumulative compliance costs from all the rules which apply to Gulf Power's fleet are very large. Upon reviewing them, and considering the wide availability of more inexpensive power sources, Gulf Power is highly likely to follow industry trends towards coal retirement.

Coal use is falling quickly, in response both to the cost of pollution controls and to national economic trends, including the growth of inexpensive wind power and the boom in shale gas production. As EPA has recently documented, "all indications suggest that very few new coal-fired power plants will be constructed in the foreseeable future." 77 Fed. Reg. at 22,413, and the Energy Information Administration (EIA) is documenting increasing retirements of existing plants. In particular, the EIA's Annual Energy Outlook for 2012 forecasts no new unplanned

[6] *See* EPA's plans for this rule at http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm
[7] *See* Ex. 4, attached.
[8] Lisa Evans, *EPA's Blind Spot: Hexavalent Chromium in Coal Ash* (2011) at 6, attached as Ex. 5.

coal capacity through 2020. RIA at 5-5. EIA's most recent Electric Power Monthly report confirms that this trend continues. Thus far this year, *none* of the 5,627 MW of new units to come online are coal-fired; instead, new capacity additions are largely in renewable power or natural gas. EIA, *Electric Power Monthly June 2012* at Table ES3.[9] Conversely, retirements to date have been predominantly coal-fired units. *See id.* at Table ES4. Utilities across the country have announced thousands of megawatts worth of coal retirements over the last few years.[10]

Industry-wide levelized cost figures compiled by independent analysts demonstrate why these retirements are occurring. The most recent (2011) edition of Lazard's Levelized Cost of Energy Analysis,[11] a widely-used reference, shows that energy efficiency, wind, and natural gas combined cycle levelized costs are already below those of coal, as the figure below demonstrates.



Under these circumstances, prudent operators are increasingly deciding not to impose additional costs on their ratepayers by running coal-fired units with costly new pollution technology. Instead, they are opting to retire older units and pursue cleaner, cheaper, energy options. Gulf Power could, and should, decide to follow the same course.

D. Recommended Commission Action

Although Gulf Power has acknowledged that some retirements may occur, it nonetheless "assume[s]" that Lansing Smith and Scholz "will be available to operate on coal throughout the 2012-2021 planning cycle." Gulf Plan at 3. As we have demonstrated above, this assumption is

[9] Available at: http://205.254.135.7/electricity/monthly/pdf/epm.pdf.

[10] *See, e.g.*, Progress Energy Press Release, "Progress Energy Carolinas to retire coal power plant ahead of schedule" (Apr. 1, 2011) (recording the retirement of four North Carolina coal plants), available at https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Carolinas+to+retire+coal+power+plant+ahead+of+schedule&pubdate=04-01-2011; FirstEnergy Press Release, "FirstEnergy, Citing Impact of Environmental Regulations, Will Retire Six Coal-Fired Power Plants" (Jan. 29, 2012) (announcing the retirement of six coal plants in Ohio), available at https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy_citingimpactofenvironmentalregulationswillretiresixc.html; Environment News Service, "Dominion Virginia to Replace Coal Plants with Gas, Nuclear" (Sept. 7, 2011) (documenting retirement of two Virginia coal plants), available at http://www.ens-newswire.com/ens/sep2011/2011-09-07-091.html.

[11] Attached as Ex. 6.

arbitrary and unsupportable: The compliance periods for the scrubber-forcing rules will run within the next two years and retirements will very likely occur within that period, and certainly will occur within the next decade. This error, and Gulf Power's failure fully to address the impacts of retirements upon its system and upon ratepayers, renders the draft plan "unsuitable" as a planning document. *See* F.S. §186.801. The Commission, "may suggest alternatives to the plan," *id.*, however, and may classify a plan as suitable upon the submission of "additional data," *see* F.A.C. § 25-22.071(5). We respectfully request that the PSC exercise its authority to ensure that Gulf Power's plan provides adequate data to allow the PSC and the public to address these plant retirements.

Specifically, we submit that the Commission should seek the following information from Gulf Power and require resubmission of a complete plan addressing these submissions:

1. The utility should provide an analysis of all environmental compliance obligations which it will experience at all of its coal-fired facilities. For each requirement, the utility should cite the relevant rule, explain how it is likely to apply to the plant, the likely costs of compliance to the utility and to ratepayers, and the timeline on which compliance will be required. The utility should also document any steps it has taken to address these compliance obligations, and alternative steps it might take. For instance, if the utility anticipates that it will have to install a scrubber to comply with MATS, it should report to the Commission on scrubber installation and operation costs, whether it has contracted to purchase a scrubber and on what timeline, and what other options it has considered. *See* F.S. § 186.801 (requiring utilities to document "[p]ossible alternatives to the proposed plan").

2. The utility should provide a comparative analysis of compliance costs and the cost costs of replacing the plant's power through energy efficiency, demand response, power purchase agreements, new generation facilities, or other means. *See* F.S. §186.801 (requiring utilities to explain the impact of their plans on fuel diversity and on the need for electric power in their regions). In light of this analysis, the utility should indicate whether it intends to retire any facility, and on what timeline, and the relative costs of retirement versus those of other options. If retirement has not been selected but is being considered, the utility should indicate when the decision will be made.

3. For any facility where retirement is possible, the utility should discuss how it intends to address any reliability issues which may be caused by the retirement. The Commission should play an active role in this regard, as it must maintain reliability of the electric grid. *See* F.S. § 366.05(7)-(8) (authorizing the Commission to "require reports from all electric utilities to assure the development of adequate and reliable energy grids" and to order "installation and repair of necessary facilities" to address reliability issues"). The Commission has determined that "[r]eserve margins in Florida typically remain well above" relevant minimums through 2020, so system-wide resource adequacy problems are unlikely, but the Commission may still need to

address localized reliability issues. If such problems appear to be present, the Commission should work proactively and transparently with the Florida Reliability Coordinating Council to address them well in advance of any planned retirement.

We appreciate this careful consideration of Gulf Power's environmental compliance options, and any resulting plant retirements, and remind the Commission that such thorough analysis is required to ensure that the Ten-Year Plan complies with legal requirements. We request that the Commission share the results of its inquiry with us and with the public, and request formal notice of the Commission's next steps.

Please contact the undersigned with any concerns or questions.

Sincerely,

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July 2, 2012

Mr. Phillip O. Ellis
Strategic Analysis & Government Affairs
Public Service Commission
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pellis@psc.state.fl.us

CC: Traci Matthews
tmatthew@psc.state.fl.us

<u>Re: Comments on Progress Energy's Ten-Year Plan Submittal</u>

Dear Mr. Ellis and Ms Matthews:

Thank you for accepting these comments on behalf of the Sierra Club and its more than 27,000 Florida members, and on behalf of Earthjustice. We look forward to participating in the Public Service Commission (PSC)'s Ten-Year Plan review process. We are writing to help inform the Commission of serious regulatory risks which should be addressed in this Ten-Year Plan.

As you know, Ten-Year Plans are designed to provide a broad overview of a utility's "power-generating needs and the general location of its proposed power plant sites;" accordingly, plans must be "suitable" for planning purposes. F.S. § 186.801; *see also* F.A.C. §§ 25-22.070 & 25-22.071. These plans are among the many tools used by the Commission as it fulfills its statutory responsibilities to maintain "sufficient, adequate, and efficient service" and "fair and reasonable rates" for all Floridians. *See, e.g.*, F.S. § 366.03.

To do so, the Commission will have to address the implications of substantial new environmental compliance obligations at several aging coal-fired units. A recent report for state utility commissioners, primarily authored by former Colorado PSC Chair Ron Binz, puts the problem succinctly, reminding regulators that "[t]he U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence now faces tremendous challenges," including the prospect of substantial retirements of coal-fired power plants. *See* Ron Binz & CERES, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (2012) at 5.[1] These "retrofit or retire" decisions will lead to significant changes in the Florida coal fleet, and the PSC will be charged with managing these shifts. As Commissioner Binz writes:

> The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities

[1] Attached as Ex. 1.

> should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

Id. at 9.

These comments highlight some of these important risks. The Commission should use the Ten-Year Plan informational docket to fully investigate them. We have submitted similar comments addressing plans filed by several different utilities; this filing focuses on coal-fired power plants operated by Progress Energy.

I. Progress Energy's Crystal River Plant Face Substantial Environmental Compliance Costs

Units 1 and 2 at Progress Energy's Crystal River plant were put into service in the late 1960s, and are operating without major pollution controls, including smokestack scrubbers. *See* FL DEP Air Operation Permit No. 0170004-025-AV (2011) at 6. These units are an increasingly bad deal for ratepayers: In addition to posing a serious threat to public health, they are not economic to operate. As utilities and PSCs around the country are increasingly recognizing, rising pollution control and fuel costs make coal power an unattractive proposition, especially as energy efficiency, demand-side resources, and renewable power become ever more available and as natural gas prices continue at record lows. Multi-million dollar life-extension projects for aging coal plants are not prudent in these circumstances. Progress has already told FL DEP that it will consider retiring units 1 and 2 within the next decade. *See* Progress Energy BART Implementation Plan for Crystal River Units 1 and 2 (June 2012) at 3.[2] Yet, Progress's Ten-Year Plan does not even mention these units, much less address their retirements.

Because of this striking gap, Progress's plan is not "suitable" for planning purposes. *See* F.S. § 186.801. The likely retirement of the Crystal River units has important implications for the "need … for electrical power" in its service territory, and for how that need is to be met, as well on "fuel diversity within the state," the "environmental impact" of any proposed replacement power, and the state "comprehensive plan." *See* F.S. § 186.801. The Commission should therefore ensure that Progress submits a corrected plan which discloses its intentions as fully as possible. It is particularly important to do so because Progress will face compliance obligations within the next few years that will lead to retirement decisions. The Commission can best protect Floridians by beginning the planning process for these likely retirements now.

Crystal River Units 1 and 2 are likely retirement targets because both units lack "scrubbers," the flue-gas desulfurization systems required to remove SO_2, which can cause deadly respiratory damage, from their emissions. Scrubber systems for these plants would cost tens of millions of dollars. Such an investment, and corresponding rate increase, would not be prudent

[2] Attached as Ex. 2.

when much cheaper sources of power are available. Accordingly, the Commission should work with Progress Energy to investigate retirement options for these plants.

In the discussion below, we explain the likely sources of scrubber liability for Crystal River, before briefly highlighting the many other environmental compliance costs which Progress is likely to face.

A. Likely Scrubber Liability for Crystal River Units 1 and 2

Three separate environmental and public health protection programs are likely to drive scrubber installation requirements, and hence "retire or retrofit" decisions, at Crystal River: the SO_2 National Ambient Air Quality Standards ("NAAQS"), 40 C.F.R. § 50.17, the Mercury and Air Toxics Standards ("MATS"), 40 C.F.R. Subpt. UUUUU, and the Regional Haze Rule, 40 C.F.R. § 51.308.

i. The SO_2 NAAQS

Just five minutes of exposure to SO_2 can make people sick; in fact, the causal link between this pollution and asthma attacks and other respiratory problems is the "strongest" such link which the EPA's scientific advisory board can identify. 75 Fed. Reg. 35,520, 35,525 (June 22, 2010). To protect the public from such pollutants, EPA is required to set NAAQS specifying the safe level of public exposure; states then develop state implementation plans (SIPs) to ensure that those standards are attained. *See* 42 U.S.C. §§ 7409 & 7410. EPA's decision to protect public health by lowering the NAAQS for SO_2 to a maximum allowable exposure of 75 ppb (a concentration equivalent to 196.2 $\mu g/m^3$) over an hour, *see* 75 Fed. Reg. 35,520 (June 22, 2010), thus obliges Florida to update its SIP to ensure that its citizens are protected from this dangerous air pollution.

States are generally required to submit updated SIPs "within 3 years" after EPA updates a NAAQS; because EPA finalized its NAAQS in 2010, Florida's plan is due in 2013. 42 U.S.C. § 7410(a)(1). The plan must "provide[] for implementation, maintenance, and enforcement of" the standard throughout Florida. *Id.* Although EPA's approval and review process may delay plan implementation for a year or two after submission, the Commission can reasonably expect Florida's SIP to be operating by 2015 or before.

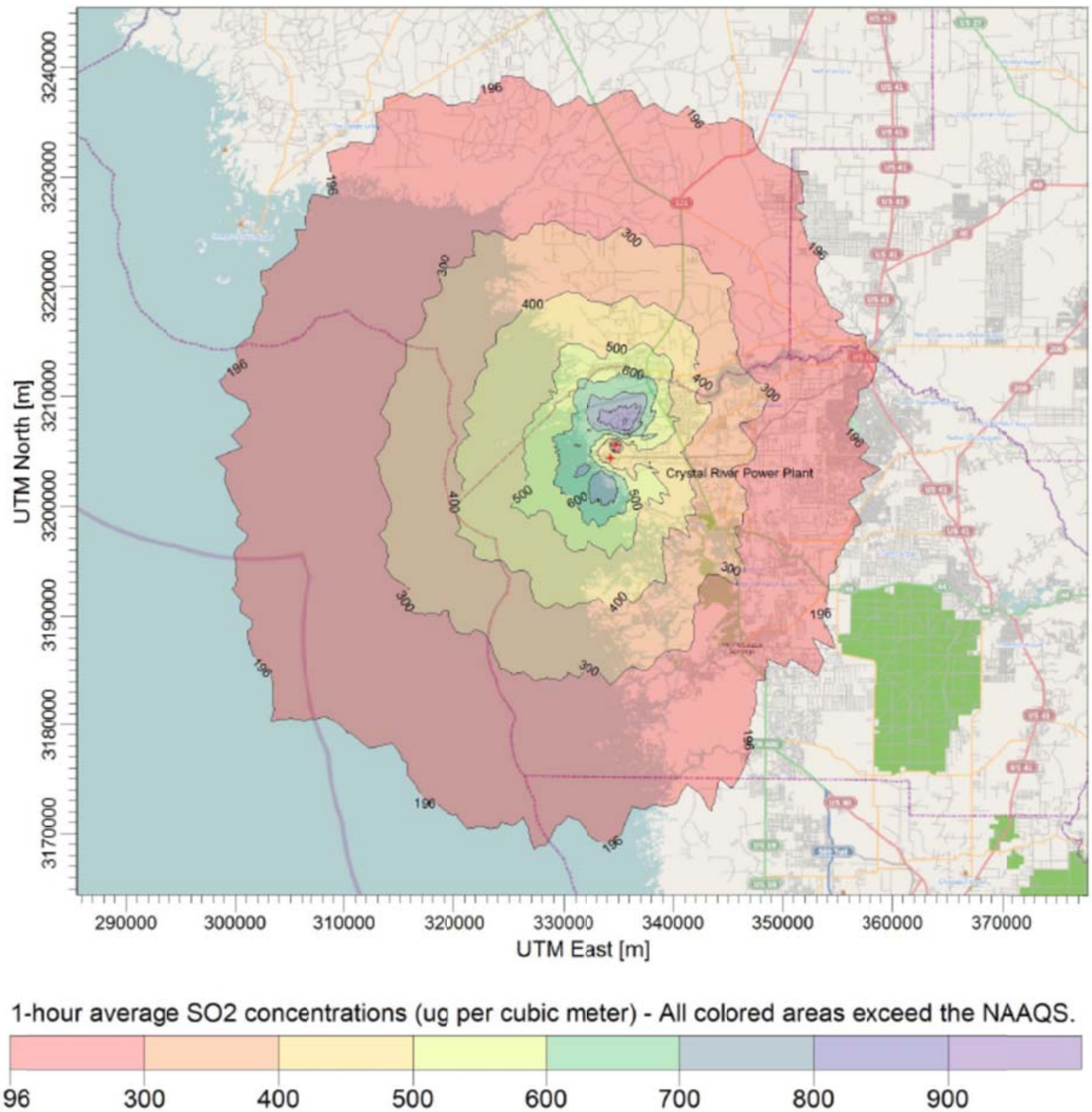
This tight timeline is directly relevant to the Commission's review of Progress Energy's plans because the Crystal River plant is causing violations of the NAAQS, and so will have to install controls under any legal SIP. Sierra Club engaged an expert air modeler, Steve Klafka of Wingra Engineering, to evaluate the plant's compliance with the NAAQS, using EPA's models and methodology.[3] We modeled both the plant's allowable emissions – those authorized by its Title V Air Operation Permit, No. 017000–025-AV, and its maximum emissions in 2011, the most recent year with complete data in EPA's Air Pollution Markets Database. Whether measured by

[3] The methodology is described in detail in the attached report, Ex. 3.

its permit or by its most recent maximum emissions, the plant causes pollutants in the air near Crystal River to reach dangerous levels.

The figure below shows the SO_2 pollution plume the plant would create when operating at its permit limits. All colored areas violate the NAAQS. While the NAAQS is set at 196.2 $\mu g/m^3$, Crystal River's permit allows pollution levels to soar to a maximum of 921.0 $\mu g/m^3$, over 460% of the safe value; even a bit further away from the plant, the pollution in the air directly over residential areas and over Crystal Bay is well above safe levels.

Crystal River Power Plant - Crystal River, Florida
Evaluation of Compliance with the 1-hour NAAQS for SO2



All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **6**	**Conducted on behalf of the Sierra Club**	
	Total Receptors **22083**	**by Wingra Engineering, S.C.**	
	Output Type **Concentration**	SCALE: 1:580,926 0 20 km	
	Maximum **921.02714 ug/m^3**	DATE: **6/25/2012**	

Importantly, Crystal River causes NAAQS violations even when operating below its permitted maximums. Last year, the plant's highest operating hour emissions saw SO_2 concentrations reach 534.6 µg/m^3, which is nearly three times the safe value. *See* Ex. 2 at Table 1.

To reduce this illegal pollution, Crystal River would have to cut total facility emissions by 79.1% from its current permit. *Id.* at Table 3. To do so, it is highly likely to have to install a scrubber, thereby confronting hundreds of millions in control costs, which we document more fully below. Importantly, these costs will be far outweighed by public health benefits. EPA determined that the NAAQS will produce on the order of $36 billion in *net* benefits once safe levels of SO_2 have been attained. 75 Fed. Reg. at 35,588. Crystal River residents will secure a substantial portion of these benefits – in the form of fewer asthma attacks, emergency room visits, and premature deaths – once the plant's pollution has been controlled.

In short, the SO_2 NAAQS, a pollution control requirement which Progress Energy does not even acknowledge in its Ten-Year Plan, is highly likely to require Crystal River Units 1 and 2 to retrofit or retire. It is not the only requirement to do so, as we next discuss.

ii. MATS Requirements

In the Clean Air Act of 1990, Congress ordered EPA to investigate hazardous air pollutants emitted by power plants, and to promulgate emissions standards for these pollutants if they threatened public health. 42 U.S.C. § 7412(n)(1). Because coal power plants are dominant sources of mercury, acid gases, and other highly toxic pollutants, EPA was obligated to issue such standards, and finally did so in 2012, 22 years later. *See* 77 Fed. Reg. 9,304 (Feb. 16, 2012).

The final MATS rule issued in response to this Congressional mandate requires operators to control mercury and acid gases. A smoke stack scrubber can be required to comply with EPA's control requirements. In EPA's analysis of compliance options, it presumed that coal plants emitting more than 2 lbs/MMBtu of SO_2 would have to install scrubbers to comply with the standard. 77 Fed. Reg. at 9,412. Crystal River's air operation permit allows it to emit 2.1 lbs/MMBtu of SO_2, meaning that the MATS rule will likely drive scrubbers installation at the facility. *See* FL DEP Air Operation Permit 0170003-025-AV at 7. Notably, Crystal River is also the single largest source of mercury in Florida, dumping more than 300 kg of mercury a year into the air around the plant.[4] On both counts, MATS compliance will, accordingly, be a major focus for the facility.

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[4] *See* Laura S. Sherman *et al.*, *Investigation of Local Mercury Deposition from a Coal-Fired Power Plant Using Mercury Isotopes*, Environment Science & Technology (2012), attached as Ex. 4.

The Clean Air Act requires that existing sources comply with MATS "as expeditiously as practicable, but in no event later than 3 years after the effective date" of the standard. 42 U.S.C. § 7412(i)(3). Because MATS was promulgated and effective on February 16, 2012, plants must comply by that date in 2015. Although limited compliance extension of up to 1-2 additional years may be available in some limited circumstances, *see id.*, these extensions are disfavored. Accordingly, Progress Energy will have to scrub Crystal River by 2015, or shortly thereafter, or retire the facility, yet it entirely fails to acknowledge this major shift in its operations in its Ten-Year Plan.

iii. Regional Haze Requirements

Since 1977, the Clean Air Act has required EPA and the states to make "reasonable progress" towards restoring natural visibility in Class I areas – which are, essentially, national parks and wildernesses. *See* 42 U.S.C. § 7491. EPA has been very slow to implement this mandatory duty, but its rule to address regional haze, promulgated in 1999, are now being implemented, and Florida is the process of a SIP revision intended to protect Class I areas affected by sources in the state. *See* FL DEP, *Regional Haze Plan for Florida Class I Areas* (Draft as amended May 2012).[5]

The regional haze rule requires that Florida impose controls at all sources of visibility-impairing pollutants to the extent such controls will be needed to make reasonable progress towards restoring natural visibility by 2064. *See* 40 C.F.R. § 51.308(d)(3). The Act and the Rule also require sources which were in existence by August 7, 1977, but which had not been in operation before August 7, 1962, to install "the best available retrofit technology" (BART) to control visibility-impairing pollutants. 42 U.S.C. § 7491(b)(2)(A) & 40 C.F.R. § 51.308(e). FL DEP has determined that the Crist facility is subject to BART. *See* FL Draft Regional Haze Plan at 102.

FL DEP had planned to rely upon a separate EPA SO_2 trading program, the Clean Air Interstate Rule ("CAIR") to address these requirements, but CAIR has been replaced with a new program which does not control SO_2 in Florida. *See* 77 Fed. Reg. 31,240, 31,248 (May 25, 2012). As such, FL DEP is reanalyzing control options and will have to propose source-specific control requirements for Crystal River Units 1 and 2.

These controls are likely to drive scrubber requirements because, according to FL DEP, SO_2 is the dominant source of visibility-impairing pollution in Florida. *See, e.g.*, FL Draft Regional Haze Plan at 91-92. Progress Energy has indicated as much to FL DEP. In a 2009 BART permit, Progress Energy agreed to retire the Crystal River units by December 31, 2020, as long as the second unit of its proposed Levy County nuclear facility was operating by that time.[6] Just a few weeks ago, Progress submitted an updated BART implementation plan to FL DEP indicating that, whether or not the Levy County facility comes online, it would either install a

[5] Available at http://www.dep.state.fl.us/air/rules/regulatory/regional_haze_imp.htm.
[6] *See* Air Permit No. 0170004-017-AC (Feb. 26, 2009) at 6, attached as Ex. 5.

scrubber (by 2018 or 5 years after Florida's haze SIP is approved), retire the units by December 31, 2020, or limit operations to keep the plant's operations below BART limits.[7] Because BART determinations will be approved within the next year, it is not at all clear how Progress expects to run its plants until 2020. Retirement within the next few years is the more likely option.

iv. Scrubber Costs

We have calculated the approximate cost of installing and running scrubbers (at 90% efficiency, a level which would likely be required, at a minimum, to meet the requirements of all three relevant rules) at Crystal River Units 1 and 2, based upon the EPA's Integrated Planning Model and a scrubber-focused appendix developed by Sargent & Lundy.[8] This model predicts that the capital costs for fitting these units with scrubbers as $486 million. The result (including operational costs) would be a $36.6/MWh spike in incremental costs. Progress Energy would no doubt seek to pass these costs on to rate-payers if it opted to continue to run the plant, rather than to retire it. These expenditures are extraordinarily high simply in order to extend the lives of these decades-old, expensive, coal-fired power plants.

B. Other Environmental Liabilities

Scrubber costs are not the only liabilities Crystal River faces. There are also pending rules requiring upgrades to coal plant cooling water systems, *see* 76 Fed. Reg. 22,174 (Apr. 20, 2011), better handling and disposal practices for coal combustion waste, *see* 75 Fed. Reg. 35,128 (June 21, 2010), and new treatment systems for liquid effluent discharges,[9] all of which are likely to be finalized in the next two years. EPA is also updating the NAAQS for particulate matter and for ozone. Moreover, EPA has recently proposed carbon controls for new electricity generating units. *See* 77 Fed. Reg. 22,39 (Apr. 13, 2012). Once finalized, these rules will obligate EPA to extend carbon controls to existing facilities, including Crystal River. *See* 42 U.S.C. § 7411(d). The cumulative impact of these liabilities on Progress Energy will be large and are likely to lend further weight to retirement decisions.

C. Likely Retirements

The cumulative compliance costs from all the rules which apply to Progress Energy's Crystal River units are substantial. Upon reviewing them, and considering the wide availability of more inexpensive power sources, Progress is highly likely to follow industry trends towards coal retirement.

Coal use is falling quickly, in response both to the cost of pollution controls and to national economic trends, including the growth of inexpensive wind power and the boom in shale gas production. As EPA has recently documented, "all indications suggest that very few new coal-

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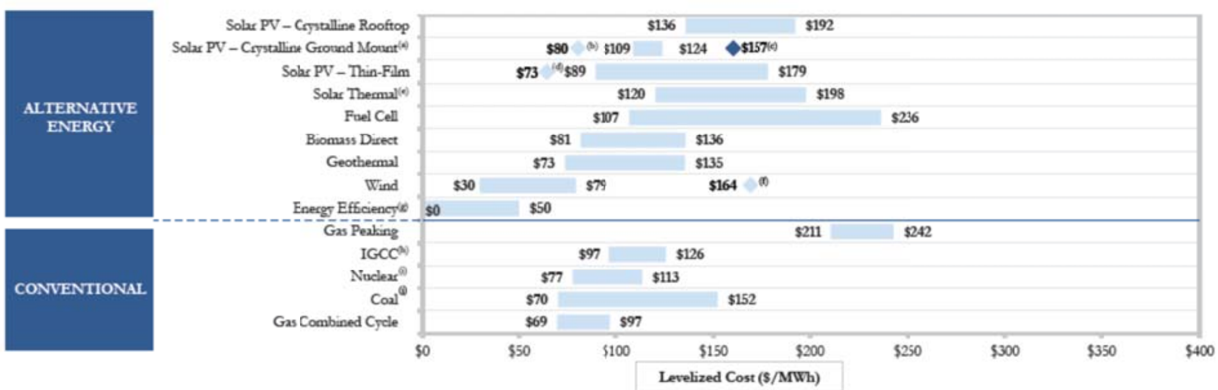
[7] *See* Ex. 2, *supra*.

[8] All modeling parameters can be found at http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html.

[9] *See* EPA's plans for this rule at http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm

fired power plants will be constructed in the foreseeable future." 77 Fed. Reg. at 22,413, and the Energy Information Administration (EIA) is documenting increasing retirements of existing plants. In particular, the EIA's Annual Energy Outlook for 2012 forecasts no new unplanned coal capacity through 2020. RIA at 5-5. EIA's most recent Electric Power Monthly report confirms that this trend continues. Thus far this year, *none* of the 5,627 MW of new units to come online are coal-fired; instead, new capacity additions are largely in renewable power or natural gas. EIA, *Electric Power Monthly June 2012* at Table ES3.[10] Conversely, retirements to date have been predominantly coal-fired units. *See id.* at Table ES4. Utilities across the country have announced thousands of megawatts worth of coal retirements over the last few years.[11]

Industry-wide levelized cost figures compiled by independent analysts demonstrate why these retirements are occurring. The most recent (2011) edition of Lazard's Levelized Cost of Energy Analysis,[12] a widely-used reference, shows that energy efficiency, wind, and natural gas combined cycle levelized costs are already below those of coal, as the figure below demonstrates.



Under these circumstances, prudent operators are increasingly deciding not to impose additional costs on their ratepayers by running coal-fired units with costly new pollution technology. Instead, they are opting to retire older units and pursue cleaner, cheaper, energy options. Progress Energy could, and should, decide to follow the same course.

D. Recommended Commission Action

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[10] Available at: http://205.254.135.7/electricity/monthly/pdf/epm.pdf.

[11] *See, e.g.*, Progress Energy Press Release, "Progress Energy Carolinas to retire coal power plant ahead of schedule" (Apr. 1, 2011) (recording the retirement of four North Carolina coal plants), available at https://www.progress-energy.com/company/media-room/news-archive/press-release.page?title=Progress+Energy+Carolinas+to+retire+coal+power+plant+ahead+of+schedule&pubdate=04-01-2011; FirstEnergy Press Release, "FirstEnergy, Citing Impact of Environmental Regulations, Will Retire Six Coal-Fired Power Plants" (Jan. 29, 2012) (announcing the retirement of six coal plants in Ohio), available at https://www.firstenergycorp.com/content/fecorp/newsroom/news_releases/firstenergy_citingimpactofenvironmentalregulationswillretiresixc.html; Environment News Service, "Dominion Virginia to Replace Coal Plants with Gas, Nuclear" (Sept. 7, 2011) (documenting retirement of two Virginia coal plants), available at http://www.ens-newswire.com/ens/sep2011/2011-09-07-091.html.

[12] Attached as Ex. 6.

Progress Energy has entirely failed to address these environmental compliance issues, and the impacts of retirements at Crystal River upon its system and upon ratepayers. The failure renders the draft plan "unsuitable" as a planning document. *See* F.S. §186.801. The Commission, "may suggest alternatives to the plan," *id.*, however, and may classify a plan as suitable upon the submission of "additional data," *see* F.A.C. § 25-22.071(5). We respectfully request that the PSC exercise its authority to ensure that Progress's plan provides adequate data to allow the PSC and the public to address these plant retirements.

Specifically, we submit that the Commission should seek the following information from Progress and require resubmission of a complete plan addressing these submissions:

1. The utility should provide an analysis of all environmental compliance obligations which it will experience at the Crystal River plant. For each requirement, the utility should cite the relevant rule, explain how it is likely to apply to the plant, the likely costs of compliance to the utility and to ratepayers, and the timeline on which compliance will be required. The utility should also document any steps it has taken to address these compliance obligations, and alternative steps it might take. For instance, if the utility anticipates that it will have to install a scrubber to comply with MATS, it should report to the Commission on scrubber installation and operation costs, whether it has contracted to purchase a scrubber and on what timeline, and what other options it has considered. *See* F.S. § 186.801 (requiring utilities to document "[p]ossible alternatives to the proposed plan").

2. The utility should provide a comparative analysis of compliance costs and the cost costs of replacing the plant's power through energy efficiency, demand response, power purchase agreements, new generation facilities, or other means. *See* F.S. §186.801 (requiring utilities to explain the impact of their plans on fuel diversity and on the need for electric power in their regions). In light of this analysis, the utility should indicate whether it intends to retire any facility, and on what timeline, and the relative costs of retirement versus those of other options. If retirement has not been selected but is being considered, the utility should indicate when the decision will be made.

3. For any facility where retirement is possible, the utility should discuss how it intends to address any reliability issues which may be caused by the retirement. The Commission should play an active role in this regard, as it must maintain reliability of the electric grid. *See* F.S. § 366.05(7)-(8) (authorizing the Commission to "require reports from all electric utilities to assure the development of adequate and reliable energy grids" and to order "installation and repair of necessary facilities" to address reliability issues"). The Commission has determined that "[r]eserve margins in Florida typically remain well above" relevant minimums through 2020, so system-wide resource adequacy problems are unlikely, but the Commission may still need to address localized reliability issues. If such problems appear to be present, the

Commission should work proactively and transparently with the Florida Reliability Coordinating Council to address them well in advance of any planned retirement.

We appreciate this careful consideration of Progress Energy's environmental compliance options, and any resulting plant retirements, and remind the Commission that such thorough analysis is required to ensure that the Ten-Year Plan complies with legal requirements. We request that the Commission share the results of its inquiry with us and with the public, and request formal notice of the Commission's next steps.

Please contact the undersigned with any concerns or questions.

Sincerely,

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Ceres

PRACTICING RISK-AWARE ELECTRICITY REGULATION:

What Every State Regulator Needs to Know

How State Regulatory Policies Can Recognize and Address the Risk in Electric Utility Resource Selection

A Ceres Report
April 2012

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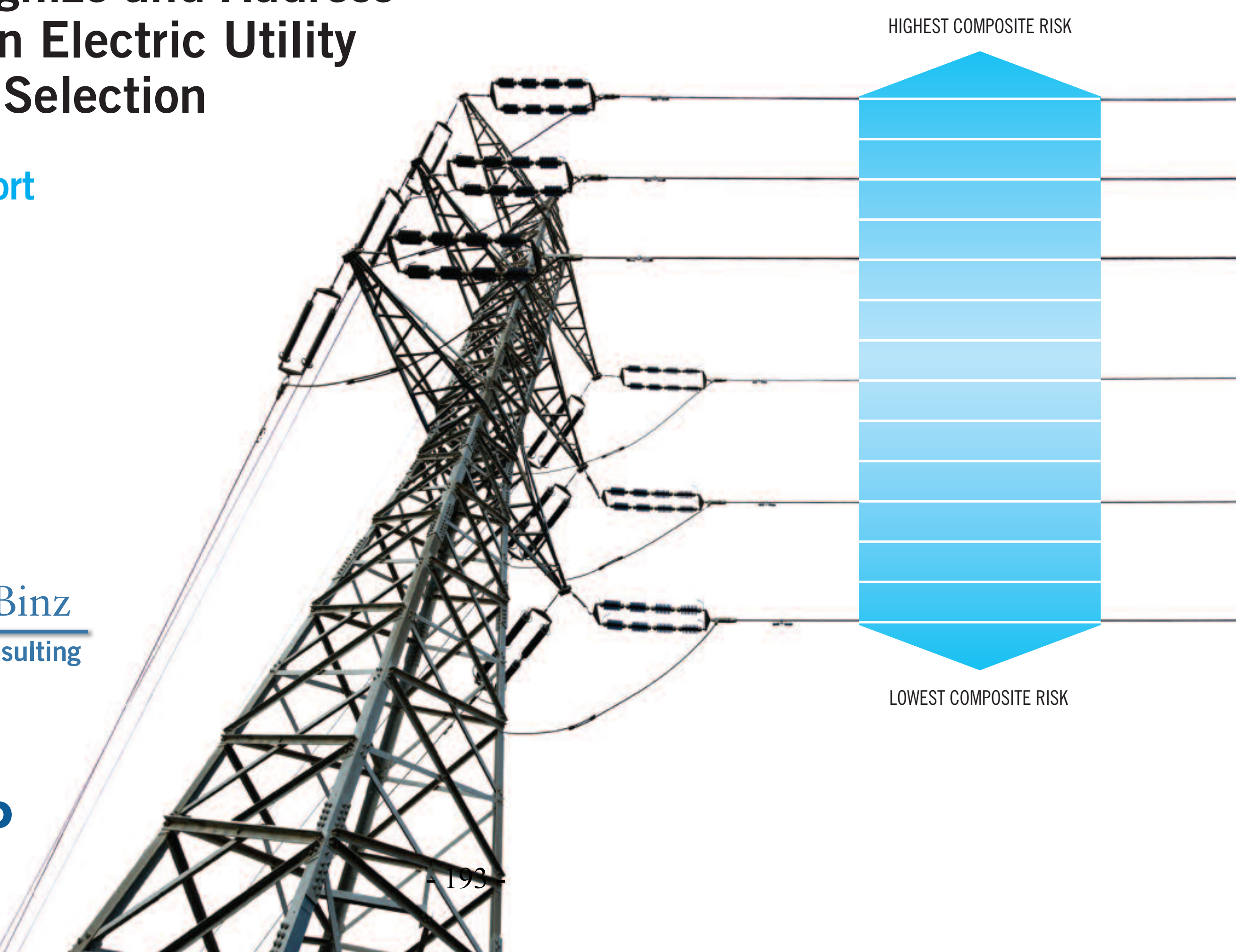

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Ceres is an advocate for sustainability leadership. It leads a national coalition of investors, environmental groups and other public interest organizations working with companies to address sustainability challenges. Ceres also directs the Investor Network on Climate Risk (INCR), a network of 100 institutional investors with collective assets totaling about $10 trillion.

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ABOUT THIS REPORT

AUDIENCE

This report is primarily addressed to **state regulatory utility commissioners**, who will preside over some of the most important investments in the history of the U.S. electric power sector during perhaps its most challenging and tumultuous period. This report seeks to provide regulators with a thorough discussion of risk, and to suggest an approach—"risk-aware regulation"—whereby regulators can explicitly and proactively seek to identify, understand and minimize the risks associated with electric utility resource investment. It is hoped that this approach will result in the efficient deployment of capital, the continued financial health of utilities, and the confidence and satisfaction of the customers on whose behalf utilities invest.

Additionally, this report seeks to present a unique discussion of risk and a perspective on appropriate regulatory approaches for addressing it that will interest numerous **secondary audiences**, including **utility managements, financial analysts, investors, electricity consumers, advocates, state legislatures and energy offices, and other stakeholders** with a particular interest in ensuring that electric system resource investments—which could soon reach unprecedented levels—are made thoughtfully, transparently and in full consideration of all associated risks.

SCOPE

While we believe that the approach described herein is applicable to a broad range of decisions facing state regulators, the report focuses primarily on resource investment decisions by investor-owned electric utilities (IOUs), which constitute roughly 70 percent of the U.S. electric power industry. The findings and recommendations may be of particular interest to regulators in states facing substantial coal generating capacity retirements and evaluating a spectrum of resource investment options.

AUTHORS

Ron Binz, the lead author of this report, is a 30-year veteran of utility and energy policy and principal with Public Policy Consulting. Most recently, he served for four years as the Chairman of the Colorado Public Utilities Commission where he implemented the many policy changes championed by the Governor and the Legislature to bring forward Colorado's "New Energy Economy." He is the author of several reports and articles on renewable energy and climate policy has testified as an expert witness in fifteen states.

Richard Sedano is a principal with the Regulatory Assistance Project (RAP), a global, non-profit team of experts focused on the long-term economic and environmental sustainability of the power and natural gas sectors, providing technical and policy assistance to policymakers and regulators on a broad range of energy and environmental issues. RAP is widely viewed as a source of innovative and creative thinking that yields practical solutions. RAP members meet directly with government officials, regulators and their staffs; lead technical workshops and training sessions; conduct in-house research and produce a growing volume of publications designed to better align energy regulation with economic and environmental goals.

Denise Furey has over 25 years of experience with financial institutions, structuring and analyzing transactions for energy and utility companies. In 2011 she founded Regent Square Advisors, a consulting firm specializing in financial and regulatory concerns faced by the sector. She worked with Citigroup covering power and oil & gas companies, and worked with Fitch Rating, Enron Corporation and MBIA Insurance Corporation. Ms. Furey also served with the Securities and Exchange Commission participating in the regulation of investment companies.

Dan Mullen, Senior Manager for Ceres' Electric Power Programs, works to identify and advance solutions that will transform the U.S. electric utility industry in line with the urgent goal of sustainably meeting society's 21st century energy needs. In addition to developing Ceres' intellectual capital and external partnerships, he has engaged with major U.S. electric utilities on issues related to climate change, clean energy and stakeholder engagement, with a particular focus on energy efficiency. A Stanford University graduate, Dan has also raised more than $5 million to support Ceres' climate change initiatives and organizational development.

TABLE OF CONTENTS

TABLE OF FIGURES

FOREWORD

Today's electric industry faces a stunning investment cycle. Across the country, the infrastructure is aging, with very old parts of the power plant fleet and electric and gas delivery systems needing to be replaced. The regulatory environment is shifting dramatically as rules tighten on air pollution from fossil-burning power plants. Fossil fuel price outlooks have shifted. New options for energy efficiency, renewable energy, distributed generation, and smart grid and consumer technologies are pressing everyone to think differently about energy and the companies that provide it. Customers expect reliable electricity and count on good decisions of others to provide it.

The critical nature of this moment and the choices ahead are the subject of this report. It speaks to key decision-makers, such as: state regulators who have a critical role in determining utility capital investment decisions; utility executives managing their businesses in this era of uncertainty; investors who provide the key capital for utilities; and others involved in regulatory proceedings and with a stake in their outcomes.

The report lays out a suite of game-changing recommendations for handling the tremendous investment challenge facing the industry. As much as $100 billion will be invested each year for the next 20 years, roughly double recent levels. A large portion of those investments will be made by non-utility companies operating in competitive markets. But another large share will be made by utilities—with their (and their key investors') decisions being greatly affected by state regulatory policies and practices.

This is no time for backward-looking decision making. It is vital—for electricity consumers and utilities' own economic viability—that their investment decisions reflect the needs of tomorrow's cleaner and smarter 21st century infrastructure and avoid investing in yesterday's technologies. The authors provide useful advice to state regulators on how they can play a more proactive role in helping frame how electric utilities face these investment challenges.

A key report conclusion in this regard: sensible, safe investment strategies, based on the report's detailed cost and risk analysis of a wide range of generation resources, should include:

- Diversifying energy resource portfolios rather than "betting the farm" on a narrow set of options (e.g., fossil fuel generation technologies and nuclear);
- More emphasis on renewable energy resources such as onshore wind and distributed and utility-scale solar;
- More emphasis on energy efficiency, which the report shows is utilities' lowest-cost, lowest-risk resource.

At its heart, this report is a call for "risk-aware regulation." With an estimated $2 trillion of utility capital investment in long-lived infrastructure on the line over the next 20 years, regulators must focus unprecedented attention to risk—not simply keeping costs down today, but minimizing overall costs over the long term, especially in the face of possible surprises. And utilities' use of robust planning tools needs to be sharpened to incorporate risk identification, analysis, and management.

This report offers some good news amid pervasive uncertainty: the authors point out that planning the lowest-cost, lowest risk investment route aligns with a low-carbon future. From a risk management standpoint, diversifying utility portfolios today by expanding investment in clean energy and energy efficiency makes sense regardless of how and when carbon controls come into play. Placing too many bets on the conventional basket of generation technologies is the highest-risk route, in the authors' analysis.

We're in a new world now, with many opportunities as well as risks. More than ever, the true risks and costs of utility investments should be made explicit and carefully considered as decisions on multi-billion-dollar commitments are made.

As the industry evolves, so too must its regulatory frameworks. The authors point out why and offer guidance about how. This is news regulators and the industry can use.

Susan F. Tierney
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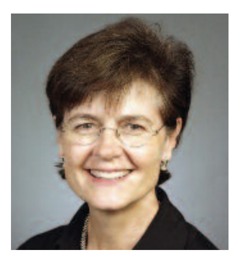
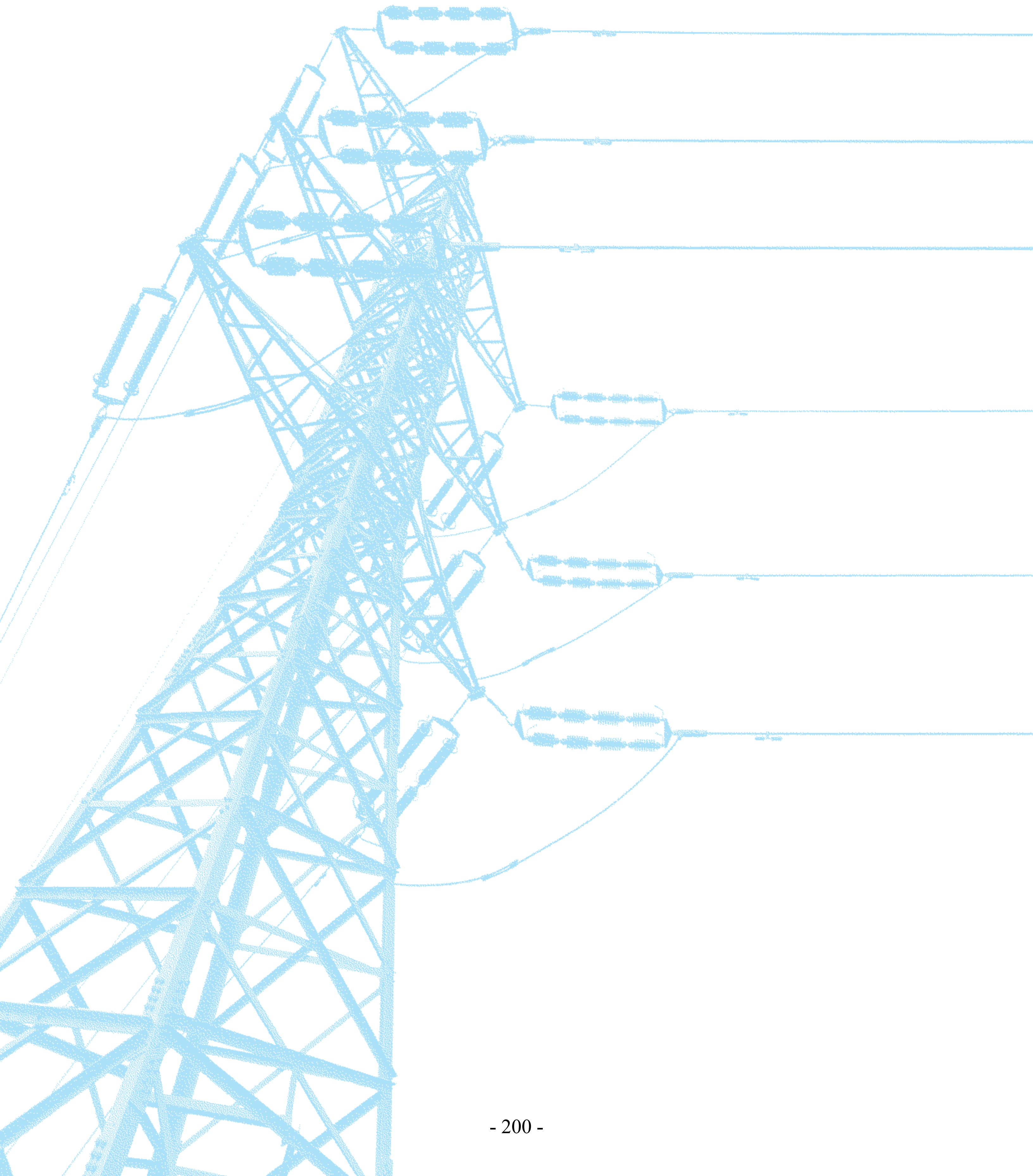




EXECUTIVE SUMMARY

CONTEXT: INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY AND RISK

The U.S. electric utility industry, which has remained largely stable and predictable during its first century of existence, now faces tremendous challenges. Navigant Consulting recently observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[1] These challenges include:

- an aging generation fleet and distribution system, and a need to expand transmission;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[2]
- disruptive changes in the economics of coal and natural gas;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- substantially weakened industry financial metrics and credit ratings, with over three-quarters of companies in the sector rated three notches or less above "junk bond" status.[3]

Many of these same factors are driving historic levels of utility investment. It is estimated that the U.S. electricity industry could invest as much as $100 billion each year for 20 years[4]—roughly twice recent investment levels. This level of investment will double the net invested capital in the U.S. electricity system by 2030. Moreover, these infrastructure investments are long lived: generation, transmission and distribution assets can have expected useful lives of 30 or 40 years or longer. This means that many of these assets will likely still be operating in 2050, when electric power producers may be required to reduce greenhouse gas emissions by 80 percent or more to avoid potentially catastrophic impacts from climate change.

1 Forrest Small and Lisa Frantzis, *The 21st Century Electric Utility: Positioning for a Low-Carbon Future*, Navigant Consulting (Boston, MA: Ceres, 2010), 28, http://www.ceres.org/resources/reports/the-21st-century-electric-utility-positioning-for-a-low-carbon-future-1.

2 Estimates of U.S. coal-fired generating capacity that could be retired in the 2015-2020 timeframe as a result of forthcoming U.S. Environmental Protection Agency (EPA) air quality regulations range from 10 to 70 gigawatts, or between three and 22 percent of U.S. coal-fired generation capacity. Forthcoming EPA water quality regulations could require the installation of costly cooling towers on more than 400 power plants that provide more than a quarter of all U.S. electricity generation. See Susan Tierney, "Electric Reliability under New EPA Power Plant Regulations: A Field Guide," *World Resources Institute*, January 18, 2011, http://www.wri.org/stories/2011/01/electric-reliability-under-new-epa-power-plant-regulations-field-guide.

3 Companies in the sector include investor-owned utilities (IOUs), utility holding companies and non-regulated affiliates.

4 Marc Chupka et al., *Transforming America's Power Industry: The Investment Challenge 2010-2030*, The Brattle Group (Washington DC: The Edison Foundation, 2008), vi, http://www.brattle.com/_documents/UploadLibrary/Upload725.pdf. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. From 2000-05, overall annual capital expenditures by U.S. IOUs averaged roughly $48 billion; from 2006-10 that number climbed to $74 billion; see Edison Electric Institute, *2010 Financial Review: Annual Report of the U.S. Shareholder-Owned Electric Utility Industry* (Washington DC: Edison Electric Institute, 2011), 18, http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/finreview/Documents/FR2010_FullReport_web.pdf.

Greatly increased utility investment combined with minimal, zero or even declining electricity demand growth means that retail electricity prices for consumers will rise sharply, claiming a greater share of household disposable income and likely leading to ratepayer resistance.[5] Because the U.S. economy was built on relatively cheap electricity—the only thing many U.S. consumers and businesses have ever known—credit rating agencies are concerned about what this dynamic could mean for utilities in the long term. Rating analysts also point out that the overall credit profile for investor-owned utilities (IOUs) could decline even further since utilities' operating cash flows won't be sufficient to satisfy their ongoing investment needs.[6]

It falls to state electricity regulators to ensure that the large amount of capital invested by utilities over the next two decades is deployed wisely. Poor decisions could harm the U.S. economy and its global competitiveness; cost ratepayers, investors and taxpayers hundreds of billions of dollars; and have costly impacts on the environment and public health.

To navigate these difficult times, it is essential that regulators understand the risks involved in resource selection, correct for biases inherent in utility regulation, and keep in mind the long-term impact that their decisions will have on consumers and society. To do this, regulators must look outside the boundaries established by regulatory tradition.

CHALLENGES TO EFFECTIVE REGULATION

To be effective in the 21st century, regulators will need to be especially attentive to two areas: identifying and addressing risk; and overcoming regulatory biases.

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Put another way, risk is "the expected value of a potential loss." *Higher risk* for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Risks for electric system resources have both time-related and cost-related aspects. *Cost risks* reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. *Time risks* reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. **Figure ES-1** summarizes the many varieties of risk for utility resource investment.

Risk is the expected value of a potential loss. Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Figure ES-1

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT

Cost-related	*Time-related*
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

5 Moody's Investors Service, *Special Comment: The 21st Century Electric Utility* (New York: Moody's Investors Service, 2010). Importantly, customers who currently enjoy the lowest electricity rates can expect the largest rate increases, in relative terms, as providers of cheap, coal-generated electricity install costly pollution controls or replace old coal-fired units with more expensive new resources. This dynamic could prove especially challenging for regulators, utilities and consumers in the heavily coal-dependent Midwest.

6 Richard Cortright, "Testimony before the Pennsylvania Public Utility Commission," Harrisburg, Pennsylvania, November 19, 2009, http://www.puc.state.pa.us/general/RegulatoryInfo/pdf/ARRA_Testimony-SPRS.pdf.

RISK

Three observations about risk should be stressed:

1. **Risk cannot be eliminated, but it can be managed and minimized.** Since risks are defined as probabilities, it is by definition probable that some risks will be realized—that, sooner or later, risk will translate into dollars for consumers, investors or both. This report concludes with recommendations for how regulators can minimize risk by practicing "risk-aware regulation."
2. **It is unlikely that consumers will bear the full cost of poor utility resource investment decisions.** The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to burden ratepayers with the full cost of utility mistakes. As a result, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investment decisions than in years past.
3. **Ignoring risk is not a viable strategy.** Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

Traditional utility regulation also contains several built-in biases that effective regulators must overcome.[7] These biases, which result in part from the incentives that traditional regulation provides to utilities, encourage utilities to invest more than is optimal for their customers—which is to say, more than is optimal for the provision of safe, reliable, affordable and environmentally sustainable electricity—and discourage them from investing in the lowest-cost, lowest-risk resources (namely, demand-side resources such as energy efficiency) that provide substantial benefits to ratepayers and local economies. Bias can also lead utilities to seek to exploit regulatory and legislative processes as a means of increasing profits (rather than, for example, improving their own operational efficiencies). Finally, regulators face an inherent information deficit when dealing with utility managements. This can hamper effective collaboration around utility planning, which is arguably the most important function of electricity regulation today.

COSTS AND RISKS OF NEW GENERATION RESOURCES

We closely examine costs and risks of new generation resources for several reasons. First, as the largest share of utility spending in the current build cycle, generation investment is where the largest amount of consumer and investor dollars is at risk. Also, today's decisions about generation investment can trigger substantial future investments in transmission and distribution infrastructure. Proposed power plants can be a lightning rod for controversy, heightening public scrutiny of regulatory and corporate decision-makers. Finally, poor investment decisions about generation resources in IOUs' last major build cycle resulted in tens of billions of dollars of losses for consumers and shareholders.[8] For these and other reasons, it is especially important that regulators address, manage and minimize the risks associated with utility investments in new generation resources.[9]

Ignoring risk is not a viable strategy. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate.

Acquiring new electric system resources involves dimensions of both cost and risk. Of these two dimensions, the tools for estimating the cost elements of new generation, while imperfect, are more fully developed than the risk-related tools. As a starting point for our examination of the relative cost and risk of new generation resources, we rank a wide range of supply-side resources and one demand-side resource (energy efficiency) according to their levelized cost of electricity, or "LCOE" **(Figure ES-2, p. 8)**.[10] This ranking is based on 2010 data and does not include recent cost increases for nuclear or cost decreases for solar PV and wind. Because carbon controls could add significant costs to certain technologies but the exact timing and extent of these costs is unknown, we include a moderate estimate for carbon cost for fossil-fueled resources. And because incentives such as tax credits and loan guarantees can significantly affect LCOE, we examine the LCOE range for each technology with and without incentives where applicable.

7 These biases, which are discussed further in the report, are *information asymmetry; the Averch-Johnson effect; the throughput incentive; "rent-seeking"*; and *the "bigger-is-better" bias.*

8 Frank Huntowski, Neil Fisher, and Aaron Patterson, *Embrace Electric Competition or It's Déjà Vu All Over Again* (Concord, MA: The NorthBridge Group, 2008), 18, http://www.nbgroup.com/publications/Embrace_Electric_Competition_Or_Its_Deja_Vu_All_Over_Again.pdf. The NorthBridge Group estimates that ratepayers, taxpayers and investors were saddled with $200 billion (in 2007 dollars) in "above-market" costs associated with the build cycle of the 1970s and 80s. Between 1981-91, shareholders lost roughly $19 billion as a result of regulatory disallowances of power plant investments by some regulated utilities; see Thomas P. Lyon and John W. Mayo, "Regulatory opportunism and investment behavior: evidence from the U.S. electric utility industry," *Rand Journal of Economics*, Vol. 36, No. 3 (Autumn 2005): 628–44, http://webuser.bus.umich.edu/tplyon/PDF/Published%20Papers/Lyon%20Mayo%20RAND%202005.pdf. The potential for negative consequences is probably higher today; since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially.

9 While our analysis of risks and costs of new generation resources may be of most interest to regulators in "vertically-integrated" states (where utilities own or control their own generation), it also has implications for regulators in restructured states. Regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as this report makes clear, are utilities' lowest-cost and lowest-risk resources.

10 LCOE indicates the cost per megawatt-hour for electricity over the life of the plant, encompassing all expected costs (e.g., capital, operations and maintenance, and fuel). We primarily reference LCOE data compiled by the Union of Concerned Scientists (UCS), which aggregates three common sources of largely consensus LCOE data: the U.S. Energy Information Administration (EIA), the California Energy Commission (CEC) and the investment firm Lazard; see Barbara Freese et al., *A Risky Proposition* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/a-risky-proposition_report.pdf. LCOE costs for technologies not included in UCS's analysis (viz., biomass co-firing, combined cycle natural gas generation with CCS, and distributed solar) were estimated by the authors based on comparable resources referenced by UCS.

