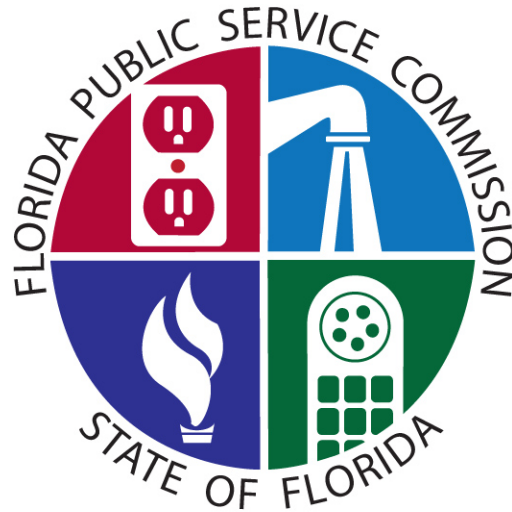


Review Of The 2013 Ten-Year Site Plans For Florida's Electric Utilities



Florida Public Service Commission

**Tallahassee, FL
October 2013**

Ten-Year Site Plan Comments List

State Agencies

- Department of Economic Opportunity
- Department of Environmental Protection
- Department of Transportation

Regional Planning Councils

- Central Florida Regional Planning Council
- East Central Florida Regional Planning Council
- North Central Florida Regional Planning Council
- Northeast Florida Regional Planning Council
- Treasure Coast Regional Planning Council

Water Management Districts

- South Florida Water Management District
- Southwest Florida Water Management District
- St. John's River Water Management District
- Suwannee River Water Management District

Local Governments

- Citrus County

Other Organizations

- Sierra Club and Earthjustice

State Agencies

- Department of Economic Opportunity
- Department of Environmental Protection
- Department of Transportation

Rick Scott
GOVERNOR



Jesse Panuccio
EXECUTIVE DIRECTOR

July 18, 2013

Mr. Phillip Ellis
Engineering Specialist III
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

Dear Mr. Ellis:

At your request we have reviewed the 2013 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 2013 Ten-Year Site Plans addressed ten 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 Scott Rogers, Planning Analyst, at (850) 717-8510, or by email at scott.rogers@deo.myflorida.com.

Sincerely,

Mike McDaniel
Comprehensive Planning Manager

MM/sr

Enclosure: Department Comments

2013 Ten-Year Site Plan Review

Three utilities, Gulf Power, Florida Power and Light, and Seminole Electric, have identified a total of ten potential sites for future power generation. Potential sites are identified 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 four properties as potential sites for future generating facilities. Two potential sites contain existing power plants: Plant Crist site in Escambia County and Plant Smith Site in Bay County. Two potential sites are undeveloped: Caryville Site in Holmes and Washington Counties and North Escambia Site in Escambia County.

A. Plant Crist Site. This site, located in Escambia County, 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 through the Land Development Code. 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) 245-8474. For information on floodplain compatibility, contact the State of Florida Floodplain Management Office at (850) 413-9960.

B. Plant Smith Site. Located in Bay County, the Plant 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. Caryville Site. The Caryville site is located in Holmes County, Washington County, and the City of Caryville, and it is adjacent to the Choctawhatchee River. The site 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 Outstanding Florida Waters, contact the Standards and Assessment section at (850) 245-8064; and (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. Northern Escambia Site. The site is located in northern Escambia County, approximately five miles southwest of the City of Century and west of the Escambia River. The Escambia County Future Land Use Map designates the site predominantly as Agriculture with a very small part designated as Rural Community. Electric power generation facilities may be allowed as a conditional use in Agriculture and Rural Community through the land development code. The site is surrounded predominantly by Agriculture future land uses and a small area of Rural Community. The site and surrounding area are primarily used for timber harvesting and agricultural use, and the site is in close proximity to transmission, natural gas pipelines, railroad, major highways and access to water. The site contains a substantial amount of uplands with some wetlands, and Mitchell Creek that traverses the site.

For information regarding wetland compatibility issues, contact the Department of Environmental Protection Office of Submerged Lands and Environmental Resources at (850) 245-8474.

2. Florida Power and Light. Florida Power and Light (FPL) has identified five potential sites as 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 County's 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 County's 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. The site is adjacent to an existing transportation corridor

with roadway capacity. Demands on water facilities have already been considered in the growth projections of the County's comprehensive plan. No environmental or other compatibility issues have been identified for this site.

C. Manatee Plan 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.

D. 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 that "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 future land use category, states that "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."

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.

E. 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.

3. Seminole Electric.

Seminole Electric has identified one site, a 350-acre parcel located northeast of the City Bell in Gilchrist County, as a potential power plant site. Much of the site has been used for silviculture (pine plantation) and consists of large tracts of planted longleaf and slash pine community. 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.

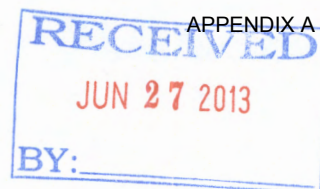
From: [Bull, Robert](#)
To: [Phillip Ellis](#)
Cc: [Mulkey, Cindy](#)
Subject: DEP Siting Coordination Office Ten Year Site Plan Review
Date: Monday, July 22, 2013 10:57:45 AM

The Department of Environmental Protection's Siting Coordination Office (SCO) has reviewed the 2013 Ten Year Site Plans for Florida's Electric Utilities and found the documents to be adequate for planning purposes. Thank you for the opportunity to review and comment on the plans. If you have any questions for our office, feel free to contact me.

Thank you,

Bobby Bull, P.E.
Florida Department of Environmental Protection
Siting Coordination Office
2600 Blairstone Road, MS 5500
Tallahassee, FL 32399-2400
robert.bull@dep.state.fl.us
850/717-9111

Please take a few minutes to share your comments on the service you received from the department by clicking on this link [DEP Customer Survey](#).



Florida Department of Transportation

**RICK SCOTT
GOVERNOR**

605 Suwannee Street
Tallahassee, FL 32399-0450

**ANANTH PRASAD, P.E.
SECRETARY**

June 26, 2013

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

Regional Planning Councils

- Central Florida Regional Planning Council
- East Central Florida Regional Planning Council
- North Central Florida Regional Planning Council
- Northeast Florida Regional Planning Council
- Treasure Coast Regional Planning Council



August 1, 2013

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

Dear Mr. Ellis,

RE: Review of 2013 Ten-Year Site Plans for Florida's Electric Utilities

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 letter dated May 21, 2013, 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 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. However, due to the scanning or production process, the figures included in the document are blurry and very hard to read.

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. The plan discusses upgrades of existing facilities. Unfortunately, since there is not a map included to show where these facilities are located, it is not possible to determine which of them may be in the region.

State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399
Page 2 of 3

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 the document does not provide clear information on the areas. 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. However, two facilities are estimated to be put in cold stand by or