Figure ES-2

RELATIVE COST RANKING OF NEW GENERATION RESOURCES

HIGHEST LEVELIZED COST OF ELECTRICITY (2010)

- Solar Thermal
- Solar—Distributed*
- Large Solar PV*
- Coal IGCC-CCS
- Solar Thermal w/ incentives
- Coal IGCC
- Nuclear*
- Coal IGCC-CCS w/ incentives
- Coal IGCC w/ incentives
- Large Solar PV w/ incentives*
- Pulverized Coal
- Nuclear w/ incentives*
- Biomass
- Geothermal
- Biomass w/ incentives
- Natural Gas CC-CCS
- Geothermal w/ incentives
- Onshore Wind*
- Natural Gas CC
- Onshore Wind w/ incentives*
- Biomass Co-firing
- Efficiency

LOWEST LEVELIZED COST OF ELECTRICITY (2010)

Figure ES-3

RELATIVE RISK RANKING OF NEW GENERATION RESOURCES

HIGHEST COMPOSITE RISK

- Nuclear
- Pulverized Coal
- Coal IGCC-CCS
- Nuclear w/ incentives
- Coal IGCC
- Coal IGCC-CCS w/ incentives
- Natural Gas CC-CCS
- Biomass
- Coal IGCC w/ incentives
- Natural Gas CC
- Biomass w/ incentives
- Geothermal
- Biomass Co-firing
- Geothermal w/ incentives
- Solar Thermal
- Solar Thermal w/ incentives
- Large Solar PV
- Large Solar PV w/ incentives
- Onshore Wind
- Solar—Distributed
- Onshore Wind w/ incentives
- Efficiency

LOWEST COMPOSITE RISK

** Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.*

But the LCOE ranking tells only part of the story. The *price* for any resource in this list does not take into account the relative *risk* of acquiring it. To establish relative risk of new generation resources, we return to the many risks identified in Figure ES-1 and compress those risks into seven main categories:

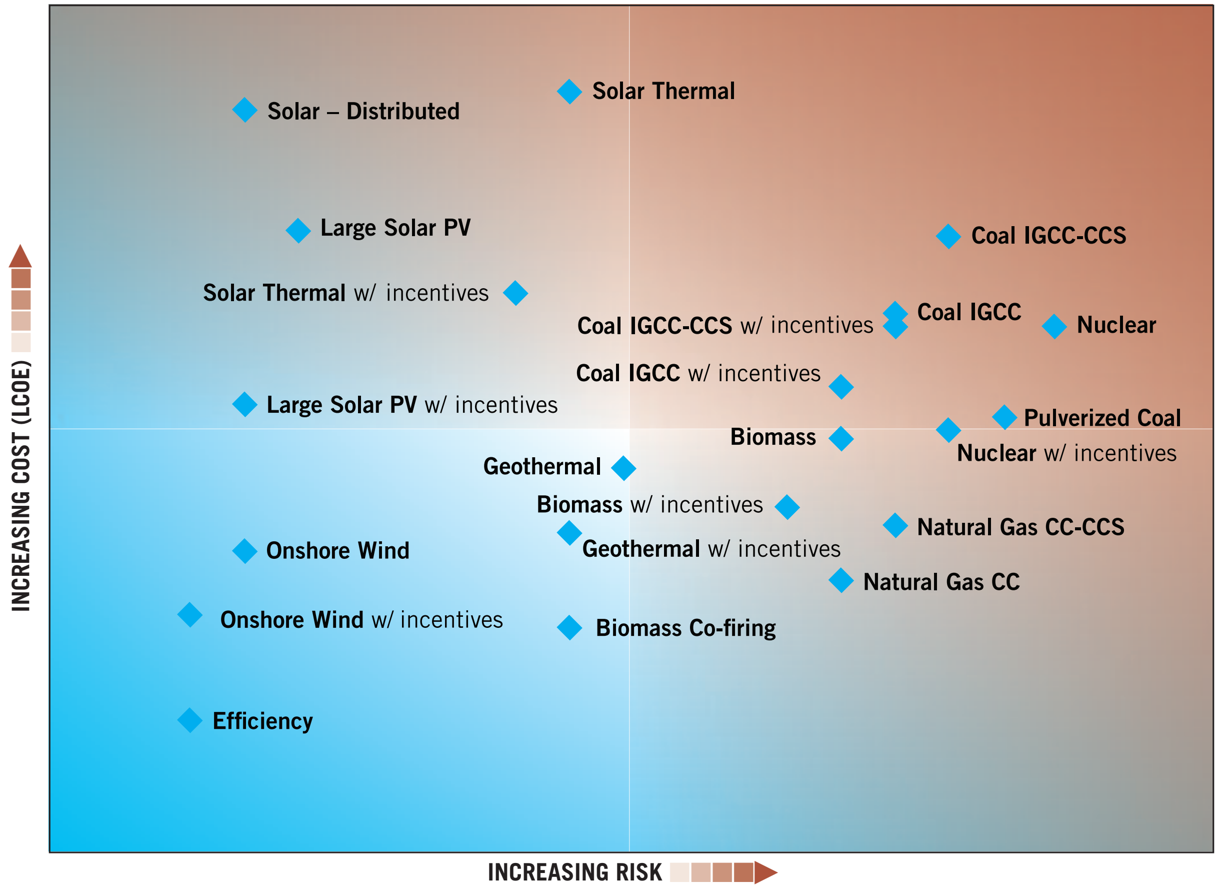
- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

We then evaluate each resource profiled in the LCOE ranking and apply our informed judgment to quantify each resource's relative exposure to each type of risk.[11] This allows us to establish a composite risk score for each resource (with the highest score indicating the highest risk) and rank them according to their relative composite risk profile **(Figure ES-3)**.

11 Risk exposure in each risk category ranges from "None" to "Very High." We assigned scores (None = 0, Very High = 4) to each risk category for each resource and then summed them to establish an indicative quantitative ranking of composite risk. We also tested the robustness of the risk ranking by calculating two additional rankings of the risk scores: one that overweighted the cost-related risk categories and one that overweighted the environmental-related risk categories.

Figure ES-4

PROJECTED UTILITY GENERATION RESOURCES IN 2015
Relative Cost and Relative Risk



The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear division between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

With largely consensus quantitative LCOE data, and having developed indicative composite risk scores for each resource, we can summarize relative risks and costs of utility generation resources in a single graph **(Figure ES-4)**.[12]

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states.

While this report focuses on new generation resources, the approach to "risk-aware regulation" described herein works equally well for the "retire or retrofit" decisions concerning existing coal plants facing regulators and utilities in many states. The question for regulators is whether to approve coal plant closures in the face of new and future EPA regulations, or to approve utility investments in costly pollution controls to keep the plants running. Regulators should treat this much like an IRP proceeding: utilities should be required to present multiple scenarios differing in their disposition of the coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. In the end, regulators should enter a decision that addresses all of the relevant risks.

12 Resources are assumed to come online in 2015.

PRACTICING RISK-AWARE REGULATION: SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

MANAGING RISK INTELLIGENTLY IS ARGUABLY THE MAIN DUTY OF REGULATORS WHO OVERSEE UTILITY INVESTMENT. EFFECTIVELY MANAGING RISK IS NOT SIMPLY ACHIEVING THE LEAST COST *TODAY*, BUT RATHER IS PART OF A STRATEGY TO *MINIMIZE OVERALL COSTS OVER THE LONG TERM*. WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS SHOULD EMPLOY TO MANAGE AND MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources and energy efficiency. Diversification—investing in different asset classes with different risk profiles—is what allows investors to reduce risk (or "volatility") in their investment portfolios. Similarly, diversifying a utility portfolio by including various supply and demand-side resources that behave independently from each other in different future scenarios reduces the portfolio's overall risk.

2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment. In many vertically integrated markets and in some organized markets, regulators use "integrated resource planning" (IRP) to oversee utilities' capital investments. IRP is an important tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of utility resource options; that the options are examined in a structured, disciplined way; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood by all.

3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk. For example, allowing a current return on construction work in progress (CWIP) to enable utilities to finance large projects doesn't actually reduce risk but rather transfers it from the utility to consumers.[13] While analysts and some regulators favor this approach, its use can obscure a project's risk and create a "moral hazard" for utilities to undertake more risky investments. Utility investment in the lowest-cost and lowest-risk resource, energy efficiency, requires regulatory adjustments that may include decoupling utility revenues from sales and performance-based financial incentives.

4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts. These allow utilities to lock in a price (e.g., for fuel), thereby avoiding the risk of higher market prices later. But these options must be used carefully since using them can foreclose an opportunity to enjoy lower market prices.

5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments. This helps to create a consistent, stable regulatory environment, which is highly valued in the marketplace and ensures that agreed-upon resource plans become reality.

6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk. In "judicial mode," a regulator takes in evidence in formal settings and resolves disputes; in contrast, a regulator operating in "legislative mode" proactively seeks to gather all relevant information and to find solutions to future challenges.

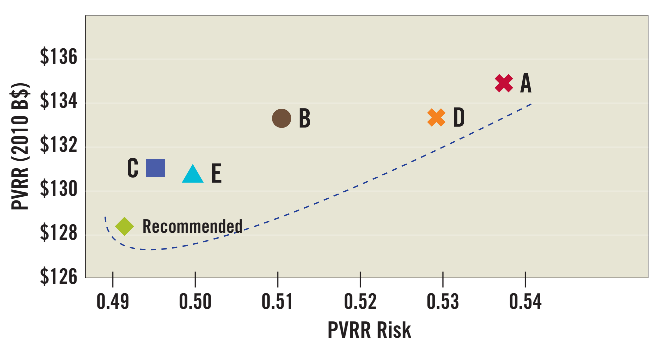
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate. Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades, which led regulators to modernize their tools and experiment with various types of incentive regulation. One area where electricity regulators might profitably question existing practices is rate design; existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

13 For example, the use of CWIP financing in Florida could result in Progress Energy customers paying the utility more than $1 billion for a new nuclear plant (the Levy County Nuclear Power Plant) that may never be built. Florida state law prohibits ratepayers from recouping their investment in Levy or other CWIP-financed projects.

Careful planning is the regulator's primary risk management tool. A recently completed IRP by the Tennessee Valley Authority (TVA) illustrates how robust planning enables risk-aware resource choices and avoids higher-cost, higher-risk supply portfolios. TVA considered five resource strategies and subjected each to extensive scenario analysis. **Figure ES-5** shows how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[14] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio[15] or emphasized new nuclear plant construction. The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy. The TVA analysis is careful and deliberate; analyses by other utilities that reach significantly different thematic conclusions must be scrutinized carefully to examine whether the costs and risks of all resources have been properly evaluated.

Figure ES-5

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK



Strategy A: Limited Change in Current Resource Portfolio
Strategy B: Baseline Plan Resource Portfolio
Strategy C: Diversity Focused Resource Portfolio
Strategy D: Nuclear Focused Resource Portfolio
Strategy E: EEDR (Energy Efficiency/Demand Response) and Renewables Focused Resource Portfolio

Updating traditional practices will require effort and commitment from regulators and regulatory staff. Is it worth it? This report identifies numerous benefits from practicing "risk-aware regulation":

- **Consumer benefits** from improved regulatory decision-making and risk management, leading to greater utility investment in lower-cost, lower-risk resources;
- **Utility benefits** in the form of a more stable, predictable business environment that enhances long-term planning capabilities;
- **Investor benefits** resulting from lowered threats to utility cost recovery, which simultaneously preserves utility credit quality and capital markets access and keeps financing costs low, benefitting all stakeholders;
- **Systemic regulatory benefits** resulting from expanded transparency, inclusion and sophistication in the regulatory process, thereby strengthening stakeholder relationships, building trust and improving policy maker understanding of energy options—all of which enhances regulators' ability to do their jobs;
- **Broad societal benefits** flowing from a cleaner, smarter, more resilient electricity system.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

Effectively managing risk is not simply achieving the least cost today, but rather is part of a strategy to minimize overall costs over the long term.

14 Tennessee Valley Authority (TVA), *TVA's Environmental and Energy Future* (Knoxville, TN: Tennessee Valley Authority, 2011), 161, http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf.

15 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent) (TVA, 73).

CONCLUSIONS & RECOMMENDATIONS

- **The U.S. electric utility industry has entered what may be the most uncertain, complex and risky period in its history.** Several forces will conspire to make the next two decades especially challenging for electric utilities: large investment requirements, stricter environmental controls, decarbonization, changing energy economics, rapidly evolving technologies and reduced load growth. Succeeding with this investment challenge—building a smarter, cleaner, more resilient electric system for the 21st century at the lowest overall risk and cost—will require commitment, collaboration, shared understanding, transparency and accountability among regulators, policy makers, utilities and a wide range of stakeholders.
- **These challenges call for new utility business models and new regulatory paradigms.** Both regulators and utilities need to evolve beyond historical practice. Today's electricity industry presents challenges that traditional electricity regulation did not anticipate and cannot fully address. Similarly, the constraints and opportunities for electric utilities going forward are very different than they were a century ago, when the traditional (and still predominant) utility business model emerged.

  Regulators must recognize the incentives and biases that attend traditional regulation, and should review and reform their approaches to resource planning, ratemaking and utility cost recovery accordingly. Utilities must endorse regulatory efforts to minimize investment risks on behalf of consumers and utility shareholders. This means promoting an inclusive and transparent planning process, diversifying resource portfolios, supporting forward-looking regulatory policies, continually reevaluating their strategies and shaking off "we've always done it that way" thinking.
- **Avoiding expensive utility investment mistakes will require improved approaches to risk management in the regulatory process.** One of the most important duties of a 21st century electricity regulator is to understand, examine and manage the risk inherent in utility resource selection. Existing regulatory tools often lack the sophistication to do this effectively.

  Higher risk for a resource or portfolio means that more value is at stake or that the likelihood of a financial loss is greater, or both. Our analysis across seven major risk categories reveals that, almost without exception, the riskiest resources—the ones that could cause the most financial harm—are large base load fossil and nuclear plants. It is therefore especially important that regulators and utilities explicitly address and manage risk when considering the development of these resources.

  Regulators practicing "risk-aware regulation" must exhaust lower-risk investment options like energy efficiency before allowing utilities to commit huge sums to higher-risk projects. Regulators should immediately notify regulated utilities of their intention to address risks more directly, and then begin explicitly to include risk assessment in all decisions about utility resource acquisition.
- **More than ever, ratepayer funding is a precious resource.** Large investment requirements coupled with flat or decreasing load growth will mean higher utility rates for consumers. Increased consumer and political resistance to rising electricity bills, and especially to paying for expensive mistakes, leaves much less room for error in resource investment decisions and could pose a threat to utility earnings.

- **Risk shifting is not risk minimization.** Some regulatory practices that are commonly perceived to reduce risk (e.g., construction work in progress financing, or "CWIP") merely transfer risk from the utility to consumers. This risk shifting can inhibit the deployment of attractive lower-cost, lower-risk resources. Regulatory practices that shift risk must be closely scrutinized to see if they actually increase risk—for consumers in the short term, and for utilities and shareholders in the longer term.
- **Investors are more vulnerable than in the past.** During the 1980s, power plant construction cost overruns and findings of utility mismanagement led regulators to disallow more than six percent of utilities' overall capital investment, costing shareholders roughly $19 billion. There will be even less tolerance for errors in the upcoming build cycle and more pressure on regulators to protect consumers. Investors should closely monitor utilities' large capex decisions and consider how the regulatory practice addresses the risk of these investments. Investors should also observe how the business models and resource portfolios of specific utilities are changing, and consider engaging with utility managements on their business strategies going forward.
- **Cost recovery mechanisms currently viewed positively by the investment community including the rating agencies could pose longer-term threats to utilities and investors.** Mechanisms like CWIP provide utilities with the assurance of cost recovery before the outlay is made. This could incentivize utilities to take on higher-risk projects, possibly threatening ultimate cost recovery and deteriorating the utility's regulatory and business environment in the long run.
- **Some successful strategies for managing risk are already evident.** Regulators and utilities should pursue diversification of utility portfolios, adding energy efficiency, demand response, and renewable energy resources to the portfolio mix. Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios. In the other direction, failing to diversify resources, "betting the farm" on a narrow set of large resources, and ignoring potentially disruptive future scenarios is asking for trouble.

Including a mix of supply and demand-side resources, distributed and centralized resources, and fossil and non-fossil generation provides important risk management benefits to resource portfolios because each type of resource behaves independently from the others in different future scenarios.

- **Regulators have important tools at their disposal.** Careful planning is the regulator's primary tool for risk mitigation. This is true for regulators in both vertically-integrated and restructured electricity markets. Effective resource planning considers a wide variety of resources, examines possible future scenarios and considers the risk of various portfolios. Regulators should employ transparent ratemaking practices that reveal and do not obscure the level of risk inherent in a resource choice; they should selectively apply financial and physical hedges, including long-term contracts. Importantly, they must hold utilities accountable for their obligations and commitments.

1. CONTEXT:

INCREASING CAPITAL INVESTMENT BY U.S. ELECTRIC UTILITIES AMID HISTORIC UNCERTAINTY & RISK

U.S. ELECTRIC UTILITIES ARE FACING A SET OF CHALLENGES UNPARALLELED IN THE INDUSTRY'S HISTORY, PROVIDING MANY REASONS TO CONCLUDE THAT THE TRADITIONAL PRACTICES OF UTILITIES AND THEIR REGULATORS MUST BE UPDATED TO ADD A SHARPER FOCUS ON RISK MANAGEMENT IN THE REGULATORY PROCESS.

Consider the forces acting on the electricity sector in 2012:

- an aging generation fleet;
- infrastructure upgrades to the distribution system;
- increasingly stringent environmental regulation limiting pollutants and greenhouse gases;[16]
- disruptive changes in the economics of coal and natural gas;
- new transmission investments;
- rapidly evolving smart grid technologies enabling greater customer control and choice;
- increased policy maker emphasis on demand-side resources requiring new regulatory approaches and utility business models;
- competition from growth in distributed generation;
- slow demand growth due to protracted economic recovery and high unemployment;
- tight credit in a difficult economy and substantially weakened industry financial metrics and credit ratings.

In a recent book, Peter Fox-Penner, principal and chairman emeritus of the Brattle Group, concluded that the sum of these forces is leading to a "second revolution" in the electric power industry.[17] Navigant Consulting has observed that "the changes underway in the 21st century electric power sector create a level and complexity of risks that is perhaps unprecedented in the industry's history."[18]

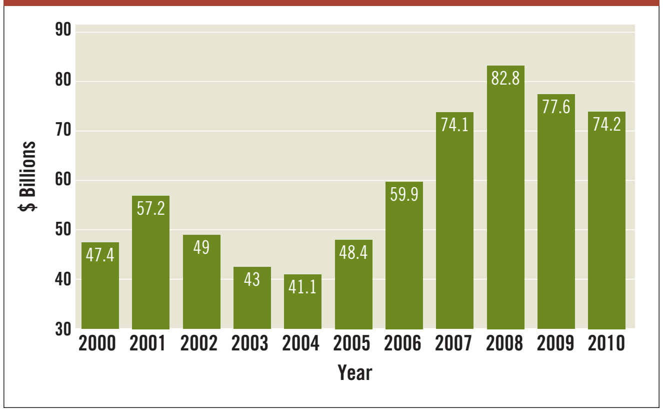
THE INVESTMENT CHALLENGE

The United States electric utility industry is a network of approximately 3,300 investor-owned utilities (IOUs), cooperative associations and government entities. In addition, about 1,100 independent power producers sell power to utilities, either under contract or through auction markets. The net asset value of the plant in service for all U.S. electric utilities in 2010 was about $1.1 trillion, broken down as $765 billion for IOUs, about $200 billion for municipal (publicly-owned) utilities (or "munis"), and $112 billion for rural electric cooperatives (or "co-ops").[19]

IOUs therefore constitute the largest segment of the U.S. electric power industry, serving roughly 70 percent of the U.S. population. **Figure 1** illustrates IOUs' capital expenditures from 2000-2010 and captures the start of the current "build cycle," beginning in 2006.[20] Between 2006 and 2010, capital spending by IOUs—for generation, transmission and distribution systems—was about 10 percent of the firms' net plant in service.

Figure 1

CAPITAL EXPENDITURES BY U.S. INVESTOR-OWNED UTILITIES, 2000-2010



16 See footnote 2.

17 Peter Fox-Penner, *Smart Power* (Washington DC: Island Press, 2010). The "first revolution" was triggered by George Westinghouse, Thomas Edison, Nicola Tesla, Samuel Insull and others more than a century ago.

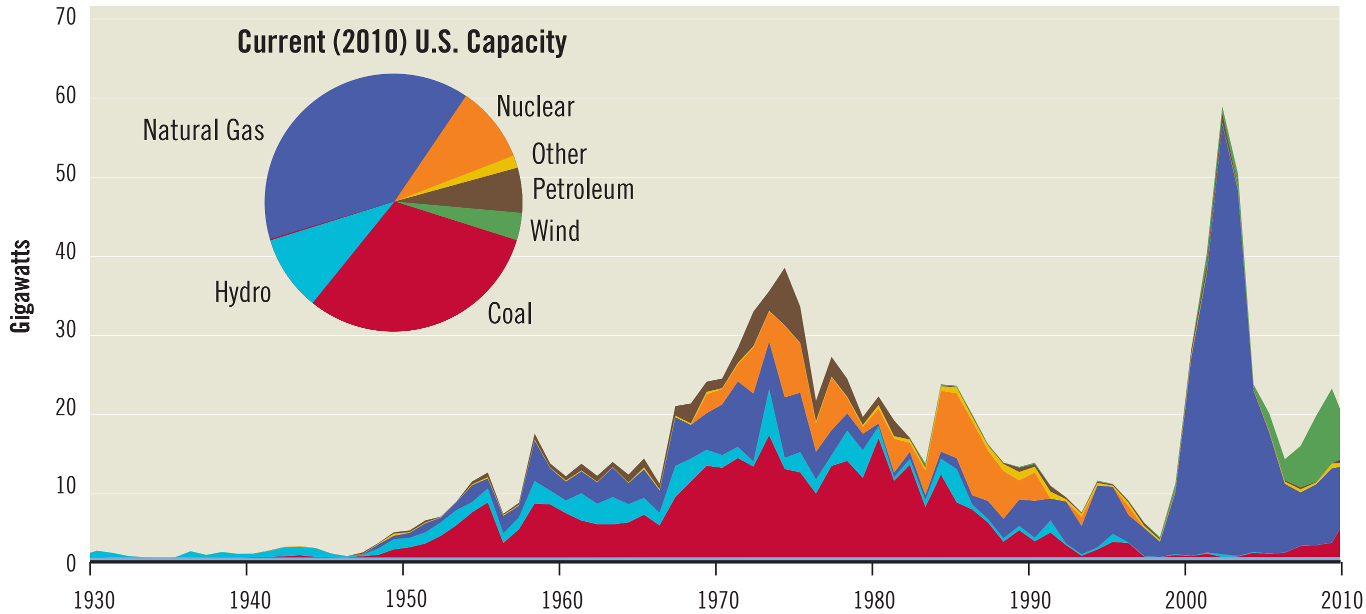
18 Small and Frantzis, *The 21st Century Electric Utility*, 28.

19 See U.S. Energy Information Administration, "Electric Power Industry Overview 2007," http://www.eia.gov/cneaf/electricity/page/prim2/toc2.html; National Rural Electric Cooperative Association, "Co-op Facts and Figures," http://www.nreca.coop/members/Co-opFacts/Pages/default.aspx; Edison Electric Institute, "Industry Data," http://www.eei.org/whatwedo/DataAnalysis/IndustryData/Pages/default.aspx. Note that these numbers do not include investment by non-utility generators.

20 Edison Electric Institute, *2010 Financial Review*, 18.

Figure 2

U.S. ELECTRIC GENERATING CAPACITY BY IN-SERVICE YEAR AND FUEL TYPE



In 2008, the Brattle Group projected that the collected U.S. electric utility industry—IOUs, munis, and co-ops—would need to invest capital at historic levels between 2010 and 2030 to replace aging infrastructure, deploy new technologies, and meet future consumer needs and government policy requirements. In all, Brattle predicted that total industry-wide capital expenditures from 2010 to 2030 would amount to between $1.5 trillion and $2.0 trillion.[21] Assuming that the U.S. implements a policy limiting greenhouse gas emissions, the collected utility industry may be expected to invest at roughly the same elevated annual rate as in the 2006-2010 period *each year for 20 years.*

If the U.S. utility industry adds $100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's $1.1 trillion to more than $2.0 trillion—a doubling of net invested capital.

If the U.S. utility industry adds $100 billion each year between 2010 and 2030, the net value of utility plant in service will grow from today's $1.1 trillion to more than $2.0 trillion—a doubling of net invested capital. This growth is considerably faster than the country has seen in many decades.

To understand the seriousness of the investment challenge facing the industry, consider the age of the existing generation fleet. About 70 percent of U.S. electric generating capacity is at least 30 years old (**Figure 2**).[22] Much of this older capacity is coal-based generation subject to significant pressure from the Clean Air Act (CAA) because of its emissions of traditional pollutants such as nitrous oxides, sulfur dioxides, mercury and particulates. Moreover, following a landmark Supreme Court ruling, the U.S. Environmental Protection Agency (EPA) is beginning to regulate as pollutants carbon dioxide and other greenhouse gas emissions from power plants.[23] These regulations will put even more pressure on coal plants, which produce the most greenhouse gas emissions of any electric generating technology. The nuclear capacity of the U.S., approximately 100,000 megawatts, was built mainly in the 1970s and 80s, with original licenses of 40 years. While the lives of many nuclear plants are being extended with additional investment, some of these plants will face retirement within the next two decades.

21 Chupka et al., *Transforming America's Power Industry*, vi. Brattle's investment estimates apply to the entire U.S. electric utility industry, including IOUs, electric cooperatives and government-owned utilities. The range in Brattle's investment estimate is due to its varying assumptions about U.S. climate policy enactment.

22 U.S. Energy Information Administration, "Today in Energy: Age of electric power generators varies widely," June 16, 2011, http://www.eia.gov/todayinenergy/detail.cfm?id=1830.

23 U.S. Supreme Court, *Massachusetts v. Environmental Protection Agency,* 549 U.S. 497 (2007), http://www.supremecourt.gov/opinions/06pdf/05-1120.pdf.

Figure 3

PROJECTED GENERATION CAPEX BY REGION

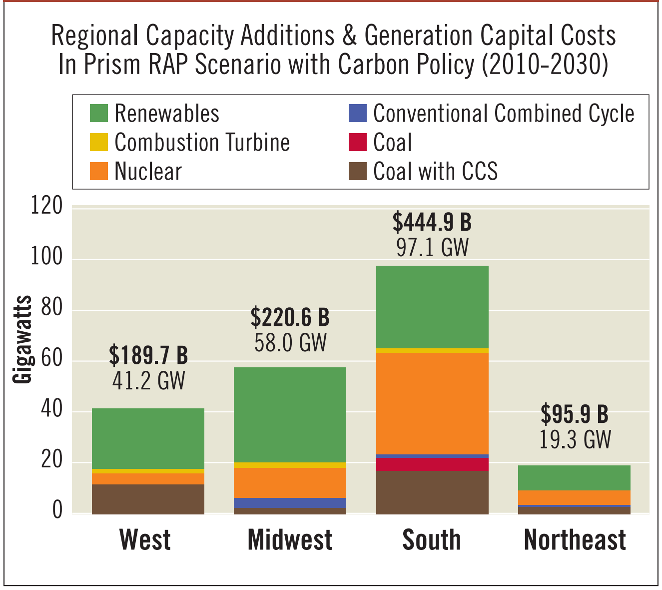


Figure 4

PROJECTED CAPACITY ADDITIONS BY STATE & AS A PERCENTAGE OF 2010 GENERATING CAPACITY

State	Predicted Capacity Additions (MW), 2010-2030[25]	Predicted Additions as a Percentage of 2010 Generating Capacity[26]
Texas	23,400	22%
Florida	12,200	21%
Illinois	11,000	25%
Ohio	8,500	26%
Pennsylvania	6,300	14%
New York	5,400	14%
Colorado	2,500	18%

Figure 3 shows the Brattle Group's investment projections for new generating capacity for different U.S. regions,[24] while **Figure 4** predicts capacity additions for selected U.S. states. Importantly, the Brattle Group noted that some of this investment in new power plants could be avoided if regulators and utilities pursued maximum levels of energy efficiency.

DRIVERS OF UTILITY INVESTMENT

Technological change, market pressures and policy imperatives are driving these historic levels of utility investment. As we will see, these same forces are interacting to create unprecedented uncertainty, risk and complexity for utilities and regulators.

Here are eight factors driving the large investment requirements:

1. **THE NEED TO REPLACE AGING GENERATING UNITS.** As mentioned earlier, the average U.S. generating plant is more than 30 years old. Many plants, including base load coal and nuclear plants, are reaching the end of their lives, necessitating either life-extending investments or replacement.

2. **ENVIRONMENTAL REQUIREMENTS.** Today's Clean Air Act (CAA) traces its lineage to a series of federal laws dating back to 1955. Until recent years, the CAA has enjoyed broad bipartisan support as it steadily tightened controls on emissions from U.S. electric power plants. These actions were taken to achieve science-based health improvements for people and the human habitat. While the current set of EPA rules enforcing the CAA has elicited political resistance, it is unlikely that the five-decade long movement in the United States to reduce acid rain, smog, ground ozone, particulates and mercury, among other toxic pollutants, will be derailed. Owners of many fossil-fueled plants will be forced to decide whether to make significant capital investments to clean up emissions and manage available water, or shutter the plants. Since the capacity is needed to serve consumers' demand for power (or "load"), these clean air and clean water policies will stimulate the need for new construction.

24 Chupka et al., *Transforming America's Power Industry,* x. Brattle's Prism RAP Scenario "assumes there is a new federal policy to constrain carbon emissions, and captures the cost of EPRI's [Electric Power Research Institute] Prism Analysis projections for generation investments (nuclear, advanced coal, renewables, etc.) that will reduce the growth in carbon emissions. This scenario further assumes the implementation of RAP [realistically achievable potential] EE/DR programs" (ibid., vi). Brattle used EPRI's original Prism analysis, published in September 2007; that document and subsequent updates are available online at http://my.epri.com/portal/server.pt?open=512&objID=216&&PageID=229721&mode=2.

25 State capacity addition predictions are based on Brattle's regional projections and assume that new capital expenditures will be made in proportion to existing investment levels.

26 State generating capacity data: U.S. Energy Information Administration, "State Electricity Profiles," January 30, 2012, http://www.eia.gov/electricity/state/. Percentage is rounded to the nearest whole number.

3 **NEW TRANSMISSION LINES AND UPGRADES.** Utility investment in transmission facilities slowed significantly from 1975 to 1998.[27] In recent years, especially after the creation of deregulated generation markets in about half of the U.S., it has become clear that the transmission deficit will have to be filled. Adding to the need for more transmission investment is the construction of wind, solar and geothermal generation resources, far from customers in areas with little or no existing generation or transmission. Regional transmission planning groups have formed across the country to coordinate the expected push for new transmission capacity.

4 **NETWORK MODERNIZATION/SMART GRID.** The internet is coming to the electric power industry. From synchrophasors on the transmission system (which enable system-wide data measurement in real time), to automated substations; from smart meters, smart appliances, to new customer web-based energy management, investments to "smarten" the grid are fundamentally changing the way electricity is delivered and used. While much of today's activity results from "push" by utilities and regulators, many observers think a "pull" will evolve as consumers engage more fully in managing their own energy use. Additionally, "hardening" the grid against disasters and to enhance national security will drive further investment in distribution infrastructure.

5 **HIGHER PRICES FOR CONSTRUCTION MATERIALS.** Concrete and steel are now priced in a world market. The demand from developing nations is pushing up the cost of materials needed to build power plants and transmission and distribution facilities.

6 **DEMAND GROWTH.** Overall U.S. demand for electric power has slowed with the recent economic recession and is projected to grow minimally in the intermediate term (though some areas, like the U.S. Southwest and Southeast, still project moderate growth). Further, the expected shift toward electric vehicles has the potential to reshape utility load curves, expanding the amount of energy needed in off-peak hours.

7 **DEPLOYING NEW TECHNOLOGIES AND SUPPORTING R&D.** To meet future environmental requirements, especially steep reductions of greenhouse gas emissions by 2050, utilities will need to develop and deploy new technologies at many points in the grid. Either directly or indirectly, utilities will be involved in funding for R&D on carbon capture and storage, new renewable and efficiency technologies, and electric storage.

8 **NATURAL GAS PRICE OUTLOOK.** Natural gas prices have fallen sharply as estimates of U.S. natural gas reserves jumped with the development of drilling technologies that can economically recover gas from shale formations. Longer-term price estimates have also dropped, inducing many utilities to consider replacing aging coal units with new gas-fired units. But in January 2012, the U.S. Energy Information Administration (EIA) sharply revised downward its estimates of U.S. shale gas reserves by more than 40 percent and its estimates of shale gas from the Marcellus region by two-thirds.[28] Reduced long-term supplies and a significant commitment to natural gas for new electric generation could obviously lead to upward pressure on natural gas prices.

FINANCIAL IMPLICATIONS

The credit quality and financial flexibility of U.S. investor-owned electric utilities has declined over the past 40 years, and especially over the last decade (**Figure 5, p. 18**).[29] The industry's financial position today is materially weaker than it was during the last major "build cycle" that was led by vertically-integrated utilities, in the 1970s and 80s. Then the vast majority of IOUs had credit ratings of "A" or higher; today the average credit rating has fallen to "BBB."

While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions.

This erosion of credit quality is mainly the result of intentional decisions by regulators and utility managements, who determined that maintaining an "A" or "AA" balance sheet wasn't worth the additional cost.[30] And while there isn't reason to believe that most utilities' capital markets access will become significantly constrained in the near future, the fact remains that more than a quarter of companies in the sector are now one notch above non-investment grade status (also called "Non-IG," "high yield" or "junk"), and nearly half of the companies in the sector are rated only two or three notches above this threshold.[31] While it is rare for utilities to experience multiple notch downgrades in a short period of time, the heightened event risk inherent in the approaching sizable capital spending cycle could cause the rating agencies to pursue more aggressive rating actions. Dropping below

27 Edison Electric Institute, *EEI Survey of Transmission Investment* (Washington DC: Edison Electric Institute, 2005), 3, http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Survey_Web.pdf.

28 U.S. Energy Information Administration, *AEO2012 Early Release Overview* (Washington DC: U.S. Energy Information Administration, 2012), 9, http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf.

29 Source: Standard & Poor's Ratings Service.

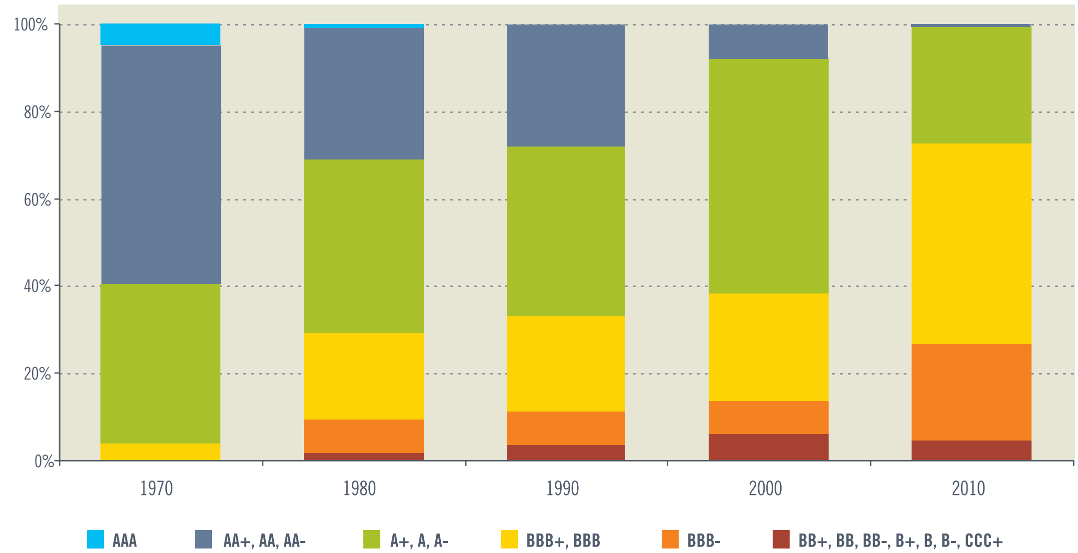
30 The difference in the interest rate on an "A" rated utility and BBB is on average over time rarely more than 100 basis points. By contrast, equity financing typically costs a utility at least 200 basis points more than debt financing.

31 Companies in the sector include IOUs, utility holding companies and non-regulated affiliates.

Figure 5

U.S. ELECTRIC IOUs CREDIT RATINGS HISTORY, 1970 – 2010

S&P Credit Ratings Distribution, U.S. Shareholder-Owned Electric Utilities



investment grade (or "IG") triggers a marked rise in interest rates for debt issuers and a marked drop in demand from institutional investors, who are largely prohibited from investing in junk bonds under the investment criteria set by their boards.

According to a Standard & Poor's analyst, utilities' capital expenditure programs will invariably cause them to become increasingly cash flow negative, pressuring company balance sheets, financial metrics and credit ratings: "In other words, utilities will be entering the capital markets for substantial amounts of both debt and equity to support their infrastructure investments as operating cash flows will not come close to satisfying these infrastructure needs."[32] Specific utilities that S&P has identified as particularly challenged are companies—such as Ameren, Dominion, FirstEnergy, and PPL—that have both regulated and merchant generation businesses and must rely on market pricing to recover environmental capital expenditures for their merchant fleets.[33]

Appendix 1 of this report presents an overview of utility finance.

While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery.

CUSTOMER IMPACTS

The surge in IOU capital investment will translate directly into higher electric rates paid by consumers. Increased capital investment means higher annual depreciation expenses as firms seek to recover their investment. Greater levels of investment mean higher revenue requirements calculated to yield a return on the investment. And since electric sales may not grow much or at all during the coming two decades, it is likely that unit prices for electricity will rise sharply.

While the growth of rate base presents an earnings opportunity for regulated utilities and their investors, the corresponding increase in customer bills could greatly exacerbate the political and regulatory risks that threaten utilities' cost recovery. The rating agency Moody's Investors Service has noted that "consumer tolerance to rising rates is a primary concern"[34] and has identified political and regulatory risks as key longer-term challenges facing the sector.[35]

Further, Moody's anticipates an "inflection point" where consumers revolt as electricity bills consume a greater share of disposable income (**Figure 6, p. 19**),[36] pressuring legislators and regulators to withhold from utilities the recovery of even prudently incurred expenses.

32 Cortright, "Testimony."

33 Standard & Poor's, *The Top 10 Investor Questions for U.S. Regulated Electric Utilities in 2012* (New York: Standard & Poor's, 2012).

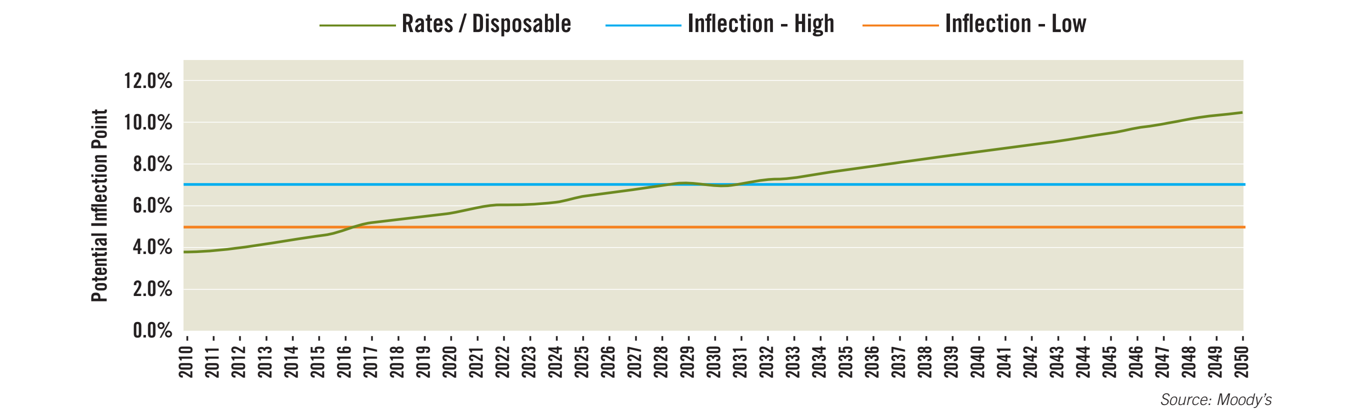
34 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2011).

35 Moody's Investors Service, *Industry Outlook: Annual Outlook* (New York: Moody's Investors Service, 2010).

36 Moody's, *Special Comment: The 21st Century Electric Utility*, 12.

Figure 6

MOODY'S PROJECTED "INFLECTION POINT" OF CONSUMER INTOLERANCE FOR RISING ELECTRICITY BILLS



Source: Moody's

THE IMPORTANCE OF REGULATORS

With this background, the challenge becomes clear: how to ensure that the large level of capital invested by utilities over the next two decades is deployed wisely? How to give U.S. ratepayers, taxpayers and investors the assurance that $2 trillion will be spent in the best manner possible? There are two parts to the answer: *effective regulators* and the *right incentives for utilities*.

If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Each regulator will, on average, vote to approve more than $6.5 billion of utility capital investment during his or her term.[37] It is essential that regulators understand the risks involved in resource selection, correct for the biases facing utility regulation and keep in mind the impact their decisions will have on consumers and society.

Are U.S. regulatory institutions prepared? Consumers, lawmakers and the financial markets are counting on it. The authors are confident that well-informed, focused state regulators are up to the task. But energy regulation in the coming decades will be quite different from much of its history. The 21st century regulator must be willing to look outside the boundaries established by regulatory tradition. Effective regulators must be informed, active, consistent, curious and often courageous.

This report focuses on techniques to address the risk associated with utility resource selection. It provides regulators with some tools needed to understand, identify and minimize the risks inherent in the industry's investment challenge. In short, we hope to help regulators become more "risk-aware."

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37 In 2012, the median number of years served by a state regulator was 3.7 years; see Janice A. Beecher, Ph.D., *IPU Research Note: Commissioner Demographics 2012* (East Lansing, MI: Michigan State University, 2012), http://ipu.msu.edu/research/pdfs/IPU-Commissioner-Demographics-2012.pdf.

2. CHALLENGES

TO EFFECTIVE REGULATION

THE CHALLENGE FOR U.S. ELECTRIC UTILITIES IS TO RAISE, SPEND AND RECOVER A HISTORIC AMOUNT OF CAPITAL DURING A PERIOD OF UNPRECEDENTED UNCERTAINTY. THE CHALLENGE FOR STATE REGULATORS IS TO DO EVERYTHING POSSIBLE TO ENSURE THAT UTILITIES' INVESTMENTS ARE MADE WISELY. TO DO THIS EFFECTIVELY, REGULATORS WILL NEED TO BE ESPECIALLY ATTENTIVE TO TWO AREAS: IDENTIFYING AND ADDRESSING RISK, AND OVERCOMING REGULATORY BIASES. THIS SECTION DISCUSSES RISK AND BIAS IN MORE DETAIL.

RISK INHERENT IN UTILITY RESOURCE SELECTION

Risk arises when there is potential harm from an adverse event that can occur with some degree of probability. Risk accumulates from multiple sources. In mathematical terms:

Risk $= \sum_i \mathit{Event}_i \times (\mathit{Probability\ of\ Event}_i)$

for a situation in which a set of independent events will cause a loss with some probability. In English, this means that risk is the sum of each possible loss times the probability of that loss, assuming the events are independent of each other. If a financial instrument valued at $100 million would be worth $60 million in bankruptcy, and the probability of bankruptcy is 2 percent, then the bankruptcy risk associated with that instrument is said to be ($100 million - $60 million) x 2%, or $800,000. Thus, risk is the *expected value of a potential loss*. There is an obvious tie to insurance premiums; leaving aside transaction costs and the time value of money, an investor would be willing to pay up to $800,000 to insure against the potential bankruptcy loss just described.

Higher risk for a resource or portfolio means a larger expected value of a potential loss. In other words, higher risk means that more value is at stake or that the likelihood of a financial loss is greater, or both.

Uncertainty is similar to risk in that it describes a situation where a deviation from the expected can occur, but it differs in two respects. First, the probability of the unexpected event cannot feasibly be determined with any precision. Consider the potential of much higher costs for natural gas used as a generation resource for an electric utility. Such an outcome is certainly possible (and perhaps even likely, given the potential for an increased rate of construction of new natural gas generation). But the likelihood and scope of such a change would be difficult to assess in terms of mathematical probabilities. Second, unlike risk, uncertainty can result in

The Historical Basis for Utility Regulation

Utilities aren't like other private sector businesses. Their services are essential in today's world, and society expects utilities to set up costly infrastructure networks supported by revenue from electric rates and to serve everyone without discrimination. Because of their special attributes, we say that investor-owned utilities are private companies that are "affected with the public interest." Indeed, this is often the statutory definition of utilities in state law.

Utility infrastructure networks include very long-lived assets. Power plants and transmission lines are designed to last decades; some U.S. transmission facilities are approaching 100 years old. The high cost of market entry makes competition impractical, uneconomic or impossible in many sectors of these markets. And because society requires universal service, it made economic sense to grant monopoly status to the owners of these essential facilities and then to regulate them.

State regulatory utility commissioners began administering a system of oversight for utilities at about the turn of the 20th century, filling a role that had previously been accorded to state legislatures. Regulatory commissions were tasked with creating a stable business environment for investment while assuring that customers would be treated "justly and reasonably" by monopoly utilities. Then as now, consumers wanted good utility services and didn't want to pay too much for them. Rules for accounting were supplemented by regulatory expectations, which were then followed by a body of precedents associated with cost recovery.

Because the sector's complexity and risks have evolved considerably since many regulatory precedents were established, today's regulators are well-advised to "think outside the box" and consider reforming past precedent where appropriate. The last section of this report, "Practicing Risk-Aware Regulation," contains specific ideas and recommendations in this regard.

Figure 7

VARIETIES OF RISK FOR UTILITY RESOURCE INVESTMENT	
Cost-related	*Time-related*
Construction costs higher than anticipated	Construction delays occur
Availability and cost of capital underestimated	Competitive pressures; market changes
Operation costs higher than anticipated	Environmental rules change
Fuel costs exceed original estimates, or alternative fuel costs drop	Load grows less than expected; excess capacity
Investment so large that it threatens a firm	Better supply options materialize
Imprudent management practices occur	Catastrophic loss of plant occurs
Resource constraints (e.g., water)	Auxiliary resources (e.g., transmission) delayed
Rate shock: regulators won't put costs into rates	Other government policy and fiscal changes

either upside or downside changes. As we will see later, uncertainty should be identified, modeled and treated much like risk when considering utility resource selection. In this report we will focus on risk and the negative aspect of uncertainty, and we will simplify by using the term "risk" to apply to both concepts.

The risks associated with utility resource selection are many and varied and arise from many possible events, as shown in **Figure 7**. There are several ways to classify these risks. One helpful distinction is made between cost-related risks and time-related risks.

Cost risks reflect the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations. Construction costs for a project can increase between regulatory approval and project completion. Transmission projects are notorious for this phenomenon due to unexpected obstacles in siting, or to unexpected changes in raw material costs.

Costs can change unexpectedly at any time. For example, a catastrophic equipment failure or the adoption of a new standard for pollution control could present unforeseen costs that a utility may not be willing to pay to keep an asset operating. Planned-for cost recovery can be disrupted by changes in costs for which regulators are unwilling to burden customers, or for other reasons. If an asset becomes obsolete, useless or uneconomic before the end of its predicted economic life, a regulator could find that it is no longer "used and useful" to consumers and remove it from the utility rate base. In these ways, decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

Time risks reflect the possibility that circumstances will change over the life of the investment and materially affect both the cost of the investment and the degree to which it benefits consumers. Sometimes this risk can manifest itself even between the time a utility makes a decision and the time approval is sought. For example, anticipated load growth may not materialize, so that a planned generation resource is not needed, at least not now.

Time risks also reflect the fact that, for some investments, some essential condition may not occur on a schedule necessary for the investment to be approved and constructed. Consider the dilemma of the developer who wishes to build a low cost wind farm in an area with weak electric transmission. The wind project might require three to four years to build, but the transmission capacity needed to move the power to market may take five to seven years to build—*if* the development goes relatively smoothly. Investors may forego the wind farm due to uncertainty that the transmission will be built, while at the same time the transmission might not be built because, without the wind farm, it is simply too speculative.

Decisions made by utilities and their regulators may turn out to be much more costly than initially expected. For this reason, it is especially important that regulators and utilities consider a full range of options and resources at the time a major investment decision is made.

In the power sector, investments are so long-lived that time can be measured in generations. Generally speaking, regulators consider it most fair if the generation of consumers that uses an asset is the same one that pays for the asset. Burdening customers before or after an asset is useful is often seen as violating the "just and reasonable" standard. The challenge to the utility, therefore, is to fit cost recovery for an asset into the timeframe in which it is used. Otherwise, the utility may bear the risk that regulators or consumers push back on assuming responsibility for the cost.

Perspectives on Risk

Risk means different things to different stakeholders. For example:

- For **utility management**, risks are a threat to the company's financial health, its growth, even its existence; a threat to the firm's competitiveness, to the firm's image, and to its legacy.
- For **customers**, risk threatens household disposable income, the profitability of businesses, the quality of energy service, and even comfort and entertainment.
- **Investors** focus on the safety of the income, value of the investment (stock or bond holders), or performance of the contract (counterparties). In addition, investors value utility investments based on their expectations of performance.
- **Employees** are uniquely connected to the utility. Their employment, safety and welfare is directly related to their company's ability to succeed and to avoid financial catastrophes.
- **Society generally** has expectations for utilities ranging from providing reliable, universal service, to aiding in economic development, to achieving satisfactory environmental and safety performance. Risk threatens these goals.

ELECTRICITY MARKET STRUCTURE AND RISK

Much has changed since non-utility power producers led the most recent industry build cycle in the 1990s and early 2000s. To begin with, financial reforms from Sarbanes-Oxley legislation, other "Enron fixes," and now the Dodd-Frank Act have substantially changed some accounting and corporate disclosure rules. Investors now receive more detailed and transparent information about asset value (which is "marked to market") and possible risks in contracts with counter-parties.

These changes, which protect investors, may have the associated effect of discouraging investments if cumulative risks are judged to be outsized for the circumstances. This is especially relevant for markets served by the competitive generation system that now supplies power to about half of U.S. consumers. It is unclear whether independent generators have the tolerance to take on large, risky investments; experience indicates that there is a frontier beyond which these companies and their backers may not go.

This dynamic could raise important questions for regulators in restructured markets, who need to be aware of the degree to which investment options might be limited by these concerns. In vertically-integrated markets, regulators' concern should be not to expose utilities, customers and investors to undue risk by approving large projects that informed market players would not pursue in the absence of regulatory approval.

One potentially risky but necessary area of investment is in low carbon generation technologies. The U.S. power sector, which has embraced generation competition, is required to develop these technologies. Some promising technologies—including coal-fired generation with carbon capture and storage or sequestration (CCS), advanced nuclear power technologies and offshore wind—have not reached a commercial stage or become available at a commercial price.

Risks requiring special attention are those associated with investments that "bet the company" on their success. Gigawatt-sized investments in any generation technology may trigger this concern, as can a thousand-mile extra high voltage transmission line. Any investment measured in billions of dollars can be proportionately out of scale with what a utility can endure if things go awry. Regulators should avoid a situation where the only choices left are a utility bankruptcy or a waiving of regulatory principles on prudence and cost recovery in order to save the utility, placing a necessary but unreasonable cost burden on consumers.

REGULATORS, RATING AGENCIES AND RISK

Investor-owned utilities sometimes attempt to get out in front of the event risk inherent in large investment projects by seeking pre-approval or automatic rate increase mechanisms. As discussed later, these approaches don't actually reduce risk, but instead shift it to consumers. This may give companies and investors a false sense of security and induce them to take on excessive risk. In the long run this could prove problematic for investors; large projects can trigger correspondingly large rate increases years later, when regulators may not be as invested in the initial deal or as willing to burden consumers with the full rate increase.

Given the influence of regulators on the operations and finances of IOUs, ratings agencies and investors closely monitor the interactions between utility executives and regulators. Constructive relationships between management and regulators are viewed as credit positive; less-than-constructive relationships, which can result from regulators' concerns about the competence or integrity of utility management, are seen as a credit negative and harmful to a utility's business prospects.

Analysts define a constructive regulatory climate as one that is likely to produce stable, predictable regulatory outcomes over time. "Constructive," then, refers as much to the quality of regulatory decision-making as it does to the financial reward for the utility. Regulatory decisions that seem overly generous to utilities could raise red flags for analysts, since these decisions could draw fire and destabilize the regulatory climate. Analysts may also become concerned about the credit quality of a company if the state regulatory process appears to become unduly politicized.

While they intend only to observe and report, ratings agencies can exert a discipline on utility managements not unlike that imposed more formally by regulators. For example, ratings agencies can reveal to utility managements the range of factors they should consider when formulating an investment strategy, thereby influencing utility decision-making. Both regulators and ratings agencies set long-term standards and expectations that utilities are wise to mind; both can provide utilities with feedback that would discourage one investment strategy or another.

Since ratings reflect the issuer's perceived ability to repay investors over time, the ratings agencies look negatively on anything that increases event risk. The larger an undertaking (e.g., large conventional generation investments), the larger the fallout if an unforeseen event undermines the project. The pressure to maintain healthy financial metrics may, in practice, serve to limit utilities' capital expenditure programs and thus the size of rate increase requests to regulators.

TAKEAWAYS ABOUT RISK

Here are three observations about risk that should be stressed:

1. RISK CANNOT BE ELIMINATED—BUT IT CAN BE MANAGED AND MINIMIZED. Because risks are defined in terms of probabilities, it is (by definition) probable that some risk materializes. In utility resource selection, this means that risk will eventually find its way into costs and then into prices for electricity. Thus, taking on risk is inevitable, and risk will translate into consumer or investor costs—into dollars—sooner or later. Later in this report, we present recommendations to enable regulators to practice their trade in a "risk-aware" manner—incorporating the notion of risk into every decision.

2. IT IS UNLIKELY THAT CONSUMERS WILL BEAR THE FULL COST OF POOR UTILITY RESOURCE INVESTMENT DECISIONS. Put another way, it is likely that utility investors (specifically shareholders) will be more exposed to losses resulting from poor utility investments than in years past. In utility regulation, risk is shared between investors and customers in a complex manner. To begin, the existence of regulation and a group of customers who depend on utility service is what makes investors willing to lend utilities massive amounts of money (since most customers have few if any choices and must pay for utility service). But the actualization of a risk, a loss, may be apportioned by regulators to utility investors, utility consumers, or a combination of both. The very large amount of capital investment that's being contemplated and the resulting upward pressure on electricity rates will make it very unappealing (or simply untenable) for regulators to make ratepayers pay for the full cost of utility mistakes.

3. IGNORING RISK IS NOT A VIABLE STRATEGY. Regulators (and utilities) cannot avoid risk by failing to make decisions or by relying on fate. In utility regulation, perhaps more so than anywhere else, making no choice is itself making a choice. Following a practice just because "it's always been done that way," instead of making a fresh assessment of risk and attempting to limit that risk, is asking for trouble.

NATURAL BIASES AFFECTING UTILITY REGULATION

Notwithstanding economic theory, we must admit that utilities are not perfectly rational actors and that their regulation is not textbook-perfect, either. Utility regulation faces several built-in biases, which one can think of as headwinds against which regulation must sail. For example, under traditional cost-of-service regulation, a considerable portion of fixed costs (i.e., investment in rate base) is often recovered through variable charges to consumers. In this circumstance, one would expect utilities to have a bias toward promoting sales of the product once rates are established—even if increasing sales might result in increased financial, reliability, or environmental risks and mean the inefficient use of consumer dollars.

Here are five natural biases that effective utility regulation must acknowledge and correct for:

- **Information asymmetry.** Regulators are typically handicapped by not having the same information that is available to the regulated companies. This becomes especially significant for the utility planning process, where regulators need to know the full range of potential options for meeting electric demand in future periods. In the same vein, regulators do not normally have adequate information to assess market risks. These are the considerations of CFOs and boardrooms, and not routinely available to regulators. Finally, operating utilities often exist in a holding company with affiliated interests. The regulator does not have insight into the interplay of the parent and subsidiary company—the role played by the utility in the context of the holding company.
- **The Averch-Johnson effect.** A second bias is recognized in the economic literature as the tendency of utilities to over-invest in capital compared to labor. This effect is known by the name of the economists who first identified the bias: the Averch-Johnson effect (or simply the "A-J effect"). The short form of the A-J effect is that permitting

a rate of return on investment will have the predictable effect of encouraging more investment than is optimal. This can manifest itself in the "build versus buy" decisions of integrated utilities and is often cited as a reason utilities might "gold plate" their assets. This effect can also be observed in the "invest versus conserve" decisions that utilities face. Under traditional regulatory rules, most utilities do not naturally turn toward energy efficiency investment, even though such investments are usually least cost for customers.

- **The throughput incentive.** A third bias that can be observed with utilities is the bias for throughput—selling more electricity. This is undoubtedly grounded in the vision that most utilities have traditionally had for themselves: providers of electricity. Importantly, the regulatory apparatus in most states reinforces the motivation to sell more electricity: a utility's short-run profitability and its ability to cover fixed costs is directly related to the utility's level of sales. The price of the marginal unit of electricity often recovers more than marginal costs, so utilities make more if they sell more. Only in recent years has the concept of an energy services provider developed in which the utility provides or enables energy efficiency, in addition to providing energy.
- **Rent-seeking.** A fourth bias often cited in the literature is "rent seeking," where the regulated company attempts to use the regulatory or legislative processes as a means of increasing profitability (rather than improving its own operational efficiency or competitive position). This can occur when firms use law or regulation to protect markets that should be open to competition, or to impose costs on competitors.
- **"Bigger-is-better"** syndrome. Another bias, related to the Averch-Johnson effect, might be called the "bigger is better" syndrome. Utilities tend to be conservative organizations that rely on past strategies and practices. Making large investments in relatively few resources had been the rule through the 1980s and into the 1990s. Because of this history, utilities may not naturally support smaller scale resources, distributed resources or programmatic solutions to energy efficiency.[38]

Regulation can compensate for these biases by conducting clear-headed analysis, using processes that bring forth a maximum of relevant information and, very importantly, identifying the risk that these biases might introduce into utility resource acquisition. In the next section, we will take a close look at the many risks facing generation resource investments, which involve some of the most important and complex decisions that regulators and utilities make.

38 To be fair, smaller scale resources can add transaction and labor expenses for which the utility would not earn a return under traditional cost of service regulation, which helps to explain limited utility interest in these options.

3. COSTS AND RISKS

OF NEW GENERATION RESOURCES

THE CAPITAL INVESTED BY U.S. ELECTRIC UTILITIES TO BUILD A SMARTER, CLEANER, MORE RESILIENT ELECTRICITY SYSTEM OVER THE NEXT TWO DECADES WILL GO TOWARDS UTILITIES' GENERATION, TRANSMISSION AND DISTRIBUTION SYSTEMS.

In this section we'll take an in-depth look at costs and risks of new generation resources, for several reasons:

- Generation investment will be the largest share of utility spending in the current build cycle; this is where the largest amount of consumer and investor dollars will be at stake.
- Today's decisions about generation investment can shape tomorrow's decisions about transmission and distribution investment (by reducing or increasing the need for such investment).
- Technology breakthroughs—in energy storage, grid management, solar PV, and elsewhere—could radically transform our need for base load power within the useful lives of power plants being built today.
- Generation resources are among utilities' most visible and controversial investments and can be a lightning rod for protest and media attention, intensifying scrutiny on regulatory and corporate decision-makers.
- The industry's familiarity with traditional generating resources (e.g., large centralized fossil and nuclear plants) and relative lack of familiarity with newer alternatives (e.g., demand-side resources such as energy efficiency and demand response, or smaller, modular generating resources like combined heat and power) could lead regulators and utilities to underestimate risks associated with traditional resources and overestimate risks of newer resources.
- Finally, investment decisions about generation resources (especially nuclear power) during the last major build cycle that was led by vertically-integrated utilities, in the 1970s and 80s, destroyed tens of billions of dollars of consumer and shareholder wealth.

For these and other reasons, a comprehensive look at risks and costs of today's generation resources is in order.

While this discussion is most directly applicable to regulators (and other parties) in vertically-integrated states where electric utilities build and own generation, it also has implications for regulators (and other parties) in restructured states. For example, regulators in some restructured states (e.g., Massachusetts) are beginning to allow transmission and distribution (T&D) utilities to own generation again, specifically small-scale renewable generation to comprise a certain percentage of a larger renewable portfolio standard. Further, enhanced appreciation of the risks embedded in T&D utilities' supply portfolios could induce regulators to require utilities to employ best practices with regard to portfolio management, thereby reducing the risks and costs of providing electricity service.[39] Finally, regulators in all states can direct electric utilities to invest in cost-effective demand-side resources, which, as the following discussion makes clear, are utilities' lowest-cost and lowest-risk resources.

PAST AS PROLOGUE: FINANCIAL DISASTERS FROM THE 1980s

The last time regulated U.S. utilities played a central role in building significant new generating capacity additions as part of a major industry-wide build cycle was during the 1970s and 80s.[40] At the time the industry's overwhelming focus was on nuclear power, with the Nuclear Regulatory Commission (NRC) licensing construction of more than 200 nuclear power plants.

The difficulties the industry experienced were numerous and well-known: more than 100 nuclear plants abandoned in various stages of development;[41] cost overruns so high that the average plant cost three times initial estimates;[42] and total "above-market" costs to society—ratepayers, taxpayers and shareholders—estimated at more than $200 billion.[43]

39 For a discussion of energy portfolio management, see William Steinhurst et al., *Energy Portfolio Management: Tools & Resources for State Public Utility Commissions* (Cambridge, MA: Synapse Energy Economics, 2006), http://www.naruc.org/Grants/Documents/NARUC%20PM%20FULL%20DOC%20FINAL1.pdf.

40 The natural gas build-out of the 1990s and early 2000s was led by independent power producers, not regulated utilities.

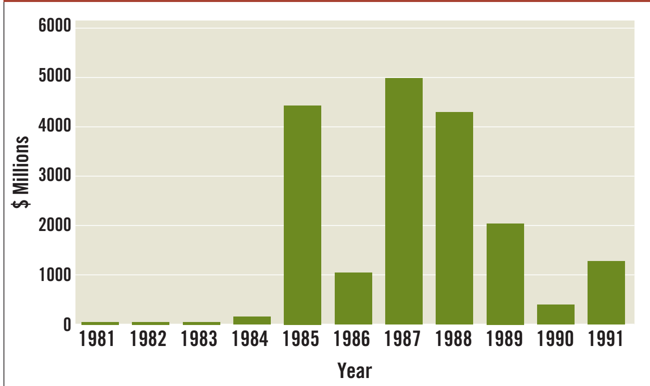
41 Peter Bradford, *Subsidy Without Borders: The Case of Nuclear Power* (Cambridge, MA: Harvard Electricity Policy Group, 2008).

42 U.S. Energy Information Administration, *An Analysis of Nuclear Power Plant Construction Costs* (Washington, DC: U.S. Energy Information Administration, 1986).

43 Huntowski, Fisher and Patterson, *Embrace Electric Competition*, 18. Estimate is expressed in 2007 dollars.

Figure 8

U.S. UTILITY GENERATION INVESTMENT DISALLOWED BY REGULATORS, 1981-1991



While the vast majority of these losses were borne by ratepayers and taxpayers, utility shareholders were not immune. Between 1981 and 1991, U.S. regulators disallowed about $19 billion of investment in power plants by regulated utilities (**Figure 8**).[44] During this time, the industry invested approximately $288 billion, so that the disallowances equated to about 6.6 percent of total investment. The majority of the disallowances were related to nuclear plant construction, and most could be traced to a finding by regulators that utility management was to blame.

To put this in perspective for the current build cycle, consider **Figure 9**. For illustrative purposes, it shows what disallowances of 6.6 percent of IOU investment would look like for shareholders in the current build cycle, using Brattle's investment projections for the 2010-2030 timeframe referenced earlier. The table also shows what shareholder losses would be if regulators were to disallow investment a) at half the rate of disallowances of the 1981-91 period; and b) at twice the rate of that period.[45]

Figure 9

ILLUSTRATIVE PROSPECTIVE SHAREHOLDER LOSSES DUE TO REGULATORY DISALLOWANCES, 2010-2030

Disallowance Ratio	Investment	
	$1.5 T	$2.0 T
3.3%	$34.6 B	$46.2 B
6.6%	$69.3 B	$92.4 B
13.2%	$138.6 B	$184.8 B

Obviously, the *average* disallowance ratio from the 1980s doesn't tell the full story. A few companies bore the brunt of the regulatory action. One of the largest disallowances was for New York's Nine Mile Point 2 nuclear plant, where the $2 billion-plus disallowance was estimated to be 34 percent of the project's original capital cost.[46] When Niagara Mohawk, the lead utility partner in the project, wrote down its investment in the project by $890 million, Standard & Poor's lowered the company's credit rating by two notches, from A- to BBB. Thus the risk inherent in building the Nine Mile Point 2 plant was visited on investors, who experienced a loss of value of at least $890 million, and consumers, who faced potentially higher interest rates going forward. A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

Another large disallowance was levied on Pacific Gas and Electric for the Diablo Canyon nuclear station in California. The disallowance took the form of a "performance plan" that set consumers' price for power at a level that was independent of the plant's actual cost. In its 1988 decision, the California Public Utilities Commission approved a settlement whereby PG&E would collect $2 billion less, calculated on a net present value basis, than it had spent to build the plant. The CPUC's decision to approve the disallowance was controversial, and some felt it didn't go far enough. The California Division of Ratepayer Advocate (DRA) calculated PG&E's actual "imprudence" to be $4.4 billion (about 75 percent of the plant's final cost), and concluded that customers ultimately paid $2.4 billion more than was prudent for the plant—even after the $2 billion disallowance.[47]

A major theme of this paper is how consumer and investor interests are intertwined, and how both are served by strategies that limit risk.

These two large disallowances could be joined by many other examples where unrecognized risk "came home to roost." Consider the destruction of shareholder equity that occurred when Public Service of New Hampshire (PSNH) declared bankruptcy in 1988 because of the burden of its investment in the Seabrook Nuclear Unit, or the enormous debt burden placed on ratepayers by the failure of New York's largest utility, Long Island Lighting Company (LILCO), or the 1983 multi-billion dollar municipal bond default by the Washington Public Power Supply System (WPPSS) when it abandoned attempts to construct five nuclear units in southeast Washington.

44 Lyon and Mayo, *Regulatory opportunism*, 632.

45 Assumes 70 percent of investment is by regulated entities. Illustrative estimates do not include potential losses for utility customers or taxpayers.

46 Fred I. Denny and David E. Dismukes, *Power System Operations and Electricity Markets* (Boca Raton, FL: CRC Press, 2002), 17.

47 The California Public Utilities Commission Decision is available on the Lexis database at: 1988 Cal. PUC LEXIS 886; 30 CPUC2d 189; 99 P.U.R.4th 141, December 19, 1988; As Amended June 16, 1989.

All of these financial disasters share four important traits:

- a weak planning process;
- the attempted development of large, capital-intensive central generation resources;
- utility management's rigid commitment to a preferred investment course; and
- regulators' unwillingness to burden consumers with costs judged retrospectively to be imprudent.

We do not propose to assess blame twenty-five years later, but we do question whether the regulatory process correctly interpreted the risk involved in the construction of these plants—whether, with all risks accounted for, these plants should actually have been part of a "least cost" portfolio for these utilities. The lesson is clear: both investors and customers would have been much better served if the regulators had practiced "risk-aware" regulation.

Finally, while the financial calamities mentioned here rank among the industry's worst, the potential for negative consequences is probably higher today. Since the 1980s, electric demand has grown significantly while the environmental risks associated with utility operations, the costs of developing new generation resources, and the pace of technology development have all increased substantially. And, as noted earlier, electric utilities have entered the current build cycle with lower financial ratings than they had in the 1980s.

CHARACTERISTICS OF GENERATION RESOURCES

A utility's generation portfolio typically consists of a variety of resources that vary in their costs and operating characteristics. Some plants have high capital costs but lower fuel costs (e.g., coal and nuclear) or no fuel costs (e.g., hydro, wind, solar PV). Other plants have lower capital costs but relatively high fuel and operating costs (e.g., natural gas combined cycle). Some plants are designed to operate continuously in "base load" mode, while others are designed to run relatively few hours each year, ramping up and down quickly.

Some resources (including demand response) offer firm capacity in the sense that they are able to be called upon, or "dispatchable," in real time, while other resources are not dispatchable or under the control of the utility or system operator (e.g., some hydro, wind, solar PV).

Generation resources also vary widely in their design lives and exposure to climate regulations, among other differences.

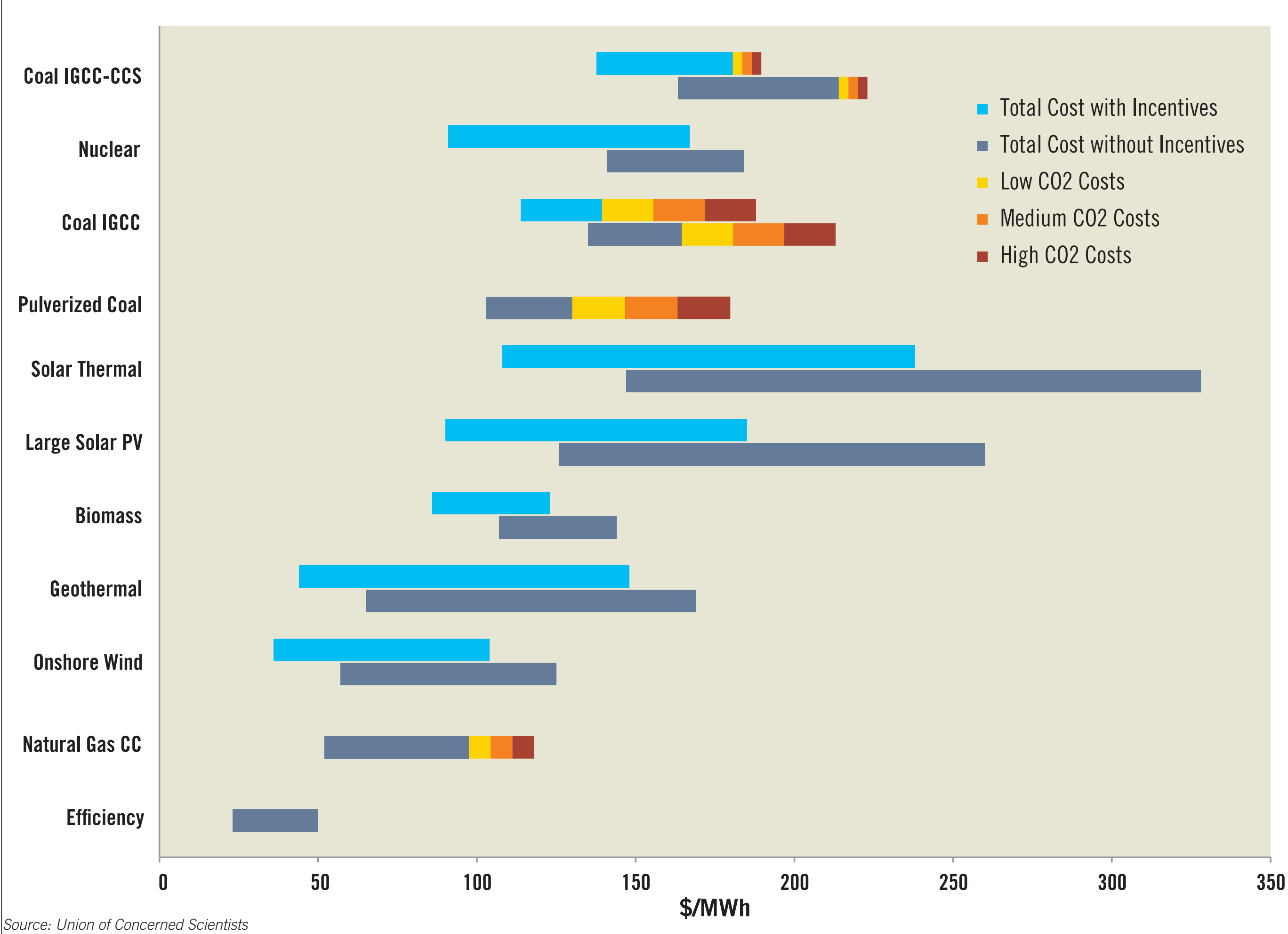
None of these characteristics *per se* makes a resource more or less useful in a utility's resource "stack." Some utility systems operate with a large percentage of generation provided by base load plants. Other systems employ a large amount of non-dispatchable generation like wind energy, combined with flexible gas or hydro generation to supply capacity. What's important is how the resources combine in a portfolio.

For example, in 2008 the Colorado Public Utilities Commission determined that an optimum portfolio for Xcel Energy would include a large amount of wind production, mixed in with natural gas generation and older base load coal plants. Xcel has learned how to manage its system to accommodate large amounts of wind production even though wind is not a "firm" resource. In October 2011, Xcel Energy set a world record for wind energy deployment by an integrated utility: in a one-hour period, wind power provided 55.6 percent of the energy delivered on the Xcel Colorado system.[48]

48 Mark Jaffe, "Xcel Sets World Record for Wind Power Generation," *The Denver Post*, November 15, 2011, http://www.denverpost.com/breakingnews/ci_19342896.

Figure 10

LEVELIZED COST OF ELECTRICITY FOR VARIOUS GENERATION TECHNOLOGIES IN 2015 (2010$)



Source: Union of Concerned Scientists

DECIPHERING THE LEVELIZED COST OF ELECTRICITY

Despite the differences between generation resources, it's possible to summarize and compare their respective costs in a single numerical measure. This quantity, called the "levelized cost of electricity," or "LCOE," indicates the cost per megawatt-hour for electricity over the life of the plant. LCOE encompasses all expected costs over the life of the plant, including costs for capital, operations and maintenance (O&M) and fuel.

Three of the most commonly cited sources of LCOE data for new U.S. generation resources are the Energy Information Administration (EIA); the California Energy Commission (CEC); and the international advisory and asset management firm Lazard. In a recent publication, the Union of Concerned Scientists (UCS) combined the largely consensus LCOE estimates from these three sources to produce a graphic illustrating LCOE for a range of resources (**Figure 10**).[49] The data is expressed in dollars per megawatt-hour, in 2010 dollars, for resources assumed to be online in 2015.

The UCS chart allows a visual comparison of the relative LCOEs among the selected group of resources. The width of the bars in the chart reflects the uncertainty in the cost of each resource, including the variation in LCOE that can result in different regions of the U.S. The UCS report also shows the resources' relative exposure to future carbon costs—not surprisingly, coal-based generation would be most heavily affected—as well as their dependence on federal investment incentives.[50]

49 Freese et al., *A Risky Proposition*, 41.

50 The UCS report estimated incentives by including tax credits for a wide range of technologies and both tax credits and loan guarantees for new nuclear plants. Tax credits currently available for wind and biomass were assumed to be extended to 2015 for illustrative purposes.

We'll use these LCOE estimates to illustrate the combined attributes of cost and risk for new generation resources. To do this, we'll take the midpoint of the cost ranges (including a medium estimate for costs associated with carbon controls) for each technology and create an indicative ranking of these resources by highest to lowest LCOE (**Figure 11**).

For consistency, we use UCS's data compilation, which is based on 2010 cost estimates, without modification. But the actual cost of nuclear power in 2015 is likely to be sharply higher than this estimate following the Fukushima nuclear accident and recent experience with new nuclear projects. For wind and photovoltaic power, the actual costs in 2015 are likely to be lower than the estimate due to recent sharp cost declines and the 2011 market prices for these resources.[51]

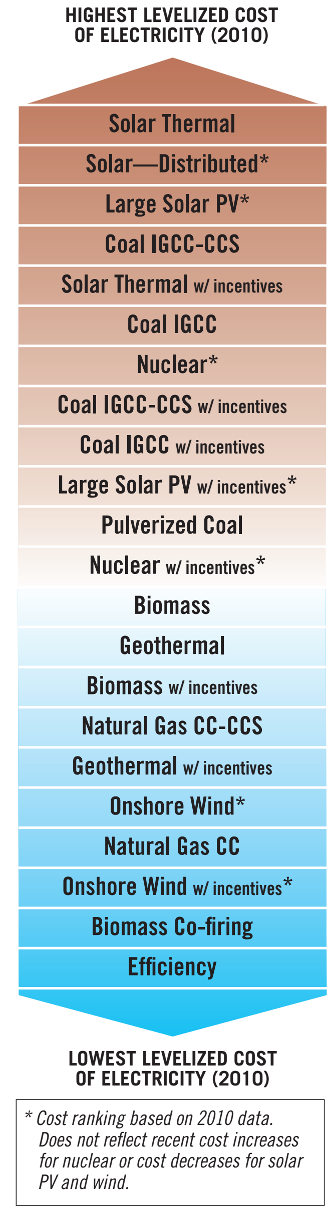
Several observations are in order about this ranking. First, some of the technologies show a very wide range of costs, notably geothermal, large solar PV and solar thermal. The breadth of the range represents, in part, the variation in performance of the technology in various regions of the country. In other words, the underlying cost estimates incorporate geographically varying geothermal and solar energy levels.

Second, the estimates used in this ranking are sensitive to many assumptions; the use of the midpoint to represent a technology in this ranking may suggest greater precision than is warranted. For this reason, the ranking shown in Figure 11 should be considered an indicative ranking. Two resources that are adjacent in the ranking might switch places under modest changes in the assumptions. That said, the ranking is useful for visualizing the relative magnitude of costs associated with various technologies and how those are projected to compare in the next few years.

Finally, the LCOE ranking tells only part of the story. The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it. In the next section we will examine these same technologies and estimate the composite risk to consumers, the utility and its investors for each technology.

Figure 11

RELATIVE COST RANKING OF NEW GENERATION RESOURCES



The main point of this paper is that the *price* for any resource does not take into account the relative *risk* of acquiring it.

51 For example, in November 2011, the Colorado Public Utilities Commission approved a 25-year power purchase agreement between Xcel Energy and NextEra for wind generation in Colorado. The contract price is $27.50 per MWh in the first year and escalates at 2 percent per year. The levelized cost of the contract over 25 years is $34.75, less than the assumed lowest price for onshore wind with incentives in 2015 in Figure 10. For details, see Colorado PUC Decision No. C11-1291, available at http://www.colorado.gov/dora/cse-google-static/?q=C11-1291&cof=FORIDA10&ie=UTF-8&sa=Search. For more on wind power cost reductions, see Ryan Wiser et al., "Recent Developments in the Levelized Cost of Energy from U.S. Wind Power Projects" (presentation materials funded by the Wind and Water Power Program of the U.S. Department of Energy, February 2012), http://eetd.lbl.gov/ea/ems/reports/wind-energy-costs-2-2012.pdf. For information on recent PV cost reductions, see Solar Energy Industries Association (SEIA), *U.S. Solar Market Insight Report: 2011 Year in Review: Executive Summary* (Washington, DC: Solar Energy Industries Association, 2012), 10-11, http://www.seia.org/cs/research/solarinsight.

RELATIVE RISK OF NEW GENERATION RESOURCES

In Figure 7 on p. 21, we identified many of the time-related and cost-related risks that attach to a decision to choose a utility resource. We will now examine various generation resource choices in light of these risks, grouping those examples of risk into seven categories:

- **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and zoning
- **Carbon Price Risk:** includes state or federal limits on greenhouse gas emissions
- **Water Constraint Risk:** includes the availability and cost of cooling and process water
- **Capital Shock Risk:** includes availability and cost of capital, and risk to firm due to project size
- **Planning Risk:** includes risk of inaccurate load forecasts, competitive pressure

These risks are discussed in detail below.

CONSTRUCTION COST RISK

Construction cost risk is the risk that the cost to develop, finance and construct a generation resource will exceed initial estimates. This risk depends on several factors, including the size of the project, the complexity of the technology, and the experience with developing and building such projects. The riskiest generation resources in this regard are technologies still in development, such as advanced nuclear and fossil-fired plants with carbon capture and storage. Construction cost risk is especially relevant for nuclear plants due to their very large size and long lead times. (Recall that a large percentage of the disallowed investment during the 1980s was for nuclear plants.) Transmission line projects are also subject to cost overruns, as are other large generation facilities. For example, Duke Energy's Edwardsport coal gasification power plant in Indiana has experienced billion-dollar cost overruns that have raised the installed cost to $5,593 per kilowatt, up from an original estimate of $3,364 per kilowatt.[52]

The lowest construction cost risk attaches to energy efficiency and to renewable technologies with known cost histories. In the middle will be technologies that are variations on known technologies (e.g., biomass) and resources with familiar construction regimes (e.g., gas and coal thermal plants).

Intermittency vs. Risk

Certain resources, like wind, solar, and some hydropower facilities, are termed "intermittent" or "variable" resources. This means that while the power produced by them can be well characterized over the long run and successfully predicted in the short run, it cannot be precisely scheduled or dispatched. For that reason, variable resources are assigned a relatively low "capacity value" compared to base load power plants. The operating characteristics of any resource affect how it is integrated into a generation portfolio, and how its output is balanced by other resources.

This characteristic, intermittency, should not be confused with the concept of risk. Recall that risk is the expected value of a loss. In this case, the "loss" would be that the plant does not perform as expected—that it does not fulfill its role in a generation portfolio. For wind or solar resources, intermittency is expected and is accommodated in the portfolio design. Thus, while individual wind towers might be highly intermittent, and a collection of towers in a wind farm less so, a wind farm can also be termed highly reliable and present low risk because it will likely operate as predicted.

FUEL AND OPERATING COST RISK

Fossil-fueled and nuclear generation is assigned "medium risk" for the potential upward trend of costs and the volatility familiar to natural gas supply.[53] Efficiency and renewable generation have no "fuel" risk. Biomass is assigned "medium" in this risk category because of a degree of uncertainty about the cost and environmental assessment of that fuel. Plants with higher labor components (e.g., nuclear, coal) have higher exposure to inflationary impacts on labor costs.

Analysts are split on the question of the future price of natural gas. The large reserves in shale formations and the ability to tap those resources economically through new applications of technology suggest that the price of natural gas may remain relatively low for the future and that the traditional volatility of natural gas prices will dampen. On the other hand, there remains substantial uncertainty about the quantity of economically recoverable shale gas reserves and controversy about the industrial processes used to develop these unconventional resources.

52 John Russell, "Duke CEO about plant: 'Yes, it's expensive,'" *The Indianapolis Star,* October 27, 2011, http://www.indystar.com/article/20111027/NEWS14/110270360/star-watch-duke-energy-Edwardsport-iurc.

53 Research conducted by the late economist Shimon Awerbuch demonstrated that adding renewable resources to traditional fossil portfolios lowers portfolio risk by hedging fuel cost variability; see Awerbuch, "How Wind and Other Renewables Really Affect Generating Costs: A Portfolio Risk Approach" (presentation at the European Forum for Renewable Energy Resources, Edinburgh, UK, October 7, 2005), http://www.eufores.org/uploads/media/Awerbuch-edinburgh_risk-portoflios-security-distver-Oct-20051.pdf. For a discussion of using renewable energy to reduce fuel price risk and environmental compliance in utility portfolios, see Mark Bolinger and Ryan Wiser, *Balancing Cost and Risk: The Treatment of Renewable Energy in Western Utility Resource Plans* (Berkeley, CA: Lawrence Berkeley National Laboratory, 2005), http://eetd.lbl.gov/ea/ems/reports/58450.pdf.

There is also significant debate at the moment about the future price of coal. Some sources of low-sulfur coal are being depleted, raising the specter of higher production costs. Further, U.S. exports to China and other countries suggest upward pressure on this traditionally stable-priced fuel.

In this report we have steered a middle course on natural gas and coal prices, assuming that the risk of future surprises in natural gas and coal availability and price to be "medium." This is consistent with the price projection for these two generation fuels used by the Energy Information Administration in its current long-term energy forecast. In its most recent estimate, EIA assumes a real annual price escalation between 2010 and 2035 of about 1.3 percent for coal at the mine mouth and 1.8 percent for natural gas at the wellhead.[54]

Finally, operating cost risk includes the potential for catastrophic failure of a resource. This is especially significant for systems that could be taken down by a single point of failure. Contrast the impact of the failure of a turbine at a large steam plant as compared to the failure of a single turbine at a 100-turbine wind farm. The first failure causes the unavailability of 100 percent of capacity; the second failure causes a 1 percent reduction in capacity availability. Even if the probabilities of the failures are widely different, the size of the loss (risk) has cost implications for the reserve capacity (insurance) that must be carried on the large plant. Small outages are much easier to accommodate than large ones.[55]

Intermittency should not be confused with the concept of risk… For wind or solar resources, intermittency is expected and is accommodated in the portfolio design.

Modularity and unit size are also relevant to demand-side resources that are, by their nature, diverse. Designing good energy efficiency programs involves scrutinizing individual measures for the potential that they may not deliver the expected level of energy savings over time. This estimate can be factored into expectations for overall program performance so that the resource performs as expected. Since it would be extremely unlikely for individual measure failures to produce a catastrophic loss of the resource, diverse demand-side resources are, on this measure, less risky than large generation-side resources.

NEW REGULATION RISK

Nuclear generation is famously affected by accidents and the resulting changes in regulations. The recent accident at Fukushima in Japan illustrates how even a seemingly settled technology—in this case, GE boiling water reactors—can receive increased regulatory scrutiny. Further, the future of nuclear waste disposal remains unclear, even though the current fleet of reactors is buffered by reserves that are designed to cover this contingency. For these reasons, we consider nuclear power to face a high risk of future regulations.

Carbon sequestration and storage (CCS) appears to be subject to similar elevated risks regarding liability. The ownership and responsibility for long-term maintenance and monitoring for carbon storage sites will remain an unknown risk factor in coal and gas generation proposed with CCS.

Other thermal generation (e.g., biomass and geothermal) are also given a "medium" probability due to potential air regulations and land use regulations. Finally, as noted above, the price of natural gas, especially shale gas produced using "fracking" techniques, is at risk of future environmental regulation.

CARBON PRICE RISK

Fossil generation without CCS has a high risk of being affected by future carbon emission limits. Although there is no political agreement on the policy mechanism to place a cost on carbon (i.e., tax or cap), the authors expect that the scientific evidence of climate change will eventually compel concerted federal action and that greenhouse gas emissions will be costly for fossil-fueled generation. Energy efficiency, renewable and nuclear resources have no exposure to carbon risk, at least with respect to emissions at the plant.[56]

A more complex story appears when we consider the emissions related to the full life-cycle of generation technologies and their fuel cycles. For example, nuclear fuel production is an energy-intensive and carbon-intensive process on its own. As the cost of emitting carbon rises, we should expect the cost of nuclear fuel to rise.

Similar comments could apply to renewable facilities that require raw materials and fabrication that will, at least in the near-term, involve carbon-emitting production processes. However, these effects are second-order and much smaller than the carbon impact of primary generation fuels or motive power (e.g., coal, gas, wind, sun, nuclear reactions). The exposure of biomass to carbon constraints will depend on the eventual interpretation of carbon offsets and life-cycle analyses. For that reason, biomass and co-firing with biomass is assigned a non-zero risk of "low."

54 U.S. Energy Information Administration, *AEO2012 Early Release Overview*, 12-13.

55 This discussion refers to the *availability factor* of a resource; the *capacity factor* of a resource is a different issue, with implications for generation system design and operation.

56 For a discussion of how larger amounts of energy efficiency in a utility portfolio can reduce risk associated with carbon regulation, see Ryan Wiser, Amol Phadke and Charles Goldman, *Pursuing Energy Efficiency as a Hedge against Carbon Regulatory Risks: Current Resource Planning Practices in the West*, Paper 20 (Washington DC: U.S. Department of Energy Publications, 2008), http://digitalcommons.unl.edu/usdoepub/20.

"Retire or Retrofit" Decisions for Coal-Fired Plants

In this report, we've stressed how risk-aware regulation can improve the outcomes of utility selection of new resources. But many regulators will be focusing on existing power plants during the next few years. A key question facing the industry is whether to close coal plants in the face of new and future EPA regulations, or spend money on control systems to clean up some of the plant emissions and keep them running.

States and utilities are just coming to grips with these sorts of decisions. In 2010, Colorado implemented the new Clean Air Clean Jobs Act, under which the Colorado PUC examined Xcel Energy's entire coal fleet. The Colorado Commission entered a single decision addressing the fate of ten coal units. Some were closed, some were retrofitted with pollution controls, and others were converted to burn natural gas. Elsewhere, Progress Energy Carolinas moved decisively to address the same issue with eleven coal units in North Carolina.

We expect that three types of coal plants will emerge in these analyses: plants that should obviously be closed; newer coal plants that should be retrofitted and continue to run; and "plants in the middle." Decisions about these plants in the middle will require regulators to assess the risk of future fuel prices, customer growth, environmental regulations, capital and variable costs for replacement capacity, etc. In short, state commissions will be asked to assess the risks of various paths forward for the plants for which the economics are subject to debate.

The tools we describe in this report for new resources apply equally well to these situations. Regulators should treat this much like an IRP proceeding (see "Utilizing Robust Planning Processes" on p. 40). Utilities should be required to present multiple different scenarios for their disposition of coal plants. The cost and risk of each scenario should be tested using sensitivities for fuel costs, environmental requirements, cost of capital, and so forth. At the end, regulators should enter a decision that addresses all of the relevant risks.

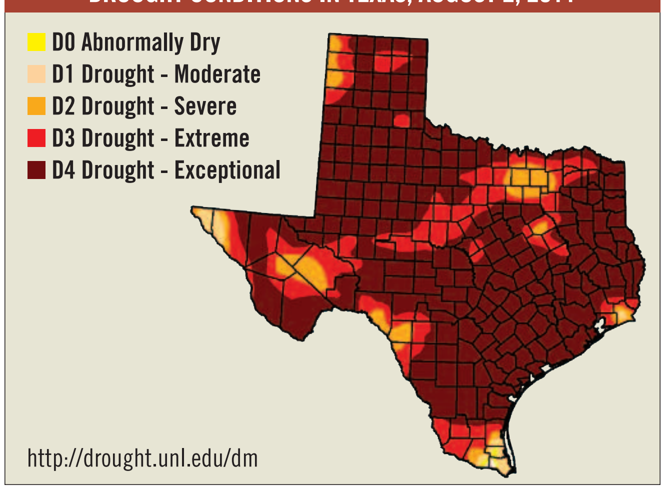
WATER CONSTRAINT RISK

Electric power generation—specifically the cooling of power plants—consumes about 40 percent of all U.S. freshwater withdrawals.[57] The availability and cost of water required for electricity generation will vary with geography but attaches to all of the thermal resources.[58] The recent promulgation by the EPA of the "once-through" cooling rule illustrates the impact that federal regulation can have on thermal facilities; one estimate predicts that more than 400 generating plants providing 27 percent of the nation's generating capacity may need to install costly cooling towers to minimize impacts on water resources.[59] One potential approach, especially for solar thermal, is the use of air-cooling, which significantly lowers water use at a moderate cost to efficiency. Non-thermal generation and energy efficiency have no exposure to this category of risk.

Water emerged as a significant issue for the U.S. electric power sector in 2011. A survey of more than 700 U.S. utility leaders by Black & Veatch indicated "water management was rated as the business issue that could have the greatest impact on the utility industry."[60] Texas suffered from record drought in 2011 at the same time that it experienced all-time highs in electricity demand. **Figure 12** depicts widespread "exceptional drought" conditions in Texas on August 2, 2011,[61] the day before the Electric Reliability Council of Texas (ERCOT) experienced record-breaking peak demand. ERCOT managed to avoid rolling blackouts but warned that continued drought and lack of sufficient cooling water could lead to generation outages totaling "several thousand megawatts."[62]

Figure 12

DROUGHT CONDITIONS IN TEXAS, AUGUST 2, 2011



57 J.F. Kenny et al., "Estimated use of water in the United States in 2005," *U.S. Geological Survey Circular 1344* (Reston, VA: U.S. Geological Survey, 2009), http://pubs.usgs.gov/circ/1344/pdf/c1344.pdf.

58 For a discussion of freshwater use by U.S. power plants, see Kristen Averyt et al., *Freshwater Use by U.S. Power Plants* (Cambridge, MA: Union of Concerned Scientists, 2011), http://www.ucsusa.org/assets/documents/clean_energy/ew3/ew3-freshwater-use-by-us-power-plants.pdf.

59 Bernstein Research, *U.S. Utilities: Coal-Fired Generation is Squeezed in the Vice of EPA Regulation; Who Wins and Who Loses?* (New York: Bernstein Research, 2010), 69.

60 "U.S. Utility Survey Respondents Believe Energy Prices Will Rise Significantly, Place Emphasis on Growing Nexus of Water and Energy Challenge," Black & Veatch press release, June 13, 2011, http://www.bv.com/wcm/press_release/06132011_9417.aspx.

61 National Drought Mitigation Center, "U.S. Drought Monitor: Texas," August 2, 2011, http://droughtmonitor.unl.edu/archive/20110802/pdfs/TX_dm_110802.pdf.

62 Samantha Bryant, "ERCOT examines grid management during high heat, drought conditions," *Community Impact Newspaper*, October 14, 2011, http://impactnews.com/articles/ercot-examines-grid-management-during-high-heat,-drought-conditions.

In addition to drought, water rights could be an issue for electricity generators in Texas (and elsewhere).[63] The North American Electric Reliability Corporation (NERC) points out that in an extreme scenario, up to 9,000 MW of Texas' generation capacity—over 10 percent of ERCOT's total installed capacity—could be at risk of curtailment if generators' water rights were recalled.[64]

CAPITAL SHOCK RISK

This risk is generally proportional to the size of the capital outlay and the time required for construction of a generating unit. Simply put, the larger the capital outlay and the longer that cost recovery is uncertain, the higher the risk to investors. In this regard, nuclear installations and large new coal facilities with CCS face the highest risk. Smaller, more modular additions to capacity and especially resources that are typically acquired through purchase power agreements record less risk. Finally, distributed solar generation, modifications to enable biomass co-firing and efficiency are accorded low exposure to the risk of capital shock.

PLANNING RISK

This risk relates to the possibility that the underlying assumptions justifying the choice of a resource may change, sometimes even before the resource is deployed. This can occur, for example, when electric demand growth is weaker than forecast, which can result in a portion of the capacity of the new resource being excess. In January 2012, lower-than-anticipated electricity demand, combined with unexpectedly low natural gas prices, led Minnesota-based wholesale cooperative Great River Energy to mothball its brand-new, $437 million Spiritwood coal-fired power plant immediately upon the plant's completion. The utility will pay an estimated $30 million next year in maintenance and debt service for the idled plant.[65]

Generation projects with a high ratio of fixed costs and long construction lead times are most susceptible to planning risk. This means that the exposure of base load plants is higher than peaking units, and larger capacity units have more exposure than smaller plants.

In addition to macroeconomic factors like recessions, the electric industry of the early 21st century poses four important unknown factors affecting energy planning. These are 1) the rate of adoption of electric vehicles; 2) the pace of energy efficiency and demand response deployment; 3) the rate of growth of customer-owned distributed generation; and 4) progress toward energy storage. These four unknowns affect various resources in different ways.

Electric vehicles could increase peak demand if customers routinely charge their cars after work, during the remaining hours of the afternoon electrical peak. On the other hand, if electric vehicle use is coupled with time-of-use pricing, this new load has the opportunity to provide relatively desirable nighttime energy loads, making wind generation and nuclear generation and underutilized fossil generation more valuable in many parts of the country.

Energy efficiency (EE) and demand response (DR) affect both electricity (kilowatt-hours) and demand (kilowatts). EE and DR programs differ in relatively how much electricity or demand they conserve. Depending on portfolio design, EE and DR may improve or worsen utility load factors, shifting toward more peaking resources and away from base load plants. Changing customer habits and new "behavioral" EE efforts add to the difficulty in forecasting demand over time.

Distributed generation, especially small solar installation, is expanding rapidly, spurred by new financing models that have lowered the capital outlay from consumers. In addition, we may expect commercial and industrial customers to continue to pursue combined heat and power applications, especially if retail electricity rates continue to rise. Both of these trends will have hard-to-predict impacts on aggregate utility demand and the relative value of different generation resources, but also impacts on primary and secondary distribution investment.

Finally, electric storage at reasonable prices would be a proverbial game-changer, increasing the relative value of intermittent resources such as wind and solar. Microgrids with local generation would also be boosted by low-cost battery storage.

63 For a discussion of how water scarcity could impact municipal water and electric utilities and their bondholders, see Sharlene Leurig, *The Ripple Effect: Water Risk in the Municipal Bond Market* (Boston, MA: Ceres, 2010), http://www.ceres.org/resources/reports/water-bonds/at_download/file. For a framework for managing corporate water risk, see Brooke Barton et al., *The Ceres Aqua Gauge: A Framework for 21st Century Water Risk Management* (Boston, MA: Ceres, 2011), http://www.ceres.org/resources/reports/aqua-gauge/at_download/file.

64 North American Electric Reliability Corporation, *Winter Reliability Assessment 2011/2012* (Atlanta, GA: North American Electric Reliability Corporation, 2011), 29, http://www.nerc.com/files/2011WA_Report_FINAL.pdf.

65 David Shaffer, "Brand new power plant is idled by economy," *Minneapolis StarTribune*, January 9, 2012, http://www.startribune.com/business/134647533.html.

Figure 13

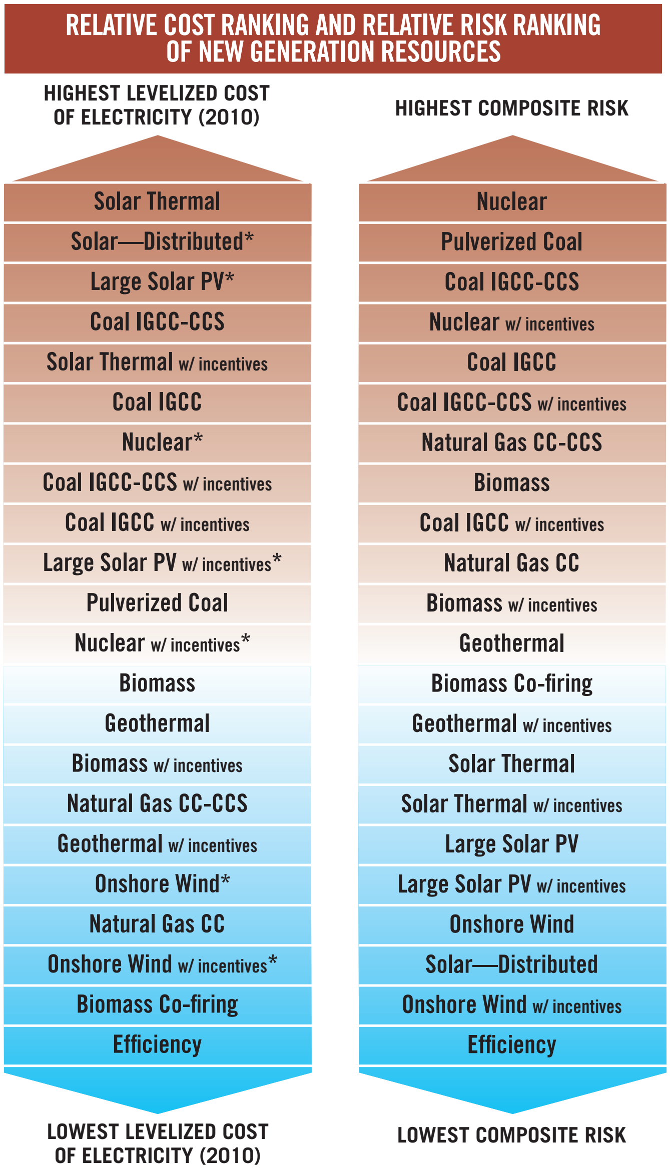
RELATIVE RISK EXPOSURE OF NEW GENERATION RESOURCES							
Resource	Initial Cost Risk	Fuel, O&M Cost Risk	New Regulation Risk	Carbon Price Risk	Water Constraint Risk	Capital Shock Risk	Planning Risk
Biomass	Medium	Medium	Medium	Medium	High	Medium	Medium
Biomass w/ incentives	Medium	Medium	Medium	Medium	High	Low	Medium
Biomass Co-firing	Low	Low	Medium	Low	High	Low	Low
Coal IGCC	High	Medium	Medium	Medium	High	Medium	Medium
Coal IGCC w/ incentives	High	Medium	Medium	Medium	High	Low	Medium
Coal IGCC-CCS	High	Medium	Medium	Low	High	High	High
Coal IGCC-CCS w/ incentives	High	Medium	Medium	Low	High	Medium	High
Efficiency	Low	None	Low	None	None	Low	None
Geothermal	Medium	None	Medium	None	High	Medium	Medium
Geothermal w/ incentives	Medium	None	Medium	None	High	Low	Medium
Large Solar PV	Low	None	Low	None	None	Medium	Low
Large Solar PV w/ incentives	Low	None	Low	None	None	Low	Low
Natural Gas CC	Medium	High	Medium	Medium	Medium	Medium	Medium
Natural Gas CC-CCS	High	Medium	Medium	Low	High	High	Medium
Nuclear	Very High	Medium	High	None	High	Very High	High
Nuclear w/ incentives	Very High	Medium	High	None	High	High	Medium
Onshore Wind	Low	None	Low	None	None	Low	Low
Onshore Wind w/ incentives	Low	None	Low	None	None	None	Low
Pulverized Coal	Medium	Medium	High	Very High	High	Medium	Medium
Solar - Distributed	Low	None	Low	None	None	Low	Low
Solar Thermal	Medium	None	Low	None	High	Medium	Medium
Solar Thermal w/ incentives	Medium	None	Low	None	High	Low	Medium

ESTABLISHING COMPOSITE RISK

In line with the foregoing discussion, the table in **Figure 13** summarizes the degree of exposure of various generation technologies to these seven categories of risk. The technologies listed are taken from UCS's LCOE ranking in Figure 10 on p. 28, plus three more: natural gas combined cycle with CCS, biomass co-firing and distributed solar PV generation. The chart estimates the degree of risk for each resource across seven major categories of risk, with estimates ranging from "None" to "Very High."

Three comments are in order. First, these assignments of relative risk were made by the authors, and while they are informed they are also subjective. As we discuss later, regulators should conduct their own robust examination of the relative costs and risks including those that are unique to their jurisdiction. Second, the assessment of risk for each resource is intended to be relative to each other, and not absolute in a quantitative sense. Third, while there are likely some correlations between these risk categories—resources with low fuel risk will have low carbon price exposure, for example—other variables exhibit substantial independence.

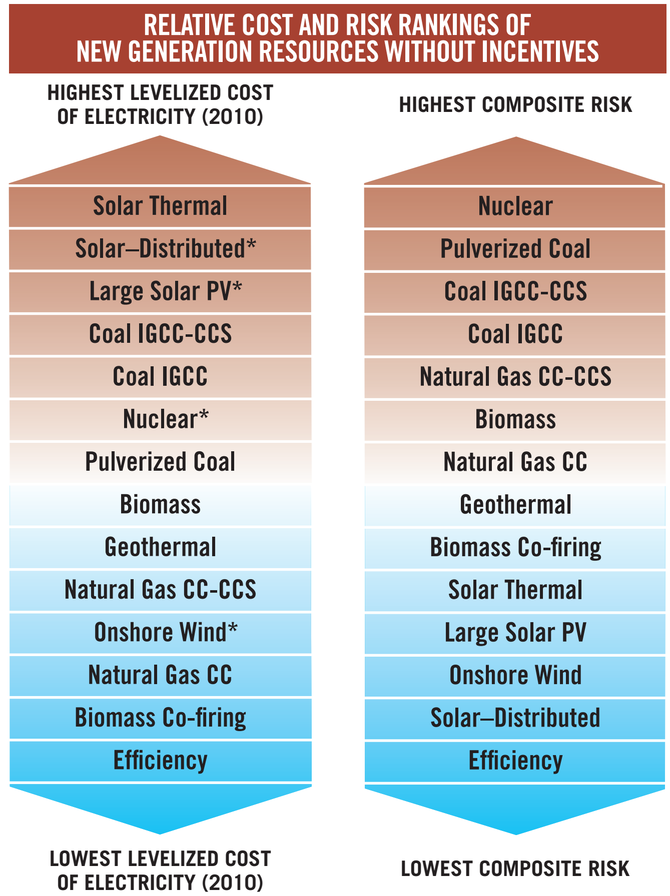
Figure 14



Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.

The risk ranking shows a clear difference between renewable resources and non-renewable resources. Nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

Figure 15



Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.

To derive a ranking of these resources with respect to risk, we assigned numeric values to the estimated degrees of risk (None=0, Very High=4) and totaled the rating for each resource. The scores were then renormalized so that the score of the highest-risk resource is 100 and the others are adjusted accordingly. The composite relative risk ranking that emerges is shown in **Figure 14**, which, for ease of comparison, we present alongside the relative cost ranking from Figure 11.

The risk ranking differs from the cost ranking in several important ways. First, the risk ranking shows a clear difference between renewable resources and non-renewable resources. Second, nuclear generation moves from the middle of the cost ranking to the top of the risk ranking. Notably, energy efficiency ranks lowest in both cost and risk.

To illustrate how resources stack up against each other in more general terms, and for simplicity of viewing, **Figure 15** presents those same rankings without information about incentives.

To test the robustness of the composite risk ranking, we also examined two rankings where the scores were weighted. In one case, the environmental factors were given double weight; in the other, the cost factors were given double weight. As before, the scores were renormalized so that the highest-scoring resource is set to 100. The results of the unweighted ranking, together with the two weighted rankings, are shown in **Figure 16**. By inspection, one can see that the rank order changes very little across the three methods, so that the risk ranking in Figure 14 appears to be relatively robust. Once again, we emphasize that these figures are intended to show the relative risk among the resources, not to be absolute measures of risk.[66]

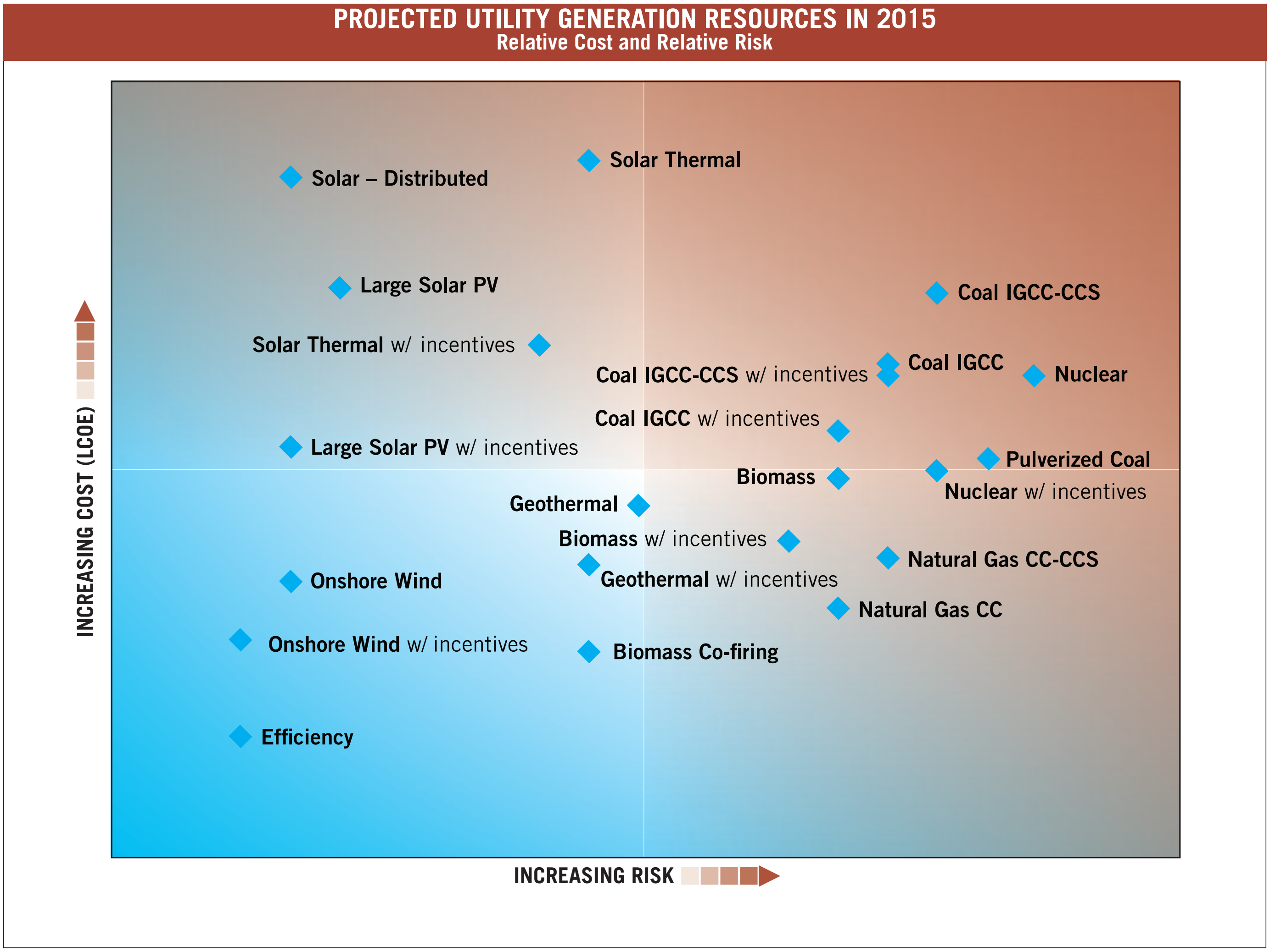
Figure 16

SUMMARY OF RISK SCORES FOR NEW GENERATION RESOURCES

Resource	Composite Score	Environmental Weighted Score	Cost Weighted Score
Biomass	79	79	72
Biomass w/ incentives	74	76	66
Biomass Co-firing	53	57	44
Coal IGCC	84	83	79
Coal IGCC w/ incentives	79	79	72
Coal IGCC-CCS	89	84	87
Coal IGCC-CCS w/ incentives	84	81	80
Efficiency	16	14	16
Geothermal	58	59	52
Geothermal w/ incentives	53	55	46
Large Solar PV	26	22	28
Large Solar PV w/ incentives	21	19	21
Natural Gas CC	79	76	75
Natural Gas CC-CCS	84	79	82
Nuclear	100	91	100
Nuclear w/ incentives	89	83	89
Onshore Wind	21	19	21
Onshore Wind w/ incentives	16	16	15
Pulverized Coal	95	100	82
Solar - Distributed	21	19	21
Solar Thermal	53	52	49
Solar Thermal w/ incentives	47	48	43

66 Dr. Mark Cooper, a longtime utility sector analyst and supporter of consumer interests, recently arrived at similar conclusions about composite risk; see Cooper, *Least-Cost Planning For 21st Century Electricity Supply* (So. Royalton, VT: Vermont Law School, 2011), http://www.vermontlaw.edu/Documents/21st%20Century%20Least%20Cost%20Planning.pdf. Cooper's analysis incorporated not only variations in "risk" and "uncertainty," but also the degrees of "ignorance" and "ambiguity" associated with various resources and the universe of possible future energy scenarios.

Figure 17



Finally, we can combine the information in the cost ranking and the risk ranking into a single chart. **Figure 17** shows how resources compare with each other in the two dimensions of cost and risk. The position of a resource along the horizontal axis denotes the relative risk of each resource, while the position on the vertical axis shows the relative cost of the resource.

4. PRACTICING RISK-AWARE REGULATION:

SEVEN ESSENTIAL STRATEGIES FOR STATE REGULATORS

UTILITY REGULATORS ARE FAMILIAR WITH A SCENE THAT PLAYS OUT IN THE HEARING ROOM: DIFFERENT INTERESTS—UTILITIES, INVESTORS, CUSTOMER GROUPS, ENVIRONMENTAL ADVOCATES AND OTHERS—COMPETE TO REDUCE COST AND RISK FOR THEIR SECTOR AT THE EXPENSE OF THE OTHERS. WHILE THE ADVERSARIAL PROCESS MAY MAKE THIS COMPETITION SEEM INEVITABLE, AN OVERLOOKED STRATEGY (THAT USUALLY LACKS AN ADVOCATE) IS TO REDUCE OVERALL RISK TO EVERYONE. MINIMIZING RISK IN THE WAYS DISCUSSED IN THIS SECTION WILL HELP ENSURE THAT ONLY THE UNAVOIDABLE BATTLES COME BEFORE REGULATORS AND THAT THE PUBLIC INTEREST IS SERVED FIRST.

Managing risk intelligently is arguably the main duty of regulators who oversee utility investment. But minimizing risk isn't simply achieving the least cost today. It is part of a strategy to *minimize overall long term costs*. And, as noted earlier, while minimizing risk is a worthy goal, eliminating risk is not an achievable goal. The regulatory process must provide balance for the interests of utilities, consumers and investors in the presence of risk.

One of the goals of "risk-aware" regulation is avoiding the kind of big, costly mistakes in utility resource acquisition that we've seen in the past. But there is another, more affirmative goal: ensuring that society's limited resources (and consumers' limited dollars) are spent wisely. By routinely examining and addressing risk in every major decision, regulators will produce lower cost outcomes in the long run, serving consumers and the public interest in a very fundamental way.

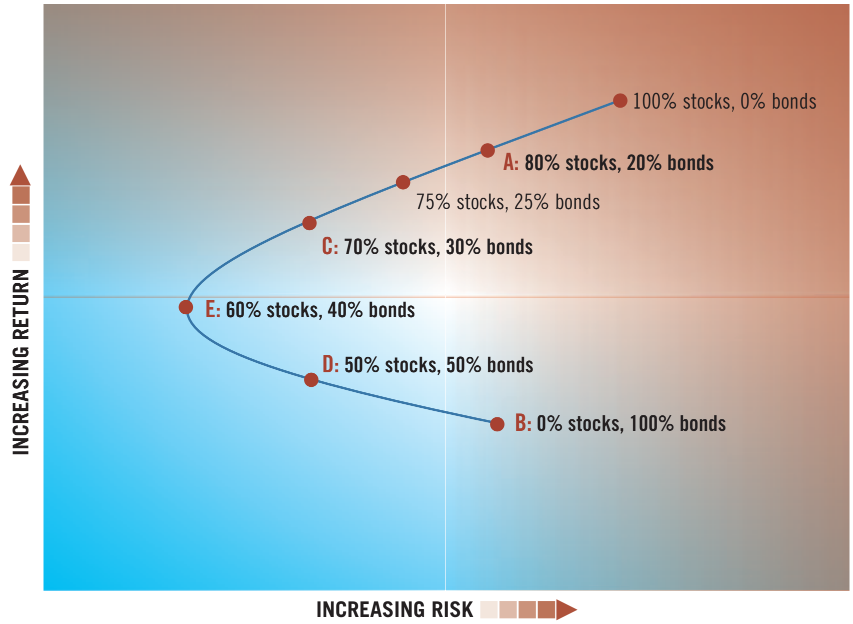
An overlooked strategy (that usually lacks an advocate) is to reduce overall risk to everyone.

WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS CAN EMPLOY TO MINIMIZE RISK:

1. **DIVERSIFYING UTILITY SUPPLY PORTFOLIOS** with an emphasis on low-carbon resources;
2. **UTILIZING ROBUST PLANNING PROCESSES** for all utility investment (i.e., generation, transmission, distribution, and demand-side resources like energy efficiency);
3. **EMPLOYING TRANSPARENT RATEMAKING PRACTICES** that reveal risk;
4. **USING FINANCIAL AND PHYSICAL HEDGES**, including long-term contracts;
5. **HOLDING UTILITIES ACCOUNTABLE** for their obligations and commitments;
6. **OPERATING IN ACTIVE, "LEGISLATIVE" MODE**, continually seeking out and addressing risk;
7. **REFORMING AND RE-INVENTING RATEMAKING POLICIES** as appropriate.

Figure 18

RISK/RETURN RELATIONSHIPS AMONG DIFFERENT FINANCIAL PORTFOLIOS
(Illustrative)



We now discuss each of these strategies in more detail.

1. DIVERSIFYING UTILITY SUPPLY PORTFOLIOS

The concept of diversification plays an important role in finance theory. Diversification—investing in different asset classes with different risk profiles—is what allows a pension fund, for example, to reduce portfolio volatility and shield it from outsized swings in value.

Properly chosen elements in a diversified portfolio can increase return for the same level of risk, or, conversely, can reduce risk for a desired level of return. The simple illustration in **Figure 18** allows us to consider the relative risk and return for several portfolios consisting of stocks and bonds. Portfolio A (80% stocks, 20% bonds) provides a higher predicted return than Portfolio B (0% stocks, 100% bonds) even though both portfolios have the same degree of risk. Similarly, Portfolios C and D produce different returns at an identical level of risk that is lower than A and B. Portfolio E (60% stocks, 40% bonds) has the lowest risk, but at the cost of a lower return than Portfolios A and C. The curve in Figure 18 (and the corresponding surface in higher dimensions) is called an *efficient frontier*.

We could complicate the example—by looking at investments in cash, real estate, physical assets, commodities or credit default swaps, say, or by distinguishing between domestic and international stocks, or between bonds of various maturities—but the general lesson would be the same: diversification helps to lower the risk in a portfolio.

Portfolios of utility investments and resource mixes can be analyzed similarly. Instead of return and risk, the analysis would examine cost and risk. And instead of stocks, bonds, real estate and gold, the elements of a utility portfolio are different types of power plants, energy efficiency, purchased power agreements, and distributed generation, among many other potential elements. Each of these elements can be further distinguished by type of fuel, size of plant, length of contract, operating characteristics, degree of utility dispatch control, and so forth. Diversification in a utility portfolio means including various supply and demand-side resources that behave independently from each other in different future scenarios. Later we will consider these attributes in greater detail and discuss what constitutes a diversified utility portfolio.

For a real-world illustration of how diversifying resources lowers cost and risk in utility portfolios, consider the findings of the integrated resource plan recently completed by the Tennessee Valley Authority (TVA).[67] TVA evaluated five resource strategies that were ultimately refined into a single "recommended planning direction" that will guide TVA's resource investments. The resource strategies that TVA considered were:

- **Strategy A:** Limited Change in Current Resource Portfolio[68]
- **Strategy B:** Baseline Plan Resource Portfolio
- **Strategy C:** Diversity Focused Resource Portfolio
- **Strategy D:** Nuclear Focused Resource Portfolio
- **Strategy E:** EEDR (Energy Efficiency/Demand Response) and Renewables Focused Resource Portfolio

67 TVA, a corporation owned by the federal government, provides electricity to nine million people in seven southeastern U.S. states; see http://www.tva.com/abouttva/index.htm.

68 As of spring 2010, TVA's generation mix consisted mainly of coal (40 percent), natural gas (25 percent) and nuclear (18 percent); see TVA, 73.

Figure 19

TVA ANALYSIS OF RESOURCE PLAN COSTS & FINANCIAL RISK

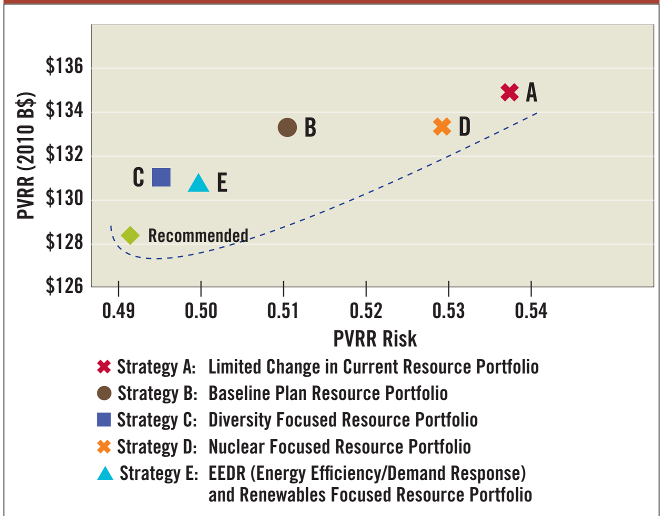


Figure 19 illustrates how these strategies mapped out along an "efficient frontier" according to TVA's analysis of cost and risk.[69] The lowest-cost, lowest-risk strategies were the ones that diversified TVA's resource portfolio by increasing TVA's investment in energy efficiency and renewable energy.[70] The highest-cost, highest-risk strategies were those that maintained TVA's current resource portfolio (mostly coal, natural gas and nuclear) or emphasized new nuclear plant construction.

The TVA analysis is very careful and deliberate. To the extent that other analyses reached conclusions thematically different from TVA's, we would question whether the costs and risks of all resources had been properly evaluated. We would also posit that resource investment strategies that differ directionally from TVA's "recommended planning direction" would likely expose customers (and, to some extent, investors) to undue risk. Finally, given the industry's familiarity with traditional resources—and the possibility that regulators and utilities may therefore underestimate the costs and risks of those resources—the TVA example illustrates how careful planning reveals the costs and risks of maintaining resource portfolios that rely heavily on large base load fossil and nuclear plants.

Robust planning processes like TVA's are therefore essential to making risk-aware resource choices. It is to these planning processes that we now turn.

2. UTILIZING ROBUST PLANNING PROCESSES

In the U.S., there are two basic utility market structures: areas where utilities own or control their own generating resources (the "vertically integrated" model), and areas where competitive processes establish wholesale prices (the "organized market" model).

In many vertically integrated markets and in some organized markets, regulators oversee the capital investments of utilities with a process called "integrated resource planning," or IRP. Begun in the 1980s, integrated resource planning is a tool to ensure that the utilities, regulators and other stakeholders have a common understanding of a full spectrum of possible utility resources; that the options are examined in a structured, disciplined way in administrative proceedings; that demand-side resources get equal consideration alongside supply-side resources; and that the final resource plan is understood (if not necessarily accepted) by all.

Elements of a Robust IRP Process

IRP oversight varies in sophistication, importance and outcomes across the states. Because a robust IRP process is critical to managing risk in a utility, we describe a model IRP process that is designed to produce utility portfolios that are lower risk and lower cost.[71]

These elements characterize a robust IRP process:

- The terms and significance of the IRP approval (including implications for cost recovery) are clearly stated at the outset, often in statute or in a regulatory commission's rules.
- The regulator reviews and approves the modeling inputs used by the utility (e.g., demand and energy forecasts, fuel cost projections, financial assumptions, discount rate, plant costs, fuel costs, energy policy changes, etc.).
- The regulator provides guidance to utility as to the policy goals of the IRP, perhaps shaping the set of portfolios examined.
- Utility analysis produces a set of resource portfolios and analysis of parameters such as future revenue requirement, risk, emissions profile, and sensitivities around input assumptions.
- In a transparent public process, the regulator examines competing portfolios, considering the utility's analysis as well as input from other interested parties.
- Demand resources such as energy efficiency and demand response are accorded equal status with supply resources.
- The regulator approves a plan and the utility is awarded a "presumption of prudence" for actions that are consistent with the approved IRP.
- The utility acquires (i.e., builds or buys) the resources approved in the IRP, possibly through a competitive bidding regime.
- Future challenges to prudence of utility actions are limited to the execution of the IRP, not to the selection of resources approved by the regulator.

69 TVA, 161.

70 In the end, TVA settled on a "recommended planning direction" that calls for demand reductions of 3,600 to 5,100 MW, energy efficiency savings of 11,400 to 14,400 GWh, and renewable generating capacity additions of 1,500 to 2,500 MW by 2020. At the same time, TVA plans to retire 2,400 to 4,700 MW of coal-fired capacity by 2017. See TVA, 156.

71 For an example of an IRP that uses sophisticated risk modeling tools, see PacifiCorp, *2011 Integrated Resource Plan* (Portland, OR: PacifiCorp, 2011), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf.

IRP: "Accepted" vs. "Approved" Plans

There are two varieties of IRP plans: "accepted plans" and "approved plans." Accepted plans are those where regulators examine the utility's process for developing its proposed plan. This can be a thorough review in which the Commission solicits the opinion of other parties as to whether the utility undertook a transparent, inclusive, and interactive process. If the regulator is convinced, the regulator "accepts" the utility's plan. This allows the utility to proceed but does not include any presumption about the Commission's future judgment concerning the prudence of actions taken under the plan.

With an "approved plan" the regulator undertakes a thorough review of the utility's preferred plan, possibly along with competing IRP plans submitted by other parties. Typically the scrutiny is more detailed and time-consuming in this version of IRP and the regulatory agency is immersed in the details of competing plans. At the end of the process, the regulator "approves" an IRP plan. This approval typically carries with it a presumption that actions taken by the utility consistent with the plan (including its approved amendments) are prudent. Over time, a Commission that approves an IRP plan will typically also examine proposed changes to the plan necessitated by changing circumstances.

In this report, we will focus on the "approved plan" process, although many of our findings apply equally to regulators that employ the "accepted plan" process.

A few of these elements deserve more elaboration.

Significance. The IRP must be meaningful and enforceable; there must be something valuable at stake for the utility and for other parties. From the regulator's point of view, the resource planning process must review a wide variety of portfolio choices whose robustness is tested and compared under different assumptions about the future. From the utilities' perspective, acceptance or approval of an IRP should convey that regulators support the plan's direction, even though specific elements may evolve as circumstances change. If a utility ignores the approved IRP or takes actions that are inconsistent with an IRP without adequate justification, such actions may receive extra scrutiny at the point where the utility seeks cost recovery.

Multiple scenarios. Many different scenarios will allow a utility to meet its future load obligations to customers. These scenarios will differ in cost, risk, generation characteristics, fuel mix, levels of energy efficiency, types of resources, sensitivity to changes in fuel cost, and so forth. While one scenario might apparently be lowest cost under baseline assumptions, it may not be very resilient under different input assumptions. Further, scenarios will differ in levels of risk and how that risk may be apportioned to different parties (e.g., consumers or shareholders). Regulators, with input from interested parties, should specify the types of scenarios that utilities should model and require utilities to perform sensitivity analyses, manipulating key variables.

Consistent, active regulation. An IRP proceeding can be a large, complex undertaking that occurs every two or three years, or even less frequently. It is critical that regulators become active early in the process and stay active throughout. The regulator's involvement should be consistent, even-handed and focused on the big-ticket items. Of course, details matter, but the process is most valuable when it ensures that the utility is headed in the right direction and that its planning avoids major errors. The regulator should then monitor a utility's performance and the utility should be able to trust the regulator's commitment to the path forward laid out in the IRP.

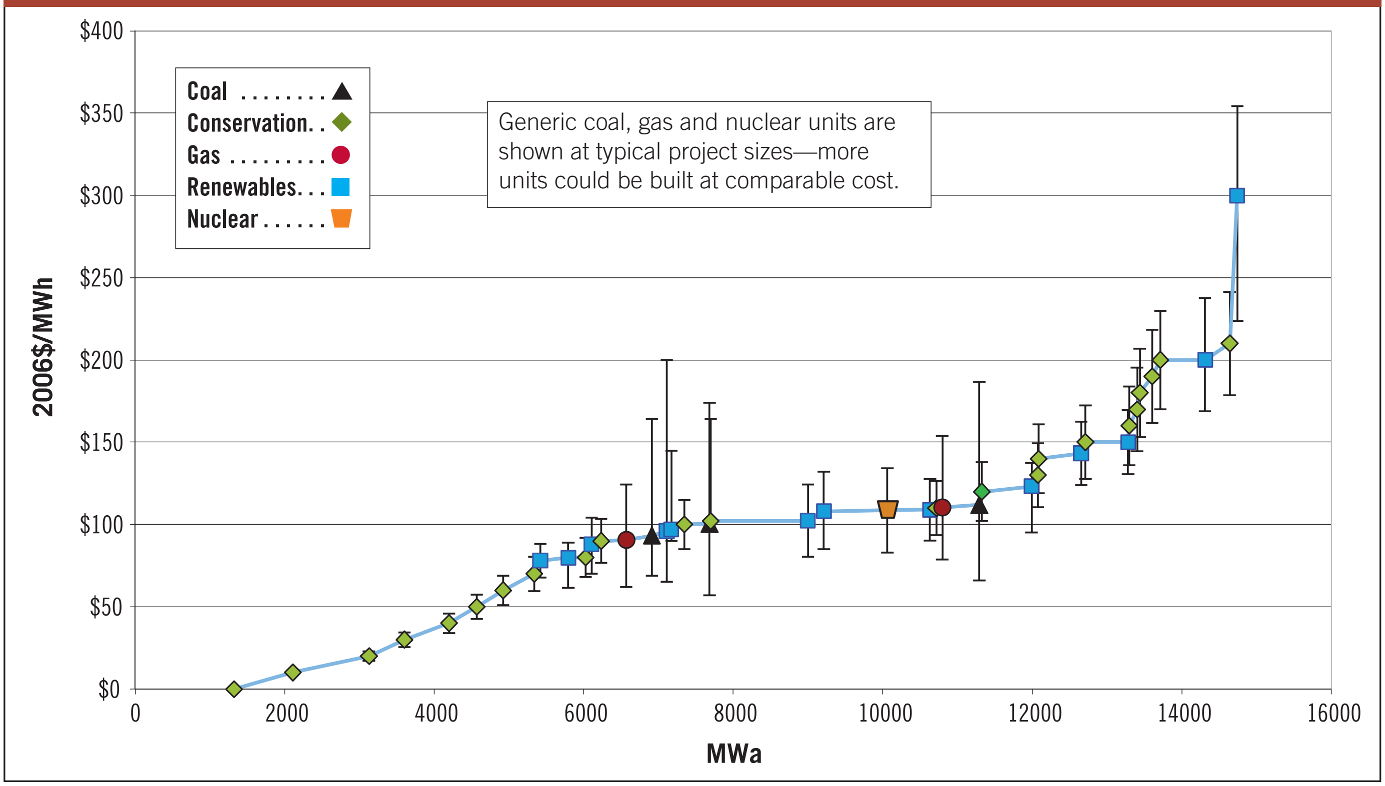
Stakeholder involvement. There are at least two good reasons to encourage broad stakeholder involvement in an IRP process. First, parties besides the utility will bring new ideas, close scrutiny and contrasting analysis to the IRP case, all of which helps the regulator to make an informed, independent decision. Second, effective stakeholder involvement can build support for the IRP that is ultimately approved, heading off collateral attacks and judicial appeals. An approved IRP will affect the fortunes of many and will signal the direction that the regulator wishes the utility to take with its supply-side and demand-side resources. Because an IRP decision is something of a political document in addition to being a working plan, regulators will be well-served to include as broad a group of stakeholders as possible when developing the IRP.

An approved IRP will affect the fortunes of many and will signal the direction that the regulator wishes the utility to take with its supply-side and demand-side resources… [R]egulators will be well-served to include as broad a group of stakeholders as possible when developing the IRP.

Transparency. Regulators must ensure that, to the greatest extent possible, all parties participating in the IRP process have timely access to utility data. Certain data may be competitively sensitive and there is often pressure on the regulator to restrict unduly the access to such data. One possible solution to this challenge is to use an "independent evaluator" who works for the commission, is trusted by all parties and has access to all the data, including proprietary data. The independent evaluator can verify the modeling of the utility and assist the regulator in making an informed decision. The cost of an independent evaluator will be small in comparison to the benefits (or avoided mistakes) that the evaluator will enable. An independent evaluator will also add

Figure 20

PORTFOLIO ANALYSIS ON ONE PAGE
How Energy Efficiency Can Substitute for Generation Resources



credibility to the regulators' decision. In any event, the integrity of the IRP process will depend on regulators' ability to craft processes that are trusted to produce unbiased results.

Competitive bidding. A successful IRP will lower risk in the design of a utility resource portfolio. After the planning process, utilities begin acquiring approved resources. Some states have found it beneficial to require the utility to undertake competitive bidding for all resources acquired by a utility pursuant to an IRP. If the utility will build the resource itself, the regulator may require the utility to join the bidding process or commit to a cap on the construction cost of the asset.[72]

Role of Energy Efficiency. A robust IRP process will fully consider the appropriate levels of energy efficiency, including demand response and load management, that a utility should undertake. Properly viewed and planned for, energy efficiency can be considered as equivalent to a generation resource. Regulators in some states list projected energy efficiency savings on the "loads and resources table" of the utility, adjacent to base load and peaking power plants. In Colorado, energy efficiency is accorded a "reserve margin" in the integrated resource plan, as is done with generation resources.[73]

Since its inception in 1980, the Northwest Power and Conservation Council, which develops and maintains a regional power plan for the Pacific Northwest, has stressed the role of energy efficiency in meeting customers' energy needs. **Figure 20** shows the Council's analysis, demonstrating the elements of a diversified energy portfolio and the role that energy efficiency (or "conservation") can play in substituting for generation resources at various levels of cost.[74]

Appendix 2 contains additional discussion of some of the modeling tools available to regulators.

3. EMPLOYING TRANSPARENT RATEMAKING PRACTICES

Economist Alfred Kahn famously observed that "all regulation is incentive regulation," meaning that any type of economic regulation provides a firm with incentives to make certain choices. Indeed, utility rate regulation's greatest effect may not be its ability to limit prices for consumers in the short run, but rather the incentives it creates for utilities in the longer run.

72 For a discussion of the use of competitive bidding in resource acquisition, see Susan F. Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices* (Boston, MA: Analysis Group, 2008), http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Competitive_Procurement.pdf.

73 For Xcel Energy in Colorado, energy efficiency is listed on the "loads and resources" table as a resource. As such, it is logical that some fraction of the planned-for load reduction might not materialize. That portion is then assigned the standard resource reserve margin of approximately 15 percent. The planning reserve margin is added to the projected peak load, which must be covered by the combined supply-side and demand-side resources in the table.

74 Tom Eckman, "The 6th Power Plan… and You" (presentation at the Bonneville Power Administration Utility Energy Efficiency Summit, Portland, Ore., March 17, 2010), http://www.bpa.gov/Energy/N/utilities_sharing_ee/Energy_Smart_Awareness/pdf/OA_EESummit_Gen-Session_Public_Power.pdf.

There have been many debates through the years about the incentives that utility cost of service regulation provides. These range from the academic and formal (e.g., the aforementioned Averch-Johnson effect, which says that rate-regulated companies will have an inefficiently high ratio of capital to labor) to the common sense (e.g., price cap regulation can induce companies to reduce quality of service; the throughput incentive discourages electric utilities from pursuing energy efficiency, etc.).

While regulators may want to limit their role to being a substitute for the competition that is missing in certain parts of the electric industry, it is rarely possible to limit regulation's effects that way. The question is usually not how to eliminate stray incentives in decisions, but rather which ones to accept and address.

To contain risk and meet the daunting investment challenges facing the electric industry, regulators should take care to examine exactly what incentives are being conveyed by the details of the regulation they practice. We examine four components of cost of service regulation that affect a utility's perception of risk, and likely affect its preference for different resources.

Current Return on Construction Work in Progress. There is a long-standing debate about whether a utility commission should allow a utility to include in its rates investment in a plant during the years of its construction. Construction Work in Progress, or "CWIP," is universally favored by utility companies and by some regulators, but almost universally opposed by advocates for small and large consumers and by other regulators. CWIP is against the law in some states, mandated by law in others.

The main argument against CWIP is that it requires consumers to pay for a plant often years before it is "used and useful," so that there isn't a careful match between the customers who pay for a plant and those who benefit from it. Proponents of CWIP point out that permitting a current return on CWIP lessens the need for the utility to issue debt and equity, arguably saving customers money, and that CWIP eases in the rate increase, compared to the case where customers feel the full costs of an expensive plant when the plant enters service. Opponents counter by noting that customers typically have a higher discount rate than the utilities' return on rate base, so that delaying a rate hike is preferred by consumers, even if the utility borrows more money to finance the plant until it enters service.

Setting aside the near-religious debate about the equity of permitting CWIP in rate base, there is another relevant consideration. Because CWIP can help utilities secure financing and phase in rate increases, CWIP is often misunderstood as a tool for reducing risk. This is not true.

CWIP, Risk Shifting and Progress Energy's Levy Nuclear Plant

In late 2006, Progress Energy announced plans to build a new nuclear facility in Levy County, Florida, a few months after the state legislature approved construction work in progress (CWIP) customer financing. The site is about 90 miles north of Tampa, near the Gulf of Mexico. In 2009, Progress customers began paying for the Levy plant, which was expected to begin service in 2016 and be built at a cost of $4-6 billion. By the end of 2011, Progress customers had paid $545 million toward Levy's construction expenses.

The Levy plant is now projected to cost up to $22 billion, roughly four times initial estimates, and that number could keep climbing. (In March 2012, Progress Energy's market value as a company was almost $16 billion; the combined market value of Duke Energy and Progress Energy, which are seeking to merge and are pursuing construction of five nuclear facilities between them, is about $44 billion.) Levy's expected in-service date has pushed beyond 2021 and possibly as late as 2027—eighteen years after Progress customers began paying for the plant. Progress has estimated that by 2020, Levy-related expenses could add roughly $50 to the average residential customer's monthly bill.

The Levy plant's development appeared to take a step forward in December 2011 when the Nuclear Regulatory Commission approved its reactor design. But in February 2012, the Florida Public Service Commission approved a settlement agreement allowing Progress to suspend or cancel Levy's construction and recover $350 million from customers through 2017.

It is unclear whether Levy will ever be built. If the plant is canceled, Progress customers will have paid more than $1 billion in rates for no electricity generation, and Florida state law prohibits their recouping any portion of that investment. Such an outcome could help to deteriorate the political and regulatory climate in which Progress operates, which could ultimately impact credit ratings and shareholder value.

CWIP does nothing to actually reduce the risks associated with the projects it helps to finance. Construction cost overruns can and do still occur (see the text box about Progress Energy's Levy County nuclear power plant); O&M costs for the plant can still be unexpectedly high; anticipated customer load may not actually materialize; and so forth. What CWIP does is to reallocate part of the risk from utilities (and would-be bondholders) to customers. CWIP therefore provides utilities with both the incentive and the means to undertake a riskier investment than if CWIP were unavailable.

Regulators must be mindful of the implications of allowing a current return on CWIP, and should consider limiting its use to narrow circumstances and carefully drawn conditions of oversight. Regulators should also pay close attention to how thoroughly utility management has evaluated the risks associated with the projects for which it requests CWIP. Regardless of CWIP's other merits or faults, an important and too-often unacknowledged downside is that it can obscure a project's risk by shifting, not reducing, that risk.

Use of Rider Recovery Mechanisms. Another regulatory issue is the use by utilities of rate "riders" to collect investment or expenses. This practice speeds up cash flow for utilities, providing repayment of capital or expense outlays more rapidly than would traditional cost of service regulation. This allows utilities to begin collecting expenses and recovering capital without needing to capitalize carrying costs or file a rate case. Once again, regulators must consider whether these mechanisms could encourage a utility to undertake a project with higher risk, for the simple reason that cost recovery is assured even before the outlay is made.

Allowing a current return on CWIP, combined with revenue riders, is favored by many debt and equity analysts, who perceive these practices as generally beneficial to investors. And indeed, these mechanisms allow bondholders and stock owners to feel more assured of a return of their investment. And they might marginally reduce the utility's cost of debt and equity. But these mechanisms (which, again, transfer risk rather than actually reducing it) could create a "moral hazard" for utilities to undertake more risky investments. A utility might, for example, proceed with a costly construction project, enabled by CWIP financing, instead of pursuing market purchases of power or energy efficiency projects that would reduce or at least delay the need for the project. If negative financial consequences of such risky decisions extended beyond customers and reached investors, the resulting losses would be partially attributable the same risk-shifting mechanisms that analysts and investors originally perceived as beneficial.

Construction Cost Caps. Some regulatory agencies approve a utility's proposed infrastructure investments only after a cap is established for the amount of investment or expense that will be allowed in rates. Assuming the regulator sticks to the deal, this action will apportion the risk between consumers and investors. We wouldn't conclude that this actually reduces risk except in the sense that working under a cap might ensure that utility management stays focused on the project, avoiding lapses into mismanagement that would raise costs and likely strain relationships with regulators and stakeholders.

Rewarding Energy Efficiency. Another relevant regulatory practice concerns the treatment of demand-side resources like energy efficiency and demand response. It is well understood that the "throughput incentive" can work to keep a utility from giving proper consideration to energy efficiency; to the extent that a utility collects more than marginal costs in its unit price for electricity, selling more electricity builds the bottom line while selling less electricity hurts profitability. There are several adjustments regulation can make, from decoupling revenues from sales, to giving utilities expedited cost recovery and incentives for energy efficiency performance. Decoupling, which guarantees that a utility will recover its authorized fixed costs regardless of its sales volumes, is generally viewed by efficiency experts and advocates as a superior approach because it neutralizes the "throughput incentive" and enables utilities to dramatically scale up energy efficiency investment without threatening profitability. Ratings agencies view decoupling mechanisms as credit positive because they provide assurance of cost recovery, and Moody's recently observed "a marked reduction in a company's gross profit volatility in the years after implementing a decoupling type mechanism."[75] Whatever the chosen approach, the takeaway here is that without regulatory intervention, energy efficiency will not likely be accorded its correct role as a low cost and low risk strategy.[76]

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4. USING FINANCIAL AND PHYSICAL HEDGES

Another method for limiting risk is the use of financial and physical hedges. These provide the utility an opportunity to lock in a price, thereby avoiding the risk of higher market prices later. Of course, this means the utility also foregoes the opportunity for a lower market price, while paying some premium to obtain this certainty.

Financial hedges are instruments such as puts, calls, and other options that a utility can purchase to limit its price exposure (e.g., for commodity fuels) to a certain profile. If the price of a commodity goes up, the call option pays off; if the price goes down, the put option pays off. Putting such a collar around risk is, of course, not free: the price of an option includes transaction costs plus a premium reflecting the instrument's value to the purchaser. Collectively these costs can be viewed as a type of insurance payment.

Another example of a financial hedge is a "temperature" hedge that can limit a utility's exposure to the natural gas price spikes that can accompany extreme weather conditions. A utility may contract with a counter-party so that, for an agreed price, the counter-party agrees to pay a utility if the number of heating-degree-days exceeds a certain level during a certain winter period. If the event never happens,

75 Moody's Investors Service, *Decoupling and 21st Century Rate Making* (New York: Moody's Investors Service, 2011), 4.

76 For a discussion of regulatory approaches to align utility incentives with energy efficiency investment, see Val Jensen, *Aligning Utility Incentives with Investment in Energy Efficiency*, ICF International (Washington, DC: National Action Plan for Energy Efficiency, 2007), http://www.epa.gov/cleanenergy/documents/suca/incentives.pdf.

Long-term Contracts for Natural Gas

In recent decades, utilities have mostly used financial instruments to hedge against volatile natural gas prices, and natural gas supply used for power generation has not been sold under long-term contracts. An exception is a recent long-term contract for natural gas purchased by Xcel Energy in Colorado. The gas will be used to fuel new combined cycle units that will replace coal generating units. The contract between Xcel Energy and Anadarko contained a formula for pricing that was independent of the market price of natural gas and runs for 10 years.

The long-term natural gas contract between Xcel Energy and Anadarko was made possible by a change in Colorado's regulatory law. For years, utilities and gas suppliers had expressed concern that a long-term contract, even if approved initially as prudent, might be subject to a reopened regulatory review if the price paid for gas under the contract was, at some future date, above the prevailing market price. Colorado regulators supported legislation making it clear in law that a finding of prudence at the outset of a contract would not be subject to future review if the contract price was later "out of the money." An exception to this protection would be misrepresentation by the contracting parties.

the utility forfeits the payment made for the hedge. If the event does happen, the utility might still need to purchase natural gas at an inflated price; even so, the hedge would pay off because it has reduced the company's total outlay. Simply stated, financial hedges can be used by a utility to preserve an expected value.

An illustration of a physical hedge would be when a utility purchases natural gas at a certain price and places it into storage. The cost of that commodity is now immune to future fluctuations in the market price. Of course, there is a cost to the utility for the storage, and the utility forgoes the possible advantage of a future lower price. But in this case the payment (storage cost) is justifiable because of the protection it affords against the risk of a price increase.

Long-term contracts can also serve to reduce risk. These instruments have been used for many years to hedge against price increases or supply interruptions for coal. Similarly, long-term contracts are used by utilities to lock in prices paid to independent power producers. Many power purchase agreements (PPAs) between distribution utilities and third party generators lock in the price of capacity, possibly with a mutually-agreed price escalator. But due to possible fuel price fluctuations (especially with natural gas), the fuel-based portion of the energy charge is not fixed in these contracts. So PPAs can shield utilities from some of the risks of owning the plants, but they do not hedge the most volatile portion of natural gas generation: the cost of fuel.

Regulated utilities and their regulators must come to an understanding about whether and how utilities will utilize these options to manage risk, since using them can foreclose an opportunity to enjoy lower prices.

5. HOLDING UTILITIES ACCOUNTABLE

From the market's perspective, one of the most important characteristics of a public utilities commission is its consistency. Consumers don't like surprises, and neither do investors. Financial analysts who rate regulatory climates across the states typically rank stability as one of the highest virtues for regulators. Indeed, this quality is often viewed to be as important as the absolute level of return on equity approved by a commission.

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Effective regulation—regulation that is consistent, predictable, forward-thinking and "risk-aware"—requires that regulators hold utilities accountable for their actions. Earlier, we stressed the value of regulators being actively involved in the utility resource planning process. But this tool works well only if regulators follow through—by requiring utilities to comply with the resource plan, to amend the resource plan if circumstances change, to live within an investment cap, to adhere to a construction schedule, and so forth. If the utility doesn't satisfy performance standards, regulatory action will be necessary.

This level of activity requires a significant commitment of resources by the regulatory agency. Utility resource acquisition plans typically span ten years or more, and a regulator must establish an oversight administrative structure that spans the terms of sitting commissioners in addition to clear expectations for the regulated companies and well-defined responsibilities for the regulatory staff.

6. OPERATING IN ACTIVE, "LEGISLATIVE" MODE

As every commissioner knows, public utility regulation requires regulators to exercise a combination of judicial and legislative duties. In "judicial mode," a regulator takes in evidence in formal settings, applies rules of evidence, and decides questions like the interpretation of a contract or the level of damages in a complaint case. In contrast, a regulator operating in "legislative mode" seeks to gather all information relevant to the inquiry at hand and to find solutions to future challenges. Judicial mode looks to the past, legislative mode

to the future. In his 1990 essay, former Ohio utilities regulator Ashley Brown put it this way:

> *Gathering and processing information is vastly different in judicial and legislative models. Legislating, when properly conducted, seeks the broadest data base possible. Information and opinions are received and/or sought, heard, and carefully analyzed. The process occurs at both formal (e.g., hearings) and informal (e.g., private conversation) levels. The goal is to provide the decision maker with as much information from as many perspectives as possible so that an informed decision can be made. Outside entities can enhance, but never be in a position to limit or preclude, the flow of information. The decision maker is free to be both a passive recipient of information and an active solicitor thereof. The latter is of particular importance in light of the fact that many of the interests affected by a decision are not likely to be present in the decision making forum.*[77]

Being a risk-aware regulator requires operating in legislative mode in regulatory proceedings, and especially in policy-making proceedings such as rulemakings. But the courts have also found that ratemaking is a proper legislative function of the states.[78] And since this state legislative authority is typically delegated by legislatures to state regulators, this means that, to some extent, regulators may exercise "legislative" initiative even in rate-setting cases.

In a recent set of essays, Scott Hempling, the former executive director of the National Regulatory Research Institute, contrasts regulatory and judicial functions and calls for active regulation to serve the public interest:

> *Courts and commissions do have commonalities. Both make decisions that bind parties. Both base decisions on evidentiary records created through adversarial truth-testing. Both exercise powers bounded by legislative line-drawing. But courts do not seek problems to solve; they wait for parties' complaints. In contrast, a commission's public interest mandate means it literally looks for trouble. Courts are confined to violations of law, but commissions are compelled to advance the public welfare.*[79]

Utility resource planning is one of the best examples of the need for a regulator to operate in legislative mode. When examining utilities' plans for acquiring new resources, regulators must seek to become as educated as possible. Up to a point, the more choices the better. The regulator should insist that the utility present and analyze multiple alternatives. These alternatives should be characterized fully, fairly, and without bias. The planning process should seek to discover as much as possible about future conditions, and the door should be opened to interveners of all stripes. Knowing all of the options—not simply the ones that the utility brings forward—is essential to making informed, risk-aware regulatory decisions.

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7. REFORM AND RE-INVENT RATEMAKING PRACTICES

It is increasingly clear that a set of forces is reshaping the electric utility business model. In addition to the substantial investment challenge discussed in this report, utilities are facing challenges from stricter environmental standards, growth in distributed generation, opportunities and challenges with the creation of a smarter grid, new load from electric vehicles, pressure to ramp up energy efficiency efforts—just to mention a few. As electric utilities change, regulators must be open to new ways of doing things, too.

77 Ashley Brown, "The Over-judicialization of Regulatory Decision Making," *Natural Resources and Environment* Vol. 5, No. 2 (Fall 1990), 15-16.

78 See, e.g., U.S. Supreme Court, *Munn vs. Illinois*, 94 U.S. 113 (1876), http://supreme.justia.com/cases/federal/us/94/113/case.html.

79 Scott Hempling, *Preside or Lead? The Attributes and Actions of Effective Regulators* (Silver Spring, MD: National Regulatory Research Institute, 2011), 22.

Today's energy industry faces disruptions similar to those experienced by the telecommunications industry over the past two decades. To deal with the digital revolution in telecommunications and the liberalization of those markets, regulators modernized their tools to include various types of incentive regulation, pricing flexibility, lessened regulation in some markets and a renewed emphasis on quality of service and customer education.

One area where electric utility regulators might profitably question existing practices is rate design. Costing and pricing decisions, especially for residential and small business customers, have remained virtually unchanged for decades. The experience in other industries (e.g., telecommunications, entertainment, music) shows that innovations in pricing are possible and acceptable to consumers. Existing pricing structures should be reviewed for the incentives they provide for customers and the outcomes they create for utilities.

The risk-aware regulator must be willing to think "way outside the box" when it comes to the techniques and strategies of effective regulation. Earlier we observed that effective regulators must be informed, active, consistent, curious and often courageous. These qualities will be essential for a regulator to constructively question status quo regulatory practice in the 21st century.

THE BENEFITS OF "RISK-AWARE REGULATION"

We have stressed throughout this report that effective utility regulators must undertake a lot of hard work and evolve beyond traditional practice to succeed in a world of changing energy services, evolving utility companies and consumer and environmental needs. What can regulators and utilities reasonably expect from all this effort? What's the payback if regulators actively practice "risk-aware regulation"?

- **FIRST**, there will be benefits to consumers. A risk-aware regulator is much less likely to enter major regulatory decisions that turn out wrong and hurt consumers. The most costly regulatory lapses over the decades have been approval of large investments that cost too much, failed to operate properly, or weren't needed once they were built. It's too late for any regulator to fix the problem once the resulting cost jolts consumers.
- **SECOND**, there will be benefits to regulated utilities. Risk aware regulation will create a more stable, predictable business environment for utilities and eliminate most regulatory surprises. It will be easier for these companies to plan for the longer-term. If regulators use a well-designed planning process, examining all options and assessing risks, utilities and their stakeholders will have greater reliance on the long-term effect of a decision.
- **THIRD**, investors will gain as well. Steering utilities away from costly mistakes, holding the companies responsible for their commitments and, most importantly, maintaining a consistent approach across the decades will be "credit-positive," reducing threats to cost-recovery. Ratings agencies will take notice, lowering the cost of debt, benefitting all stakeholders.
- **FOURTH**, governmental regulation itself will benefit. Active, risk-aware regulators will involve a wide range of stakeholders in the regulatory process, building support for the regulators' decision. Consistent, transparent, active regulation will help other state officials—governors and legislators—develop a clearer vision of the options for the state's energy economy.
- **FINALLY**, our entire society will benefit as utilities and their regulators develop a cleaner, smarter, more resilient electricity system. Regulation that faithfully considers all risks, including the future environmental risks of various utility investments, will help society spend its limited resources most productively. In other words, risk-aware regulation can improve the economic outcome of these large investments.

With two trillion dollars on the line, both the stakes and the potential benefits are high. If history is a guide, fewer than 700 state regulators will serve in office during the next 20 years. Practicing risk-aware regulation will enable them to avoid expensive mistakes and identify the most important utility investments for realizing the promise of an advanced 21st century electricity system.

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APPENDIX 1:

UNDERSTANDING UTILITY FINANCE

MOST INVESTOR-OWNED UTILITIES (IOUS) IN THE UNITED STATES ARE IN A CONSTRUCTION CYCLE OWING TO THE NEED TO COMPLY WITH MORE STRINGENT AND EVOLVING ENVIRONMENTAL POLICIES AND TO IMPROVE AGING INFRASTRUCTURE. NEW INFRASTRUCTURE PROJECTS INCLUDE SMART GRID, NEW GENERATION AND TRANSMISSION. THE IOUS, THEREFORE, WILL BE LOOKING TO THE CAPITAL MARKETS TO HELP FINANCE THEIR RATHER LARGE CAPITAL EXPENDITURE PROGRAMS.

DEBT FINANCING

While the IOUs will be issuing some additional equity, a higher percentage of the new investment will be financed with debt. In general, utilities tend to be more leveraged than comparably-rated companies in other sectors (see the Rating Agencies section below). The electric utility sector's debt is primarily publicly issued bonds, including both first mortgage bonds (FMB) and senior unsecured bonds. While the utilities also issue preferred stock and hybrid debt securities, these instruments tend to represent a small portion of a company's capital structure. Non-recourse project finance is rare for utilities, but it is commonly used by unregulated affiliates.

Most regulated IOUs in the U.S. are owned by holding companies whose assets are primarily their equity interests in their respective subsidiaries. These operating company subsidiaries are typically wholly owned by the parent, so that all publicly-held stock is issued by the parent. Because most of these holding companies are quite large, the market for a holding company's stock is usually highly liquid.

In contrast to equity, bonds are issued by both the utility holding company and individual operating subsidiaries. Typically, holding and operating company bonds are non-recourse to affiliates. This means that each bond issuer within the corporate family will have its own credit profile that affects the price of the respective bonds. To illustrate this point, compare two American Electric Power subsidiaries, Ohio Power and Indiana Michigan. The companies have different regulators, generation mix, customer bases and, consequently, different senior unsecured Moody's bond ratings of Baa1 and Baa2, respectively. For this reason, each bond issuance of the corporate family trades somewhat independently.

Utility bonds trade in secondary markets and are traded over-the-counter rather than in exchanges like equities. For bond issuance of less than $300 million, the secondary market is illiquid and not very robust. Smaller utilities are frequently forced into the private placement market with their small issuances and accordingly pay higher interest rates compared to similarly-rated larger companies. Even if these smaller issues are placed in the public market, there is a premium for the expected lack of liquidity.

Secured debt in the form of FMBs is common in the electric utility sector. Such bonds are usually secured by an undivided lien on almost all of the assets of an operating utility. Bond documentation (called an "indenture") prohibits the issuance of such bonds in an amount that exceeds a specified percentage (usually in the range of 60 percent) of the asset value of the collateral. The maturities of these bonds are frequently as long as 30 years, and in rare occasions longer). While the lien on assets may limit a company's financing flexibility, the interest rate paid to investors is lower than for unsecured debt. The proceeds from FMBs are usually used to finance or refinance long-lived assets.

Senior unsecured bonds can be issued at any maturity, but terms of five and ten years are most common. These instruments are "junior" to FMBs, so that, in an event of default, these debt holders would be repaid only after the secured debt. But these bonds are "senior" to hybrids and preferred stock. In a bankruptcy, senior unsecured bonds are usually deemed equal in standing with trade obligations, such as unpaid fuel and material bills.

Utilities typically have "negative trade cycles," meaning that cash receipts tend to lag outlays. IOUs' short-term payables such as fuel purchases, salaries and employee benefits are due in a matter of days after the obligation is incurred. In contrast, the utility's largest short-term assets are usually customer receivables which are not due for 45—60 days after the gas or electricity is delivered. Therefore, utilities have short term cash needs referred to as "working capital" needs. To finance these short term needs utilities have bank credit lines and sometimes trade receivable facilities.

For larger utility corporate families, these bank lines can amount to billions of dollars. For example, American Electric Power has two large bank lines of $1.5 and $1.7 billion that mature in 2015 and 2016, respectively. AEP's lines and most of those of other utilities are revolving in nature. While termination dates typically range from one to five years for these lines, the utility usually pays down borrowings in a few months and accesses the line again when needed.

Interest on bank lines of credit is paid only when the lines are used, with a much lower fee paid on the unused portion of the lines. For financially weak utility companies, banks often require security for bank lines . But because utility operating companies are rarely rated below BBB-/Baa3, bank lines are, for the most part, unsecured.

Some larger utilities have receivable facilities in addition to revolving bank lines. The lender in a receivables facility usually purchases the customer receivables. There is an assumed interest expense in these transactions which is usually lower than the rate charged by banks for unsecured revolving lines.

Although preferred stock is a form of equity, it is usually purchased by a bond investor who is comfortable with the credit quality of the issuer and willing to take a junior position in order to get a higher return on its investment. There are also hybrid securities. Although they are technically debt instruments, they are so deeply subordinate and with such long repayment periods that investors and the rating agencies view these instruments much like equities. Frequently, hybrids allow the issuer to defer interest payments for a number of years. Some hybrids can be converted to equity at either the issuer's or investor's option.

S&P is the most rigorous of the rating agencies in treating the fixed component of power purchase agreements (PPA) as debt-like in nature. Also, some Wall Street analysts look at PPAs as liabilities with debt-like attributes. That being said, those analysts who do not consider PPAs as debt-like still incorporate in their analysis the credit implications of these frequently large obligations.

EQUITY FINANCING

In order to maintain debt ratings and the goodwill of fixed income investors, utility managers must finance some portion of their projects with equity. Managements are usually reluctant to go to market with large new stock issuances. Equity investors often see new stock as being dilutive to their interests, resulting in a decrease in the market price of the stock. But if a utility has a large capital expenditure program it may have no choice but to issue equity in order maintain its credit profile.

For more modest capital expenditure programs, a company may be able to rely on incremental increases to equity to maintain a desired debt to equity ratio. While the dividend payout ratios are high in this sector, they are rarely 100 percent, so that for most companies, equity increases, at least modestly, through retained earnings. Many companies issue equity in small incremental amounts every year to fulfill commitments to employee pension or rewards programs. Also, many utility holding companies offer their existing equity holders the opportunity to reinvest dividends in stock. For larger companies these programs can add $300 - $500 million annually in additional equity. Since these programs are incremental, stock prices are usually unaffected.

OTHER FINANCING

Project finance (PF) can also be used to fund capital expenditures. These instruments are usually asset-specific and non-recourse to the utility, so that the pricing is higher than traditional investment-grade utility debt. Project finance is usually used by financially weaker non-regulated power developers.

Some companies are looking to PF as a means of financing large projects so that risk to the utility is reduced. However, the potential of cost overruns, the long construction/development periods and use of new technology will make it hard to find PF financing for projects like new nuclear plants. This also applies to carbon capture/sequestration projects, as the technology is not seasoned enough for most PF investors. This means that, utilities may need to finance new nuclear and carbon capture/ sequestration projects using their existing balance sheets.

In order to reduce risk, a utility can pursue projects in partnership with other companies. Currently proposed large gas transport and electric transmission projects are being pursued by utility consortiums. Individual participants in gas transport projects in particular have used Master Limited Partnerships (MLPs) as a way to finance their interests. MLPs are owned by general and limited partners. Usually the general partner is the pipeline utility or a utility holding company. Limited partner units are sold to passive investors and are frequently traded on the same stock exchanges that list the parent company's common stock. One big difference between the MLP and an operating company is that earnings are not subject to corporate income tax. The unit holders pay personal income tax on the profits.

Companies have used both capital and operating lease structures to finance discrete projects, including power plants. The primary difference between an operating and capital lease is that the capital lease is reflected on the company's balance sheet. The commitment of the utility to the holder of the operating lease is deemed weaker. Most fixed income analysts, as well as the rating agencies, do not view these instruments as being materially different and treat operating leases for power plants as debt.

TYPICAL UTILITY INVESTORS

The largest buyers of utility equities and fixed income securities are large institutional investors such as insurance companies, mutual funds and pension plans. As of September 2011, 65 percent of utility equities were owned by institutions. While insurance companies and pension plans own utility equities, both trail mutual funds in the level of utility stock holdings. For example, the five largest holders of Exelon stock are mutual fund complexes.

Most retail investors own utility stock and bonds indirectly through mutual funds and 401k plans. But many individual investors also own utility equities directly, including utility employees. Small investors tend not to buy utility bonds because the secondary market in these instruments is rather illiquid, especially if the transaction size is small.

Common stock mutual funds with more conservative investment criteria are most interested in utility equities. While the market price of these stocks can vary, there is a very low probability of a catastrophic loss. Also, utility stocks usually have high levels of current income through dividend distributions. Another attractive attribute of these equities is that they are highly liquid. Essentially all utilities in the U.S. are owned by utility holding companies that issue common stock. Due to extensive consolidation in the sector over the past 20 years, these holding companies are large and have significant market capitalization. For these reasons, utility stocks are highly liquid and can be traded with limited transaction costs.

Utility fixed-income investments are far less liquid than equities. Thus, the typical bond investor holds onto the instruments much longer than the typical equity investor. Bonds are issued both by the utility holding company and individual operating subsidiaries. Because bonds are less liquid in the secondary market, investors in these instruments, such as pension plans and insurance companies, tend to have longer time horizons. Four of the top five investors in Exelon Corp bonds due 2035 are pension plans and insurance companies. Mutual bond funds tend to buy shorter-dated bonds.

The buyers of first mortgage bonds (FMBs) are frequently buy-and-hold investors. As FMBs are over-collateralized, bondholders are comfortable that they will be less affected by unforeseen negative credit events. It is not unusual for a large insurance company to buy a large piece of an FMB deal at issuance and hold it to maturity. Retail investors in utility bonds also tend to be buy-and-hold investors, as it is hard for them to divest their positions which are typically small compared to the large institutions. The relative illiquidity of utility bonds means that transaction costs can be high and greatly reduce the net proceeds from a sale.

Utility employees frequently own the stock of the companies for which they work. Employees with defined benefit pensions, however, are not large holders of utility stocks because pension plans hold little if any of an employer's stock owing to ERISA rules and prudent asset management practices. Mid-level non-unionized employees frequently have 401ks that are typically invested in mutual funds or similar instruments. However, it is not unusual for company matching of the employees' 401k contributions to be in company stock. Finally, senior management's incentive compensation is frequently paid in the company's common equity, in part to ensure that management's interests are aligned with those of the shareholders.

RATING AGENCIES

Most utilities have ratings from three rating agencies: Moody's Investors Services, Standard & Poor's Ratings Services, and Fitch Ratings. Having three ratings is unlike other sectors, which frequently use two ratings—Moody's or Standard & Poor's. Most utility bonds are held by large institutional investors who demand that issuers have at least Moody's and Standard & Poor's ratings.

Failing to have two ratings would cause investors to demand a very high premium on their investments, far more than the cost to utilities of paying the agencies to rate them. Having a third rating from Fitch usually slightly lowers the interest rate further. While investors have become less comfortable with the rating agencies' evaluations of structured finance transactions, this dissatisfaction has not carried over greatly into the corporate bond market, and especially not the utility bond market.

The agencies usually assign a rating for each company referred to as an *issuer rating*. They also rate specific debt issues, which may be higher or lower than the issuer rating. Typically a secured bond will have a higher rating than its issuer; preferred stock is assigned a lower rating than the issuer. Ratings range from AAA to D.[80] The "AAA" rating is reserved for entities that have virtually no probability of default. A "D" rating indicates that the company is in default.

The three agencies each take into account both the probability of default, as well as the prospects of recovery for the bond investor if there is a default. Utilities traditionally are considered to have high recovery prospects because they are asset-heavy companies. In other words, if liquidation were necessary, bond holders would be protected because their loans are backed by hard assets that could be sold to cover the debt. Further, the probability of default is low because utility rates are regulated, and regulators have frequently increased rates when utilities have encountered financial

80 Standard & Poor's and Fitch use the same ratings nomenclature. It was designed by Fitch and sold to S&P. For entities rated between AA and CCC the agencies break down each rating category further with a plus sign or a minus sign. For example, bonds in the BBB category can be rated BBB+, BBB and BBB-. Moody's ratings nomenclature is slightly different. The corresponding ratings in BBB category for Moody's are Baa1, Baa2 and Baa3. The agencies will also provide each rating with an outlook that is stable, positive or negative.

problems owing to events outside of companies' control. However, there are a few notable instances where commissions could not or would not raise rates to avoid defaults including the bankruptcies of Public Service of New Hampshire and Pacific Gas and Electric.

It is unusual for a utility operating company to have a non-investment grade rating (Non-IG, also referred to as high yield, speculative grade, or junk). Typically Non-IG ratings are the result of companies incurring sizable expenses for which regulators are not willing or able to give timely or adequate rate relief. Dropping below IG can be problematic for utilities because interest rates increase markedly. Large institutional investors have limited ability to purchase such bonds under the investment criteria set by their boards. Another problem with having an Non-IG rating is that the cost of hedging rises owing to increased collateral requirements as counterparties demand greater security from the weakened credit.

In developing their ratings, the agencies consider both quantitative and more subjective factors. The quantitative analysis tends to look at cash flow "coverage" of total debt and of annual fixed income payment obligations, as well as overall debt levels. In contrast, the typical equity analyst focuses on earnings. The rating agencies are less interested in the allowed returns granted by regulators than they are in the size of any rate decrease or increase and its effect on cash flow.

That said, the rating agency may look at allowed returns to evaluate the "quality" of regulation in a given state. All things being equal, they may give a higher rating to a company in a state with "constructive" regulation than to a company in a state with a less favorable regulatory climate. Constructive regulation to most rating agencies is where regulatory process is transparent and consistent across issuers in the state. Also, the agencies favor regulatory constructs that use forward-looking test years and timely recovery of prudently-incurred expenses. The agencies consider tracking mechanisms for fuel and purchased power costs as credit supportive because they help smooth out cash fluctuations. The agencies believe that while trackers result in periodic changes in rates for the customer, these mechanisms are preferable for consumers than the dramatic change in rates caused by fuel factors being lumped in with other expenses in a rate case.

Analysts also will look to see how utility managers interact with regulators. The agencies deem it a credit positive if management endeavors to develop construct relationships with regulators. The agencies may become concerned about the credit quality of a company if the state regulatory process becomes overly politicized. This may occur if a commission renders decisions with more of an eye toward making good press than applying appropriate utility regulatory standards. Politicized regulatory environments can also occur when a commission is professional and fair, but outside political forces, such as governors, attorneys general or legislators challenge a prudently decided case.

The rating agencies themselves can at times act as *de facto* regulators. Because utilities are more highly levered than most any other sector, interest expenses can be a significant part of a company's cost structure. Ratings affect interest rates. The agencies will look negatively at anything that increases event risk. The larger an undertaking, the greater the fallout if an unforeseen event undermines the project. A utility embarking on the development of a large facility like a large generation or transmission project, especially if is not preapproved by the regulators, might result in a heightened focus on the company by the agencies. The rating action could merely be change in outlook from stable to negative, which could in turn have a negative impact on the market price of outstanding bonds, interest rates on new issuances and even on equity prices. Many utility stock investors are conservative and pay more attention to rating agency comments and actions than investors with holdings in more speculative industries.

APPENDIX 2:

TOOLS IN THE IRP PROCESS

REGULATORS HAVE SEVERAL TOOLS AT THEIR DISPOSAL IN THE IRP PROCESS. ONE OF THE MOST IMPORTANT IS THE UTILITY REDISPATCH MODEL. THIS IS A COMPLEX COMPUTER PROGRAM THAT SIMULATES THE OPERATION OF A UTILITY'S SYSTEM UNDER INPUT ASSUMPTIONS PROVIDED BY THE USER. THE TERM "REDISPATCH" REFERS TO THE FACT THAT THE SOFTWARE MIMICS THE OPERATION OF AN ACTUAL UTILITY SYSTEM, "DISPATCHING" THE HYPOTHETICAL GENERATION RESOURCES AGAINST A MODEL LOAD SHAPE, OFTEN HOUR-BY-HOUR FOR MOST COMMONLY USED MODELS.

Three examples of these models are Prosym, licensed by Henwood Energy Services; Strategist, licensed by Ventyx; and GE MAPS, licensed by General Electric.

A model typically creates a 20- or 40-year future utility scenario, based on load projections provided by the user. The utility's energy and peak demand is projected for each hour of the time period, using known relationships about loads during different hours, days of the week and seasons of the year. The model then "dispatches" the most economic combination of existing or hypothetical new resources to meet the load in every hour of that time period.

The operating characteristics of each generating resource is specified as to its availability, fuel efficiency, fuel cost, maintenance schedule, and, in some models, its emissions profile. The resources available to the model will be a mixture of existing plants, taking note of their future retirement dates, plus any hypothetical new resources required by load growth. The model incorporates estimates of regional power purchases and their price, transmission paths and their constraints, fuel contracts, the retirement of existing facilities, etc.

In this way, the user of the model can test various combinations (scenarios) of proposed new generating plants, including base load plants, intermediate and peaking plants, intermittent renewable resources, etc. The model will calculate the utility's revenue requirement, fuel costs, and purchased power expenses in each scenario. The model might be used to estimate the cost of operating the system with a specific hypothetical portfolio, predict the level of emissions for a portfolio, measure the value of energy efficiency programs, test the relative value of different resources, measure the reliability of the system, etc.

The reader might analogize this modeling to "fantasy" baseball, where hypothetical teams play hypothetical games, yielding win-loss records, batting averages and pennant races.

As powerful as these modeling tools are, they are *production* models, first and foremost. As such, they are not particularly good at dealing with assumptions about energy efficiency and demand response. In using such models, the regulator must insist that the utility gives appropriate treatment to demand-side resources. It may be possible to re-work models to do this, or it may be necessary to conduct extra sensitivity analyses at varying levels of energy efficiency and demand response.

IRP SENSITIVITY ANALYSES

A redispatch modeling tool allows a utility and the regulator to test the resilience of portfolios against different possible futures. For example, a regulator might want to know how five different generation portfolios behave under situations of high natural gas prices, or tougher environmental regulations. By varying the input assumptions while monitoring the relevant output (e.g., net present value of future revenue requirements) the regulator can assess the risk that contending portfolios pose to future rates if, for example, fuel prices vary from their predicted levels.

To illustrate this idea, consider the following material from a case in Colorado. **Figure Appendix - 1** is a page excerpted from Xcel Energy's 2009 analysis in support of a resource plan filed before the Colorado Public Utilities Commission. The page shows the results of sensitivity analyses for the price of natural gas (high and low) and the cost of carbon emissions (high and low) for twelve different portfolios being considered by the Colorado PUC.

In all, the Colorado PUC studied 48 different generation portfolios in this IRP case. The portfolios differed based on how much natural gas generation was added, how much wind and solar generation was added, the schedule for closing some existing coal-fired power plants, the level of energy efficiency assumed, etc. (The actual generation units in each portfolio are not identified in this public document.

Figure Appendix - 1

EXAMPLE OF IRP SENSITIVITY ANALYSES

Base Scenario Assumption: High Efficiency, Medium Solar

Representative of Preferred Plan

Portfolios 1-12

PVRR & Rank

		Primary Scenario High DSM (130% Goal) Medium Section 123 (200 MW) Base Load											
		Portfolio Number											
		1	2	3	4	5	6	7	8	9	10	11	12
		Portfolio Rank within Scenario (PVRR)											
Key Portfolio Characteristic		1	2	3	4	5	6	7	8	9	10	11	12
Wind (MW)													
Solar (MW)													
Intermittent (MW)													
Solar Storage (MW)													
Gas (MW)													
Other (MW)	1												
Total (MW)		1,872	1,902	1,907	1,932	1,977	1,966	1,911	1,860	1,936	2,039	1,982	2,078
Owned %													
Owned MW													
Total 123 (MW)													
CO2 (M ton)	2	26.8	26.7	26.8	26.7	26.6	26.8	26.8	26.8	26.9	26.6	26.5	26.6
% New Build	3												
Externalities	4	2	2	2	2	2	1	2	2	1	2	3	2
PVRR rank		1	2	3	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	49,344	49,361	49,365	49,387	49,402	49,478	49,490	49,526	49,645	49,675	49,675	49,822
PVRR Delta ($M)	6	-	17	21	43	58	134	146	182	301	331	331	478
PV Rate ($/MWh)	7	71.87	71.90	71.90	71.94	71.96	72.07	72.09	72.14	72.31	72.36	72.36	72.57
CO2 Delta (M ton)	8	-	(0.30)	(0.02)	(0.50)	(0.68)	1.79	(0.09)	(0.04)	0.80	(0.57)	(0.81)	(0.65)
$10/ton CO2 Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	9	10	11	12
PVRR ($M)	5	43,695	43,722	43,716	43,758	43,786	43,805	43,845	43,877	43,981	44,054	44,080	44,203
Change ($M)	10	(5,649)	(5,638)	(5,649)	(5,628)	(5,616)	(5,673)	(5,645)	(5,649)	(5,664)	(5,622)	(5,596)	(5,619)
PVRR Delta ($M)	11	-	27	21	63	91	110	150	182	286	358	384	508
$40/ton CO2 Sensitivity													
PVRR rank	9	3	2	5	4	1	7	6	8	11	10	9	12
PVRR ($M)	5	60,066	60,061	60,087	60,067	60,056	60,247	60,204	60,250	60,392	60,311	60,285	60,451
Change ($M)	10	10,723	10,701	10,723	10,680	10,654	10,769	10,714	10,724	10,747	10,636	10,610	10,629
PVRR Delta ($M)	11	10	5	31	11	-	191	148	194	336	255	229	395
Low Gas Price Sensitivity													
PVRR rank	9	1	3	2	4	5	6	7	8	10	9	11	12
PVRR ($M)	5	47,935	47,959	47,956	47,992	48,016	48,055	48,075	48,118	48,234	48,230	48,318	48,371
Change ($M)	10	(1,409)	(1,402)	(1,409)	(1,395)	(1,386)	(1,423)	(1,415)	(1,407)	(1,411)	(1,445)	(1,357)	(1,451)
PVRR Delta ($M)	11	-	24	22	57	81	121	140	184	299	295	383	436
High Gas Price Sensitivity													
PVRR rank	9	5	4	6	3	1	7	8	10	9	11	2	12
PVRR ($M)	5	57,122	57,091	57,144	57,070	57,025	57,295	57,326	58,234	57,421	58,268	57,059	58,464
Change ($M)	10	7,778	7,730	7,780	7,684	7,623	7,817	7,836	8,708	7,776	8,593	7,384	8,642
PVRR Delta ($M)	11	97	66	120	46	-	270	302	1,209	396	1,244	34	1,439

Otherwise, it would have created problems for the competitive bidding process used to award contracts to supply the power to the utility.)

Each column in the table represents a different portfolio, numbered 1 to 12. Portfolio 2 is the Xcel's preferred plan. The rows show the modeling results for each portfolio. For example, the Present Value of Revenue Requirements (PVRR) is calculated for each portfolio and is shown the line indicated by the first PVRR arrow, along with the ranking of that portfolio. The lower half of the chart shows the cost of each portfolio under different assumptions about the cost of carbon emissions (higher or lower than base case predictions) and for natural gas prices (higher or lower than base case predictions).

CAVEATS

Models are a terrific way to keep track of all the moving parts in the operation of a utility portfolio. But it is one thing to know that each resource has certain operating characteristics; it is quite another to see these qualities interact with each other in dynamic fashion. And while utility modeling tools, such as production cost models can be helpful, care must be taken with their use.

Obviously the models are helpful only to the extent that the inputs are reasonable and cover the range of possibilities the regulator wishes to examine. Load forecast must be developed with care; assumptions about future fuel costs are really educated guesses, and should be bracketed with ranges of sensitivity.

Because there are so many possible combinations, variations and sensitivities, the regulator in an IRP case must make a decision early in the process about the scope of the portfolios to be examined. The utility should be directed to analyze and present all scenarios requested by the regulator, together with any portfolios preferred by the utility.

Finally, the model's best use is to inform judgment, not substitute for it. The amount of data produced by models can be overwhelming and may give a false sense of accuracy. The risk-aware regulator will always understand the fundamental uncertainties that accompany projections of customer demand, future fuel costs and future environmental requirements.

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Lansing Smith Electric Generating Plant

Lynn Haven, Florida

Sierra Club Evaluation of Compliance with 1-hour SO_2 NAAQS

June 26, 2012

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1. Introduction

The Sierra Club prepared an air modeling impact analysis to help USEPA, state and local air agencies identify facilities that are likely causing violations of the 1-hour sulfur dioxide (SO_2) national ambient air quality standard (NAAQS). This document describes the results and procedures for an evaluation conducted for the Lansing Smith Electric Generating Plant located in Lynn Haven, Florida.

The dispersion modeling analysis predicted ambient air concentrations for comparison with the one hour SO_2 NAAQS. The modeling was performed using the most recent version of AERMOD, AERMET, and AERMINUTE, with data provided to the Sierra Club by regulatory air agencies and through other publicly-available sources as documented below. The analysis was conducted in adherence to all available USEPA guidance for evaluating source impacts on attainment of the 1-hour SO_2 NAAQS via aerial dispersion modeling, including the AERMOD Implementation Guide; USEPA's Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010; modeling guidance promulgated by USEPA in Appendix W to 40 CFR Part 51; and, USEPA's March 2011 Modeling Guidance for SO_2 NAAQS Designations, available at http://www.epa.gov/ttn/scram/SO2%20Designations%20Guidance%202011.pdf.

2. Compliance with the 1-hour SO_2 NAAQS

2.1 1-hour SO_2 NAAQS

The 1-hour SO_2 NAAQS takes the form of a three-year average of the 99^{th}-percentile of the annual distribution of daily maximum 1-hour concentrations, which cannot exceed 75 ppb.[1] Compliance with this standard was verified using USEPA's AERMOD air dispersion model, which produces air concentrations in units of $\mu g/m^3$. The 1-hour SO_2 NAAQS of 75 ppb equals 196.2 $\mu g/m^3$, and this is the value used for determining whether modeled impacts exceed the NAAQS.[2] The 99^{th}-percentile of the annual distribution of daily maximum 1-hour concentrations corresponds to the fourth-highest value at each receptor for a given year.

2.2 Modeling Results

Modeling results for Lansing Smith Electric Generating Plant are summarized in Table 1. It was determined that based on either currently permitted emissions or measured actual emissions, the Lansing Smith Electric Generating Plant is estimated to create downwind SO_2 concentrations which

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[1] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010.
[2] The ppb to $\mu g/m^3$ conversion is found in the source code to AERMOD v. 11103, subroutine Modules. The conversion calculation is $75/0.3823 = 196.2\ \mu g/m^3$.

exceed the 1-hour NAAQS.

The currently permitted emissions and measured actual emissions used for the modeling analysis are summarized in Table 2. Based on the modeling results, emission reductions from current rates considered necessary to achieve compliance with the 1-hour NAAQS were calculated and presented in Table 3.

Predicted exceedences of the 1-hour NAAQS for SO_2 extend throughout the region to a maximum distance of 50 kilometers.

Figure 1 provided at the end of this report shows the extent of NAAQS violations throughout the entire 50 kilometer modeling domain.

Figure 2 provides a close-up local view of NAAQS violations.

Air quality impacts in Florida are based on a background concentration of 5.2 $\mu g/m^3$. This is the 2008-10 design value for Miami - Dade County, Florida - the lowest measured background concentration in the state. This is the most recently available design value.

2.3 Conservative Modeling Assumptions

A dispersion modeling analysis requires the selection of numerous parameters which affect the predicted concentrations. For the enclosed analysis, several parameters were selected which under-predict facility impacts.

Assumptions used in this modeling analysis which likely under-estimate concentrations include the following:

- Allowable emissions are based on a limitation with an averaging period which is greater than the 1-hour average used for the SO_2 air quality standard. Emissions and impacts during any 1-hour period may be higher than assumed for the modeling analysis.
- No consideration of facility operation at less than 100% load. Stack parameters such as exit flow rate and temperature are typically lower at less than full load, reducing pollutant dispersion and increasing predicted air quality impacts.
- No consideration of building or structure downwash. These downwash effects typically increase predicted concentrations near the facility.
- No consideration of off-site sources. These other sources of SO_2 will increase the predicted impacts.

Table 1 - SO_2 Modeling Results for Lansing Smith Electric Generating Plant

Emission Rates	Averaging Period	99th Percentile 1-hour Daily Maximum (µg/m^3)				Complies with NAAQS?
		Impact	Background	Total	NAAQS	
Allowable	1-hour	853.2	5.2	858.4	196.2	No
Maximum	1-hour	341.3	5.2	346.5	196.2	No

Table 2 - Modeled SO_2 Emissions from Lansing Smith Electric Generating Plant [3,4]

Stack ID	Unit ID	Allowable Emissions Monthly Average (lbs/hr)	Maximum Emissions 1-hour Average (lbs/hr)
S01	Unit 1	8,751.6	-
	Unit 2	10,107.9	-
Stack Total	All Units	18,859.5	7,543.5

Table 3 - Required Emission Reductions for Compliance with 1-hour SO_2 NAAQS

Acceptable Impact (NAAQS - Background) 99th Percentile 1-hour Daily Max (µg/m^3)	Required Total Facility Reduction Based on Allowable Emissions (%)	Required Total Facility Emission Rate (lbs/hr)	Required Total Facility Emission Rate (lbs/mmbtu)
191.0	77.6%	4,221.9	1.0

[3] Florida Department of Environmental Protection, Division of Air Resource Management, Title V Air Operation Permit No. 0050014-018-AV, January 1, 2010. The emissions limit for Units 1 and 2 is 4.5 lbs/mmbtu.
[4] Maximum emissions are measured hourly rates reported for 2011 in USEPA, Clean Air Markets - Data and Maps.

3. Modeling Methodology

3.1 Air Dispersion Model

The modeling analysis used USEPA's AERMOD program, version 12060. AERMOD, as available from the Support Center for Regulatory Atmospheric Modeling (SCRAM) website, was used in conjunction with a third-party modeling software program, *AERMOD View*, sold by Lakes Environmental Software.

3.2 Control Options

The AERMOD model was run with the following control options:

- 1-hour average air concentrations
- Regulatory defaults
- Flagpole receptors

To reflect a representative inhalation level, a flagpole height of 1.5 meters was used for all modeled receptors. This parameter was added to the receptor file when running AERMAP, as described in Section 4.4.

An evaluation was conducted to determine if the modeled facility was located in a rural or urban setting using USEPA's methodology outlined in Section 7.2.3 of the Guideline on Air Quality Models.[5] For urban sources, the URBANOPT option is used in conjunction with the urban population from an appropriate nearby city and a default surface roughness of 1.0 meter. Methods described in Section 4.1 to determine whether rural or urban dispersion coefficients were used.

3.3 Output Options

The AERMOD analysis was based on five years of recent meteorological data. The modeling analyses used one run with five years of sequential meteorological data from 2005-2009. Consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations, AERMOD provided a table of fourth-high 1-hour SO_2 impacts concentrations consistent with the form of the 1-hour SO_2 NAAQS.[6]

Please refer to Table 1 for the modeling results.

---

[5] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005.
[6] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 24-26.

4. Model Inputs

4.1 Geographical Inputs

The "ground floor" of all air dispersion modeling analyses is establishing a coordinate system for identifying the geographical location of emission sources and receptors. These geographical locations are used to determine local characteristics (such as land use and elevation), and also to ascertain source to receptor distances and relationships.

The Universal Transverse Mercator (UTM) NAD83 coordinate system was used for identifying the easting (x) and northing (y) coordinates of the modeled sources and receptors. Stack locations were obtained from facility permits and prior modeling files provided by the state regulatory agency. The stack locations were then verified using aerial photographs.

The facility was evaluated to determine if it should be modeled using the rural or urban dispersion coefficient option in AERMOD. A GIS was used to determine whether rural or urban dispersion coefficients apply to a site. Land use within a three-kilometer radius circle surrounding the facility was considered. USEPA guidance states that urban dispersion coefficients are used if more than 50% of the area within 3 kilometers has urban land uses. Otherwise, rural dispersion coefficients are appropriate.[7]

USEPA's AERSURACE model Version 08009 was used to develop the meteorological data for the modeling analysis. This model was also used to evaluate surrounding land use within 3 kilometers. Based on the output from the AERSURFACE, approximately 26% of surrounding land use around the airport was of urban land use types including: 21 – Low Intensity Residential, 22 – High Intensity Residential, and 23 - Commercial/Industrial/Transportation.

This is less than the 50% value considered appropriate for the use of urban dispersion coefficients. Based on the AERSURFACE analysis, it was concluded that the rural option would be used for the modeling summarized in this report. Please refer to Section 4.5.3 for a discussion of the AERSURFACE analysis.

4.2 Emission Rates and Source Parameters

The modeling analyses only considered SO_2 emissions from the facility. Off-site sources were not considered. Concentrations were predicted for two scenarios shown in Table 2:

[7] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005, Section 7.2.3.

1) approved or allowable emissions based on permits issued by the regulatory agency, and

2) measured actual hourly SO_2 emissions obtained from USEPA's Clean Air Markets Database. To assure realistic emission rates were used, emissions from all units at the facility were combined and the hour with the maximum total facility emissions was used to determine the actual emissions.

Stack parameters and emissions used for the modeling analysis are summarized in Table 4.

Table 4 – Facility Stack Parameters and Emissions [8]

Stack	S12
Description	Units 1 and 2
X Coord. [m]	625046
Y Coord. [m]	3349251
Base Elevation [m]	3.72
Release Height [m]	60.66
Gas Exit Temperature [°K]	399.817
Gas Exit Velocity [m/s]	31.302
Inside Diameter [m]	5.486
Allowable Emission Rate [g/s]	2376
Maximum Emission Rate [g/s]	950.5

The above stack parameters and emissions were obtained from regulatory agency documents and databases identified in Section 2.3. The analysis was conducted based on 100% operating load using maximum exhaust flow rates and emission rates. Operation at less than full capacity loads was not considered. This assumption tends to under-predict impacts since stack parameters such as exit flow rate and temperature are typically lower at less than full load, reducing pollutant dispersion and increasing predicted air quality impacts. Stack location, height and diameter were verified using aerial photographs, and flue gas flow rate and temperature were verified using combustion calculations.

4.3 Building Dimensions and GEP

No building dimensions or prior downwash evaluations were available. Therefore this modeling analysis did not address the effects of downwash which may increase predicted concentrations.

[8] Florida Department of Environmental Protection, Division of Air Resource Management, Title V Air Operation Permit No. 0050014-018-AV, January 1, 2010.

4.4 Receptors

For Lansing Smith Electric Generating Plant, three receptor grids were employed:

1. A 100-meter Cartesian receptor grid centered on Lansing Smith Electric Generating Plant and extending out 5 kilometers.
2. A 500-meter Cartesian receptor grid centered on Lansing Smith Electric Generating Plant and extending out 10 kilometers.
3. A 1,000-meter Cartesian receptor grid centered on Lansing Smith Electric Generating Plant and extending out 50 kilometers. 50 kilometers is the maximum distance accepted by USEPA for the use of the AERMOD dispersion model.[9]

A flagpole height of 1.5 meters was used for all these receptors.

Elevations from stacks and receptors were obtained from National Elevation Dataset (NED) GeoTiff data. GeoTiff is a binary file that includes data descriptors and geo-referencing information necessary for extracting terrain elevations. These elevations were extracted from 1 arc-second (30 meter) resolution NED files. The USEPA software program AERMAP v. 11103 is used for these tasks.

4.5 Meteorological Data

To improve the accuracy of the modeling analysis, recent meteorological data for the 2005 to 2009 period were prepared using the USEPA's program AERMET which creates the model-ready surface and profile data files required by AERMOD. Required data inputs to AERMET included surface meteorological measurements, twice-daily soundings of upper air measurements, and the micrometeorological parameters surface roughness, albedo, and Bowen ratio. One-minute ASOS data were available so USEPA methods were used to reduce calm and missing hours.[10] The USEPA software program AERMINUTE v. 11325 is used for these tasks.

This section discusses how the meteorological data was prepared for use in the 1-hour SO_2 NAAQS modeling analyses. The USEPA software program AERMET v. 11059 is used for these tasks.

4.5.1 Surface Meteorology

Surface meteorology was obtained for Panama City-Bay County International Airport located near

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[9] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, Section A.1.(1), November 9, 2005.

[10] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19.

the Lansing Smith Electric Generating Plant. Integrated Surface Hourly (ISH) data for the 2005 to 2009 period were obtained from the National Climatic Data Center (NCDC). The ISH surface data was processed through AERMET Stage 1, which performs data extraction and quality control checks. Typically the most recent years of data (i.e. 2007 to 2011) would be used for the modeling analysis. However, the Panama City station stopped collecting surface measurements in June of 2010 so the 2005 to 2009 period is most recent complete five year data.

4.5.2 Upper Air Data

Upper-air data are collected by a "weather balloon" that is released twice per day at selected locations. As the balloon is released, it rises through the atmosphere, and radios the data back to the surface. The measuring and transmitting device is known as either a radiosonde, or rawindsonde. Data collected and radioed back include: air pressure, height, temperature, dew point, wind speed, and wind direction. The upper air data were processed through AERMET Stage 1, which performs data extraction and quality control checks.

For Lansing Smith Electric Generating Plant, the concurrent 2005 through 2009 upper air data from twice-daily radiosonde measurements obtained at the most representative location were used. This location was the Tallahasee, Florida measurement station. These data are in Forecast Systems Laboratory (FSL) format and were downloaded in ASCII text format from NOAA's FSL website.[11] All reporting levels were downloaded and processed with AERMET.

4.5.3 AERSURFACE

AERSURFACE is a non-guideline program that extracts surface roughness, albedo, and daytime Bowen ratio for an area surrounding a given location. AERSURFACE uses land use and land cover (LULC) data in the U.S. Geological Survey's 1992 National Land Cover Dataset to extract the necessary micrometeorological data. LULC data was used for processing meteorological data sets used as input to AERMOD.

AERSURFACE v. 08009 was used to develop surface roughness, albedo, and daytime Bowen ratio values in a region surrounding the meteorological data collection site. AERSURFACE was used to develop surface roughness in a one kilometer radius surrounding the data collection site. Bowen ratio and albedo was developed for a 10 kilometer by 10 kilometer area centered on the meteorological data collection site. These micrometeorological data were processed for seasonal periods using 30-degree sectors. Seasonal moisture conditions were considered average with no months with continuous snow cover.

[11] Available at: http://esrl.noaa.gov/raobs/

4.5.4 Data Review

Missing meteorological data were not filled as the data file met USEPA's 90% data completeness requirement.[12] The AERMOD output file shows there were 3.4% missing data.

The representativeness of airport meteorological data is a potential concern in modeling industrial source sites.[13] The surface characteristics of the airport data collection site and the modeled source location were compared. Since the Panama City-Bay County International Airport is located close to Lansing Smith Electric Generating Plant (i.e. 4 miles), this meteorological data set was considered appropriate for this modeling analysis.

5. Background SO_2 Concentrations

Background concentrations were determined consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations.[14] To preserve the form of the 1-hour SO_2 standard, based on the 99th percentile of the annual distribution of daily maximum 1-hour concentrations averaged across the number of years modeled, the background fourth-highest daily maximum 1-hour SO_2 concentration was added to the modeled fourth-highest daily maximum 1-hour SO_2 concentration.[15]

Background concentrations were based on the 2008-10 design value measured by the ambient monitors located in Florida.[16]

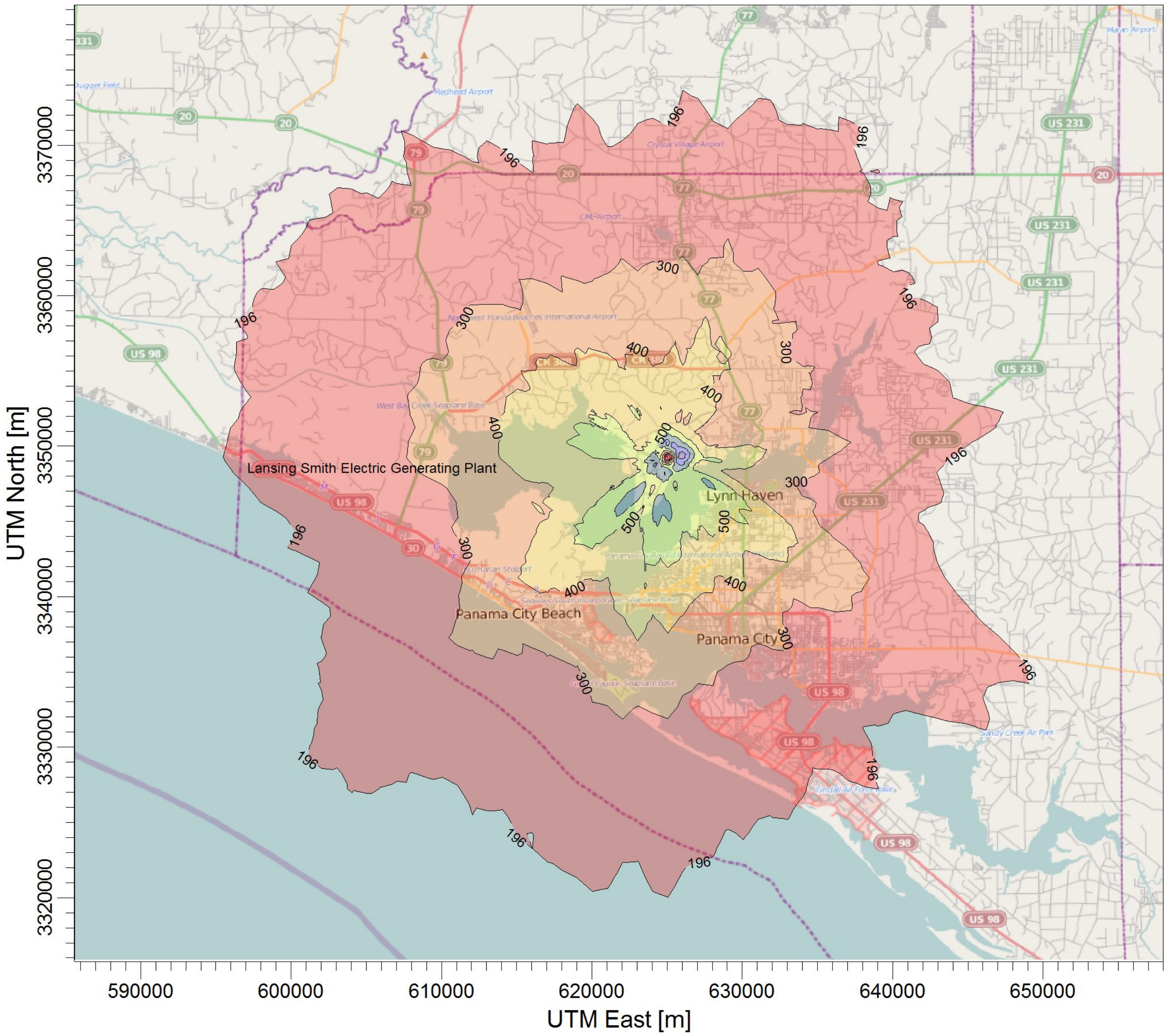
6. Reporting

All files from the programs used for this modeling analysis are available to regulatory agencies. These include analyses prepared with AERSURFACE, AERMET, AERMAP, and AERMOD.

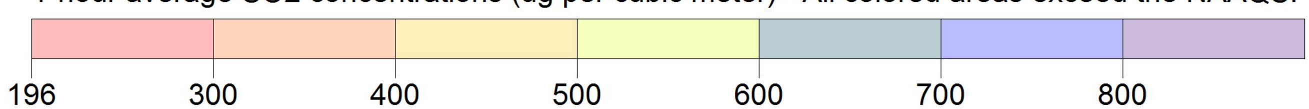
---

[12] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, Section 5.3.2, pp. 5-4 to 5-5.
[13] USEPA, AERMOD Implementation Guide, March 19, 2009, pp. 3-4.
[14] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 20-23.
[15] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010, p. 3.
[16] http://www.epa.gov/airtrends/values.html

Lansing Smith Electric Generating Plant - Lynn Haven, Florida
Evaluation of Compliance with the 1-hour NAAQS for SO2



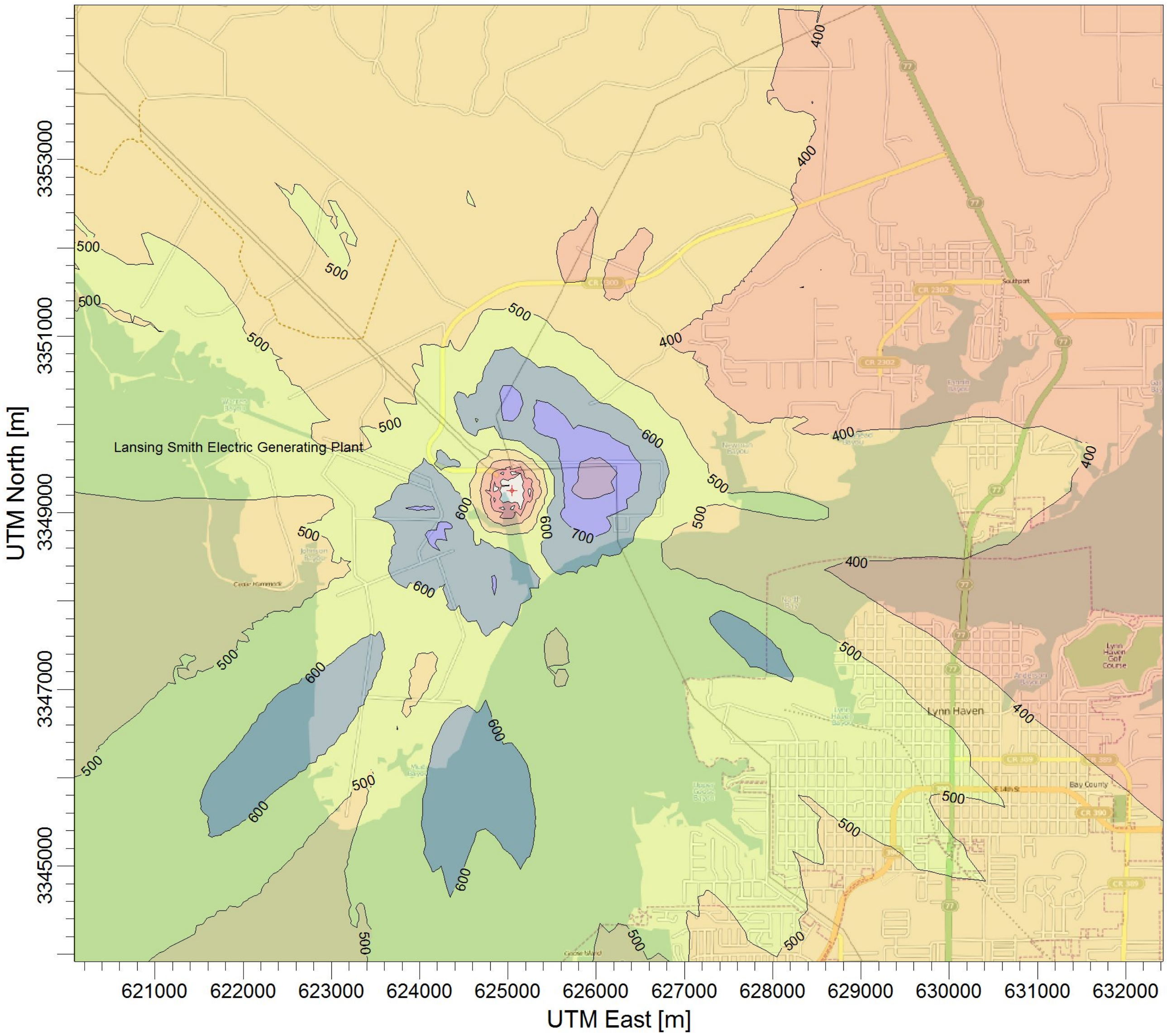
1-hour average SO2 concentrations (ug per cubic meter) - All colored areas exceed the NAAQS.



All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **2**	**Conducted on behalf of the Sierra Club**	
	Total Receptors **22084**	**by Wingra Engineering, S.C.**	
	Output Type **Concentration**	SCALE: 1:455,316 0 10 km	
	Maximum **858.44834 ug/m^3**	DATE: **6/25/2012**	

AERMOD View - Lakes Environmental Software

Lansing Smith Electric Generating Plant - Lynn Haven, Florida
Evaluation of Compliance with the 1-hour NAAQS for SO2



1-hour average SO2 concentrations (ug per cubic meter) - All colored areas exceed the NAAQS.

196 300 400 500 600 700 800

All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **2**	**Conducted on behalf of the Sierra Club**	
	Total Receptors **22084**	**by Wingra Engineering, S.C.**	
	Output Type **Concentration**	SCALE: 1:77,587 0 3 km	
	Maximum **858.44834 ug/m^3**	DATE: **6/25/2012**	

AERMOD View - Lakes Environmental Software

Progress Energy

Jamie Hunter
Lead Environmental Specialist
Environmental Services & Strategy

June 15, 2012

RECEIVED
JUN 18 2012
DIVISION OF AIR
RESOURCE MANAGEMENT

Mr. Jon Holtom, P.E.
Title V Administrator
Florida Department of Environmental Protection
Bureau of Air Regulation
2600 Blair Stone Road, MS#5505
Tallahassee, Florida 32399-2400

RE: Progress Energy Florida – Crystal River Power Plant Units 1&2
BART Implementation Plan for Crystal River Power Plant Units 1&2
Facility ID No. 0170004 Project No.: 0170004-036-AC

Dear Mr. Holtom:

Enclosed please find the BART implementation plan for Crystal River Units 1&2.

If you have any questions regarding these documents please contact Jamie Hunter at (727) 820-5764 or at John.Hunter@PGNmail.com.

Sincerely,

Jamie Hunter
Lead Environmental Specialist
Environmental Services & Strategy

RECEIVED
JUN 18 2012
DIVISION OF AIR
RESOURCE MANAGEMENT

REPORT

BART IMPLEMENTATION PLAN FOR CRYSTAL RIVER POWER PLANT UNITS 1 AND 2

Progress Energy Florida, Inc.

Prepared For: Progress Energy Florida, Inc.
Environmental Services Section
299 First Avenue North, PEB PEF-903
St. Petersburg, FL 33701

Submitted By: Golder Associates Inc.
5100 West Lemon Street
Suite 208
Tampa, FL 33609 USA

Distribution: 4 Copies – Florida Department of Environmental Protection
1 Copy – PEF
1 Copy – Golder Associates Inc.

June 2012 **123-89547**

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Table of Contents

1.0 BACKGROUND

The 1977 Clean Air Act Amendments established a national goal of "preventing future, and remedying existing, visibility impairment" in 156 national parks and wilderness areas referred to as "mandatory Class I Federal areas." In response to this congressional mandate, the U.S. Environmental Protection Agency (EPA) promulgated its Regional Haze Rule (RHR) on July 1, 1999, codified at 40 CFR 51.300, et seq. 64 Fed. Reg. 35714. The RHR set a long-term ultimate goal of returning visibility in the Class I areas to "natural conditions" by the year 2064. A key component of the RHR was a requirement for certain existing emission sources (i.e., those determined to cause or contribute to visibility impairment in the mandatory Class I areas) to install Best Available Retrofit Technology (BART). BART determinations are made according to EPA guidelines promulgated in July 2005 (70 Fed. Reg. 39104).

BART determinations consist of three basic components: (1) an identification of all BART-eligible sources; (2) an assessment of whether those BART-eligible sources are in fact subject to BART; and (3) a determination of any BART controls.

A source is BART-eligible if it has the potential to emit 250 tons or more of a visibility-impairing air pollutant, was placed into operation between August 7, 1962 and August 7, 1977, and is included within one of 26 specifically listed source categories. Units 1 and 2 at Progress Energy Florida's (PEF's) Crystal River Power Plant meet these criteria and thus are BART-eligible sources subject to this rule.

BART-eligible sources are subject to BART if they are reasonably anticipated to cause or contribute to any visibility impairment in any Class I area. Thus, a BART-eligible source may be exempt from BART if modeling demonstrates that the source's sulfur dioxide (SO_2), nitrogen oxide (NO_x) and particulate matter (PM) emissions do not contribute to visibility impairment in any Class I area.

A BART determination analysis for PM emissions from the BART-eligible emissions units (i.e., Unit Nos. 1 and 2) at the Crystal River Power Plant was previously submitted to the Florida Department of Environmental Protection (FDEP) in 2007. The visibility assessment only evaluated impacts from PM because Crystal River is subject to EPA's Clean Air Interstate Rule (CAIR) for SO_2 and NO_x, which EPA determined was "better-than-BART," alleviating the need to include SO_2 and NO_x in BART exemption modeling for PM. A BART permit was issued on February 25, 2009 (permit No. 0170004-017-AC), which imposed a revised allowable PM emission limit. Specifically, PM emissions from Unit Nos. 1 and 2 combined are not to exceed 0.04 lb/mmBtu on a weighted average basis of the total heat input during steady state operations and 0.12 lb/mmBtu on a weighted average basis of the total heat input (not to exceed 3 hours in any 24-hour period) during steady state operations. Compliance with these revised standards is to be demonstrated no later than December 31, 2013. Further, the permit assumes that Unit Nos. 1 and 2 will cease to be operated as coal-fired units by December 31, 2020. The permit requires Progress Energy Florida to notify the Department of any developments that would delay the shutdown (or repowering) of Unit Nos. 1 and 2 beyond this date.

In 2008, CAIR was remanded by the U. S. Circuit Court for the District of Columbia and, in response, on July 6, 2011, EPA issued CAIR's successor, the Cross-State Air Pollution Rule (CSAPR). On December 30, 2011, the court stayed CSAPR, however, leaving CAIR in effect pending judicial review of CSAPR. A decision on CSAPR is expected this Summer.

This circumstance results in some uncertainty for RHR purposes because while EPA issued a final determination that – like CAIR – CSAPR is better-than-BART, CSAPR applies differently in Florida; only regulating ozone-season NO_x and not annual NO_x or SO_2. As a result, if CSAPR is upheld as is, a BART analysis may be necessary for SO_2 and PM emissions. In light of this uncertainty, FDEP has requested a BART analysis for SO_2, NO_x and PM emissions from Crystal River Units 1 and 2.

Accordingly, this application is made in a cooperative effort to address RHR implementation issues resulting from recent regulatory developments related to EPA's CAIR and its successor, CSAPR. Depending on the court's decision on CSAPR, Progress Energy Florida may revisit, revise or withdraw this analysis and application.

2.0 CRYSTAL RIVER BART IMPLEMENTATION PLAN

BART-eligible sources determined to be subject to BART must conduct a five-factor analysis to determine required controls unless it is demonstrated that the source: (1) is subject to a better-than-BART alternative pursuant to 40 CFR 51.308(e)(2)-(3); or, (2) already has top-level controls in use.

The Crystal River Power Plant BART Implementation Plan includes the following components:

- Progress Energy Florida will complete a BART five-factor analysis for Crystal River Unit Nos. 1 and 2 relative to visibility impairment at the Class I areas within 300 km of the plant, including:
  - Saint Marks National Wilderness Area (NWA) - 174 km
  - Chassahowitzka NWA - 21 km
  - Wolf Island NWA - 293 km
  - Okefenokee NWA- 178 km

  The analysis will include cost, remaining useful life and visibility improvement factors focusing on maximum level control-technology for SO_2, NOx and PM.
- Progress Energy Florida will make a final decision by January 1, 2015 or within 2 years of EPA's final approval of Florida's final Regional Haze SIP, whichever is later, on the Crystal River BART Implementation Plan which includes, at a minimum, either the installation of BART control equipment or commitment to a unit-specific retirement date in order to meet BART requirements or taking a permit limit sufficient to exempt out of BART. To implement this decision, Progress Energy Florida is applying for a Florida Air Construction Permit for Crystal River Units 1 and 2 to:
  - Install and operate a SO_2 Flue Gas Desulfurization (FGD) scrubber system before January 1, 2018 or within 5 years of EPA's final approval of Florida's final Regional Haze SIP, whichever is later. This system will be designed to meet either 95 percent removal efficiency of SO_2 from Crystal River Units 1 and 2 or an emission rate limit of 0.15 lb/mmBtu (presumptive BART) from Crystal River Units 1 and 2; or
  - Commit to retire the operations of Crystal River Units 1 and 2 by December 31, 2020 based upon a "remaining useful life" cost-effectiveness evaluation; or
  - Agree to a permit limit for SO_2 by January 1, 2018 or within 5 years of EPA's final approval of Florida's final Regional Haze SIP, whichever is later, at a level sufficient to exempt out of BART or meet other control options identified in the BART five-factor analysis.
- Progress Energy Florida will request that such conditions be included in a federally enforceable air construction permit and incorporated into the Crystal River Title V Permit as a specific operating condition.

ATTACHMENT A
APPLICATION FOR AIR PERMIT—LONG FORM
DEP FORM NO. 62-210.900(1)

Department of Environmental Protection

RECEIVED
JUN 18 2012
DIVISION OF AIR RESOURCE MANAGEMENT

Division of Air Resource Management

APPLICATION FOR AIR PERMIT - LONG FORM

I. APPLICATION INFORMATION

Air Construction Permit – Use this form to apply for an air construction permit:

- For any required purpose at a facility operating under a federally enforceable state air operation permit (FESOP) or Title V air operation permit;
- For a proposed project subject to prevention of significant deterioration (PSD) review, nonattainment new source review, or maximum achievable control technology (MACT);
- To assume a restriction on the potential emissions of one or more pollutants to escape a requirement such as PSD review, nonattainment new source review, MACT, or Title V; or
- To establish, revise, or renew a plantwide applicability limit (PAL).

Air Operation Permit – Use this form to apply for:

- An initial federally enforceable state air operation permit (FESOP); or
- An initial, revised, or renewal Title V air operation permit.

To ensure accuracy, please see form instructions.

Identification of Facility

1. Facility Owner/Company Name: **FLORIDA POWER CORPORATION DBA PROGRESS ENERGY, INC.**	
2. Site Name: **CRYSTAL RIVER POWER PLANT**	
3. Facility Identification Number: **0170004**	
4. Facility Location... Street Address or Other Locator: **NORTH OF CRYSTAL RIVER, WEST OF U.S. 19** City: **CRYSTAL RIVER** County: **CITRUS** Zip Code: **34428**	
5. Relocatable Facility? ☐ Yes ☒ No	6. Existing Title V Permitted Facility? ☒ Yes ☐ No

Application Contact

1. Application Contact Name: **JAMIE HUNTER, LEAD ENVIRONMENTAL SPECIALIST**
2. Application Contact Mailing Address... Organization/Firm: **PROGRESS ENERGY FLORIDA** Street Address: **299 FIRST AVENUE, NORTH, PEF 903** City: **ST. PETERSBURG** State: **FL** Zip Code: **33701**
3. Application Contact Telephone Numbers... Telephone: **(727) 820-5764** ext. Fax: **(727) 820-5292**
4. Application Contact E-mail Address: **John.Hunter@PGNmail.com**

Application Processing Information (DEP Use)

1. Date of Receipt of Application: 06-18-2012	3. PSD Number (if applicable):
2. Project Number(s): 0170004-036-AC	4. Siting Number (if applicable):

APPLICATION INFORMATION

Purpose of Application

This application for air permit is being submitted to obtain: (Check one)

Air Construction Permit

- ☒ Air construction permit.
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL).
- ☐ Air construction permit to establish, revise, or renew a plantwide applicability limit (PAL), and separate air construction permit to authorize construction or modification of one or more emissions units covered by the PAL.

Air Operation Permit

- ☐ Initial Title V air operation permit.
- ☐ Title V air operation permit revision.
- ☐ Title V air operation permit renewal.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is required.
- ☐ Initial federally enforceable state air operation permit (FESOP) where professional engineer (PE) certification is not required.

Air Construction Permit and Revised/Renewal Title V Air Operation Permit (Concurrent Processing)

- ☐ Air construction permit and Title V permit revision, incorporating the proposed project.
- ☐ Air construction permit and Title V permit renewal, incorporating the proposed project.

Note: By checking one of the above two boxes, you, the applicant, are requesting concurrent processing pursuant to Rule 62-213.405, F.A.C. In such case, you must also check the following box:

- ☐ I hereby request that the department waive the processing time requirements of the air construction permit to accommodate the processing time frames of the Title V air operation permit.

Application Comment

Florida Power Corporation, doing business as Progress Energy Florida, Inc. (PEF), has conducted a five-factor best available retrofit technology (BART) determination analysis for the Crystal River Power Plant. As part of this analysis, PEF has developed a BART Implementation Plan which includes the installation of BART control equipment or commitment to a unit specific retirement date in order to meet BART requirements or taking a permit limit sufficient to exempt out of BART. PEF is applying for an Air Construction Permit for Crystal River Units 1 and 2 in order to implement the options included in the BART Implementation Plan.

APPLICATION INFORMATION

Scope of Application

Emissions Unit ID Number	Description of Emissions Unit	Air Permit Type	Air Permit Processing Fee
001	Unit 1 Fossil Fuel Steam Generator (FFSG)	AC1F	NA
002	Unit 2 FFSG	AC1F	NA

Application Processing Fee

Check one: ☐ Attached - Amount:________________ ☒ Not Applicable

APPLICATION INFORMATION

Owner/Authorized Representative Statement

Complete if applying for an air construction permit or an initial FESOP.

1.	Owner/Authorized Representative Name : **ROBBY ODOM, PLANT MANAGER**
2.	Owner/Authorized Representative Mailing Address... Organization/Firm: **PROGRESS ENERGY FLORIDA** Street Address: **299 FIRST AVENUE, NORTH, CN77** City: **ST PETERSBURG** State: **FLORIDA** Zip Code: **33701**
3.	Owner/Authorized Representative Telephone Numbers... Telephone: **(352) 501-5682** ext. Fax: **(352) 501-5787**
4.	Owner/Authorized Representative E-mail Address: **ROBBY.ODOM@PGNMAIL.COM**
5.	Owner/Authorized Representative Statement: *I, the undersigned, am the owner or authorized representative of the corporation, partnership, or other legal entity submitting this air permit application. To the best of my knowledge, the statements made in this application are true, accurate and complete, and any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department.* Signature: [signature] Date: 6/14/12

APPLICATION INFORMATION

Application Responsible Official Certification

Complete if applying for an initial, revised, or renewal Title V air operation permit or concurrent processing of an air construction permit and revised or renewal Title V air operation permit. If there are multiple responsible officials, the "application responsible official" need not be the "primary responsible official."

1. Application Responsible Official Name:
2. Application Responsible Official Qualification (Check one or more of the following options, as applicable): ☐ For a corporation, the president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit under Chapter 62-213, F.A.C. ☐ For a partnership or sole proprietorship, a general partner or the proprietor, respectively. ☐ For a municipality, county, state, federal, or other public agency, either a principal executive officer or ranking elected official. ☐ The designated representative at an Acid Rain source or CAIR source.
3. Application Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
4. Application Responsible Official Telephone Numbers... Telephone: ext. Fax:
5. Application Responsible Official E-mail Address:
6. Application Responsible Official Certification: I, the undersigned, am a responsible official of the Title V source addressed in this air permit application. I hereby certify, based on information and belief formed after reasonable inquiry, that the statements made in this application are true, accurate and complete and that, to the best of my knowledge, any estimates of emissions reported in this application are based upon reasonable techniques for calculating emissions. The air pollutant emissions units and air pollution control equipment described in this application will be operated and maintained so as to comply with all applicable standards for control of air pollutant emissions found in the statutes of the State of Florida and rules of the Department of Environmental Protection and revisions thereof and all other applicable requirements identified in this application to which the Title V source is subject. I understand that a permit, if granted by the department, cannot be transferred without authorization from the department, and I will promptly notify the department upon sale or legal transfer of the facility or any permitted emissions unit. Finally, I certify that the facility and each emissions unit are in compliance with all applicable requirements to which they are subject, except as identified in compliance plan(s) submitted with this application. Signature Date

APPLICATION INFORMATION

Professional Engineer Certification

1. Professional Engineer Name: **Scott H. Osbourn**
   Registration Number: **57557**
2. Professional Engineer Mailing Address...
   Organization/Firm: **Golder Associates Inc.***
   Street Address: **5100 West Lemon St., Suite 208**
   City: **Tampa** State: **FL** Zip Code: **33609**
3. Professional Engineer Telephone Numbers...
   Telephone: **(813) 287-1717** ext. **53304** Fax: **(813) 287-1716**
4. Professional Engineer E-mail Address: **sosbourn@golder.com**
5. Professional Engineer Statement:

I, the undersigned, hereby certify, except as particularly noted herein, that:*

(1) To the best of my knowledge, there is reasonable assurance that the air pollutant emissions unit(s) and the air pollution control equipment described in this application for air permit, when properly operated and maintained, will comply with all applicable standards for control of air pollutant emissions found in the Florida Statutes and rules of the Department of Environmental Protection; and

(2) To the best of my knowledge, any emission estimates reported or relied on in this application are true, accurate, and complete and are either based upon reasonable techniques available for calculating emissions or, for emission estimates of hazardous air pollutants not regulated for an emissions unit addressed in this application, based solely upon the materials, information and calculations submitted with this application.

(3) If the purpose of this application is to obtain a Title V air operation permit (check here ☐, if so), I further certify that each emissions unit described in this application for air permit, when properly operated and maintained, will comply with the applicable requirements identified in this application to which the unit is subject, except those emissions units for which a compliance plan and schedule is submitted with this application.

(4) If the purpose of this application is to obtain an air construction permit (check here ☒, if so) or concurrently process and obtain an air construction permit and a Title V air operation permit revision or renewal for one or more proposed new or modified emissions units (check here ☐, if so), I further certify that the engineering features of each such emissions unit described in this application have been designed or examined by me or individuals under my direct supervision and found to be in conformity with sound engineering principles applicable to the control of emissions of the air pollutants characterized in this application.

(5) If the purpose of this application is to obtain an initial air operation permit or operation permit revision or renewal for one or more newly constructed or modified emissions units (check here ☐, if so), I further certify that, with the exception of any changes detailed as part of this application, each such emissions unit has been constructed or modified in substantial accordance with the information given in the corresponding application for air construction permit and with all provisions contained in such permit.

Signature ______________ Date 6/13/12

(seal)

SCOTT OSBOURN
LICENSE
No. 57557
STATE OF
FLORIDA
PROFESSIONAL ENGINEER

*** Board of Professional Engineers Certificate of Authorization # 00001670**

II. FACILITY INFORMATION

A. GENERAL FACILITY INFORMATION

Facility Location and Type

1. Facility UTM Coordinates... Zone 17 East (km) 334.3 North (km) 3204.5		2. Facility Latitude/Longitude... Latitude (DD/MM/SS) 28/57/34 Longitude (DD/MM/SS) 82/42/01	
3. Governmental Facility Code: 0	4. Facility Status Code: A	5. Facility Major Group SIC Code: 49	6. Facility SIC(s): 4911
7. Facility Comment :			

Facility Contact

1. Facility Contact Name: JAMIE HUNTER, LEAD ENVIRONMENTAL SPECIALIST
2. Facility Contact Mailing Address... Organization/Firm: PROGRESS ENERGY FLORIDA Street Address: 299 FIRST AVENUE, NORTH, PEF 903 City: ST PETERSBURG State: FLORIDA Zip Code: 33701
3. Facility Contact Telephone Numbers: Telephone: (727) 820-5764 ext. Fax:
4. Facility Contact E-mail Address: John.Hunter@PGNmail.com

Facility Primary Responsible Official

Complete if an "application responsible official" is identified in Section I that is not the facility "primary responsible official."

1. Facility Primary Responsible Official Name:
2. Facility Primary Responsible Official Mailing Address... Organization/Firm: Street Address: City: State: Zip Code:
3. Facility Primary Responsible Official Telephone Numbers... Telephone: ( ) - ext. Fax: ( ) -
4. Facility Primary Responsible Official E-mail Address:

Facility Regulatory Classifications

Check all that would apply *following* completion of all projects and implementation of all other changes proposed in this application for air permit. Refer to instructions to distinguish between a "major source" and a "synthetic minor source."

1. ☐ Small Business Stationary Source	☐ Unknown
2. ☐ Synthetic Non-Title V Source	
3. ☒ Title V Source	
4. ☒ Major Source of Air Pollutants, Other than Hazardous Air Pollutants (HAPs)	
5. ☐ Synthetic Minor Source of Air Pollutants, Other than HAPs	
6. ☒ Major Source of Hazardous Air Pollutants (HAPs)	
7. ☐ Synthetic Minor Source of HAPs	
8. ☒ One or More Emissions Units Subject to NSPS (40 CFR Part 60)	
9. ☒ One or More Emissions Units Subject to Emission Guidelines (40 CFR Part 60)	
10. ☒One or More Emissions Units Subject to NESHAP (40 CFR Part 61 or Part 63)	
11. ☐ Title V Source Solely by EPA Designation (40 CFR 70.3(a)(5))	
12. Facility Regulatory Classifications Comment:	

List of Pollutants Emitted by Facility

1. Pollutant Emitted	2. Pollutant Classification	3. Emissions Cap [Y or N]?
$PM/PM_{10}/PM_{2.5}$	A	N
CO	A	N
VOC	A	N
SO_2	A	N
NO_x	A	N
SAM	A	N

B. EMISSIONS CAPS

Facility-Wide or Multi-Unit Emissions Caps

1. Pollutant Subject to Emissions Cap	2. Facility-Wide Cap [Y or N]? (all units)	3. Emissions Unit ID's Under Cap (if not all units)	4. Hourly Cap (lb/hr)	5. Annual Cap (ton/yr)	6. Basis for Emissions Cap

7. Facility-Wide or Multi-Unit Emissions Cap Comment:

C. FACILITY ADDITIONAL INFORMATION

Additional Requirements for All Applications, Except as Otherwise Stated

1.	Facility Plot Plan: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ______ ☒ Previously Submitted, Date: **May 20, 2009**
2.	Process Flow Diagram(s): (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ______ ☒ Previously Submitted, Date: **May 20, 2009**
3.	Precautions to Prevent Emissions of Unconfined Particulate Matter: (Required for all permit applications, except Title V air operation permit revision applications if this information was submitted to the department within the previous five years and would not be altered as a result of the revision being sought) ☐ Attached, Document ID: ______ ☒ Previously Submitted, Date: **May 20, 2009**

Additional Requirements for Air Construction Permit Applications

1. Area Map Showing Facility Location: ☐ Attached, Document ID:__________ ☒ Not Applicable (existing permitted facility)
2. Description of Proposed Construction, Modification, or Plantwide Applicability Limit (PAL): ☒ Attached, Document ID: **CR-FI-C2**
3. Rule Applicability Analysis: ☐ Attached, Document ID: **NA**
4. List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☒ Not Applicable (no exempt units at facility)
5. Fugitive Emissions Identification: ☐ Attached, Document ID:__________ ☒ Not Applicable
6. Air Quality Analysis (Rule 62-212.400(7), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
7. Source Impact Analysis (Rule 62-212.400(5), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
8. Air Quality Impact since 1977 (Rule 62-212.400(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
9. Additional Impact Analyses (Rules 62-212.400(8) and 62-212.500(4)(e), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable
10. Alternative Analysis Requirement (Rule 62-212.500(4)(g), F.A.C.): ☐ Attached, Document ID:__________ ☒ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for FESOP Applications -- NA

1. List of Exempt Emissions Units: ☐ Attached, Document ID:__________ ☐ Not Applicable (no exempt units at facility)

Additional Requirements for Title V Air Operation Permit Applications - NA

1. List of Insignificant Activities: (Required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable (revision application)
2. Identification of Applicable Requirements: (Required for initial/renewal applications, and for revision applications if this information would be changed as a result of the revision being sought) ☐ Attached, Document ID:__________ ☐ Not Applicable (revision application with no change in applicable requirements)
3. Compliance Report and Plan: (Required for all initial/revision/renewal applications) ☐ Attached, Document ID:____ Note: A compliance plan must be submitted for each emissions unit that is not in compliance with all applicable requirements at the time of application and/or at any time during application processing. The department must be notified of any changes in compliance status during application processing.
4. List of Equipment/Activities Regulated under Title VI: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Equipment/Activities Onsite but Not Required to be Individually Listed ☐ Not Applicable
5. Verification of Risk Management Plan Submission to EPA: (If applicable, required for initial/renewal applications only) ☐ Attached, Document ID:__________ ☐ Not Applicable
6. Requested Changes to Current Title V Air Operation Permit: ☐ Attached, Document ID:__________ ☐ Not Applicable

C. FACILITY ADDITIONAL INFORMATION (CONTINUED)

Additional Requirements for Facilities Subject to Acid Rain, CAIR, or Hg Budget Program

1. Acid Rain Program Forms:

   Acid Rain Part Application (DEP Form No. 62-210.900(1)(a)):
   ☐ Attached, Document ID: ☒ Previously Submitted, Date: **May 20, 2009**
   ☐ Not Applicable (not an Acid Rain source)

   Phase II NO_X Averaging Plan (DEP Form No. 62-210.900(1)(a)1.):
   ☐ Attached, Document ID:________ ☒ Previously Submitted, Date: **May 20, 2009**
   ☐ Not Applicable

   New Unit Exemption (DEP Form No. 62-210.900(1)(a)2.):
   ☐ Attached, Document ID:________ ☐ Previously Submitted, Date:________
   ☒ Not Applicable

2. CAIR Part (DEP Form No. 62-210.900(1)(b)):
   ☐ Attached, Document ID: ☒ Previously Submitted, Date: **May 20, 2009**
   ☐ Not Applicable (not a CAIR source)

Additional Requirements Comment

Crystal River Power Plant

Crystal River, Florida

Sierra Club Evaluation of Compliance with 1-hour SO_2 NAAQS

June 25, 2012

Conducted by:

Steven Klafka, P.E., BCEE

Wingra Engineering, S.C.

Madison, Wisconsin

1. Introduction

The Sierra Club prepared an air modeling impact analysis to help USEPA, state and local air agencies identify facilities that are likely causing violations of the 1-hour sulfur dioxide (SO_2) national ambient air quality standard (NAAQS). This document describes the results and procedures for an evaluation conducted for the Crystal River Power Plant located in Crystal River, Florida.

The dispersion modeling analysis predicted ambient air concentrations for comparison with the one hour SO_2 NAAQS. The modeling was performed using the most recent version of AERMOD, AERMET, and AERMINUTE, with data provided to the Sierra Club by regulatory air agencies and through other publicly-available sources as documented below. The analysis was conducted in adherence to all available USEPA guidance for evaluating source impacts on attainment of the 1-hour SO_2 NAAQS via aerial dispersion modeling, including the AERMOD Implementation Guide; USEPA's Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010; modeling guidance promulgated by USEPA in Appendix W to 40 CFR Part 51; and, USEPA's March 2011 Modeling Guidance for SO_2 NAAQS Designations, available at http://www.epa.gov/ttn/scram/SO2%20Designations%20Guidance%202011.pdf.

2. Compliance with the 1-hour SO_2 NAAQS

2.1 1-hour SO_2 NAAQS

The 1-hour SO_2 NAAQS takes the form of a three-year average of the 99th-percentile of the annual distribution of daily maximum 1-hour concentrations, which cannot exceed 75 ppb.[1] Compliance with this standard was verified using USEPA's AERMOD air dispersion model, which produces air concentrations in units of $\mu g/m^3$. The 1-hour SO_2 NAAQS of 75 ppb equals 196.2 $\mu g/m^3$, and this is the value used for determining whether modeled impacts exceed the NAAQS.[2] The 99th-percentile of the annual distribution of daily maximum 1-hour concentrations corresponds to the fourth-highest value at each receptor for a given year.

2.2 Modeling Results

Modeling results for Crystal River Power Plant are summarized in Table 1. It was determined that based on either currently permitted emissions or measured actual emissions, the Crystal River Power Plant is estimated to create downwind SO_2 concentrations which exceed the 1-hour NAAQS.

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[1] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010.
[2] The ppb to $\mu g/m^3$ conversion is found in the source code to AERMOD v. 11103, subroutine Modules. The conversion calculation is $75/0.3823 = 196.2\ \mu g/m^3$.

The currently permitted emissions and measured actual emissions used for the modeling analysis are summarized in Table 2. Based on the modeling results, emission reductions from current rates considered necessary to achieve compliance with the 1-hour NAAQS were calculated and presented in Table 3.

Predicted exceedences of the 1-hour NAAQS for SO_2 extend throughout the region to a maximum distance of 40 kilometers.

Figure 1 provided at the end of this report shows the extent of NAAQS violations throughout the entire 50 kilometer modeling domain.

Figure 2 provides a close-up local view of NAAQS violations.

Air quality impacts in Florida are based on a background concentration of 5.2 $\mu g/m^3$. This is the 2008-10 design value for Miami - Dade County, Florida - the lowest measured background concentration in the state. This is the most recently available design value.

2.3 Conservative Modeling Assumptions

A dispersion modeling analysis requires the selection of numerous parameters which affect the predicted concentrations. For the enclosed analysis, several parameters were selected which under-predict facility impacts.

Assumptions used in this modeling analysis which likely under-estimate concentrations include the following:

- Allowable emissions are based on a limitation with an averaging period which is greater than the 1-hour average used for the SO_2 air quality standard. Emissions and impacts during any 1-hour period may be higher than assumed for the modeling analysis.
- No consideration of facility operation at less than 100% load. Stack parameters such as exit flow rate and temperature are typically lower at less than full load, reducing pollutant dispersion and increasing predicted air quality impacts.
- No consideration of building or structure downwash. These downwash effects typically increase predicted concentrations near the facility.
- No consideration of off-site sources. These other sources of SO_2 will increase the predicted impacts.

Table 1 - SO_2 Modeling Results for Crystal River Power Plant Modeling Analysis

Emission Rates	Averaging Period	99th Percentile 1-hour Daily Maximum (µg/m³)				Complies with NAAQS?
		Impact	Background	Total	NAAQS	
Allowable	1-hour	915.8	5.2	921.0	196.2	No
Maximum	1-hour	529.4	5.2	534.6	196.2	No

Table 2 - Modeled SO_2 Emissions from Crystal River Power Plant [3,4]

Stack ID	Unit ID	Allowable Emissions 24-hour Average (lbs/hr)	Maximum Emissions 1-hour Average (lbs/hr)
S01	Unit 1	7,875.0	4,319.0
S02	Unit 2	10,069.5	5,092.0
S45	Units 4 and 5	17,280.0	10,531.0
Stack Total	All Units	32,224.5	19,942.0

Table 3 - Required Emission Reductions for Compliance with 1-hour SO_2 NAAQS

Acceptable Impact (NAAQS - Background) 99th Percentile 1-hour Daily Max (µg/m³)	Required Total Facility Reduction Based on Allowable Emissions (%)	Required Total Facility Emission Rate (lbs/hr)	Required Total Facility Emission Rate (lbs/mmbtu)
191.0	79.1%	6,720.8	0.25

[3] Florida Department of Environmental Protection, Division of Air Resource Management, Title V Air Operation Permit No. 0170004-025-AV, April 11, 2011. All units have an emission limitation of 1.2 lbs/mmbtu.
[4] Maximum emissions are measured hourly rates reported for 2011 in USEPA, Clean Air Markets - Data and Maps.

3. Modeling Methodology

3.1 Air Dispersion Model

The modeling analysis used USEPA's AERMOD program, version 12060. AERMOD, as available from the Support Center for Regulatory Atmospheric Modeling (SCRAM) website, was used in conjunction with a third-party modeling software program, *AERMOD View*, sold by Lakes Environmental Software.

3.2 Control Options

The AERMOD model was run with the following control options:

- 1-hour average air concentrations
- Regulatory defaults
- Flagpole receptors

To reflect a representative inhalation level, a flagpole height of 1.5 meters was used for all modeled receptors. This parameter was added to the receptor file when running AERMAP, as described in Section 4.4.

An evaluation was conducted to determine if the modeled facility was located in a rural or urban setting using USEPA's methodology outlined in Section 7.2.3 of the Guideline on Air Quality Models.[5] For urban sources, the URBANOPT option is used in conjunction with the urban population from an appropriate nearby city and a default surface roughness of 1.0 meter. Methods described in Section 4.1 to determine whether rural or urban dispersion coefficients were used.

3.3 Output Options

The AERMOD analysis was based on five years of recent meteorological data. The modeling analyses used one run with five years of sequential meteorological data from 2007-2011. Consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations, AERMOD provided a table of fourth-high 1-hour SO_2 impacts concentrations consistent with the form of the 1-hour SO_2 NAAQS.[6]

Please refer to Table 1 for the modeling results.

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[5] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005.
[6] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 24-26.

4. Model Inputs

4.1 Geographical Inputs

The “ground floor” of all air dispersion modeling analyses is establishing a coordinate system for identifying the geographical location of emission sources and receptors. These geographical locations are used to determine local characteristics (such as land use and elevation), and also to ascertain source to receptor distances and relationships.

The Universal Transverse Mercator (UTM) NAD83 coordinate system was used for identifying the easting (x) and northing (y) coordinates of the modeled sources and receptors. Stack locations were obtained from facility permits and prior modeling files provided by the state regulatory agency. The stack locations were then verified using aerial photographs.

The facility was evaluated to determine if it should be modeled using the rural or urban dispersion coefficient option in AERMOD. A GIS was used to determine whether rural or urban dispersion coefficients apply to a site. Land use within a three-kilometer radius circle surrounding the facility was considered. USEPA guidance states that urban dispersion coefficients are used if more than 50% of the area within 3 kilometers has urban land uses. Otherwise, rural dispersion coefficients are appropriate.[7]

USEPA’s AERSURACE model Version 08009 was used to develop the meteorological data for the modeling analysis. This model was also used to evaluate surrounding land use within 3 kilometers. Based on the output from the AERSURFACE, approximately 20.2% of surrounding land use around the airport was of urban land use types including: 21 – Low Intensity Residential, 22 – High Intensity Residential, and 23 - Commercial/Industrial/Transportation.

This is less than the 50% value considered appropriate for the use of urban dispersion coefficients. Based on the AERSURFACE analysis, it was concluded that the rural option would be used for the modeling summarized in this report. Please refer to Section 4.5.3 for a discussion of the AERSURFACE analysis.

[7] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, November 9, 2005, Section 7.2.3.

4.2 Emission Rates and Source Parameters

The modeling analyses only considered SO_2 emissions from the facility. Off-site sources were not considered. Concentrations were predicted for two scenarios shown in Table 2:

1) approved or allowable emissions based on permits issued by the regulatory agency, and

2) measured actual hourly SO_2 emissions obtained from USEPA's Clean Air Markets Database. To assure realistic emission rates were used, emissions from all units at the facility were combined and the hour with the maximum total facility emissions was used to determine the actual emissions.

Stack parameters and emissions used for the modeling analysis are summarized in Table 4.

Table 4 – Facility Stack Parameters and Emissions [8]

Stack	S01	S02	S45
Description	Unit 1	Unit 2	Units 4 and 5
X Coord. [m]	334265.16	334329.64	334783.6
Y Coord. [m]	3204413.63	3204413.63	3205565.58
Base Elevation [m]	2.74	2.96	2.89
Release Height [m]	152.1	153.01	167.64
Gas Exit Temperature [°K]	417.039	422.039	327.594
Gas Exit Velocity [m/s]	40.473	48.796	15.333
Inside Diameter [m]	4.572	4.877	9.296
Allowable Emission Rate [g/s]	992.2	1,269.0	2,177.0
Maximum Emission Rate [g/s]	544.2	641.6	1,327.0

The above stack parameters and emissions were obtained from regulatory agency documents and databases identified in Section 2.3. The analysis was conducted based on 100% operating load using maximum exhaust flow rates and emission rates. Operation at less than full capacity loads was not considered. This assumption tends to under-predict impacts since stack parameters such as exit flow rate and temperature are typically lower at less than full load, reducing pollutant dispersion and increasing predicted air quality impacts. Stack location, height and diameter were verified using aerial photographs, and flue gas flow rate and temperature were verified using combustion calculations.

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[8] Florida Department of Environmental Protection, Division of Air Resource Management, Title V Air Operation Permit No. 0170004-025-AV, April 11, 2011.

4.3 Building Dimensions and GEP

No building dimensions or prior downwash evaluations were available. Therefore this modeling analysis did not address the effects of downwash which may increase predicted concentrations.

4.4 Receptors

For Crystal River Power Plant, three receptor grids were employed:

1. A 100-meter Cartesian receptor grid centered on Crystal River Power Plant and extending out 5 kilometers.
2. A 500-meter Cartesian receptor grid centered on Crystal River Power Plant and extending out 10 kilometers.
3. A 1,000-meter Cartesian receptor grid centered on Crystal River Power Plant and extending out 50 kilometers. 50 kilometers is the maximum distance accepted by USEPA for the use of the AERMOD dispersion model.[9]

A flagpole height of 1.5 meters was used for all these receptors.

Elevations from stacks and receptors were obtained from National Elevation Dataset (NED) GeoTiff data. GeoTiff is a binary file that includes data descriptors and geo-referencing information necessary for extracting terrain elevations. These elevations were extracted from 1 arc-second (30 meter) resolution NED files. The USEPA software program AERMAP v. 11103 is used for these tasks.

4.5 Meteorological Data

To improve the accuracy of the modeling analysis, recent meteorological data for the 2007 to 2011 period were prepared using the USEPA's program AERMET which creates the model-ready surface and profile data files required by AERMOD. Required data inputs to AERMET included surface meteorological measurements, twice-daily soundings of upper air measurements, and the micrometeorological parameters surface roughness, albedo, and Bowen ratio. One-minute ASOS data were available so USEPA methods were used to reduce calm and missing hours.[10] The USEPA software program AERMINUTE v. 11325 is used for these tasks.

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[9] USEPA, Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions, Appendix W to 40 CFR Part 51, Section A.1.(1), November 9, 2005.

[10] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, p. 19.

This section discusses how the meteorological data was prepared for use in the 1-hour SO_2 NAAQS modeling analyses. The USEPA software program AERMET v. 11059 is used for these tasks.

4.5.1 Surface Meteorology

Surface meteorology was obtained for Hernando County Airport located near the Crystal River Power Plant. Integrated Surface Hourly (ISH) data for the 2007 to 2011 period were obtained from the National Climatic Data Center (NCDC). The ISH surface data was processed through AERMET Stage 1, which performs data extraction and quality control checks.

4.5.2 Upper Air Data

Upper-air data are collected by a "weather balloon" that is released twice per day at selected locations. As the balloon is released, it rises through the atmosphere, and radios the data back to the surface. The measuring and transmitting device is known as either a radiosonde, or rawindsonde. Data collected and radioed back include: air pressure, height, temperature, dew point, wind speed, and wind direction. The upper air data were processed through AERMET Stage 1, which performs data extraction and quality control checks.

For Crystal River Power Plant, the concurrent 2007 through 2011 upper air data from twice-daily radiosonde measurements obtained at the most representative location were used. This location was the Tampa Bay/Ruskin, Florida measurement station. These data are in Forecast Systems Laboratory (FSL) format and were downloaded in ASCII text format from NOAA's FSL website.[11] All reporting levels were downloaded and processed with AERMET.

4.5.3 AERSURFACE

AERSURFACE is a non-guideline program that extracts surface roughness, albedo, and daytime Bowen ratio for an area surrounding a given location. AERSURFACE uses land use and land cover (LULC) data in the U.S. Geological Survey's 1992 National Land Cover Dataset to extract the necessary micrometeorological data. LULC data was used for processing meteorological data sets used as input to AERMOD.

AERSURFACE v. 08009 was used to develop surface roughness, albedo, and daytime Bowen ratio values in a region surrounding the meteorological data collection site. AERSURFACE was used to develop surface roughness in a one kilometer radius surrounding the data collection site. Bowen ratio and albedo was developed for a 10 kilometer by 10 kilometer area centered on the meteorological data collection site. These micrometeorological data were processed for seasonal

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[11] Available at: http://esrl.noaa.gov/raobs/

periods using 30-degree sectors. Seasonal moisture conditions were considered average with no months with continuous snow cover.

4.5.4 Data Review

Missing meteorological data were not filled as the data file met USEPA's 90% data completeness requirement.[12] The AERMOD output file shows there were 6.0% missing data.

The representativeness of airport meteorological data is a potential concern in modeling industrial source sites.[13] The surface characteristics of the airport data collection site and the modeled source location were compared. Since the Hernando County Airport is located close to Crystal River Power Plant, this meteorological data set was considered appropriate for this modeling analysis.

5. Background SO_2 Concentrations

Background concentrations were determined consistent with USEPA's Modeling Guidance for SO_2 NAAQS Designations.[14] To preserve the form of the 1-hour SO_2 standard, based on the 99th percentile of the annual distribution of daily maximum 1-hour concentrations averaged across the number of years modeled, the <u>background</u> fourth-highest daily maximum 1-hour SO_2 concentration was added to the <u>modeled</u> fourth-highest daily maximum 1-hour SO_2 concentration.[15]

Background concentrations were based on the 2008-10 design value measured by the ambient monitors located in Florida.[16]

6. Reporting

All files from the programs used for this modeling analysis are available to regulatory agencies. These include analyses prepared with AERSURFACE, AERMET, AERMAP, and AERMOD.

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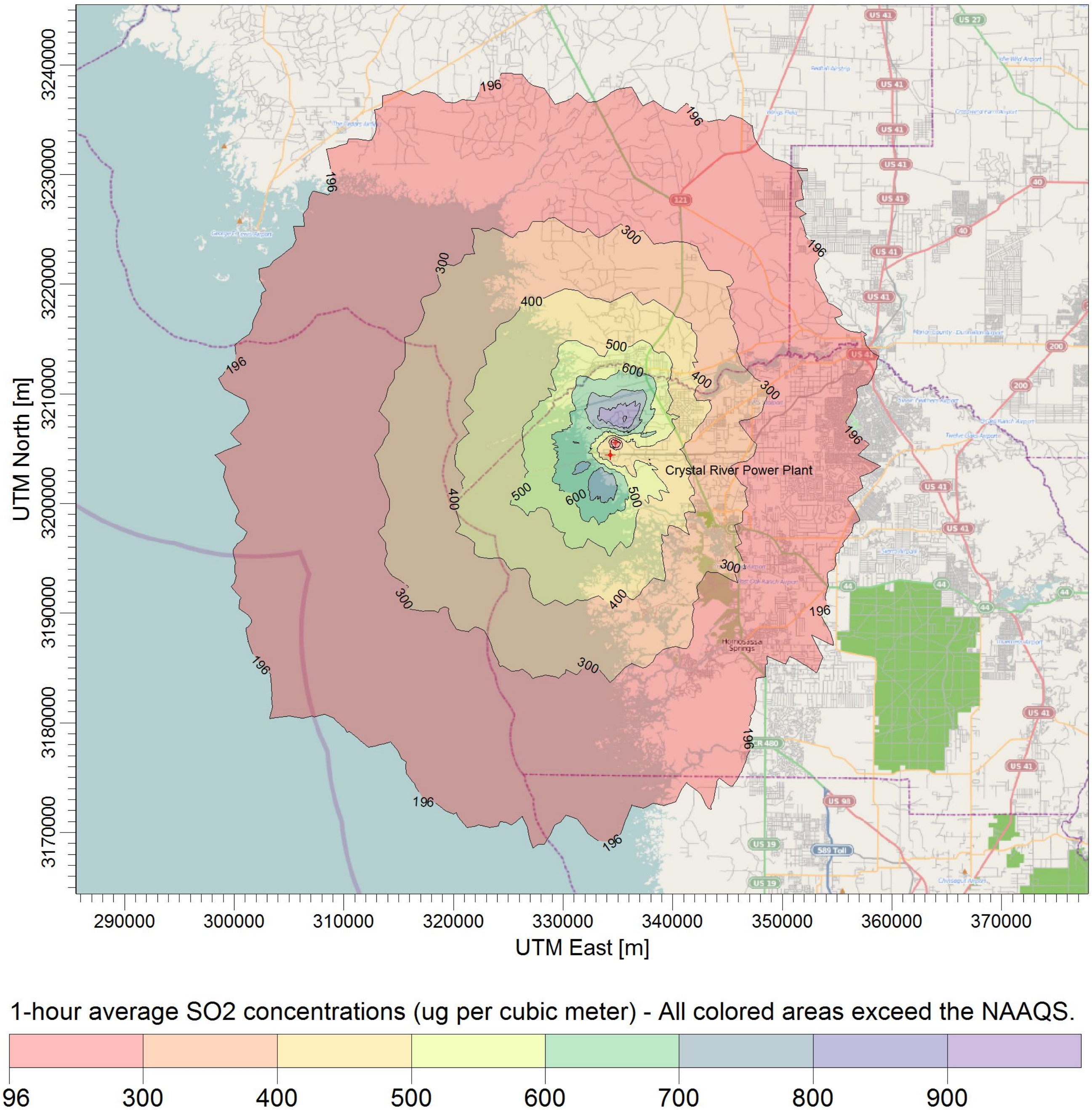
[12] USEPA, Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-05, February 2000, Section 5.3.2, pp. 5-4 to 5-5.
[13] USEPA, AERMOD Implementation Guide, March 19, 2009, pp. 3-4.
[14] USEPA, Area Designations for the 2010 Revised Primary Sulfur Dioxide National Ambient Air Quality Standards, Attachment 3, March 24, 2011, pp. 20-23.
[15] USEPA, Applicability of Appendix W Modeling Guidance for the 1-hour SO_2 National Ambient Air Quality Standard, August 23, 2010, p. 3.
[16] http://www.epa.gov/airtrends/values.html

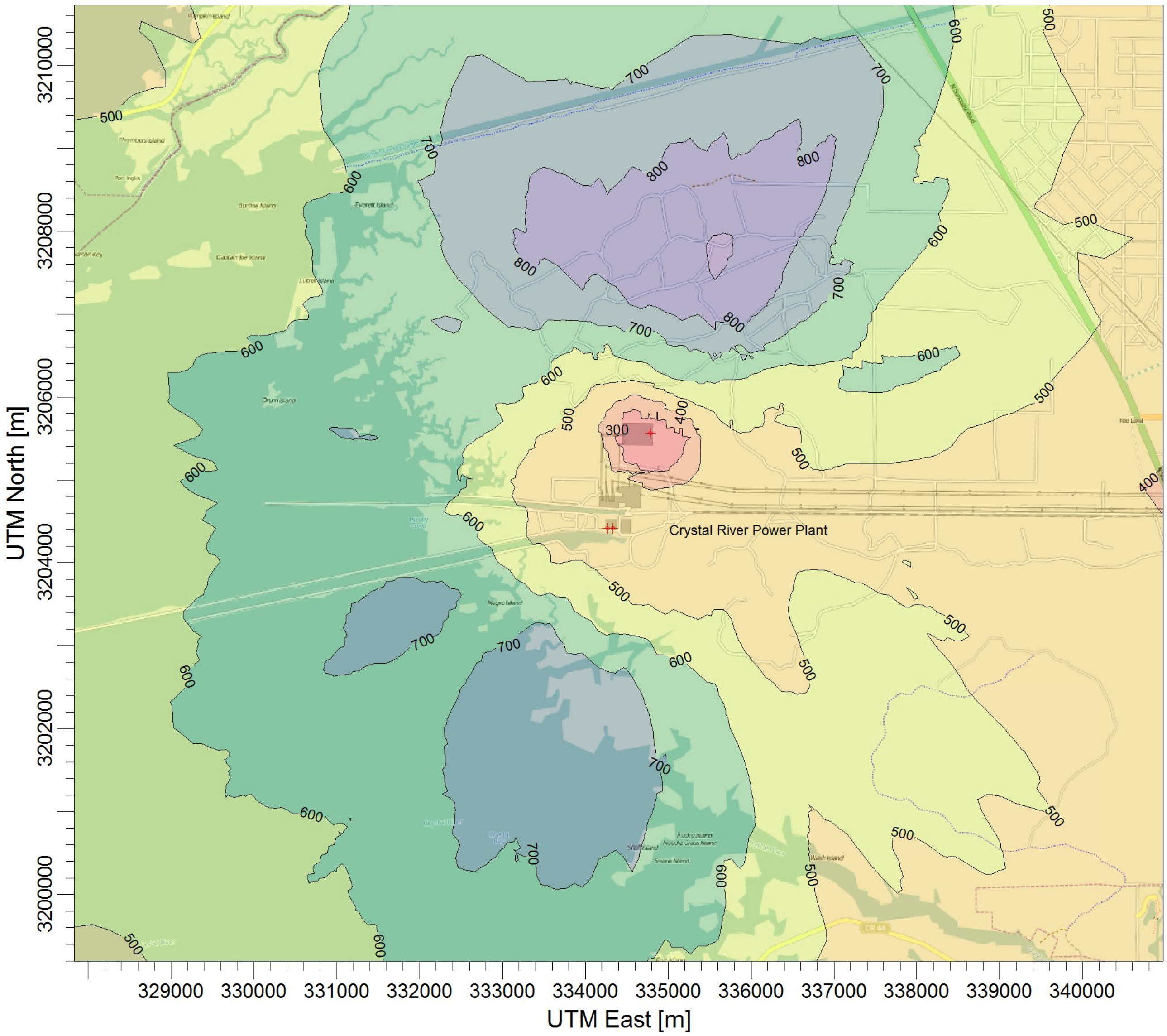
Crystal River Power Plant - Crystal River, Florida
Evaluation of Compliance with the 1-hour NAAQS for SO2



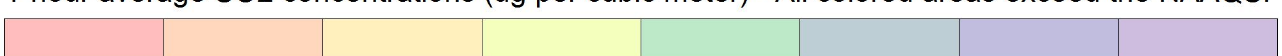
All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **6**	**Conducted on behalf of the Sierra Club**	
	Total Receptors **22083**	**by Wingra Engineering, S.C.**	
	Output Type **Concentration**	SCALE: 1:580,926 (0 – 20 km)	
	Maximum **921.02714 ug/m^3**	DATE: **6/25/2012**	

AERMOD View - Lakes Environmental Software

Crystal River Power Plant - Crystal River, Florida
Evaluation of Compliance with the 1-hour NAAQS for SO2



1-hour average SO2 concentrations (ug per cubic meter) - All colored areas exceed the NAAQS.



All concentrations include a background of 5.2 ug/m3. This figure is based on allowable emissions.	Total Sources **6**	**Conducted on behalf of the Sierra Club**	
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	Maximum **921.02714 ug/m^3**	DATE: **6/25/2012**	

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Investigation of Local Mercury Deposition from a Coal-Fired Power Plant Using Mercury Isotopes

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S *Supporting Information*

ABSTRACT: Coal combustion accounts for approximately two-thirds of global anthropogenic mercury (Hg) emissions. Enhanced deposition of Hg can occur close to coal-fired utility boilers (CFUBs), but it is difficult to link specific point sources with local deposition. Measurement of Hg stable isotope ratios in precipitation holds promise as a tool to assist in the identification of local Hg deposition related to anthropogenic emissions. We collected daily event precipitation samples in close proximity to a large CFUB in Crystal River, Florida. Precipitation samples collected in Crystal River were isotopically distinct and displayed large negative δ^{202}Hg values (mean = −2.56‰, 1 SD = 1.10‰, n = 28). In contrast, precipitation samples collected at other sites in FL that were not greatly impacted by local coal combustion were characterized by δ^{202}Hg values close to 0‰ (mean = 0.07‰, 1 SD = 0.17‰, n = 13). These results indicate that, depending on factors such as powdered coal isotopic composition and efficiency of Hg removal from flue gas, Hg deposited near CFUBs can be isotopically distinct. As this tool is further refined through future studies, Hg stable isotopes may eventually be used to quantify local deposition of Hg emitted by large CFUBs.

INTRODUCTION

Mercury (Hg) is a bioaccumulative neurotoxin that can enter aquatic ecosystems via atmospheric deposition.[1,2] Complex atmospheric Hg chemistry and the mixing of emissions from local, regional, and long-range sources make it challenging to directly trace Hg pollution from sources to receptor sites. Gaseous elemental Hg (GEM) has a relatively long atmospheric residence time and can be transported regionally and globally, whereas reactive gaseous Hg (RGM) and fine particle-bound Hg ($Hg_{(p)}$) are more water-soluble and particle reactive.[3,4] As a result, these forms of Hg are rapidly scavenged from the atmosphere and deposited to surface environments.[5,6] Mercury deposition near point sources and urban areas can be enhanced because RGM and $Hg_{(p)}$ are often emitted in higher proportions from anthropogenic sources.[7−11] However, the relative contribution to Hg deposition from local, regional, and long-range sources is location-specific and depends on a number of factors including the types and quantities of local and regional sources, atmospheric transport patterns, atmospheric oxidants, and local meteorology.[9,12,13]

Multivariate receptor models based on ratios of trace element co-pollutants in combination with meteorological data have been used to quantify the relative impact of local sources on Hg deposition.[9,11,13−15] A number of studies have utilized these techniques to investigate Hg deposition in Florida (FL), USA.[9,13,14,16,17] Elevated levels of Hg have been found across FL in freshwater fish,[18,19] wading birds,[20] and precipitation.[13,21] Mercury concentrations in FL precipitation can be an order of magnitude greater than those in the urban midwestern USA,[12,13,22] especially during the summer months.[13,23] In the 1990s, researchers found that local sources of Hg including coal-fired utility boilers (CFUBs), oil-fired utility boilers, municipal and medical waste incinerators, and cement manufacturing facilities contributed significantly to Hg deposition in south FL.[9,13,14] Recent regulations on emissions from municipal and medical waste incinerators have significantly reduced Hg emissions from those sources.[24−26] Despite these emissions reductions, Hg wet deposition remains elevated across FL, and the current relative impact of local versus long-range transported emissions is not well understood.

The measurement of Hg stable isotope ratios in atmospheric samples has the potential to assist in the identification of Hg emissions from local point sources.[27−31] This study represents the first use of Hg stable isotope ratios to investigate near-source Hg deposition resulting from coal combustion. This research was performed in collaboration with a study conducted to understand current Hg deposition patterns across FL and provide Hg total maximum daily load estimates.

Mercury Stable Isotopes. There are seven stable isotopes of Hg (196, 198, 199, 200, 201, 202, and 204 amu), and isotopic variation has been documented in reservoirs including fossil fuels[29] and the atmosphere.[27,28] Mercury isotope ratios are reported

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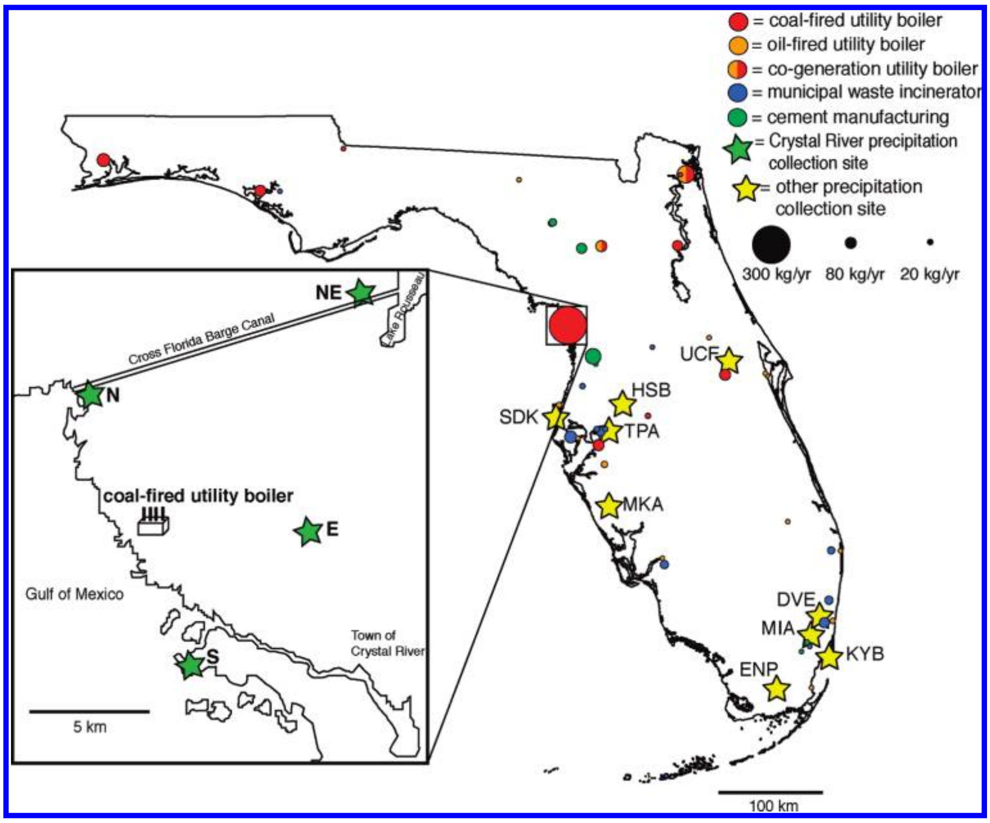

Figure 1. Map of Hg emissions sources and sample collection sites with inset showing sites surrounding Crystal River utility. Symbols for point sources are scaled linearly (with respect to radius) according to total estimated Hg emissions relative to the largest source.[8] Only sources emitting >1 kg of Hg per year are shown. Precipitation collection sites surrounding the Crystal River CFUB (green stars) are labeled as N, NE, S, and E. The other precipitation collection sites are shown as yellow stars.

using delta notation as

$$\delta^{xxx}\mathrm{Hg}(‰) = ([(^{xxx}\mathrm{Hg}/^{198}\mathrm{Hg})_{sample}/(^{xxx}\mathrm{Hg}/^{198}\mathrm{Hg})_{SRM3133}] - 1) \times 1000 \quad (1)$$

where ^{xxx}Hg is an isotope of Hg and SRM 3133 is a NIST Hg standard.[32] Mercury isotopes can undergo mass-dependent fractionation (MDF) during processes such as photochemical reduction and evasion from aqueous solutions.[33,34] Following previous work, we report MDF of Hg isotopes using δ^{202}Hg.[35] Mercury isotopes can also undergo mass-independent fractionation (MIF). A relatively small amount of MIF (<~0.5‰) can be caused by differences in nuclear charge radii between the isotopes (the nuclear field shift effect).[33,36−38] A greater magnitude of MIF can occur during spin-selective photochemical reactions involving radical pairs (the magnetic isotope effect) in which the even and odd-mass-number isotopes react at different rates.[28,39−41] MIF is reported as the deviation of a measured delta value from that theoretically predicted to result due to kinetic MDF according to the equation:

$$\Delta^{xxx}\mathrm{Hg} = \delta^{xxx}\mathrm{Hg} - (\delta^{202}\mathrm{Hg} \times \beta) \quad (2)$$

where β is equal to 0.252 for ^{199}Hg, 0.502 for ^{200}Hg, and 0.752 for ^{201}Hg.[32]

EXPERIMENTAL SECTION

Site Descriptions. During July 2009 daily event precipitation samples were collected at four sites (designated N, NE, S, and E) surrounding the CFUB in Crystal River, FL, at distances of 5.0 to 10.6 km (Figure 1 and Table S1 of Supporting Information). These sites and the CFUB were located in close proximity to the Gulf of Mexico coast. As depicted in Figure 1, the only significant point source of Hg emissions (>1 kg of Hg per year) within ~50 km of the Crystal River area is the CFUB. Additionally, according to the 2005 U.S. EPA National Emissions Inventory (NEI), the Crystal River CFUB is the largest point source of total Hg emissions in FL and emitted a total of ~300 kg of Hg per year during the period of our study.[8] It is important to consider the speciation of these emissions because RGM and $Hg_{(p)}$ species are readily deposited near point sources and air pollution control devices (APCDs) can impact Hg speciation. For example, selective catalytic reduction units (SCRs) promote oxidation of GEM to reactive species[42] that are efficiently removed from the flue gas in wet flue-gas desulfurization units or electrostatic precipitators.[42,43] For this reason, CFUBs with SCRs and flue-gas desulfurization units are predicted to release a lower percentage of Hg as RGM than those without these APCDs (Table S2 of Supporting Information). In contrast, because the Crystal River CFUB had only limited APCDs in July 2009, an estimated 68% of the Hg emissions from the CFUB were RGM species (Table S2).[8] Because the Crystal River CFUB is a large point source of RGM emissions isolated from other emissions sources, the area surrounding the utility was a good location to isolate and measure the isotopic composition of locally deposited Hg emitted by a CFUB.

Between July and September 2009, daily event precipitation samples were also collected at nine other sites across FL (Figure 1 and Table S1). These sites were located near a variety of anthropogenic Hg sources and, depending on meteorological conditions and source characteristics, Hg deposition at these sites may have been influenced by a mixture of local sources and non-local, long-range transported Hg. It is possible that local coal combustion may have impacted samples collected at several of the sites including TPA and UCF. However, not only do the CFUBs near those sites emit much less total Hg than the Crystal River CFUB, but also, due to their APCDs, it is estimated that only ~8% of their Hg emissions are RGM species (Table S2). We do not expect, therefore, that these sites were influenced by local coal combustion to the same degree as the Crystal River sites. The Sand Key Park (SDK) site was chosen because it was located on the Gulf of Mexico coast, and during specific meteorological conditions, Hg deposition at that site was primarily composed of non-local, long-range transported Hg.

Sample Collection. Precipitation samples were collected daily using manually deployed tripods (~2 m above ground level) with sampling trains that were similar to those previously deployed in automated collectors.[11,21,44] Tipping bucket rain gauges (R. M. Young) were mounted on the tripods. At each of the four Crystal River sites, three Hg sampling trains were deployed per event to ensure collection of sufficient Hg for isotope analyses (see Supporting Information). These sites were maintained daily from 7/4/09 through 7/24/09; after 7/24/09, samples were collected only at the NE site. Two field blanks were collected at each site during the course of the study (see Supporting Information).

Five coal samples were obtained from the Pennsylvania State University Coal Sample Bank. These coal samples were from the same regions in eastern Kentucky (KY) and West Virginia (WV), but not necessarily the same mines, as those that supplied coal to the Crystal River CFUB during July 2009[45] (Table S2).

Meteorological Analysis. The precipitation events included in this study were analyzed meteorologically using GRLevel2 Analyst software[46] with archived NEXRAD Level II radar data[47] (see Supporting Information). Using these data, we measured a variety of parameters including storm motion, maximum rainfall intensity, maximum echo top height, and average precipitating cell size at 5-min intervals throughout each event. We characterized surface wind direction using surface meteorological maps[48] and air sounding data.[5] Air mass transport to the sites was additionally modeled using the NOAA Hybrid Single-Particle Lagrangian Integrated Trajectory (HYSPLIT) model.[49] The hour of maximum precipitation was used as the starting time for each back trajectory, and trajectories were calculated using starting heights of 500 and 1000 m above ground level.

Sample Processing and Analysis. After collection, precipitation samples were oxidized to a concentration of 1% BrCl (v/v) and stored in a cold room for four months. Mercury concentrations were then measured in the field blanks and a subset of the samples by atomic absorption spectrometry (AAS; MA-2000, Nippon Instruments) (see Supporting Information). The method detection limit (MDL) for these analyses was 0.82 ng/L (3 SD of blank analyses), and all sample replicates were within 8.1% relative percent difference (RPD) (mean RPD = 2.0 ± 1.9%, 1 SD, n = 78). The Crystal River field blanks contained an average of 0.39 ng of Hg (1 SD = 0.46 ng, n = 8) while field blanks collected at the other sites in FL contained an average of 0.07 ng of Hg (1 SD = 0.10 ng, n = 43). The field blanks collected at the Crystal River sites may be somewhat higher because equipment limitations only allowed cleaning of the funnels and adapters in 5% HNO_3 for 4−8 h compared to 24 h at the other sites. However, the Hg in the Crystal River field blanks represents only a small percentage of the average amount of Hg contained in precipitation samples collected at those sites (mean = 1.8%, 1 SD = 1.8%, n = 8), and this amount of contamination could not have significantly influenced the isotopic compositions of the samples (see Supporting Information).

Mercury in the precipitation samples with sufficient mass for isotopic analyses (i.e., >8 ng) was concentrated into acidic 1% $KMnO_4$ solutions (w/w, Alfa Aesar). Each sample was poured into a 2 L Pyrex bottle, and 0.3 mL of 30% $NH_2OH \cdot HCl$ was added and allowed to react for 30 min. A peristaltic pump was then used to add 100 mL of 5% $SnCl_2$ at a rate of 10 mL/min. Mercury-free air was pulled through the sample and carried the resulting GEM into the trapping solution at a rate of 0.7 L/min for 4 h. Procedural standards (NIST SRM 3133) and blanks were processed in the same manner (see Supporting Information). Each of four sample replicates were processed by separating the total sample volume in half and processing the two splits in parallel. After transfer into the $KMnO_4$ solutions, final Hg concentrations were measured by AAS and used to determine Hg concentrations in the original precipitation samples. Mercury in procedural standards was consistently recovered completely in the final solutions (mean = 94%, 1 SD = 6%, n = 23; see Supporting Information).

Hg in the coal samples was thermally released and concentrated into 1% $KMnO_4$ solutions according to previously reported methods.[29] Briefly, the samples were crushed to a fine powder, weighed into ceramic boats, and combusted over 5.75 h in a two-stage quartz tube furnace in which the temperature of the first furnace was incrementally increased to 550 °C while the second furnace was held at 1000 °C. The resulting GEM was swept by O_2 gas into the $KMnO_4$ solution. Procedural standards (NIST SRM 1632c) and blanks were processed using the same methods. Mercury in procedural standards was consistently recovered completely in the final solutions (mean = 94%, 1 SD = 5%, n = 7; see Supporting Information).

Hg isotopic compositions were measured using continuous-flow cold vapor generation MC-ICP-MS (Nu Instruments) according to previously published methods.[32,39] We estimate the maximum sample analytical uncertainty of a given isotope ratio as 2 SD of the measurement of the ratio in procedural standards (e.g., δ^{202}Hg uncertainty = 0.13‰, 2 SD). Replicate analyses of the UM-Almadén secondary standard (n = 37) and precipitation sample replicates (n = 4) were reproducible within this uncertainty (Table S4 of Supporting Information).

■ RESULTS AND DISCUSSION

Precipitation Events. To better interpret the results of our isotopic analyses, we analyzed the meteorological conditions during each precipitation event in Crystal River (Table S3 of Supporting Information). The observed precipitation events fell broadly into two categories based on meteorological conditions. We further characterized the events in "Event Group 1" into three subcategories, 1A, 1B, and 1C as follows. During the first week of the study (7/4/09 to 7/9/09) and on 7/20/09 (Table S3, Event Group 1A), slow-moving cold and stationary fronts persisted over northern FL and southern Georgia. Predominantly westerly winds transported air masses onshore from over the Gulf of Mexico, and westerly and southwesterly surface winds transported emissions from the CFUB over the collection sites. These events were characterized by large convective cells that covered the entire study area and resulted in precipitation at all of the Crystal River sites. The events on 7/17/09 and 7/18/09 (Table S3, Event Group 1B) similarly were related to the presence of a cold front over southern Georgia and were characterized by westerly surface winds. In contrast to the earlier events, during the events on 7/17/09 and 7/18/09, large isolated precipitating convective cells (~6 to 10 km in diameter) passed over the CFUB and only resulted in precipitation at some of the sites. Finally, the event on 7/12/11 (Table S3, Event Group 1C) was characterized by a local high pressure system and a north–south band of convective precipitating cells (~26 km in north–south length) that moved inland from the west over the CFUB and impacted the NE and E sites. In general, the Group 1 precipitation events (7/4/09 to 7/20/09) were characterized by persistent cold and stationary fronts over northern FL and central Georgia, westerly/southwesterly storm motion and surface winds, and large convective precipitating cells that often impacted the entire study area. Under these conditions, RGM emitted by the CFUB was likely incorporated into cloud droplets,[23] and because the precipitating cells were larger in diameter than the distance between the collection sites, this Hg was likely deposited at all of the Crystal River sites.

The precipitation events on 7/30/09 and 7/31/09 ("Event Group 2") were meteorologically different than the preceding events (Table S3). The event on 7/30/09 was not related to a frontal system. During that event, convective cells formed over central FL and were transported into the Crystal River area by southeasterly winds. Southerly surface winds transported emissions from the Crystal River CFUB to the north. On 7/31/09, precipitating cells were transported into the area from the northwest and southerly surface winds similarly transported the CFUB emissions to the north. Especially on 7/30/09 it is unlikely that local emissions from the Crystal River CFUB were incorporated into the precipitating cells that impacted the NE site. We hypothesize that Hg deposited during these events at the NE site was transported to the area from non-local sources.

We also analyzed the meteorological conditions during events sampled at the Sand Key Park (SDK) site on the Gulf of Mexico coast (Figure 1). On 7/26/09, southwesterly onshore flow transported air masses to the area that had spent the previous two days over the Gulf of Mexico. Convective heating caused the formation of offshore cells that moved inland and caused precipitation at the site. Given these conditions and the coastal location of the SDK site, Hg deposited during this event was primarily of non-local origin and transported from over the Gulf of Mexico.

Mercury Concentrations. Mercury concentrations in precipitation are presented in Table S4. Mercury concentrations in samples collected in Crystal River that were analyzed for Hg isotopic composition ranged from 4.0 to 130 ng/L and concentrations in samples collected at the other sites that were analyzed for Hg isotopic composition ranged from 18 to 69 ng/L. Volume-weighted mean (VWM) sample Hg concentrations at each of the Crystal River sites were calculated by dividing the total amount of Hg deposited by the total volume of precipitation. The VWM concentrations for the four sites were 41 ng/L (N), 27 ng/L (NE), 44 ng/L (E), and 51 ng/L (S). These VWM concentrations are relatively high compared to those reported by previous studies conducted during the summer in south FL (13–27 ng/L)[21] and those measured at the FL Mercury Deposition Network sites in

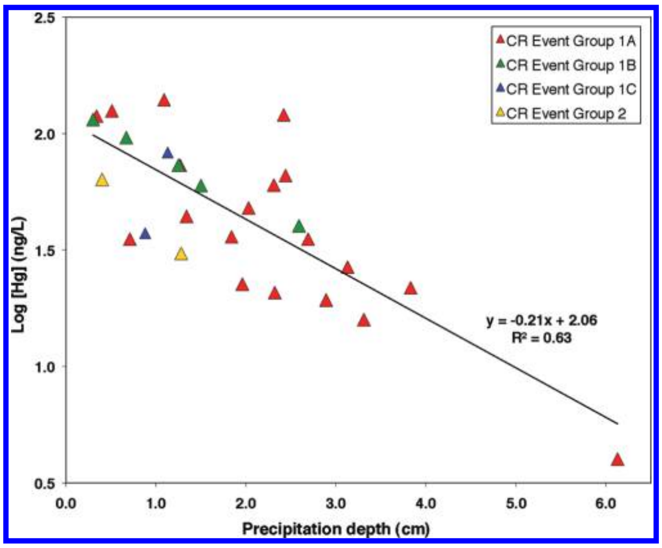

Figure 2. Precipitation depth (cm) versus log Hg concentration (ng/L). Precipitation samples collected at sites in Crystal River, FL are shown as triangles. Precipitation events are colored according to Event Group: Event Group 1A (red triangles) includes events from 7/4/09 to 7/9/09 and 7/20/09, Event Group 1B (green triangles) includes the events on 7/17/09 and 7/18/09, Event Group 1C (blue triangles) represents the event on 7/12/09, and Event Group 2 (yellow triangles) includes the events on 7/30/09 and 7/31/09. A linear regression through all of the data points is shown.

July 2009 (15–26 ng/L).[50] The lower VWM Hg concentration at the NE site and higher VWM concentration at the S site may be partly explained by differences in total precipitation amount collected at these sites during individual events. To assess this relationship, precipitation depth (cm) was regressed against the logarithm of Hg concentrations (Figure 2; see Supporting Information). As shown in Figure 2, the slope of the relationship between precipitation depth and Hg concentration is negative (slope = -0.21 ± 0.03, 1 SE; $t = -6.62$, $p < 0.0001$, $r^2 = 0.63$, $n = 28$) and 63% of the variation in concentration is explained by differences in precipitation depth.[51] Although the high volume sample collected at the NE site on 7/4/09 falls outside of the range of the rest of the data, it had little influence on the slope estimate (slope without NE 7/4/09 = -0.19 ± 0.04, 1 SE; $t = -4.40$, $p = 0.0002$, $r^2 = 0.44$, $n = 27$). Similar relationships between Hg concentration and precipitation amount have been observed in previous studies.[13,21,22,52] Several of these studies suggest that at locations impacted to varying degrees by Hg from local sources, variations in Hg concentration are largely controlled by the magnitude of local source impacts and not by differences in precipitation amount.[11,13] The correlation between Hg concentration and precipitation depth in the Crystal River samples suggests that variations in Hg concentration were not caused by varying impacts from the local CFUB. Instead, on the basis of meteorological analyses, high Hg concentrations, and Hg isotopic analyses, we argue that this correlation resulted because of deposition of Hg from the CFUB at all of the collection sites.

Mercury Isotopic Compositions. Complete isotopic data are presented in Table S4. As depicted in Figure 3, precipitation samples collected in Crystal River were characterized by negative δ^{202}Hg values as low as -4.37 ± 0.13‰, 2 SD (mean = -2.56‰, 1 SD = 1.10‰, $n = 28$) and slightly positive Δ^{199}Hg values (mean = 0.32‰, 1 SD = 0.12‰, $n = 28$). In contrast, precipitation collected at the other sites in FL did not exhibit large

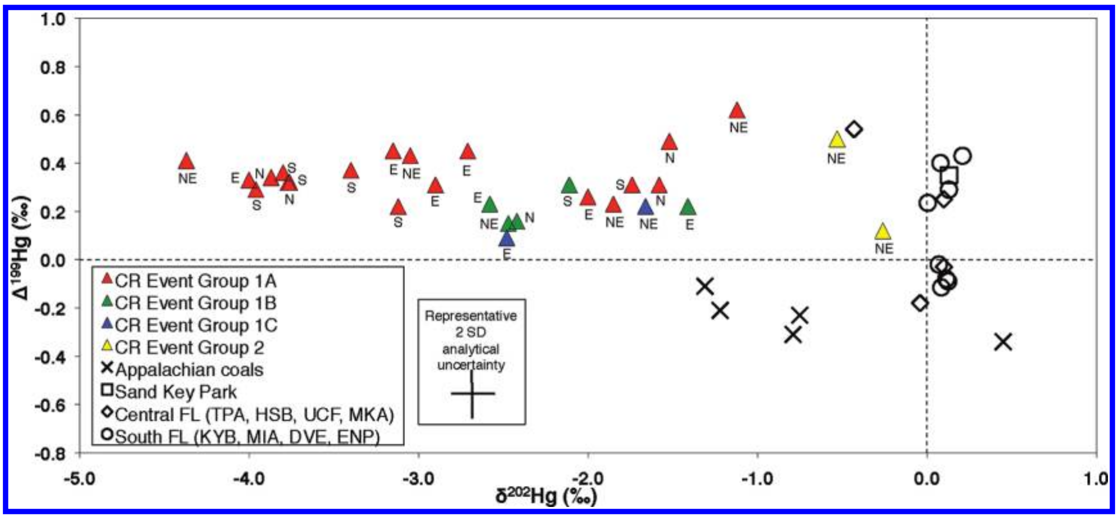

Figure 3. δ^{202}Hg (‰) versus Δ^{199}Hg (‰) measured in precipitation and coal samples. Precipitation samples collected at sites in Crystal River, FL are shown as solid triangles and secondarily labeled by collection site location (N, NE, S, E). Precipitation events are grouped according to Event Group (1A = 7/4/09 to 7/9/09 and 7/20/09; 1B = 7/17/09 and 7/18/09; 1C = 7/12/09; 2 = 7/30/09 and 7/31/09). Precipitation samples collected at other sites are shown as open symbols where the Sand Key Park sample is a square, central FL site samples are diamonds, and south FL site samples are circles. Representative Appalachian coal samples are shown as black X's. Precipitation sample analytical uncertainty based on replicate analyses of procedural standards (2 SD) is depicted. Black dashed lines depict the zero values for both axes.

negative δ^{202}Hg values (mean = 0.07‰, 1 SD = 0.17‰, n = 13) and had a wider range of Δ^{199}Hg values (mean = 0.15‰, 1 SD = 0.25‰, n = 13). All of the precipitation samples exhibited slightly positive Δ^{200}Hg values (mean = 0.11‰, 1 SD = 0.07‰, n = 41) that were similar in magnitude to those reported for Midwest precipitation[27] (see Supporting Information).

Four of the five coal samples from mines similar to those that supplied the Crystal River CFUB also displayed negative δ^{202}Hg values as low as -1.31 ± 0.13‰, 2 SD (mean = -0.72‰, 1 SD = 0.70‰, n = 5) but exhibited negative Δ^{199}Hg values (mean = -0.24‰, 1 SD = 0.09‰, n = 5). These samples did not display MIF of ^{200}Hg (mean Δ^{200}Hg = -0.02‰, 1 SD = 0.03‰, n = 5).

The magnitude of the negative δ^{202}Hg values measured in samples collected in Crystal River greatly exceeds that previously reported for atmospheric samples.[27,28,53] With the exception of the two precipitation samples collected at the NE site on 7/30/09 and 7/31/09 (Table S3, Event Group 2), all of the Crystal River samples exhibited δ^{202}Hg values lower than -1.10‰ and there are no clear differences between the four Crystal River collection sites in terms of isotopic composition (Figure 3). This is likely due to the fact that large precipitating cells covered the study area during these events and all of the collection sites were similarly impacted by emissions from the CFUB.

Factors Influencing Hg Isotopic Compositions. The Hg isotopic composition of any particular precipitation sample is the result of mixing of Hg from different sources combined with the effects of in-source and post-emission fractionation.[27] Here we address these factors and their potential influence on the observed Hg isotopic compositions of the collected precipitation samples.

Source Isotopic Composition. Mercury deposited in precipitation at the Crystal River sites was a mixture of local CFUB-emitted Hg and Hg from non-local sources. During the Event Group 1 precipitation events (7/4/09 through 7/20/09), storm motion was primarily from the west and any non-local Hg deposited at the collection sites was transported to the area from over the Gulf of Mexico. To estimate the isotopic composition of this Hg, we analyzed Hg in precipitation collected at the SDK site on 7/26/09. On the basis of meteorological analyses, Hg deposited during that event was primarily non-local and transported from over the Gulf of Mexico. This sample was characterized by a slightly positive δ^{202}Hg value (0.13 ± 0.13‰, 2 SD). Therefore, it is unlikely that the large negative δ^{202}Hg values observed in Crystal River precipitation are due to the influence of non-local Hg transported from over the Gulf of Mexico. Instead, we argue that local deposition of Hg emitted by the Crystal River CFUB resulted in the observed negative δ^{202}Hg values.

The isotopic composition of Hg emitted by a CFUB could be affected by several factors including (1) original source coal isotopic composition, (2) coal cleaning, and (3) in-system fractionation within the power plant. Although we did not have access to coal burned at the Crystal River CFUB during the sampling period, coal samples from mines in the same region as those that supplied coal to the CFUB displayed negative δ^{202}Hg values and negative Δ^{199}Hg values. Biswas et al.[29] measured similarly negative δ^{202}Hg values (mean = -1.23‰, 1 SD = 0.29‰, n = 6) and slightly negative Δ^{199}Hg values (mean = -0.13‰, 1 SD = 0.01‰, n = 2) in other Appalachian coals. Assuming that these values represent the isotopic composition of the original bulk source coal delivered to the Crystal River CFUB in July 2009, additional negative MDF and positive MIF of Hg are required to produce the observed precipitation Hg isotopic compositions.

Coal cleaning prior to combustion may result in powdered coal that displays δ^{202}Hg values lower than that of the original bulk source coal. To reduce sulfur concentrations, high sulfur Appalachian coals are generally cleaned at the mine prior to shipment using fluidized density separation.[54] During this process, denser minerals such as Hg-rich sulfides sink and are removed.[54] Secondary coal cleaning is also conducted at many CFUBs (including the Crystal River CFUB) wherein the more coarse and dense sulfides are rejected at the coal pulverizer

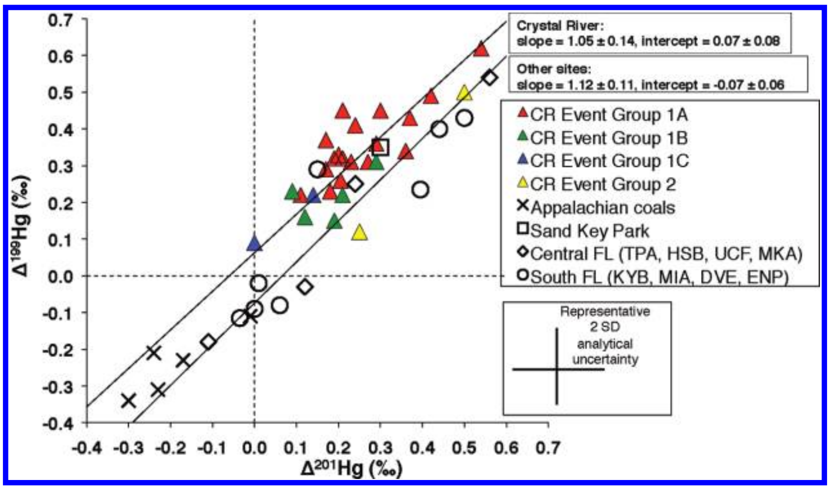

Figure 4. Δ^{201}Hg (‰) versus Δ^{199}Hg (‰) in precipitation and coal samples. Precipitation samples collected at sites in Crystal River, FL are shown as solid triangles. Precipitation events are grouped according to Event Group (1A = 7/4/09 to 7/9/09 and 7/20/09; 1B = 7/17/09 and 7/18/09; 1C = 7/12/09; 2 = 7/30/09 and 7/31/09). Precipitation samples collected at other sites are shown as open symbols where the Sand Key Park sample is a square, central FL site samples are diamonds, and south FL site samples are circles. Representative Appalachian coal samples are shown as black X's. Δ^{199}Hg/Δ^{201}Hg ratios calculated for samples collected in Crystal River and samples collected at the other sites using York regressions[67] are shown as solid lines. Representative sample analytical uncertainty for precipitation samples based on replicate analyses of procedural standards (2 SD) is depicted. Black dashed lines depict the zero values for both axes.

during crushing.[55−58] Because a large percentage of Hg in coal is associated with sulfides,[54,59] these processes can remove a significant amount of Hg from the original source coal.[54] A recent study of coals from the Illinois basin found that sulfide-associated Hg had much higher δ^{202}Hg values (mean = −0.11‰, 1 SD = 0.05‰, n = 3) than that of Hg associated with coexisting organic matter (mean = −1.46‰, 1 SD = 0.34‰, n = 21).[60] Removal of sulfides through coal cleaning may, therefore, result in the preferential removal of the heavier isotopes of Hg and produce powdered coal with a lower δ^{202}Hg value than that of the original bulk source coal.

In-System Fractionation. Essentially all of the Hg liberated during coal combustion is expected to be GEM.[58] As the flue gas leaves the boiler and enters the APCDs, it cools to ~130 °C, and some portion of the GEM is oxidized to RGM through gas-phase reactions or via heterogeneous reactions on particles.[42,58] The reactive Hg species can subsequently be removed to varying degrees by the APCDs.[42,58] MDF of heavy metals (including Zn, Cd, and Hg) has been observed at similarly high temperatures during industrial and volcanic processes.[53,61−64] Zambardi et al.[53] observed MDF of Hg isotopes in volcanic fumerole emissions and found that downwind of the vents, oxidized plume $Hg_{(p)}$ displayed higher δ^{202}Hg values (−0.11 ± 0.18‰, 2 SD) than that of total gaseous Hg (−1.74 ± 0.36‰, 2 SD).[53] The authors hypothesized that this was due to the preferential equilibrium oxidation of the heavy isotopes of Hg.[53] If a similar process occurs in CFUB flue gas, the heavier isotopes of Hg would be progressively oxidized, adsorbed onto particles, and removed in electrostatic precipitators and baghouses.[42,58] This process would result in MDF of Hg isotopes such that the Hg remaining in the flue gas would exhibit progressively lower δ^{202}Hg values relative to the powdered coal that was combusted. Unfortunately, because we cannot determine the Hg removal efficiency from the flue gas at the Crystal River CFUB and because we do not know the exact isotopic composition of the powdered coal that was combusted, we are not able to model this fractionation process.

Post-Emission Atmospheric Fractionation. In addition to source isotopic composition and in-system fractionation, post-emission atmospheric processes may cause additional MDF and MIF. To our knowledge, the effects of atmospheric reactions on Hg isotopes have not been studied.[35] However, once emitted to the atmosphere, RGM is strongly scavenged by aqueous droplets.[3] Thus, we do not expect that significant secondary MDF affects RGM emitted by the Crystal River CFUB prior to deposition. It is, however, possible that atmospheric processes could have played a role in modifying the observed Δ^{199}Hg values in the precipitation samples. The Crystal River precipitation samples displayed higher Δ^{199}Hg values (~0.5‰) than that of the representative source coal samples (mean coal Δ^{199}Hg = −0.24‰, 1 SD = 0.09‰, n = 5; mean precipitation Δ^{199}Hg = 0.32‰, 1 SD = 0.12‰, n = 28). Although this magnitude of MIF could have occurred in the power plant system during reactions influenced by the nuclear field shift (NFS) effect,[33] it is more likely that photochemical reactions in the atmosphere caused the observed positive MIF.

Gratz et al.[27] hypothesized that a difference between near-zero Δ^{199}Hg values in total gaseous Hg (mean = −0.09‰, 1 SD = 0.09‰, n = 7) and positive Δ^{199}Hg values observed in Midwest precipitation (mean = 0.30‰, 1 SD = 0.14‰, n = 20) could be the result of the magnetic isotope effect (MIE) occurring during photochemical reduction and evasion of Hg from cloud droplets. In experimental studies, the MIE has been demonstrated to result in a Δ^{199}Hg/Δ^{201}Hg ratio between 1.0 and 1.3.[33,39] In contrast, the NFS effect has been theoretically calculated and experimentally demonstrated to result in a higher Δ^{199}Hg/Δ^{201}Hg ratio between 1.6 and 2.5.[33,36,37,65,66] Precipitation samples collected during this study were characterized by Δ^{199}Hg/Δ^{201}Hg ratios within error of 1.0 (Crystal River samples = 1.05 ± 0.14, 1 SD; other precipitation samples = 1.12 ± 0.11, 1 SD;[67] Figure 4). This suggests that the MIE occurring during photochemical processes in the atmosphere is at least partially responsible for the observed Δ^{199}Hg values in the precipitation samples.

This study of Hg deposited in precipitation across the state of FL provides evidence that Hg isotopes may be useful as a tool to help identify locally deposited Hg emitted by large CFUBs. We hypothesize that the isotopic composition of source coal, coal cleaning, and processes inherent to the removal of Hg from the flue gas stream caused the emission of Hg with extreme negative δ^{202}Hg values from the Crystal River CFUB. It is likely that the isotopic composition of Hg emissions varies between CFUBs depending on a number of factors such as powdered coal isotopic composition, thermal profile of the power plant system, properties of particles in the flue gas, type of APCDs, and efficiency of Hg removal by APCDs. It is also likely that local Hg deposition near other types of anthropogenic point sources is isotopically different than that measured near the Crystal River CFUB. Future measurements of the Hg isotopic composition of powdered coal and flue gas emissions, percentage of RGM in emissions, and efficiency of Hg removal by APCDs would enable more quantitative estimates of the contribution of local coal combustion to Hg deposition. Additionally, future measurements of the isotopic composition of dry deposited Hg may help to further quantify the impact of anthropogenic point sources on local Hg deposition. In areas surrounding large CFUBs such as Crystal River, FL, the anomalous Hg isotope signature of local CFUB emissions may be useful in tracing the impact of this pollution on local ecosystems.

ASSOCIATED CONTENT

S Supporting Information. Detailed experimental methods and supporting data. This material is available free of charge via the Internet at http://pubs.acs.org.

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Notes

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Florida Department of Environmental Protection

Memorandum

TO:	Joseph Kahn, Division of Air Resource Management
THROUGH:	Trina Vielhauer, Bureau of Air Regulation TV
FROM:	Jon Holtom, Title V Section JH
DATE:	February 24, 2009
SUBJECT:	Air Permit No. 0170004-017-AC Progress Energy Florida Crystal River Final BART Permit

The final permit for this BART project is attached for your approval and signature.

The attached final determination identifies issuance of the draft permit, summarizes the publication process, and provides the Department's response to comments (if any) on the draft permit. The Department granted an extension of time to file a petition for an administrative hearing on February 13th. The extension of time request was withdrawn on February 24th.

I recommend your approval of the attached final permit for this project.

Attachments

NOTICE OF FINAL PERMIT

In the Matter of an Application for Permit by:

Progress Energy Florida
100 Central Avenue CN 77
St. Petersburg, Florida 33701
Authorized Representative:
Mr. Bernie Cumbie, Plant Manager

Air Permit No. 0170004-017-AC
Crystal River Power Plant
BART Project
Citrus County

Enclosed is final permit No. 0170004-017-AC. This air construction permit is being issued to satisfy the requirements of Best Available Retrofit Technology (BART) in Rule 62-296.340, Florida Administrative Code (F.A.C.) for the eligible units at the facility identified above. For the existing Crystal River Power Plant, the BART-eligible units are coal-fired Units 1 and 2. The Department of Environmental Protection (Department) reviewed the application and establishes BART emissions standards for particulate matter. The existing facility is located in Citrus County on Power Line Road, West of U.S. Highway 19, in Crystal River, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes.

Any party to this order has the right to seek judicial review of it under Section 120.68 of the Florida Statutes by filing a notice of appeal under Rule 9.110 of the Florida Rules of Appellate Procedure with the clerk of the Department of Environmental Protection in the Office of General Counsel (Mail Station #35, 3900 Commonwealth Boulevard, Tallahassee, Florida 32399-3000) and by filing a copy of the notice of appeal accompanied by the applicable filing fees with the appropriate District Court of Appeal. The notice must be filed within 30 days after this order is filed with the clerk of the Department.

Executed in Tallahassee, Florida.

Trina L Vielhauer

Trina Vielhauer, Chief
Bureau of Air Regulation

TLV/jh

CERTIFICATE OF SERVICE

The undersigned duly designated deputy agency clerk hereby certifies that this Notice of Final Permit (including the Final Permit and Final Determination), or a link to these documents available electronically on a publicly accessible server, was sent by electronic mail with received receipt requested to the persons listed below:

Mr. Bernie Cumbie, Plant Manager, Progress Energy Florida (bernie.cumbie@pgnmail.com)
Mr. Dave Kellermeyer, Northern Star Generation (dave.kellermeyer@northernstargen.com)
Mr. Scott Osbourn, P.E., Golder Associates (sosbourn@golder.com)
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Ms. Katy Forney, EPA Region 4 (forney.kathleen@epa.gov)
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Mr. Dee Morse, NPS (dee_morse@nps.gov)
Ms. Barbara Friday, DEP BAR: barbara.friday@dep.state.fl.us (for posting with U.S. EPA, Region 4)
Ms. Victoria Gibson, DEP BAR: victoria.gibson@dep.state.fl.us (for reading file)

Clerk Stamp

FILING AND ACKNOWLEDGMENT FILED, on this date, pursuant to Section 120.52(7), Florida Statutes, with the designated agency clerk, receipt of which is hereby acknowledged.

(Clerk) 2/26/09 (Date)

PERMITTEE

Progress Energy Florida
100 Central Avenue CN 77
St. Petersburg, Florida 33701

PERMITTING AUTHORITY

Florida Department of Environmental Protection (Department)
Division of Air Resource Management
Bureau of Air Regulation, Title V Section
2600 Blair Stone Road, MS #5505
Tallahassee, Florida 32399-2400

PROJECT

Air Permit No. 0170004-017-AC
Crystal River Power Plant BART Determination

The purpose of this air construction permit is to satisfy the requirements of Best Available Retrofit Technology (BART) in Rule 62-296.340, Florida Administrative Code (F.A.C.) for the eligible units at the facility identified above. For the existing Crystal River Power Plant, the BART-eligible units are coal-fired Units 1 and 2. The Department of Environmental Protection (Department) reviewed the application and establishes BART emissions standards for particulate matter. The existing facility is located in Citrus County on Power Line Road, West of U.S. Highway 19, in Crystal River, Florida. This permit is issued pursuant to Chapter 403, Florida Statutes.

NOTICE AND PUBLICATION

The Department distributed an Intent to Issue Permit package on December 19, 2008. The applicant published the Public Notice of Intent to Issue in the Citrus County Chronicle on January 14, 2009. The Department received the proof of publication on January 27, 2009. The Department granted an extension of time to file a petition for an administrative hearing on February 13th. The extension of time request was withdrawn on February 24th.

COMMENTS

No comments on the Draft Permit were received from the public, the Department's SW District Office, the EPA Region 4 Office or the National Park Service; however, on January 27, 2009, the Department received comments from the applicant. The following summarizes the comments and the Department's response. Revised language added to the permit is indicated by a double underline format.

1. The applicant commented that the excess emissions provisions listed in condition 7 do not recognize the fact that Boilers 1 and 2 meet the definition of existing units contained in Rule 62-210.700(2), F.A.C. and has requested that condition 7 be revised accordingly. This provision is already contained within the Title V permit and it was not intended for this permit to alter that provision. However, at the applicant's request for clarity, condition 7 is revised as follows:

   7. Excess Emissions Allowed. Unless otherwise specified by permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration.

      Excess emissions from existing fossil fuel steam generators resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.

[Rules 62-210.700(1) & (2), F.A.C.]

CONCLUSION

The final action of the Department is to issue the permit with the minor revisions, corrections, and clarifications as described above.

Florida Department of Environmental Protection

Bob Martinez Center
2600 Blair Stone Road
Tallahassee, Florida 32399-2400

Charlie Crist
Governor

Jeff Kottkamp
Lt. Governor

Michael W. Sole
Secretary

PERMITTEE

Progress Energy Florida (PEF)
100 Central Avenue CN 77
St. Petersburg, Florida 33701

Air Permit No. 0170004-017-AC
Expiration Date: 07/01/2014
Crystal River Power Plant
BART Project

Authorized Representative:
Bernie Cumbie, Plant Manager

PLANT AND LOCATION

Progress Energy Florida operates the Crystal River Power Plant, which is a located on Power Line Road, West of U.S. Highway 19, Crystal River, Citrus County, Florida. The UTM coordinates are Zone 17, 334.3 km East and 3204.5 km North. The facility is an existing coal-fired power plant, which is identified by Standard Industrial Classification code No. 4911.

STATEMENT OF BASIS

This air pollution construction permit is issued under the provisions of Chapter 403 of the Florida Statutes (F.S.), and Chapters 62-4, 62-204, 62-210, 62-212, 62-296, and 62-297 of the Florida Administrative Code (F.A.C.). Specifically, this project is subject to Rule 62-296.340, F.A.C., which requires a determination of the Best Available Retrofit Technology (BART) for each BART-eligible source as defined in 40 CFR 51.301. The state rule implements the federal provisions of Appendix Y in 40 CFR Part 51, "Guidelines for BART Determinations Under the Regional Haze Rule". The affected visibility-impairing pollutants include only particulate matter (PM) for electric utilities subject to CAIR. Pursuant to Rule 62-296.340, F.A.C., the permittee shall install or modify the air pollution control equipment to achieve the specified BART standards.

EFFECTIVE DATE

Unless otherwise specified by this permit, the BART-eligible sources shall demonstrate compliance with the conditions of this permit no later than December 31, 2013. [Rule 62-296.340(3)(b)2, F.A.C.]

Executed in Tallahassee, Florida

Joseph Kahn, Director
Division of Air Resource Management

2/25/09
(Date)

JK/tlv/jh

FACILITY DESCRIPTION

Progress Energy Florida, operates an existing coal-fired power plant, which consists of four coal-fired fossil fuel steam generating (FFSG) units and associated equipment.

FACILITY REGULATORY CLASSIFICATIONS

- The facility is a major source of hazardous air pollutants (HAP).
- The facility operates units subject to the acid rain provisions of the Clean Air Act.
- The facility is a Title V major source of air pollution in accordance with Chapter 213, F.A.C.
- The facility is a major stationary source pursuant to Rule 62-212.400, F.A.C. for the Prevention of Significant Deterioration (PSD) of Air Quality.
- The facility operates BART-eligible units subject to Rule 62-296.340 (BART), F.A.C.

BART-ELIGIBLE EMISSIONS UNITS

This permitting action affects the following BART-eligible emissions units at the plant.

EU No.	Emission Unit Description
-001	Fossil Fuel Steam Generator Unit 1
-002	Fossil Fuel Steam Generator Unit 2

CONTENTS

1. Permitting Authority. The Permitting Authority for this project is the Bureau of Air Regulation in the Division of Air Resource Management of the Florida Department of Environmental Protection. The mailing address for the Bureau of Air Regulation is 2600 Blair Stone Road, MS #5505, Tallahassee, Florida 32399-2400.

2. Compliance Authority. All documents related to compliance activities such as reports, tests, and notifications shall be submitted to the Department of Environmental Protection's Southwest District Office. The mailing address and phone number of the Southwest District Office is: 13051 North Telecom Parkway, Temple Terrace, FL 33637-0926, telephone: 813/632-7600, fax: 813/632-7668.

3. Appendices. The following Appendices are attached as an enforceable part of this permit: Appendix A (Citation Formats), Appendix B (General Conditions), and Appendix C (Standard Testing Requirements).

4. Applicable Regulations, Forms and Application Procedures. Unless otherwise specified in this permit, the construction and operation of the subject emissions units shall be in accordance with the capacities and specifications stated in the application. The facility is subject to the applicable provisions of: Chapter 403, Florida Statutes (F.S.); Chapters 62-4, 62-204, 62-210, 62-212, 62-213, 62-296, and 62-297, Florida Administrative Code (F.A.C.); and the applicable parts and subparts of Title 40, Code of Federal Regulations (CFR). Issuance of this permit does not relieve the permittee from compliance with any applicable federal, state, or local permitting or regulations.

5. Title V Permit. This permit authorizes specific modifications and/or new construction on the affected emissions units as well as initial operation to determine compliance with conditions of this permit. A Title V operation permit is required for regular operation of the permitted emissions unit. The permittee shall apply for a Title V operation permit **on or before December 31, 2013**. To apply for a Title V operation permit, the applicant shall submit the appropriate application form, compliance test results, and such additional information as the Department may by law require. The application shall be submitted to the Bureau of Air Regulation with copies to the Compliance Authority. [Rules 62-4.030, 62-4.050, 62-4.220, and Chapter 62-213, F.A.C.]

6. Records Retention. All measurements, records, and other data required by this permit shall be documented in a permanent, legible format and retained for at least 5 years following the date on which such measurements, records, or data are recorded. Records shall be made available to the Department upon request. [Rule 62-213.440(1)(b)2, F.A.C.]

7. Annual Operating Report. The permittee shall submit an annual report that summarizes the actual operating rates and emissions from this facility. Annual operating reports shall be submitted to the Compliance Authority by March 1st of each year. [Rule 62-210.370(3), F.A.C.]

C. Emissions Units 1 and 2(EU-001 & -002)

This subsection addresses the following affected emissions unit.

ID No.	Emissions Unit Description
-001 and -002	*Description*: -001: 3,750 MMBtu/hr pulverized coal, dry bottom, tangentially-fired boiler. -002: 4,795 MMBtu/hr pulverized coal, dry bottom, tangentially-fired boiler. *Fuels*: The fuels allowed to be burned in these units are: bituminous coal; a bituminous coal and bituminous coal briquette mixture, on-specification used oil, and distillate fuel oil for startup. These units may also burn up to 2%, by weight, of oily fly ash generated by Unit 1 at the Bartow Power Plant. *Controls*: Emissions of particulate matter are controlled from each unit with a high efficiency electrostatic precipitator, manufactured by Buell Manufacturing Company, Inc. *Monitors*: Continuous opacity monitor systems (COMS) are used to measure opacity in conformance with 40 CFR Part 75. *Unit 1 Stack Parameters*: Exhaust gas exits at 291° F and 1,407,923 acfm through a 15-foot diameter stack that is 499 feet tall. *Unit 2 Stack Parameters*: Exhaust gas exits at 300° F and 1,931,324 acfm through a 16-foot diameter stack that is 502 feet tall.

Pursuant to Rule 62-296.340 (BART), F.A.C., the following standards represent the Best Available Retrofit Technology. These standards apply to each BART-eligible unit and are in addition to, and supplement, all other applicable standards.

CONTROL EQUIPMENT

1. Particulate Controls. To control emissions of particulate matter (PM), the permittee shall continue to operate and maintain the existing electrostatic precipitators (ESP) for Units 1 and 2 to meet the BART standards specified in this permit. This permit authorizes any upgrades to the ESP for Unit 2 necessary to meet the BART emissions limits, below. [Rule 62-296.340 (BART), F.A.C.]

2. Circumvention. The permittee shall not circumvent any air pollution control device, or allow the emission of air pollutants without the applicable air pollution control device operating properly. [Rule 62-210.650, F.A.C.]

BART EMISSIONS STANDARDS

3. Particulate Matter Emissions Standard – Steady State Operations. As determined by EPA Method 5 or 17, particulate matter emissions from Units 1 and 2 combined shall not exceed 0.04 lb/MMBtu, on a weighted average basis of the total heat input. Compliance shall be demonstrated based on the average of the 3 required 1-hour test runs. [Rule 62-296.340 (BART), F.A.C.]

4. Particulate Matter Emissions Standard – Soot Blowing and Load Change Operations. As determined by EPA Method 5 or 17, particulate matter emissions from Units 1 and 2 combined shall not exceed 0.12 lb/MMBtu, on a weighted average basis of the total heat input, not to exceed 3 hours in any 24-hour period. Compliance shall be demonstrated based on the average of the 3 required 1-hour test runs. [Rule 62-296.340 (BART), F.A.C.]

5. Opacity Standard – Steady-State Operations. As determined by data collected from the existing COMS or EPA Method 9, visible emissions during steady-state operations from: Unit 1 shall not exceed 30% opacity

based on a 6-minute average except for one 6-minute average per hour not to exceed 35% opacity; Unit 2 shall not exceed 15% opacity based on a 6-minute average except for one 6-minute average per hour not to exceed 20% opacity. [Rule 62-296.340 (BART), F.A.C.]

6. Opacity Standard – Soot-Blowing and Load Change Operations. As determined by data collected from the existing COMS or EPA Method 9, visible emissions resulting from soot-blowing and load change operations shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized. In no case shall the duration of such emissions s exceed 3 hours in any 24-hour period and visible emissions from: Unit 1 shall not exceed 40% opacity based on a 6-minute average; Unit 2 shall not exceed 25% opacity based on a 6-minute average. A load change occurs when the operational capacity of a unit is in the 10 percent to 100 percent capacity range, other than startup or shutdown, which exceeds 10 percent of the unit's rated capacity and which occurs at a rate of 0.5 percent per minute or more. [Rule 62-296.340 (BART), F.A.C.]

EXCESS EMISSIONS

7. Excess Emissions Allowed. Unless otherwise specified by permit, excess emissions resulting from startup, shutdown or malfunction of any emissions unit shall be permitted providing (1) best operational practices to minimize emissions are adhered to and (2) the duration of excess emissions shall be minimized but in no case exceed two hours in any 24-hour period unless specifically authorized by the Department for longer duration.

   Excess emissions from existing fossil fuel steam generators resulting from startup or shutdown shall be permitted provided that best operational practices to minimize emissions are adhered to and the duration of excess emissions shall be minimized.

   [Rules 62-210.700(1) & (2), F.A.C.]

8. Excess Emissions Prohibited. Excess emissions caused entirely or in part by poor maintenance, poor operation, or any other equipment or process failure that may reasonably be prevented during startup, shutdown or malfunction shall be prohibited. [Rule 62-210.700(4), F.A.C.]

9. Excess Emissions Notification. In case of excess emissions resulting from malfunctions, the permittee shall notify the Compliance Authority in accordance with Rule 62-4.130, F.A.C. A full written report on the malfunctions shall be submitted in a quarterly report, if requested by the Department. [Rule 62-210.700(6), F.A.C.]

MONITORING REQUIREMENTS

10. Control Equipment Monitoring. The ESPs used for the control of particulate matter emissions from these units are subject to the Compliance Assurance Monitoring (CAM) provisions contained in 40 CFR 64. The CAM parameter ranges to be monitored (total ESP power and continuous VE) shall be re-established during the initial testing required in Condition 13 and shall be submitted with the Title V operation permit revision application required by Section 2, Condition 5. Adherence to an approved CAM plan will satisfy the BART control equipment monitoring requirement. [Rules 62-296.340 (BART) and 62-4.070(3), F.A.C.; and 40 CFR 64]

    {Permitting Note: Because these units are subject to CAM, sufficient testing shall be conducted prior to submitting an application for a Title V permit revision to support the chosen CAM excursion indicators and ranges.}

EMISSIONS PERFORMANCE TESTING

11. Test Methods. The following reference methods (or more recent versions) shall be used to conduct any

required emissions tests.

Method	Description of Method and Comments
1 - 4	Traverse Points, Velocity and Flow Rate, Gas Analysis, and Moisture Content
5 or 17	Determination of PM Emissions from Stationary Sources
9	Visual Determination of Opacity from Stationary Sources

EPA Methods 1, 2, 3, 4, and 19 shall be used as necessary to support the other test methods. The above methods are described in 40 CFR 60, Appendix A, which is adopted by reference in Rule 62-204.800, F.A.C. No other methods shall be used without prior written approval from the Permitting Authority. [Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

12. Standard Testing Requirements. All required emissions tests shall be conducted in accordance with the requirements specified in Appendix C (Standard Testing Requirements) of this permit. [Rules 62-204.800 and 62-297.100, F.A.C.; and 40 CFR 60, Appendix A]

13. Compliance Tests. During each federal fiscal year (October 1st to September 30th), the permittee shall conduct tests on Units 1 and 2 to demonstrate compliance with the BART standards for particulate matter and opacity. Initial compliance tests shall be conducted during federal fiscal year 2012/2013 (following the upgrades to the Unit 2 ESP) and a test report demonstrating compliance shall be submitted before October 1, 2013. [Rules 62-204.800, 62-296.340(3)(b)2 and 62-297.310(7)(a)4, F.A.C.; and 40 CFR 60, Appendix A, Method 9]

NOTIFICATIONS, RECORDS AND REPORTS

14. Plant Operation - Problems. If temporarily unable to comply with any of the conditions of the permit due to breakdown of equipment or destruction by fire, wind or other cause, the permittee shall notify each Compliance Authority as soon as possible, but at least within one working day, excluding weekends and holidays. The notification shall include: pertinent information as to the cause of the problem; steps being taken to correct the problem and prevent future recurrence; and, where applicable, the owner's intent toward reconstruction of destroyed facilities. Such notification does not release the permittee from any liability for failure to comply with the conditions of this permit or the regulations. [Rule 62-4.130, F.A.C.]

15. BART Permit Application for SO_2 and NO_X. In the event that CAIR is vacated by the Federal courts, the Department reserves the right to require the submission of a BART application for SO_2 and NO_X within 60 days of notification by the Department. [Rule 62-296.340, F.A.C.]

16. Shut Down of Units 1 and 2. Units 1 and 2 shall cease to be operated as coal-fired units by December 31, 2020. This date assumes timely licensing, construction and commencement of commercial operation of PEF's proposed new nuclear units (Levy County Units 1 and 2). The shutdown (or repowering) of Units 1 and 2 coal-fired units is contingent upon completion of the first fuel cycle for Levy County Unit 2. PEF shall timely advise the Department of any developments that would delay the shutdown (or repowering) of Units 1 and 2 beyond the completion of the first fuel cycle for Levy County Unit 2. [Rule 62-296.340 (BART), F.A.C. and Applicant Request]

SECTION 4. APPENDICES

CONTENTS

SECTION 4. APPENDIX A
CITATION FORMATS

The following examples illustrate the format used in the permit to identify applicable permitting actions and regulations.

REFERENCES TO PREVIOUS PERMITTING ACTIONS

Old Permit Numbers

Example: Permit No. AC50-123456 or Air Permit No. AO50-123456

Where: "AC" identifies the permit as an Air Construction Permit
"AO" identifies the permit as an Air Operation Permit
"123456" identifies the specific permit project number

New Permit Numbers

Example: Permit Nos. 099-2222-001-AC, 099-2222-001-AO, or 099-2222-001-AV

Where: "099" represents the specific county ID number in which the project is located
"2222" represents the specific facility ID number
"001"identifies the specific permit project
"AC" identifies the permit as an air construction permit
"AO" identifies the permit as a minor source air operation permit
"AV" identifies the permit as a Title V Major Source Air Operation Permit

PSD Permit Numbers

Example: Permit No. PSD-FL-317

Where: "PSD" means issued pursuant to the Prevention of Significant Deterioration of Air Quality
"FL" means that the permit was issued by the State of Florida
"317" identifies the specific permit project

RULE CITATION FORMATS

Florida Administrative Code (F.A.C.)

Example: [Rule 62-213.205, F.A.C.]

Means: Title 62, Chapter 213, Rule 205 of the Florida Administrative Code

Code of Federal Regulations (CFR)

Example: [40 CRF 60.7]

Means: Title 40, Part 60, Section 7

SECTION 4. APPENDIX B

GENERAL CONDITIONS

The permittee shall comply with the following general conditions from Rule 62-4.160, F.A.C.

1. The terms, conditions, requirements, limitations, and restrictions set forth in this permit are "Permit Conditions" and are binding and enforceable pursuant to Sections 403.161, 403.727, or 403.859 through 403.861, Florida Statutes. The permittee is placed on notice that the Department will review this permit periodically and may initiate enforcement action for any violation of these conditions.
2. This permit is valid only for the specific processes and operations applied for and indicated in the approved drawings or exhibits. Any unauthorized deviation from the approved drawings, exhibits, specifications, or conditions of this permit may constitute grounds for revocation and enforcement action by the Department.
3. As provided in Subsections 403.087(6) and 403.722(5), Florida Statutes, the issuance of this permit does not convey and vested rights or any exclusive privileges. Neither does it authorize any injury to public or private property or any invasion of personal rights, nor any infringement of federal, state or local laws or regulations. This permit is not a waiver or approval of any other Department permit that may be required for other aspects of the total project which are not addressed in the permit.
4. This permit conveys no title to land or water, does not constitute State recognition or acknowledgment of title, and does not constitute authority for the use of submerged lands unless herein provided and the necessary title or leasehold interests have been obtained from the State. Only the Trustees of the Internal Improvement Trust Fund may express State opinion as to title.
5. This permit does not relieve the permittee from liability for harm or injury to human health or welfare, animal, or plant life, or property caused by the construction or operation of this permitted source, or from penalties therefore; nor does it allow the permittee to cause pollution in contravention of Florida Statutes and Department rules, unless specifically authorized by an order from the Department.
6. The permittee shall properly operate and maintain the facility and systems of treatment and control (and related appurtenances) that are installed or used by the permittee to achieve compliance with the conditions of this permit, as required by Department rules. This provision includes the operation of backup or auxiliary facilities or similar systems when necessary to achieve compliance with the conditions of the permit and when required by Department rules.
7. The permittee, by accepting this permit, specifically agrees to allow authorized Department personnel, upon presentation of credentials or other documents as may be required by law and at a reasonable time, access to the premises, where the permitted activity is located or conducted to:
   a. Have access to and copy and records that must be kept under the conditions of the permit;
   b. Inspect the facility, equipment, practices, or operations regulated or required under this permit, and,
   c. Sample or monitor any substances or parameters at any location reasonably necessary to assure compliance with this permit or Department rules.

   Reasonable time may depend on the nature of the concern being investigated.
8. If, for any reason, the permittee does not comply with or will be unable to comply with any condition or limitation specified in this permit, the permittee shall immediately provide the Department with the following information:
   a. A description of and cause of non-compliance; and
   b. The period of noncompliance, including dates and times; or, if not corrected, the anticipated time the non-compliance is expected to continue, and steps being taken to reduce, eliminate, and prevent recurrence of the non-compliance.

The permittee shall be responsible for any and all damages which may result and may be subject to enforcement action by the Department for penalties or for revocation of this permit.

9. In accepting this permit, the permittee understands and agrees that all records, notes, monitoring data and other information relating to the construction or operation of this permitted source which are submitted to the Department may be used by the Department as evidence in any enforcement case involving the permitted source arising under the Florida Statutes or Department rules, except where such use is prescribed by Sections 403.73 and 403.111, Florida Statutes. Such evidence shall only be used to the extent it is consistent with the Florida Rules of Civil Procedure and appropriate evidentiary rules.
10. The permittee agrees to comply with changes in Department rules and Florida Statutes after a reasonable time for compliance, provided, however, the permittee does not waive any other rights granted by Florida Statutes or Department rules.
11. This permit is transferable only upon Department approval in accordance with Florida Administrative Code Rules 62-4.120 and 62-730.300, F.A.C., as applicable. The permittee shall be liable for any non-compliance of the permitted activity until the transfer is approved by the Department.
12. This permit or a copy thereof shall be kept at the work site of the permitted activity.
13. This permit also constitutes:
    a. Determination of Best Available Control Technology (Not Applicable);
    b. Determination of Prevention of Significant Deterioration (Not Applicable); and
    c. Compliance with New Source Performance Standards (Not Applicable).
14. The permittee shall comply with the following:
    a. Upon request, the permittee shall furnish all records and plans required under Department rules. During enforcement actions, the retention period for all records will be extended automatically unless otherwise stipulated by the Department.
    b. The permittee shall hold at the facility or other location designated by this permit records of all monitoring information (including all calibration and maintenance records and all original strip chart recordings for continuous monitoring instrumentation) required by the permit, copies of all reports required by this permit, and records of all data used to complete the application or this permit. These materials shall be retained at least three years from the date of the sample, measurement, report, or application unless otherwise specified by Department rule.
    c. Records of monitoring information shall include:
        1) The date, exact place, and time of sampling or measurements;
        2) The person responsible for performing the sampling or measurements;
        3) The dates analyses were performed;
        4) The person responsible for performing the analyses;
        5) The analytical techniques or methods used; and
        6) The results of such analyses.
15. When requested by the Department, the permittee shall within a reasonable time furnish any information required by law which is needed to determine compliance with the permit. If the permittee becomes aware that relevant facts were not submitted or were incorrect in the permit application or in any report to the Department, such facts or information shall be corrected promptly.

STANDARD CEMS REQUIREMENTS

Unless otherwise specified by permit, all emissions units that require testing are subject to the following conditions as applicable.

1. Required Number of Test Runs: For mass emission limitations, a compliance test shall consist of three complete and separate determinations of the total air pollutant emission rate through the test section of the stack or duct and three complete and separate determinations of any applicable process variables corresponding to the three distinct time periods during which the stack emission rate was measured; provided, however, that three complete and separate determinations shall not be required if the process variables are not subject to variation during a compliance test, or if three determinations are not necessary in order to calculate the unit's emission rate. The three required test runs shall be completed within one consecutive five-day period. In the event that a sample is lost or one of the three runs must be discontinued because of circumstances beyond the control of the owner or operator, and a valid third run cannot be obtained within the five-day period allowed for the test, the Secretary or his or her designee may accept the results of two complete runs as proof of compliance, provided that the arithmetic mean of the two complete runs is at least 20% below the allowable emission limiting standard. [Rule 62-297.310(1), F.A.C.]
2. Operating Rate During Testing: Unless otherwise stated in the applicable emission limiting standard rule, testing of emissions shall be conducted with the emissions unit operating at permitted capacity as defined below. If it is impracticable to test at permitted capacity, an emissions unit may be tested at less than the maximum permitted capacity; in this case, subsequent emissions unit operation is limited to 110 percent of the test rate until a new test is conducted. Once the unit is so limited, operation at higher capacities is allowed for no more than 15 consecutive days for the purpose of additional compliance testing to regain the authority to operate at the permitted capacity.
   a. *Combustion Turbines*. (Reserved)
   b. *All Other Sources*. Permitted capacity is defined as 90 to 100 percent of the maximum operation rate allowed by the permit.

   [Rule 62-297.310(2), F.A.C.]
3. Calculation of Emission Rate: For each emissions performance test, the indicated emission rate or concentration shall be the arithmetic average of the emission rate or concentration determined by each of the three separate test runs unless otherwise specified in a particular test method or applicable rule. [Rule 62-297.310(3), F.A.C.]
4. Applicable Test Procedures:
   a. *Required Sampling Time*.
      1) Unless otherwise specified in the applicable rule, the required sampling time for each test run shall be no less than one hour and no greater than four hours, and the sampling time at each sampling point shall be of equal intervals of at least two minutes.
      2) Opacity Compliance Tests. When either EPA Method 9 or DEP Method 9 is specified as the applicable opacity test method, the required minimum period of observation for a compliance test shall be sixty (60) minutes for emissions units which emit or have the potential to emit 100 tons per year or more of particulate matter, and thirty (30) minutes for emissions units which have potential emissions less than 100 tons per year of particulate matter and are not subject to a multiple-valued opacity standard. The opacity test observation period shall include the period during which the highest opacity emissions can reasonably be expected to occur. Exceptions to these requirements are as follows:
         a) For batch, cyclical processes, or other operations which are normally completed within less than the minimum observation period and do not recur within that time, the period of observation

shall be equal to the duration of the batch cycle or operation completion time.

b) The observation period for special opacity tests that are conducted to provide data to establish a surrogate standard pursuant to Rule 62-297.310(5)(k), F.A.C., Waiver of Compliance Test Requirements, shall be established as necessary to properly establish the relationship between a proposed surrogate standard and an existing mass emission limiting standard.

c) The minimum observation period for opacity tests conducted by employees or agents of the Department to verify the day-to-day continuing compliance of a unit or activity with an applicable opacity standard shall be twelve minutes.

b. *Minimum Sample Volume.* Unless otherwise specified in the applicable rule, the minimum sample volume per run shall be 25 dry standard cubic feet.

c. *Required Flow Rate Range.* For EPA Method 5 particulate sampling, acid mist/sulfur dioxide, and fluoride sampling which uses Greenburg Smith type impingers, the sampling nozzle and sampling time shall be selected such that the average sampling rate will be between 0.5 and 1.0 actual cubic feet per minute, and the required minimum sampling volume will be obtained.

d. *Calibration of Sampling Equipment.* Calibration of the sampling train equipment shall be conducted in accordance with the schedule shown in Table 297.310-1.

e. *Allowed Modification to EPA Method 5.* When EPA Method 5 is required, the following modification is allowed: the heated filter may be separated from the impingers by a flexible tube.

TABLE 297.310-1 CALIBRATION SCHEDULE			
Item	Minimum Frequency	Reference Instrument	Tolerence
Liquid in glass thermometer	Annually	ASTM Hg in glass ref. thermometer or equivalent or thermometric points	± 2%
Bimetallic thermometer	Quarterly	Calib. liq. in glass	5° F
Thermocouple	Annually	ASTM Hg in glass ref. thermometer, NBS calibrated reference and potentiometer	5° F
Barometer	Monthly	Hg barometer or NOAA station	± 1% scale
Pitot Tube	When required or when damaged	By construction or measurements in wind tunnel D greater than 16" and standard pitot tube	See EPA Method 2, Fig. 2-2 & 2-3
Probe Nozzles	Before each test or when nicked, dented, or corroded	Micrometer	± 0.001" mean of at least three readings; maximum deviation between readings, 0.004"
Dry Gas Meter and Orifice Meter	1. Full Scale: When received, when 5% change observed, annually	Spirometer or calibrated wet test or dry gas test meter	2%
	2. One Point: Semiannually		
	3. Check after each test series	Comparison check	5%

[Rule 62-297.310(4), F.A.C.]

5. Determination of Process Variables:

    a. *Required Equipment*. The owner or operator of an emissions unit for which compliance tests are required shall install, operate, and maintain equipment or instruments necessary to determine process variables, such as process weight input or heat input, when such data are needed in conjunction with emissions data to determine the compliance of the emissions unit with applicable emission limiting standards.

    b. *Accuracy of Equipment*. Equipment or instruments used to directly or indirectly determine process variables, including devices such as belt scales, weight hoppers, flow meters, and tank scales, shall be calibrated and adjusted to indicate the true value of the parameter being measured with sufficient accuracy to allow the applicable process variable to be determined within 10% of its true value.

    [Rule 62-297.310(5), F.A.C.]

6. Required Stack Sampling Facilities: Sampling facilities include sampling ports, work platforms, access to work platforms, electrical power, and sampling equipment support. All stack sampling facilities must meet any Occupational Safety and Health Administration (OSHA) Safety and Health Standards described in 29 CFR Part 1910, Subparts D and E.

    a. *Permanent Test Facilities*. The owner or operator of an emissions unit for which a compliance test, other than a visible emissions test, is required on at least an annual basis, shall install and maintain permanent stack sampling facilities.

    b. *Temporary Test Facilities*. The owner or operator of an emissions unit that is not required to conduct a compliance test on at least an annual basis may use permanent or temporary stack sampling facilities. If the owner chooses to use temporary sampling facilities on an emissions unit, and the Department elects to test the unit, such temporary facilities shall be installed on the emissions unit within 5 days of a request by the Department and remain on the emissions unit until the test is completed.

    c. *Sampling Ports*.

        1) All sampling ports shall have a minimum inside diameter of 3 inches.

        2) The ports shall be capable of being sealed when not in use.

        3) The sampling ports shall be located in the stack at least 2 stack diameters or equivalent diameters downstream and at least 0.5 stack diameter or equivalent diameter upstream from any fan, bend, constriction or other flow disturbance.

        4) For emissions units for which a complete application to construct has been filed prior to December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 15 feet or less. For stacks with a larger diameter, four sampling ports, each 90 degrees apart, shall be installed. For emissions units for which a complete application to construct is filed on or after December 1, 1980, at least two sampling ports, 90 degrees apart, shall be installed at each sampling location on all circular stacks that have an outside diameter of 10 feet or less. For stacks with larger diameters, four sampling ports, each 90 degrees apart, shall be installed. On horizontal circular ducts, the ports shall be located so that the probe can enter the stack vertically, horizontally or at a 45 degree angle.

        5) On rectangular ducts, the cross sectional area shall be divided into the number of equal areas in accordance with EPA Method 1. Sampling ports shall be provided which allow access to each sampling point. The ports shall be located so that the probe can be inserted perpendicular to the gas flow.

d. *Work Platforms.*

1) Minimum size of the working platform shall be 24 square feet in area. Platforms shall be at least 3 feet wide.

2) On circular stacks with 2 sampling ports, the platform shall extend at least 110 degrees around the stack.

3) On circular stacks with more than two sampling ports, the work platform shall extend 360 degrees around the stack.

4) All platforms shall be equipped with an adequate safety rail (ropes are not acceptable), toeboard, and hinged floor-opening cover if ladder access is used to reach the platform. The safety rail directly in line with the sampling ports shall be removable so that no obstruction exists in an area 14 inches below each sample port and 6 inches on either side of the sampling port.

e. *Access to Work Platform.*

1) Ladders to the work platform exceeding 15 feet in length shall have safety cages or fall arresters with a minimum of 3 compatible safety belts available for use by sampling personnel.

2) Walkways over free-fall areas shall be equipped with safety rails and toeboards.

f. *Electrical Power.*

1) A minimum of two 120-volt AC, 20-amp outlets shall be provided at the sampling platform within 20 feet of each sampling port.

2) If extension cords are used to provide the electrical power, they shall be kept on the plant's property and be available immediately upon request by sampling personnel.

g. *Sampling Equipment Support.*

1) A three-quarter inch eyebolt and an angle bracket shall be attached directly above each port on vertical stacks and above each row of sampling ports on the sides of horizontal ducts.

   a) The bracket shall be a standard 3 inch × 3 inch × one-quarter inch equal-legs bracket which is 1 and one-half inches wide. A hole that is one-half inch in diameter shall be drilled through the exact center of the horizontal portion of the bracket. The horizontal portion of the bracket shall be located 14 inches above the centerline of the sampling port.

   b) A three-eighth inch bolt which protrudes 2 inches from the stack may be substituted for the required bracket. The bolt shall be located 15 and one-half inches above the centerline of the sampling port.

   c) The three-quarter inch eyebolt shall be capable of supporting a 500 pound working load. For stacks that are less than 12 feet in diameter, the eyebolt shall be located 48 inches above the horizontal portion of the angle bracket. For stacks that are greater than or equal to 12 feet in diameter, the eyebolt shall be located 60 inches above the horizontal portion of the angle bracket. If the eyebolt is more than 120 inches above the platform, a length of chain shall be attached to it to bring the free end of the chain to within safe reach from the platform.

2) A complete monorail or dualrail arrangement may be substituted for the eyebolt and bracket.

3) When the sample ports are located in the top of a horizontal duct, a frame shall be provided above the port to allow the sample probe to be secured during the test.

7. Frequency of Compliance Tests: The following provisions apply only to those emissions units that are subject to an emissions limiting standard for which compliance testing is required.

   a. General Compliance Testing.

      1) The owner or operator of a new or modified emissions unit that is subject to an emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining an operation permit for such emissions unit.

      2) For excess emission limitations for particulate matter specified in Rule 62-210.700, F.A.C., a compliance test shall be conducted annually while the emissions unit is operating under soot blowing conditions in each federal fiscal year during which soot blowing is part of normal emissions unit operation, except that such test shall not be required in any federal fiscal year in which a fossil fuel steam generator does not burn liquid and/or solid fuel for more than 400 hours other than during startup.

      3) The owner or operator of an emissions unit that is subject to any emission limiting standard shall conduct a compliance test that demonstrates compliance with the applicable emission limiting standard prior to obtaining a renewed operation permit. Emissions units that are required to conduct an annual compliance test may submit the most recent annual compliance test to satisfy the requirements of this provision. In renewing an air operation permit pursuant to sub-subparagraph 62-210.300(2)(a)3.b., c., or d., F.A.C., the Department shall not require submission of emission compliance test results for any emissions unit that, during the year prior to renewal:

         a) Did not operate; or

         b) In the case of a fuel burning emissions unit, burned liquid and/or solid fuel for a total of no more than 400 hours,

      4) During each federal fiscal year (October 1 – September 30), unless otherwise specified by rule, order, or permit, the owner or operator of each emissions unit shall have a formal compliance test conducted for:

         a) Visible emissions, if there is an applicable standard;

         b) Each of the following pollutants, if there is an applicable standard, and if the emissions unit emits or has the potential to emit: 5 tons per year or more of lead or lead compounds measured as elemental lead; 30 tons per year or more of acrylonitrile; or 100 tons per year or more of any other regulated air pollutant; and

         c) Each NESHAP pollutant, if there is an applicable emission standard.

      5) An annual compliance test for particulate matter emissions shall not be required for any fuel burning emissions unit that, in a federal fiscal year, does not burn liquid and/or solid fuel, other than during startup, for a total of more than 400 hours.

      6) For fossil fuel steam generators on a semi-annual particulate matter emission compliance testing schedule, a compliance test shall not be required for any six-month period in which liquid and/or solid fuel is not burned for more than 200 hours other than during startup.

      7) For emissions units electing to conduct particulate matter emission compliance testing quarterly pursuant to paragraph 62-296.405(2)(a), F.A.C., a compliance test shall not be required for any quarter in which liquid and/or solid fuel is not burned for more than 100 hours other than during startup.

      8) Any combustion turbine that does not operate for more than 400 hours per year shall conduct a

visible emissions compliance test once per each five-year period, coinciding with the term of its air operation permit.

9) The owner or operator shall notify the Department, at least 15 days prior to the date on which each formal compliance test is to begin, of the date, time, and place of each such test, and the test contact person who will be responsible for coordinating and having such test conducted for the owner or operator.

10) An annual compliance test conducted for visible emissions shall not be required for units exempted from air permitting pursuant to subsection 62-210.300(3), F.A.C.; units determined to be insignificant pursuant to subparagraph 62-213.300(2)(a)1., F.A.C., or paragraph 62-213.430(6)(b), F.A.C.; or units permitted under the General Permit provisions in paragraph 62-210.300(4)(a) or Rule 62-213.300, F.A.C., unless the general permit specifically requires such testing.

b. Special Compliance Tests. When the Department, after investigation, has good reason (such as complaints, increased visible emissions or questionable maintenance of control equipment) to believe that any applicable emission standard contained in a Department rule or in a permit issued pursuant to those rules is being violated, it shall require the owner or operator of the emissions unit to conduct compliance tests which identify the nature and quantity of pollutant emissions from the emissions unit and to provide a report on the results of said tests to the Department.

8. <u>Test Reports</u>:

a. The owner or operator of an emissions unit for which a compliance test is required shall file a report with the Department on the results of each such test.

b. The required test report shall be filed with the Department as soon as practical but no later than 45 days after the last sampling run of each test is completed.

c. The test report shall provide sufficient detail on the emissions unit tested and the test procedures used to allow the Department to determine if the test was properly conducted and the test results properly computed. As a minimum, the test report, other than for an EPA or DEP Method 9 test, shall provide the following information:

1) The type, location, and designation of the emissions unit tested.

2) The facility at which the emissions unit is located.

3) The owner or operator of the emissions unit.

4) The normal type and amount of fuels used and materials processed, and the types and amounts of fuels used and material processed during each test run.

5) The means, raw data and computations used to determine the amount of fuels used and materials processed, if necessary to determine compliance with an applicable emission limiting standard.

6) The type of air pollution control devices installed on the emissions unit, their general condition, their normal operating parameters (pressure drops, total operating current and GPM scrubber water), and their operating parameters during each test run.

7) A sketch of the duct within 8 stack diameters upstream and 2 stack diameters downstream of the sampling ports, including the distance to any upstream and downstream bends or other flow disturbances.

8) The date, starting time and duration of each sampling run.

9) The test procedures used, including any alternative procedures authorized pursuant to Rule 62-297.620, F.A.C. Where optional procedures are authorized in this chapter, indicate which option was used.

10) The number of points sampled and configuration and location of the sampling plane.

11) For each sampling point for each run, the dry gas meter reading, velocity head, pressure drop across the stack, temperatures, average meter temperatures and sample time per point.

12) The type, manufacturer and configuration of the sampling equipment used.

13) Data related to the required calibration of the test equipment.

14) Data on the identification, processing and weights of all filters used.

15) Data on the types and amounts of any chemical solutions used.

16) Data on the amount of pollutant collected from each sampling probe, the filters, and the impingers, are reported separately for the compliance test.

17) The names of individuals who furnished the process variable data, conducted the test, analyzed the samples and prepared the report.

18) All measured and calculated data required to be determined by each applicable test procedure for each run.

19) The detailed calculations for one run that relate the collected data to the calculated emission rate.

20) The applicable emission standard and the resulting maximum allowable emission rate for the emissions unit plus the test result in the same form and unit of measure.

21) A certification that, to the knowledge of the owner or his authorized agent, all data submitted are true and correct. When a compliance test is conducted for the Department or its agent, the person who conducts the test shall provide the certification with respect to the test procedures used. The owner or his authorized agent shall certify that all data required and provided to the person conducting the test are true and correct to his knowledge.

[Rule 62-297.310(8), F.A.C.]

9. <u>Stack</u>: The terms stack and duct are used interchangeably in this rule. [Rule 62-297.310(9), F.A.C.]

Walker, Elizabeth (AIR)

From: Exchange Administrator
Sent: Thursday, February 26, 2009 5:13 PM
To: Walker, Elizabeth (AIR)
Subject: Delivery Status Notification (Relay)
Attachments: ATT239233.txt; FW: CRYSTAL RIVER POWER PLANT; 0170004-017-AC/BART

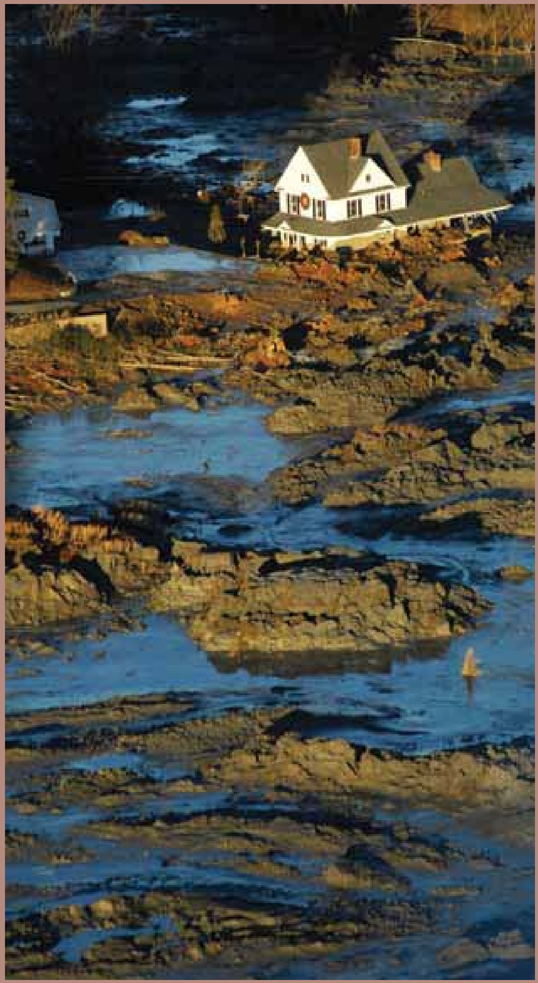
This is an automatically generated Delivery Status Notification.

Your message has been successfully relayed to the following recipients, but the requested delivery status notifications may not be generated by the destination.

bernie.cumbie@pgnmail.com

EPA's Blind Spot: Hexavalent Chromium in Coal Ash

Coal ash may be the secret source of cancer-causing chromium in your drinking water



EARTHJUSTICE Because the earth needs a good lawyer

PSR Physicians for Social Responsibility

EIP ENVIRONMENTAL INTEGRITY PROJECT

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February 1, 2011

Introduction

Hexavalent chromium is again in the headlines. In the 1990s, Erin Brockovich achieved fame by uncovering the presence of extraordinarily high levels of industrial hexavalent chromium contamination in the drinking water of a small desert town ravaged by cancer. Today, attention to the deadly chemical is fueled by new data and extensive scientific research. In December 2010, the Environmental Working Group released a report documenting the cancer-causing chemical in tap water in 31 of 35 cities tested in the United States.[1] Days later, on December 31, 2010, the California Office of Environmental Health Hazard Assessment (OEHHA) completed a multi-year, peer-reviewed examination of the oral toxicity of the chemical, involving scientists in both the public and private sectors, and released a ground breaking proposal to establish a public health goal for hexavalent chromium in drinking water of just 0.02 parts per billion (or ug/L), 5,000 times lower than the current federal drinking water standard for total chromium.[2]

On January 11, 2011, on the heels of these announcements, the U.S. Environmental Protection Agency (EPA) issued new guidelines recommending that public water utilities nationwide test drinking water for hexavalent chromium (Cr(VI)).[3] EPA's swift reaction to the widespread presence of hexavalent chromium in American tap water is laudable. However, EPA's well-placed concern for protection of public health has a dangerous blind spot. While government regulators express concern for small quantities of the cancer-causing substance in our water, they are ignoring one of the largest sources of the hazardous chemical—coal combustion waste (or coal ash)[4] from the nation's coal burning power plants.

This report documents the connection between coal ash and hexavalent chromium. It reviews the sources, toxicity, and known coal ash dump sites where chromium has been found in groundwater. The report identifies studies of numerous power plants where testing of coal ash leachate found extremely high levels of hexavalent chromium. The report also identifies 28 coal ash disposal sites in 17 states where groundwater was documented to exceed existing federal or state standards for chromium and to exceed by many orders of magnitude the proposed California drinking water goal for hexavalent chromium. These contaminated coal ash dump sites are likely the tip of the iceberg. The threat of drinking water contamination by hexavalent chromium is present in hundreds of communities near unlined coal ash disposal sites across the United States. While the EPA doesn't need another reason to define coal ash as a hazardous waste when disposed, it certainly has one now.

Hexavalent Chromium and Coal Ash: The Deadly Connection

It has long been known that chromium readily leaches from coal ash.[5] Chromium, however, occurs primarily in two forms: trivalent chromium, which is an essential nutrient in small amounts, and hexavalent chromium, Cr(IV), which is highly toxic even in small doses. In EPA's latest report on the hazardous contaminants in coal ash, the agency made two important findings:

• Coal ash leaches chromium in amounts that can greatly exceed EPA's threshold for hazardous waste at 5000 parts per billion (ppb),[6] and

• The chromium that leaches from coal ash is "nearly 100 percent [hexavalent] Cr(VI)."[7]

Remarkably, the U.S. Department of Energy (DOE) and the energy industry have also known for years about the aggressive leaching of hexavalent chromium from coal ash. In a 2006 report co-sponsored by DOE, the Electric Power Research Institute (EPRI) found that the chromium that leaches from coal ash (including flue gas desulfurization (FGD) sludge) is typically close to 100% hexavalent chromium.[8]

These findings, buried in government reports, need to see the light of day. Hundreds – maybe thousands – of leaking and unlined coal ash dumps are situated near water supplies. EPA and DOE have demonstrated that the contaminated leachate (the liquid leaking from coal ash landfills and ponds) is often rich in this cancer-causing chemical. Therefore it is imperative that EPA Administrator Lisa Jackson act decisively to protect U.S. communities from this significant source of hexavalent chromium.

Hexavalent Chromium's Deadly Link to Cancer

In 2008, a two-year study by the U.S. Department of Health and Human Services' National Toxicology Program (NTP)[9] demonstrated that hexavalent chromium in drinking water causes cancer in laboratory animals.[10] While it has long been known that hexavalent chromium causes lung cancer when inhaled, the NTP undertook a study of Cr(VI) ingestion following a request from California's Office of Environmental Health Hazard Assessment (OEHHA). Based on a variety of cancerous oral and intestinal tumors, the NTP study definitively concluded "hexavalent chromium can also cause cancer in animals when administered orally."[11]

Furthermore, scientists believe chronic ingestion of minute amounts of Cr(VI) can be harmful. In fact, after an extensive peer-reviewed study, the California Office of Environmental Health Hazard Assessment lowered its original hexavalent chromium draft goal by 66 percent this year to account for the special sensitivity of infants and children to carcinogens. California's proposed public health goal, 0.02 parts per billion, is a mere 0.02% of the present federal drinking water standard for total chromium. If the current federal drinking water standard (100 parts per billion) is compared to a 100-yard football field, California's proposed goal for Cr(VI)would be a distance of three-quarters of an inch.

According to EPA's 2010 draft toxicological review of hexavalent chromium, EPA agrees with the estimate of cancer potency used by California's Office of Environmental Health Hazard Assessment. California's Draft Public Health Goal[12] and the U.S. EPA Draft Toxicological Review of Hexavalent Chromium[13] both use the same cancer potency value for ingested hexavalent chromium of 0.5 $(mg/kg\text{-}d)^{-1}$. Using EPA's default assumptions for body weight and drinking water ingestion rate, it is possible to estimate the lifetime cancer risk associated with drinking water at the current federal drinking water standard for total chromium of 100 ppb (established in 1991) – the risk is 1.4 in 1,000 people.[14] This risk is 140 – 1400 times greater than EPA's range of acceptable cancer risk (between1 in 100,000 and 1 in 1,000,000 people).[15] Clearly, in view of this elevated risk recognized by both EPA and OEHHA, the 1991 federal drinking water standard of 100 ppb for total chromium is not sufficiently protective of human health from ingestion of hexavalent chromium. While a new federal drinking water standard for hexavalent chromium may be higher than California's proposed goal of 0.02 ppb, this health-protective level, as well as the current federal standard, are used as a comparison to coal ash-contaminated waters in this report.

Ingestion of Hexavalent Chromium Is Missing from EPA's Coal Ash Risk Assessment

Although the cancer risk associated with Cr(VI) in groundwater is substantial, EPA completely ignored this risk in its proposed coal ash rulemaking. While Cr(VI) was discussed in the preamble to the proposed rule, it was treated as a carcinogen by inhalation only. For purposes of calculating the human health risk by ingestion, Cr(VI) was treated as a non-carcinogen.[16] Despite the clear findings of NTP's 2008 studies, the cancer risk of ingested Cr(VI) was not mentioned once in EPA's 400-page "*Health and Ecological Risk Assessment for Coal Combustion Wastes*."

Coal Ash Dump Sites Are Significant Sources of Hexavalent Chromium

Coal ash can leach deadly quantities of Cr(VI) to drinking water.[17] For example, in the 2006 study[18] by the Electric Power Research Institute, an organization that vehemently opposes a hazardous designation for coal ash, EPRI tested leachate—liquid collected from wells, ponds or seeps at coal ash dumps—at 29 coal ash landfills and ponds and found hexavalent chromium at hundreds of times the proposed California drinking water goal at 15 coal ash disposal sites. Their findings included three landfills where leachate exceeded the proposed drinking water goal by 5,000 times, with two landfills exceeding that goal by 100,000 and 250,000 times. The location of these potentially deadly dumps is not known, but the high levels of hexavalent chromium at the sites may pose a danger to those living near the landfills. Table A lists the coal ash dump sites where leachate was found containing hexavalent chromium over 5,000 times the proposed California health goal.

Table A

Coal Ash Dump Sites Identified by the Electric Power Research Institute with Leachate containing Hexavalent Chromium (Cr(VI))

Coal ash Dump Site (Location Undisclosed)	Type of Dump Site	Type of Coal Ash Waste	Amount of Hexavalent Chromium Found in Landfill Leachate (parts per billion (ppb))	Number of Times By Which Cr(VI) Level Exceeds California Drinking Water Goal	Amount of Cr(VI) over the Federal Drinking Water Standard
EPRI Id. No. 50213	Landfill	Fly Ash	5090 ppb	254,500 times	50.9 times
EPRI Id. No. 27413	Landfill	Fly Ash	109 ppb	5,450 times	1.09 times
EPRI Id. No. 50212	Landfill	Fly Ash	2230 ppb	111,500 times	223 times

Source: Electric Power Research Institute, Characterization of Field Leachates at Coal Combustion Product Management Sites, EPRI Report 1012578 (2006).

In addition, data from **known coal ash disposal sites** obtained from EPA reports[19] and recent studies by Earthjustice, the Environmental Integrity Project (EIP) and the Sierra Club[20] make it eminently clear that the threat is widespread and serious. For example, chromium in groundwater contaminated by a coal ash landfill in Ohio reached 1.68 parts per million – a level 84,000 times California's proposed drinking water goal (if nearly all the chromium measured was hexavalent, as predicted in both EPA's and EPRI's reports). Table B lists 28 coal ash dump sites in 17 states where coal ash contaminated groundwater was found to contain chromium at levels exceeding the current federal drinking water standard (100 ppb) or an applicable state standard (50 ppb for groundwater in North Carolina). Often EPA did not provide a specific value for the chromium found in groundwater wells, but simply indicated that it was greater than the federal standard of 100 ppb. These chromium concentrations, if 100 percent hexavalent chromium, represent a level 5,000 times higher than the proposed California goal. In Table B, all chromium is assumed to be hexavalent chromium, a premise supported by the studies conducted by EPA, DOE and EPRI. In addition, most of the coal ash ponds, landfills and fill sites listed below are unlined – a factor that greatly increases the danger to neighboring communities. Lastly, while many of the sites below have undergone some form of remediation under Superfund or state authorities, in most cases the contamination has been left in place, and there may be little attempt to monitor its migration off-site to protect well users from harmful exposure to hexavalent chromium or other toxic metals commonly found in coal ash leachate.

Table B

Name and Location of Coal Ash Disposal Site	Type of Dump Site	Level of Chromium (Highest Level Reported)	Number of Times By Which Cr(VI) Level Exceeds California Drinking Water Goal	Amount of Chromium Above Federal Drinking Water Standard	Source
TVA Colbert Fossil Fuel Plant **Tuscambia, Alabama**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA[a]
2. TVA Widows Creek Fossil Plant **Stevenson, Alabama**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
3. Flint Creek Power Plant **Gentry, Arkansas**	Landfill	128 ppb	6,400 times	1.28 times	EJ/EIP/ SC[b]
4. Indian River Power Station **Millsboro, Delaware**	Unlined Landfill (closed)	211 ppb	10,550 times	2.11 times	EJ/EIP[c]
5. FP&L Lansing Smith Plant **Southport, Florida**	unknown	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
6. Rocky Acres/Grays Siding Coal Combustion Byproduct Landfill **Oakwood, Illinois**	Unlined Fill Site	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EJ/EIP
7. Merom Generating Station Coal Combustion Waste Landfill **Sullivan, Indiana**	Landfill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
8. Xcel Energy/Southern Minnesota Municipal Power Agency - Sherburne County (Sherco) Generating Plant **Becker, Minnesota**	unknown	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
9. Salem Acres Site, **Salem Massachusetts**	Unlined Landfill (closed)	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
10. Brayton Point Power Station, **Somerset, Massachusetts**	Unlined Landfill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
11. Duke Dan River Steam Station **Eden, North Carolina**	Unlined Ponds and Landfill	61 ppb	3,050 times	22% over NC groundwater standard	EJ/EIP/

Name and Location of Coal Ash Disposal Site	Type of Dump Site	Level of Chromium (Highest Level Reported)	Number of Times By Which Cr(VI) Level Exceeds California Drinking Water Goal	Amount of Chromium Above Federal Drinking Water Standard	Source
12. Progress Energy Asheville Steam Electric Plant **Asheville, North Carolina**	Unlined Pond	83 ppb	4,150 times	66% over NC groundwater standard	EJ/EIP
13. Progress Energy Cape Fear Steam Plant **Montcure, North Carolina**	Unlined Pond	100 ppb	5,000 times	Equal to federal maximum	EJ/EIP
14. Basin Electric Power Cooperative W.J. Neal Station Surface Impoundment **Velva, North Dakota**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
15. Reid Gardner Generating Facility **Moapa, Nevada**	Landfill	110 ppb	5,500 times	1.1 time	EJ/EIP
16. Conesville Fixed FGD Sludge Landfill **Coshocon County, Ohio**	Unlined Landfill	Above 100 ppb	Over 5000 times	Above standard, but degree unknown	EPA
17. Industrial Excess Landfill **Uniontown, OH**	Unlined Landfill	1680 ppb	84,000 times	1.68 times	EJ/EIP/
18. American Electric Power Northeastern Station **Oologah, Oklahoma**	Unlined Landfill and Pond	417 ppb	20,850 times	4.17 times	EJ/EIP/
19. Allegheny Energy Hatfield Ferry Power Station **Masontown, Pennsylvania**	Landfill	104 ppb	5,200 times	1.04 times	EJ/EIP/
20. Seward Generating Station **New Florence, Pennsylvania**	Unlined Pond and Landfill	330 ppb	16,500 times	3.3 times	EJ/EIP
21. PPL Martins Creek Power Plant **Martins Creek, Pennsylvania**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
22. TVA Johnsonville Fossil Plant **New Johnsonville, Tennessee**	Unlined Pond	620 ppb	31,000 times	6.2 times	EJ/EIP/
23. Trans-Ash, Inc CCW Landfill, **Camden, Tennessee**	Partially Unlined Landfill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EJ/EIP

Name and Location of Coal Ash Disposal Site	Type of Dump Site	Level of Chromium (Highest Level Reported)	Number of Times By Which Cr(VI) Level Exceeds California Drinking Water Goal	Amount of Chromium Above Federal Drinking Water Standard	Source
24. TVA Kingston Fossil Plant **Harriman, Tennessee**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
25. Battlefield Golf Course **Chesapeake, Virginia**	Unlined Fill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
26. Virginia Power Yorktown Power Station Chisman Creek Disposal Site **Yorktown, Virginia**	Unlined Landfill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
27. Dairyland Power Cooperative E.J. Stoneman Generating Station Ash Disposal Pond **Cassville, Wisconsin**	Unlined Pond	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA
28. Lemberger Landfill, **Wisconsin**	Unlined Landfill	Above 100 ppb	Over 5,000 times	Above standard, but degree unknown	EPA

a: U.S. EPA, Damage Case Report for Coal Combustion Wastes (August 2007) and additional damage cases described in EPA's Proposed Coal Ash Rule, 75 Fed. Reg. 35128.
b: Earthjustice, Environmental Integrity Project, and Sierra Club. In Harm's Way: Lack of Federal Coal Ash Regulations Endangers Americans and their Environment (August 2010).
c: Earthjustice and Environmental Integrity Project. Out of Control: Mounting Damages from Coal Ash Waste Sites (May 2010).

Uniontown, Ohio: A Coal Ash Site Where Health May be Endangered

The **Industrial Excess Landfill**, near Uniontown, Ohio is an example of the kind of site that may be posing a threat to the surrounding community from contamination of drinking water with hexavalent chromium. The landfill is a Superfund site surrounded on three sides by residential neighborhoods. Roughly one million tons of coal ash were dumped at the landfill in the 1960s. The landfill was closed in 1980, and EPA listed it as a Superfund site in 1986. Groundwater monitoring since then has shown chromium concentrations to be increasing to very dangerous levels. Systematic groundwater monitoring began in 1987, and chromium was detected at concentrations up to 180 ppb in off-site wells. Sampling in the early 1990s found concentrations of chromium over 100 ppb in eight monitoring wells, with concentrations up to 739 ppb. Monitoring through 2001 detected chromium at up to 1,680 ppb in off-site wells located in or near residential areas- over 15 times the federal drinking water standard. Residents report many incidences of cancer in the affected neighborhoods.

Despite alarming evidence of off-site groundwater contamination with heavy metals, including chromium, metals monitoring was phased out around 2001, and remedial actions stopped in 2005. And yet the potential for human exposure to this contamination is very high—there are almost 4,000 private drinking water wells within two miles of the site, and about 90 wells within 1,500 feet. Some homes have been provided with alternative water supplies, but many have not. The cancer risk associated with drinking water having chromium concentrations over 100 ppb is greater than 1 in 1,000. The risk associated with the highest known concentration, 1,680 ppb, would be greater than 1 in 50. Furthermore, this cancer risk would be amplified by the presence of arsenic and other carcinogens in the coal ash contaminant plume.

EPA Laboratory Testing of Coal Ash Reveals Dramatic Chromium Leaching

EPA also found that leachate produced in the laboratory from coal ash at a variety of plants contained sky-high chromium. In a 2009 report, EPA tested coal ash leachate by obtaining waste from numerous operating power plants.[21] EPA found that many ashes and sludges produce leachate extremely rich in chromium. The table below provides EPA's results from five plants. These results represent the highest level of chromium in leachate determined by EPA lab tests. Unlike the EPRI data in Table A and the groundwater and surface water data in Table B, the results below were not field samples. However, EPA used a leach test that mimics field conditions in order to determine the range of chromium that would leach from coal ash disposed under real-world conditions. If this leachate were seeping or leaking into groundwater from a landfill or pond, it could threaten drinking water wells and human health. While the public is not likely to be exposed to coal ash leachate at full strength, leachate this rich in chromium, even if it is diluted as it flows through groundwater, can still pose a significant hazard when it reaches drinking water wells.

Table C

Name and Location of Power Plant	Level of Chromium In Leachate	Number of Times Cr(VI) Level Exceeds CA Drinking Water Goal	Number of Times Above Federal Drinking Water Standard
DTE Energy St. Clair Power Plant **East China, Michigan**	1140 ppb (all Cr(VI))	57,000 times	11.4 times
TVA's Widows Creek Plant **Stevenson, Alabama**	7370 ppb	368,500 times	73.7 times
Progress Energy Roxboro Plant **Semora, North Carolina**	1850 ppb	92,500 times	18.5 times
Southern Company Crist Plant **Pensacola, Florida**	1920 ppb	96,000 times	19.2 times
WE Energies Pleasant Prairie Plant **Kenosha, Wisconsin**	3443 ppb	172,150 times	34.3 times

How much chromium is released by U.S. Coal-Fired Power Plants each year?

The amount of chromium released by our nation's coal-burning power plants dwarfs all other industrial sources. According to EPA's Toxic Release Inventory, the electric power industry dumps over ten million pounds of chromium and chromium compounds in on-and off-site disposal sites each year. Between 2000 and 2009, **over 116 million pounds** of chromium and chromium compounds were released from coal-fired power plants. The overwhelming majority of this chromium ends up in unlined or inadequately lined coal ash landfills, ponds, and mines. See Table D.

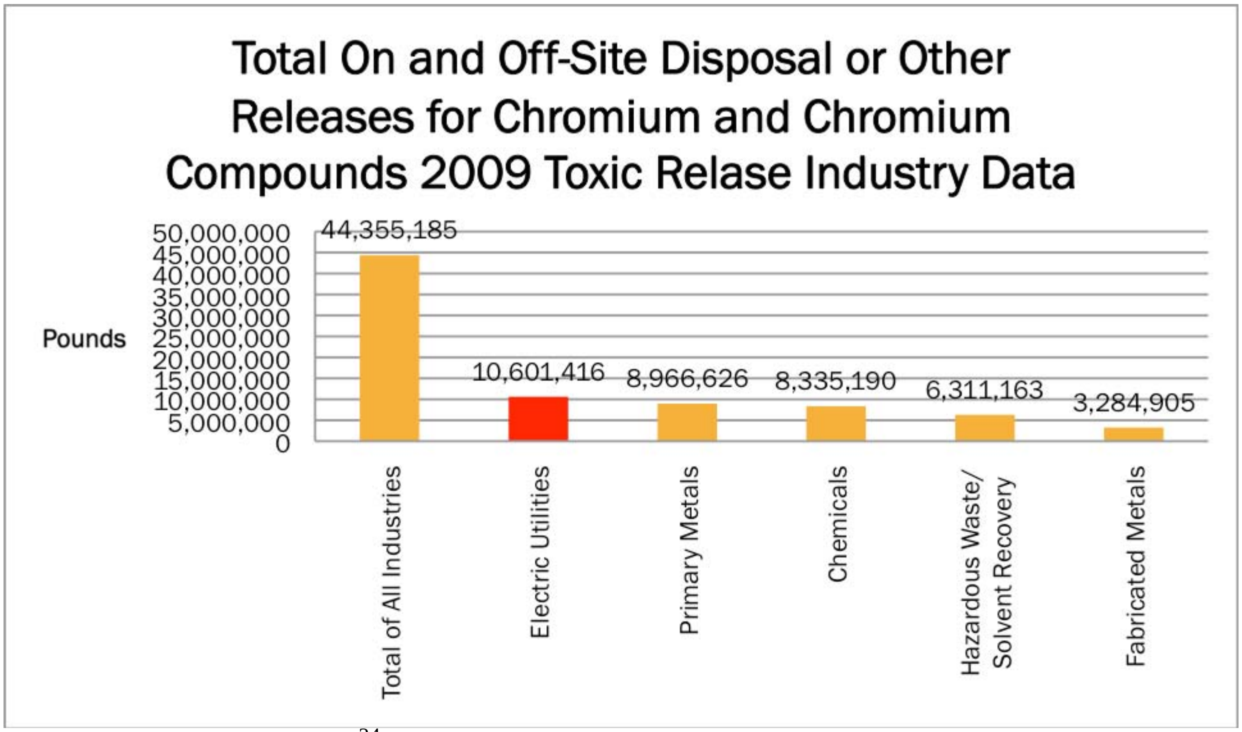
Table D

Chromium and Chromium Compound Disposal Reported to TRI By Year (pounds) 2000-2009		
YEAR	RELEASES TO DISPOSAL UNITS	TOTAL AMOUNT RELEASED
2009	10,161,172	10,601,419
2008	11,502,282	12,102,656
2007	11,459,398	11,871,535
2006	10,877,609	11,220,349
2005	11,577,014	11,960,425
2004	11,537,051	11,963,400
2003	11,607,647	12,057,221
2002	11,720,460	12,285,721
2001	10,293,621	12,202,505
2000	8,375,845	10,221,991
Total	109,112,099	116,487,222

In 2009, the electric power industry reported 10.6 million pounds of chromium and chromium compounds were released to the environment (10.1 million of which was dumped in disposal sites). These 10.6 million pounds represent **24 percent** of the total chromium and chromium compounds released by **all industries** in 2009. See Chart, below. In fact, the top ten chromium-releasing coal-fired power plants alone released almost 1.8 million pounds of chromium and chromium compounds in 2009, and each of these has at least one – if not, more than one – unlined coal ash disposal unit. Despite the obvious significance of this source of chromium, coal-fired power plants are rarely tagged as a source of hexavalent chromium.

As the Air Gets Cleaner, the Threat to Drinking Water Increases

EPA has found that as power plants reduce their emissions of nitrogen oxides (NO_X) by employing pollution controls at the power plant stacks, more hexavalent chromium is found in the flue gas desulfurization (FGD) sludge.[22] According to EPA, over half of the U.S. coal-fired capacity is projected to be equipped with SCR and/or FGD technology by 2020.[23] In fact, EPA anticipates an increase of approximately 16%



in scrubbed units by 2015.[24] Thus as the Clean Air Act requires more and more plants to install pollution controls, we may experience a much greater threat to our drinking water from hexavalent chromium if disposal of the increased volume of FGD sludge is not properly controlled.

EPA Must Determine that Coal Ash is Hazardous When Disposed

Although coal ash readily leaches hexavalent chromium, the waste is currently not federally regulated and is routinely dumped in unlined ponds and pits and used as construction fill without restriction. **EPA must keep this dangerous chemical out of our water – by regulating coal ash, when disposed, as a hazardous waste, thereby requiring its disposal in safe, secure landfills.**

In addition, EPA should immediately investigate the ponds, landfills and fill sites identified in this report to determine if public health is being threatened by exposure to hexavalent chromium, including:

- The three landfills identified in the DOE/EPRI report where Cr(VI) levels in leachate exceed proposed drinking water goals by thousands to hundreds of thousands of times (Table A);

- The 28 landfills, ponds and fill sites where groundwater has been contaminated with chromium over the current federal drinking water standard (Table B) and thousands of times over the proposed drinking water goal (Table B); and

- The disposal sites at the five plants where EPA's laboratory tests document the potential for dangerous levels of Cr(VI) to leach from ash and sludge (Table C).

EPA must conduct these investigations to ensure that highly contaminated leachate from these coal ash disposal sites is not leaking into drinking water and threatening human health. However, it is important to understand that these sites do not represent the universe of coal ash sites that have contaminated groundwater with chromium. Most coal ash disposal sites in the U.S. is are not monitored sufficiently to determine whether they are contaminating groundwater, and certainly very few coal ash sites are monitored for hexavalent chromium at all. Ultimately only the regulation of coal ash under subtitle C of the Resource Conservation and Recovery Act will ensure that these disposal sites, as well as every coal ash dump in the nation, are constructed securely and monitored sufficiently to keep hexavalent chromium out of our drinking water.

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[1] Envtl. Working Group, Chromium-6 Is Widespread in U.S. Tap Water, http://static.ewg.org/reports/2010/chrome6/html/home.html.

[2] California Environmental Protection Agency, Office of Environmental Health and Hazard Assessment, Press Release: OEHHA Releases Revised Draft Public Health Goal for Hexavalent Chromium (Dec. 31, 2010), *available at* http://oehha.ca.gov/water/phg/pdf/Chrom6press123110.pdf.

[3] U.S. Envtl. Protection Agency (U.S. EPA), Press Release: EPA Issues Guidance for Enhanced Monitoring of Hexavalent Chromium in Drinking Water (Jan. 11, 2011), *available at*

http://yosemite.epa.gov/opa/admpress.nsf/a883dc3da7094f97852572a00065d7d8/93a75b03149d30b08525781500600f62!OpenDocument.

[4]Coal ash is commonly used to encompass the entire solid waste stream resulting from the combustion of coal, including fly ash, flue gas desulfurization (FGD) sludge, bottom ash and boiler slag.

[5] *Office of Solid Waste & Emergency Response, U.S. EPA, Report to Congress: Wastes from the Combustion of Fossil Fuels* (Mar. 1999).

[6] *Office of Research & Dev., U.S. EPA, Characterization of Coal Combustion Residues from Electric Utilities – Leaching and Characterization Data* (EPA-600/R-09/151) at xiv, 91 (Dec. 2009), http://www.epa.gov/nrmrl/pubs/600r09151/600r09151.pdf.

[7] *Id*. at 91.

[8] *Electric Power Research Institute, Characterization of Field Leachates at Coal Combustion Product Management Sites, Arsenic, Selenium, Chromium, and Mercury Speciation* (Nov. 2006) at 5–26.

[9] The NTP, established in 1978, is an interagency program whose mission is to evaluate agents of public health concern by developing and applying tools of modern toxicology and molecular biology. According to HHS, "The program maintains an objective, science-based approach in dealing with critical issues in toxicology and is committed to using the best science available to prioritize, design, conduct, and interpret its studies." *See* Nat'l Toxicology Program, Dep't Health & Human Serv., History of the NTPhttp://ntp.niehs.nih.gov/?objectid=720163C9-BDB7-CEBA-FE4B970B9E72BF54.

[10] Nat'l Toxicology Program, Dep't Health & Human Serv., Hexavalent Chromium, http://ntp.niehs.nih.gov/files/NTPHexaVChrmFactR5.pdf.

[11] *Id.*

[12] Cal. Envtl. Prot. Agency, Public Health Goal for Hexavalent Chromium in Drinking Water, 1, 75–77 (draft, Dec. 2010).

[13] U.S. EPA, Toxicological Review of Hexavalent Chromium, 240 (external review draft, Sept. 2010).

[14] It is standard practice when converting a cancer potency estimate to a unit risk (risk per ug/L) or a risk estimate to assume a 70 kg body weight and a drinking water ingestion rate of 2 L/d. *See, e.g., U.S. EPA, Exposure Factors Handbook* (Aug. 1997), *available at* http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=12464.

[15] U.S. EPA, Hazardous and Solid Waste Management System; Identification and Listing of Special Wastes; Disposal of Coal Combustion Residuals From Electric Utilities75 Fed. Reg. 35,128, 35,169–70 (proposed June 21, 2010).

[16] U.S. EPA, Human and Ecological Risk Assessment of Coal Combustion Wastes (draft, Apr. 2010)

[17] U.S. EPA, *Characterization of Coal Combustion Residues from Electric Utilities – Leaching and Characterization Data* (EPA-600/R-09/151), at 7 (Dec. 2009).

[18] *Electric Power Research Institute, Characterization of Field Leachates at Coal Combustion Product Management Sites, Arsenic, Selenium, Chromium, and Mercury Speciation* (Nov. 2006).

[19] *U.S. EPA, Coal Combustion waste Damage Cases* (July 9, 2007); *Office of Research & Dev., U.S. EPA, Characterization of Coal Combustion Residues from Electric Utilities – Leaching and Characterization Data* (EPA-600/R-09/151) (Dec. 2009).

[20] *The Environmental Integrity Project, Earthjustice, & Sierra Club, In Harm's Way: How Lack of Federal Coal Ash Regulations Endangers Americans and Their Environment* (Aug. 26, 2010), *available at* http://earthjustice.org/sites/default/files/files/report-in-harms-way.pdf; *The Environmental Integrity Project and Earthjustice, Out of Control: Mounting Damages from Coal Ash Waste Sites* (Feb. 24, 2010), *available at* http://www.environmentalintegrity.org/news_reports/documents/OutofControl-MountingDamagesFromCoalAshWasteSites.pdf.

[21] *Office of Research & Dev., U.S. EPA, Characterization of Coal Combustion Residues from Electric Utilities – Leaching and Characterization Data* (EPA-600/R-09/151) (Dec. 2009).

[22] *Id.* at 91.

[23] *Id.* at 7.

[24] U.S. EPA, *Steam Electric Power Generating Point Source Category: Final Detailed Study Report* 4-1-4-6 (2009).

JUNE 2011

LEVELIZED COST OF ENERGY ANALYSIS – VERSION 5.0

LAZARD

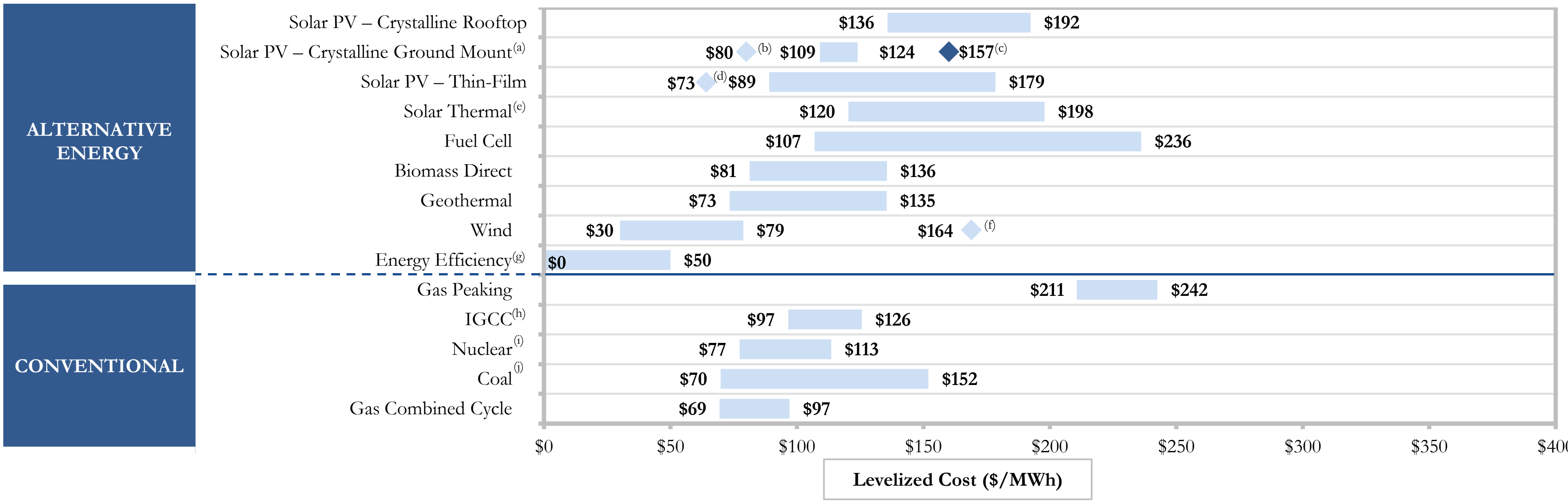
Introduction

Lazard's Levelized Cost of Energy Analysis ("LCOE") addresses the following topics:

- **Comparative "levelized cost of energy" for various technologies on a $/MWh basis, including sensitivities, as relevant, for:**
  - Fuel costs
  - U.S. federal tax subsidies
  - Anticipated capital costs, over time
- **Illustration of how the costs of solar-produced energy compare against peak power costs in large metropolitan areas of the United States**
- **Comparison of assumed capital costs on a $/kW basis for various generation technologies**
- **Decomposition of the levelized costs of energy for various generation technologies by capital costs, fixed operations & maintenance expense, variable operations & maintenance expense, and fuel costs, as relevant**
- **Considerations regarding the applicability of various generation resources, taking into account factors such as location requirements/constraints, dispatch characteristics, land and water requirements and other contingencies**
- **Summary assumptions for the various generation technologies examined**
- **Summary of Lazard's approach to comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies, including identification of key potential sensitivities not addressed in the scope of this presentation**

Levelized Cost of Energy Comparison

Certain Alternative Energy generation technologies are becoming increasingly cost-competitive with conventional generation technologies under some scenarios, before factoring in environmental and other externalities (e.g., RECs, transmission and back-up generation/system reliability costs) as well as construction and fuel costs dynamics affecting conventional generation technologies



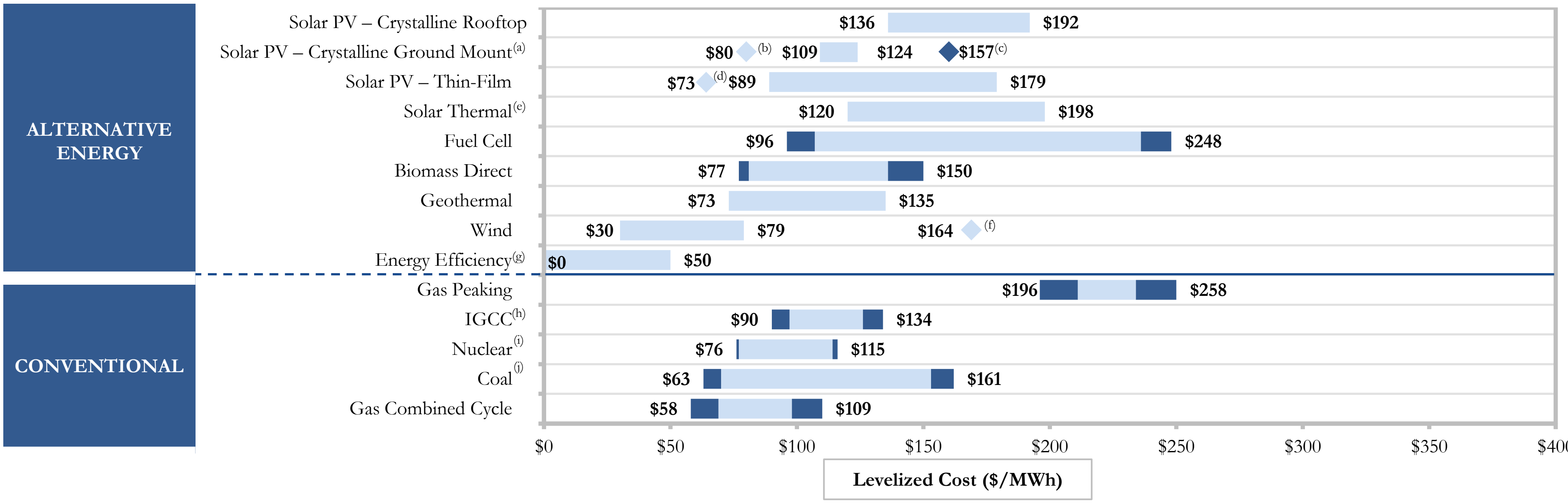
Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.
(b) Represents estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline.
(c) Represents a leading concentrating photovoltaic company's targeted levelized cost of energy, assuming a total system cost of approximately $4.00 per watt.
(d) Represents a leading thin-film company's targeted implied levelized cost of energy in 2012, assuming a total system cost of $2.00 per watt.
(e) Represents both solar tower and solar trough, each with 3 hour storage capability.
(f) Represents estimated midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.10 – $5.00 per watt.
(g) Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely.
(h) High end incorporates 90% carbon capture and compression.
(i) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(j) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.

Levelized Cost of Energy Comparison – Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the levelized cost of energy for conventional generation technologies, but direct comparisons against "competing" Alternative Energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)



Source: Lazard estimates.

Note: Darkened areas in horizontal bars represent low end and high end levelized cost of energy corresponding with ±25% fuel price fluctuations

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.

(b) Represents estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline.

(c) Represents a leading concentrating photovoltaic company's targeted levelized cost of energy, assuming a total system cost of approximately $4.00 per watt.

(d) Represents a leading thin-film company's targeted implied levelized cost of energy in 2012, assuming a total system cost of $2.00 per watt.

(e) Represents both solar tower and solar trough, each with 3 hour storage capability.

(f) Represents estimated midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.10 – $5.00 per watt.

(g) Estimates per National Action Plan for Energy Efficiency; actual cost for various initiatives varies widely.

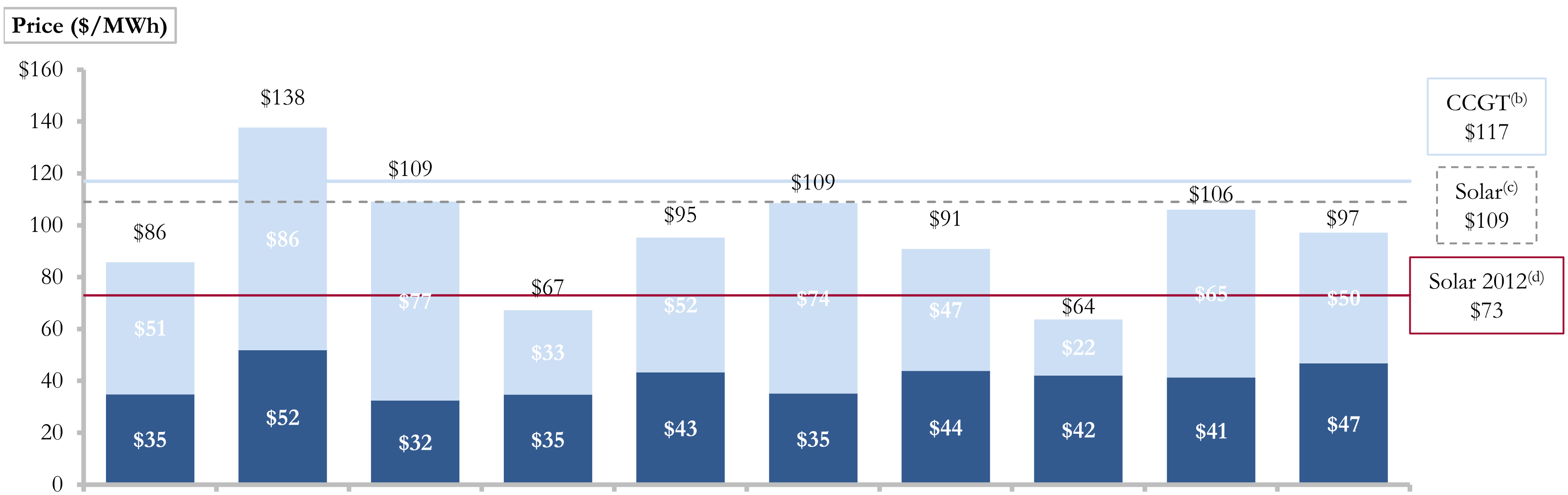
(h) High end incorporates 90% carbon capture and compression.

(i) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(j) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.

Peak Pricing for the 10 Largest U.S. Metropolitan Areas[(a)]

Setting aside the legislatively-mandated demand for solar and other Alternative Energy resources, solar is becoming a more economically viable peaking energy product in many areas of the U.S., and, as pricing declines, could become economically competitive across a broader array of geographies; this observation, however, does not take into account the full costs of incremental transmission and back-up generation/system reliability costs



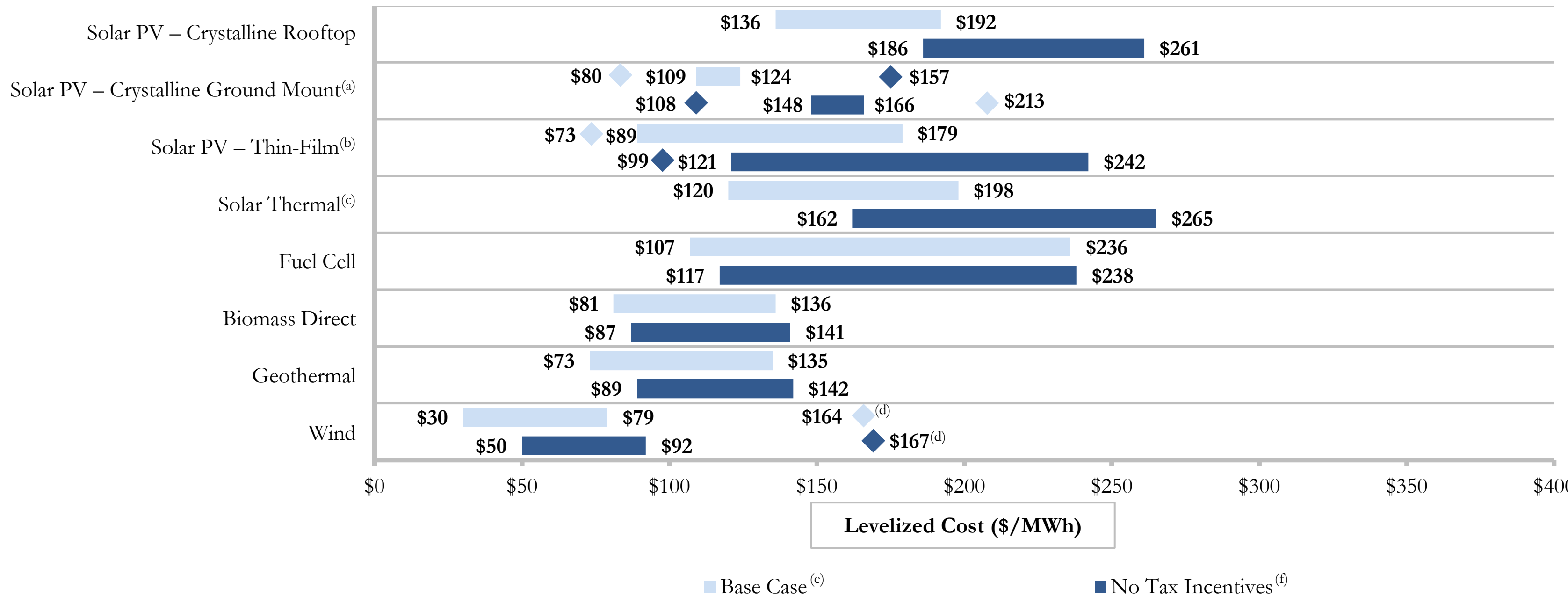
Metropolitan Statistical Area	Los Angeles	New York	Chicago	Dallas	Philadelphia	Houston	Miami	Washington	Atlanta	Boston
Population (mm)	33	30	17	6	6	6	5	5	5	4
Cumulative % of U.S. population	11%	21%	27%	29%	31%	33%	34%	36%	38%	39%

■ Peak Power Price[(e)] ■ Illustrative Delivery Charge

(a) Defined as 10 largest Metropolitan Statistical Areas per the U.S. Census Bureau for a total population of 119 million.
(b) Assumes 25% capacity factor.
(c) Represents low end of solar PV crystalline.
(d) Represents a leading thin-film company's targeted implied levelized cost of energy in 2012.
(e) Represents the average of the hourly wholesale prices between 12 noon and 6pm at a normalized natural gas price.

Levelized Cost of Energy – Sensitivity to U.S. Federal Tax Subsidies

U.S. federal tax subsidies remain an important component of the economics of Alternative Energy generation technologies (and government incentives are important in all regions); future cost reductions in technologies such as solar PV, solar thermal and fuel cells have the potential to enable these technologies to approach "grid parity" without tax subsidies and wind currently reaches "grid parity" under certain conditions (albeit such observation does not take into account issues such as dispatch characteristics, the cost of incremental transmission and back-up generation/system reliability costs or other factors)



Source: Lazard estimates.

Note: Assumes 2010 dollars, 60% debt at 8.0% interest rate and 40% common equity at 12% cost, 20-year economic life and 40% tax rate. Assumes natural gas price of $5.50 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation. Diamonds represent estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline and a leading concentrating photovoltaic company's targeted levelized cost of energy, assuming a total system cost of approximately $4.00 per watt.

(b) Diamonds represent a leading thin-film company's targeted implied levelized cost of energy in 2012, assuming a total system cost of $2.00 per watt.

(c) Represents both solar tower and solar trough, each with 3 hour storage capability.

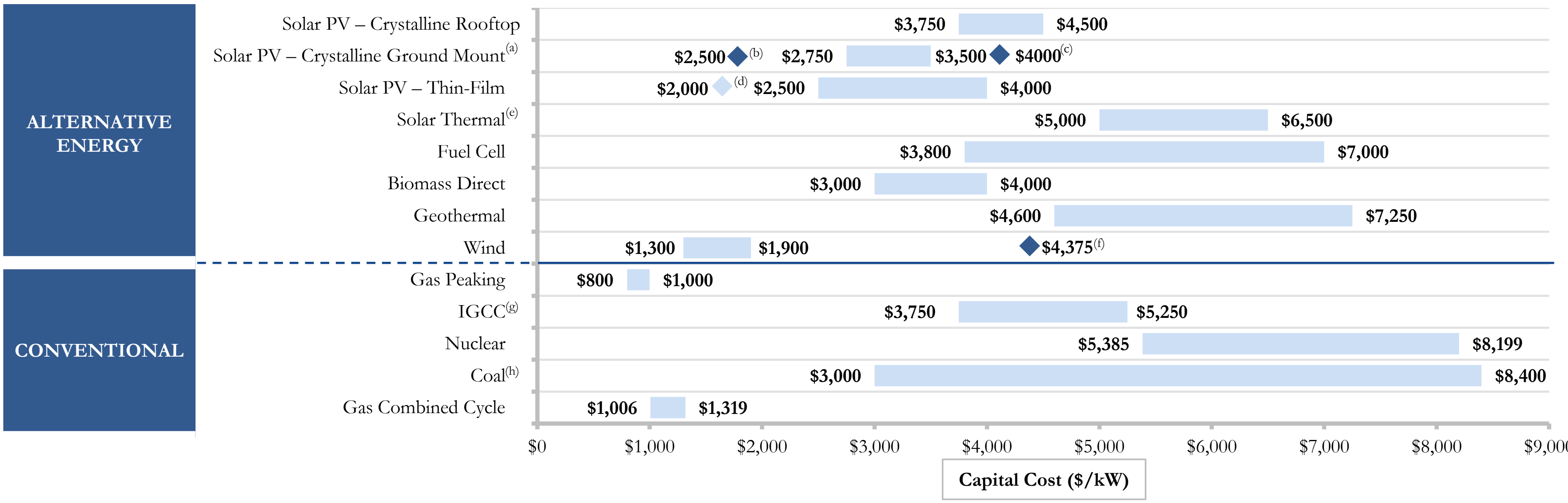
(d) Represents midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.10 – $5.00 per watt.

(e) Reflects production tax credit, investment tax credit, and accelerated asset depreciation, as applicable.

(f) Illustrates levelized cost of energy in the absence of U.S. federal tax incentives such as investment tax credits, production tax credits and assuming 20-year tax life for conventional technologies and 5-year MACRS for renewables technologies.

Capital Cost Comparison

While capital costs for a number of Alternative Energy generation technologies (e.g., solar PV, solar thermal) are currently in excess of conventional generation technologies (e.g., gas, coal), declining costs for many Alternative Energy generation technologies, coupled with rising long-term construction and uncertain long-term fuel costs for conventional generation technologies, are working to close formerly wide gaps in electricity costs. This assessment, however, does not take into account issues such as dispatch characteristics, capacity factors, fuel and other costs needed to compare generation technologies



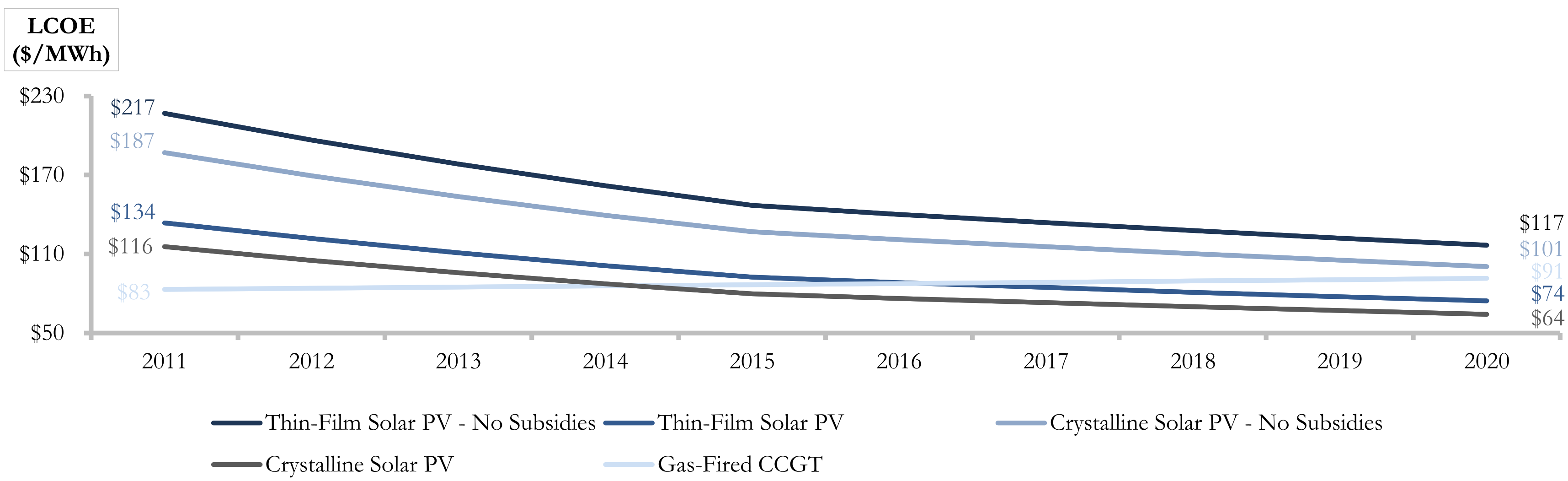
Source: *Lazard estimates.*

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.
(b) Represents estimated implied levelized cost of energy in 2012, assuming a total system cost of $2.50 per watt for single-axis tracking crystalline.
(c) Represents a leading concentrating photovoltaic company's total system cost of approximately $4.00 per watt.
(d) Based on a leading thin-film company's guidance of 2012 total system cost of $2.00 per watt.
(e) Low end represents solar trough without storage, high end represents solar trough with 3 hour storage capability.
(f) Represents estimated midpoint of off-shore wind's levelized cost of energy, assuming a range of total system cost of $3.10 – $5.00 per watt.
(g) High end incorporates 90% carbon capture and compression.
(h) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.

Levelized Cost of Energy – Sensitivity to Capital Costs[(a)]

An important finding in respect of solar PV technologies is the potential for significant cost reductions over time as manufacturing scale along the entire production value chain increases; by contrast, conventional generation technologies are experiencing capital cost inflation, driven by long-term global demand for conventional generation equipment, where potentially cost-reducing manufacturing improvements for these mature technologies are largely incremental in nature

- **This assessment, however, does not take into account the intermittent nature of solar PV as compared with the dispatchable nature of conventional generation; the key finding in this regard is that solar PV technologies will play an increasingly *complementary* role in generation portfolios**



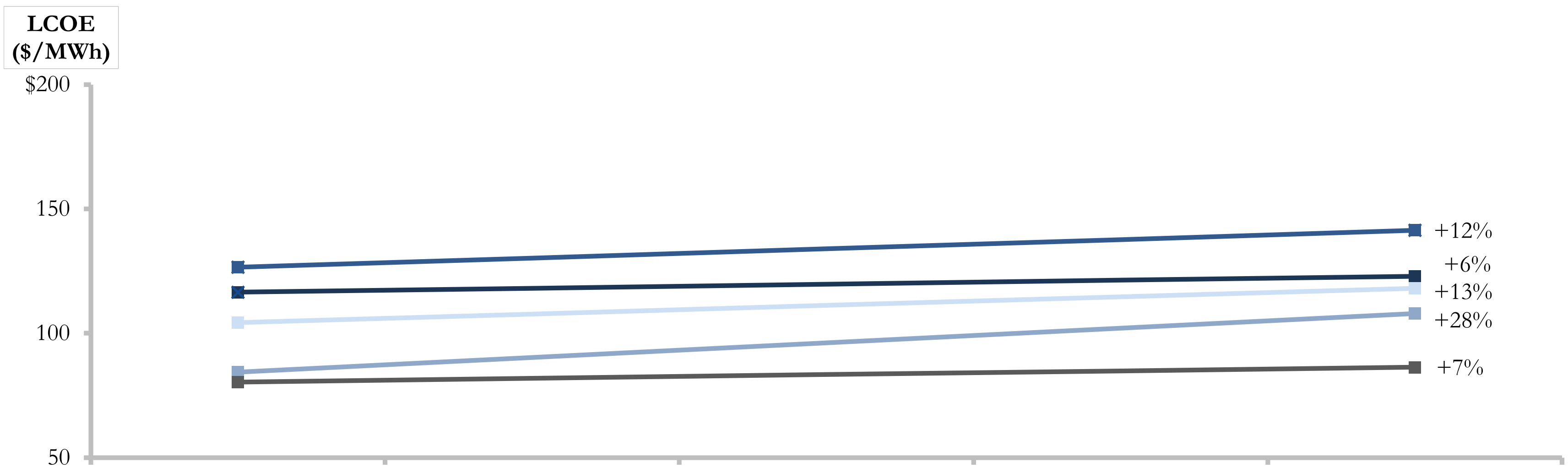
Source: Lazard estimates.

Note: Reflects investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-year economic life and 40% tax rate. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes natural gas price of $5.50 per MMBtu. Assumes midpoint of analysis conducted earlier.

(a) Assumes capital costs for thin-film and crystalline solar PV decline by 10% annually through 2014 and 5% annually thereafter. Assumes capital costs for gas-fired CCGT increase by 2.5% annually.

Levelized Cost of Energy – Sensitivity to Cost of Capital

A key issue facing Alternative Energy generation technologies resulting from the potential for intermittently disrupted capital markets is the reduced availability, and increased cost, of capital; these dynamics have a greater relative impact on Alternative Energy generation technologies, whose costs reflect essentially only return on, and of, the capital investment required to build them



After-Tax IRR/WACC	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	6.0%	7.0%	8.0%	9.0%	10.0%

Crystalline Solar PV   Thin-Film Solar PV   Nuclear[(a)]   Coal[(b)]   CCGT

Source: Lazard estimates.

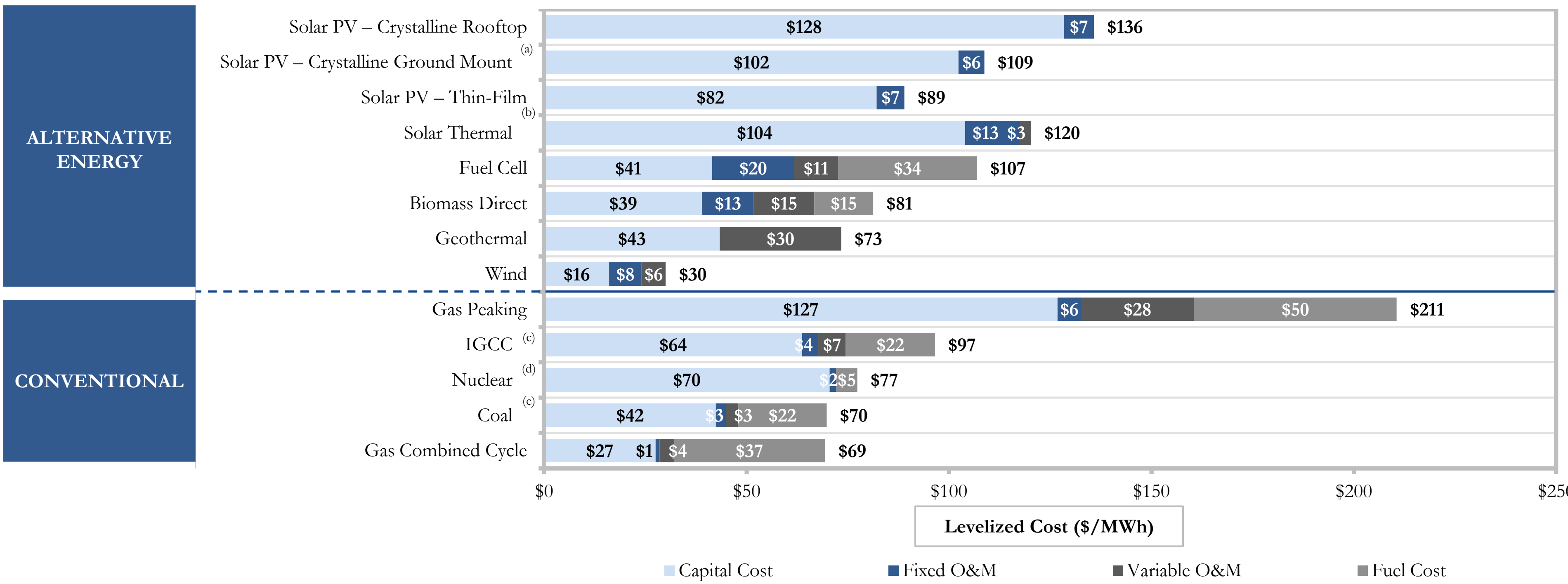
Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-year economic life, 40% tax rate and 5-40 year tax life. Assumes 30% debt at the stated interest rate, 20% common equity at the stated cost and 50% tax equity at 8.5% cost for Alternative Energy generation technologies. Assumes 60% debt at the stated interest rate and 40% equity at the stated cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(b) Based on advanced supercritical pulverized coal.

Levelized Cost of Energy Components – Low End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as is anticipated with solar PV technologies)



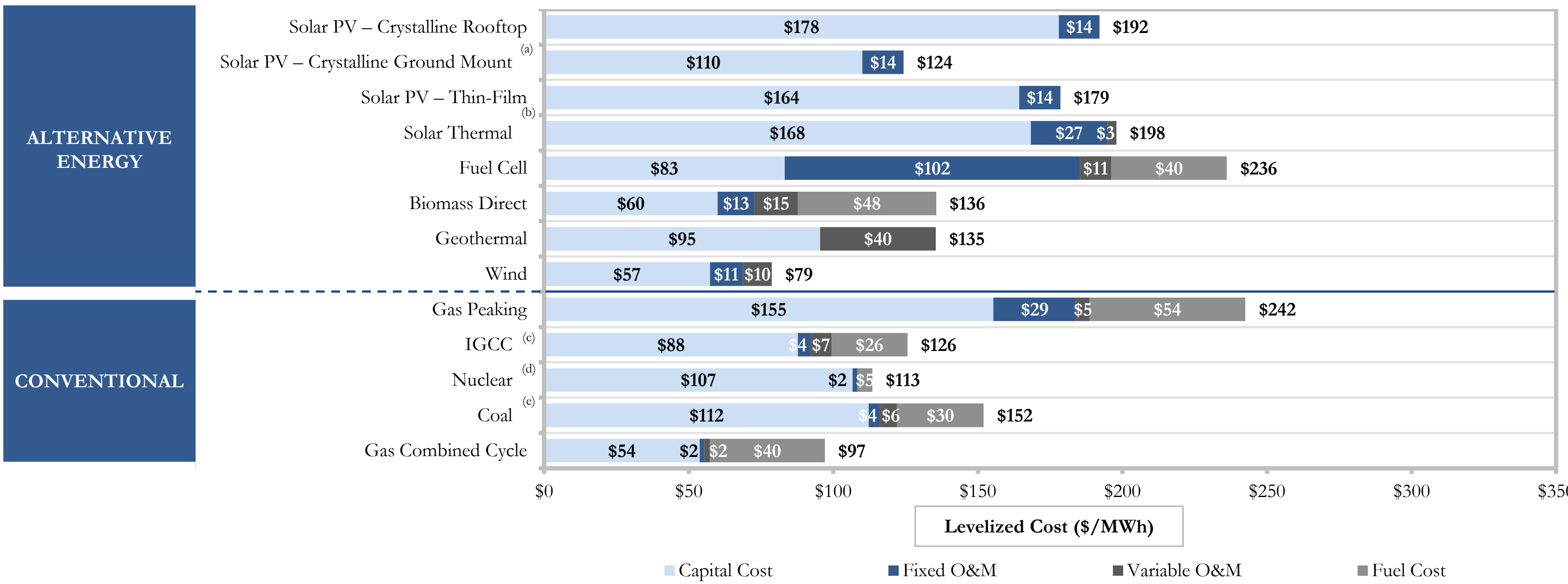
Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.
(b) Represents both solar tower and solar trough, each with 3 hour storage capability.
(c) Incorporates no carbon capture and compression.
(d) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(e) Based on advanced supercritical pulverized coal. Incorporates no carbon capture and compression.

Levelized Cost of Energy Components – High End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as is anticipated with solar PV technologies)



Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 4–20 year tax life. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Low end represents single-axis tracking crystalline. High end represents fixed installation.
(b) Low end represents solar tower, high end represents solar trough, each with 3 hour storage capability.
(c) Incorporates 90% carbon capture and compression.
(d) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(e) Based on advanced supercritical pulverized coal. Incorporates 90% carbon capture and compression.

Energy Resources: Matrix of Applications

While the levelized cost of energy for Alternative Energy generation technologies is becoming increasingly competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., central station vs. customer-located) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

					LOCATION			DISPATCH			
		LEVELIZED COST OF ENERGY	CARBON NEUTRAL/ REC POTENTIAL	STATE OF TECHNOLOGY	CUSTOMER LOCATED	CENTRAL STATION	GEOGRAPHY	INTERMITTENT	PEAKING	LOAD-FOLLOWING	BASE-LOAD
ALTERNATIVE ENERGY	FUEL CELL	$107-236	?[a]	Emerging/ Commercial	✓		Universal				✓
	SOLAR PV	$89-192	✓	Commercial/ Evolving	✓	✓	Universal[b]	✓	✓		
	SOLAR THERMAL	$120-198	✓	Emerging		✓	Southwest	✓	✓	✓	
	BIOMASS DIRECT	$81-136	✓	Mature		✓	Universal			✓	✓
	GEOTHERMAL	$73-135	✓	Mature		✓	Varies				✓
	ONSHORE WIND	$30-79	✓	Mature		✓	Varies	✓			
CONVENTIONAL	GAS PEAKING	$211-242	×	Mature	✓	✓	Universal		✓		
	IGCC	$97-126	×[c]	Emerging[d]		✓	Co-located or rural				✓
	NUCLEAR	$77-113	✓	Mature/ Emerging		✓	Co-located or rural				✓
	COAL	$70-152	×[c]	Mature[d]		✓	Co-located or rural				✓
	GAS COMBINED CYCLE	$69-97	×	Mature	✓	✓	Universal			✓	✓

Source: *Lazard estimates.*
(a) Qualification for RPS requirements varies by location.
(b) LCOE study capacity factor assumes Southwest location.
(c) Could be considered carbon neutral technology, assuming carbon capture and compression.
(d) Carbon capture and compression technologies are in emerging stage.

Levelized Cost of Energy – Key Assumptions

	Units	Solar PV: Thin-Film Utility[b]	Solar PV: Crystalline Ground Mount[c]	Solar PV: Crystalline Rooftop	Solar Thermal: Trough-No Storage[d]	Solar Thermal: Trough 3 Hours Storage	Solar Thermal: Tower[e]
Net Facility Output	MW	10	10	10	250	250	120 - 100
EPC Cost	$/kW	$2,500 - $4,000	$3,500 - $2,750	$3,750 - $4,500	$3,700 - $5,400	$4,600 - $4,700	$5,600 - $6,300
Capital Cost During Construction	$/kW	included	included	included	included	included	included
Other Owner's Costs	$/kW	included	included	included	$1,300 - included	$1,700 - $1,800	included
Total Capital Cost[a]	$/kW	$2,500 - $4,000	$3,500 - $2,750	$3,750 - $4,500	$5,000 - $5,400	$6,300 - $6,500	$5,600 - $6,300
Fixed O&M	$/kW-yr	$15.00 - $25.00	$15.00 - $25.00	$15.00 - $25.00	$34.00 - $66.00	$60.00	$50.00 - $70.00
Variable O&M	$/MWh	—	—	—	—	—	$3.00
Heat Rate	Btu/kWh	—	—	—	—	—	—
Capacity Factor	%	25% - 20%	27% - 20%	23% - 20%	29% - 26%	34% - 30%	43% - 30%
Fuel Price	$/MMBtu	—	—	—	—	—	—
Construction Time	Months	12	12	12	24	24	24
Facility Life	Years	20	20	20	20	20	20
CO_2 Equivalent Emissions	Tons/MWh	—	—	—	—	—	—
Investment Tax Credit	%	30%	30%	30%	30%	30%	30%
Production Tax Credit	$/MWh	—	—	—	—	—	—
Levelized Cost of Energy	$/MWh	$\boxed{\$89}$ - $179	$\boxed{\$109}$ - $124	$136 - $192	$146 - $191	$167 - $\boxed{\$198}$	$\boxed{\$120}$ - $198

Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 2.5% annual escalation for production tax credit, O&M costs and fuel prices. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(b) An illustrative manufacturer of Thin-Film PV would be FirstSolar.
(c) Left side represents single-axis tracking crystalline; right side represents fixed installation. An illustrative manufacturer of high-efficiency Crystalline PV would be SunPower.
(d) Left side represents wet-cooled; right side represents dry-cooled. Illustrative manufacturers/developers of Trough Solar Thermal would be Abengoa Solar, Flagsol, Solar Millennium and Siemens.
(e) Represents a range of solar thermal tower estimates. Illustrative manufacturers/developers of Solar Thermal Tower would be BrightSource Energy, eSolar and SolarReserve.

Levelized Cost of Energy – Key Assumptions (cont'd)

	Units	IGCC[b]	Gas Combined Cycle	Gas Peaking[c]	Coal[d]	Nuclear[e]
Net Facility Output	MW	580	550	152 - 34	600	1,100
EPC Cost	$/kW	$3,054 - $4,193	$743 - $1,004	$580 - $700	$2,027 - $6,067	$3,750 - $5,250
Capital Cost During Construction	$/kW	$696 - $1,057	$107 - $145	included	$487 - $1,602	$1,035 - $1,449
Other Owner's Costs	$/kW	included	$156 - $170	$220 - $300	$486 - $731	$600 - $1,500
Total Capital Cost[a]	$/kW	$3,750 - $5,250	$1,006 - $1,319	$800 - $1,000	$3,000 - $8,400	$5,385 - $8,199
Fixed O&M	$/kW-yr	$26.40 - $28.20	$6.20 - $5.50	$5.00 - $25.00	$20.40 - $31.60	$12.80
Variable O&M	$/MWh	$6.80 - $7.30	$3.50 - $2.00	$28.00 - $4.70	$3.00 - $5.90	—
Heat Rate	Btu/kWh	8,800 - 10,520	6,800 - 7,220	9,100 - 9,800	8,750 - 12,000	10,450
Capacity Factor	%	75%	70% - 40%	10%	93%	90%
Fuel Price	$/MMBtu	$2.50	$5.50	$5.50	$2.50	$0.50
Construction Time	Months	57 - 63	36	25	60 - 66	69
Facility Life	Years	40	20	20	40	40
CO_2 Equivalent Emissions	Tons/MWh	0.74 - 0.89	0.40 - 0.42	0.63 - 0.60	0.95 - 1.27	—
Investment Tax Credit	%	—	—	—	—	—
Production Tax Credit	$/MWh	—	—	—	—	—
Levelized Cost of Energy	$/MWh	$97 - $126	$69 - $97	$211 - $242	$70 - $152	$77 - $113

Source: *Lazard estimates.*

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 2.5% annual escalation for production tax credit, O&M costs and fuel prices. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(b) High end incorporates 90% carbon capture and compression.
(c) Low end represents assumptions regarding GE 7FA. High end represents assumptions regarding GE LM6000PC.
(d) Based on advanced supercritical pulverized coal. High end incorporates 90% carbon capture and compression.
(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

Levelized Cost of Energy – Key Assumptions (cont'd)

	Units	Fuel Cell[a]	Biomass Direct	Wind	Off-Shore Wind	Geothermal
Net Facility Output	MW	2.4	35	100	210	30
EPC Cost	$/kW	$3,000 - $7,000	$2,641 - $3,522	$1,000 - $1,500	$2,500 - $4,120	$4,050 - $6,383
Capital Cost During Construction	$/kW	included	$359 - $478	included	included	$550 - $867
Other Owner's Costs	$/kW	$800 - included	included	$300 - $400	$600 - $880	included
Total Capital Cost[b]	$/kW	$3,800 - $7,000	$3,000 - $4,000	$1,300 - $1,900	$3,100 - $5,000	$4,600 - $7,250
Fixed O&M	$/kW-yr	$169 - $850	$95.00	$30.00 - $30.00	$60.00 - $100.00	—
Variable O&M	$/MWh	$10.83	$15.00	—	$13.00 - $18.00	$30.00 - $40.00
Heat Rate	Btu/kWh	6,239 - 7,260	14,500	—	—	—
Capacity Factor	%	95%	85%	41% - 30%	45% - 32%	90% - 80%
Fuel Price	$/MMBtu	$5.50	$1.00 - $3.30	—	—	—
Construction Time	Months	3	36	12	12	36
Facility Life	Years	20	20	20	20	20
CO_2 Equivalent Emissions	Tons/MWh	0.26 - 0.42	—	—	—	—
Investment Tax Credit	%	30%	—	—	—	—
Production Tax Credit	$/MWh	—	$10	$20	$20	$20
Levelized Cost of Energy	$/MWh	$107 - $236	$81 - $136	$30 - $79	$94 - $235	$73 - $135

Source: Lazard estimates.

Note: Reflects production tax credit, investment tax credit and accelerated asset depreciation, as applicable. Assumes 2010 dollars, 20-40-year economic life, 40% tax rate and 5-40 year tax life. Assumes 2.5% annual escalation for production tax credit, O&M costs and fuel prices. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 8.5% cost and 20% common equity at 12% cost for Alternative Energy generation technologies. Assumes 60% debt at 8.0% interest rate and 40% equity at 12% cost for conventional generation technologies. Assumes coal price of $2.50 per MMBtu and natural gas price of $5.50 per MMBtu.

(a) Low end incorporates illustrative economic and efficiency benefits of combined heat and power ("CHP") applications.

(b) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

Summary Considerations

Lazard has conducted this study comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies in order to understand which Alternative Energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions, as well as to understand which technologies are best suited for various applications based on locational requirements, dispatch characteristics and other factors. We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including government subsidies, RPS requirements, and continuously improving economics as underlying technologies improve and production volumes increase.

In this study, Lazard's approach was to determine the levelized cost of energy, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, and economic life) were identical for all technologies, in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and U.S. federal tax incentives on the levelized cost of energy. These inputs were developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant.

Lazard has not manipulated capital costs or capital structure for various technologies, as the goal of the study was to compare the current state of various generation technologies, rather than the benefits of financial engineering. The results contained in this study would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or capital costs (e.g., a willingness to accept lower returns than those assumed herein).

Key sensitivities examined included fuel costs and tax subsidies. Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include scale benefits or detriments, the value of Renewable Energy Credits ("RECs") or carbon emissions offsets, the impact of transmission costs, second-order system costs to support intermittent generation (e.g., backup generation, voltage regulation, etc.), and the economic life of the various assets examined.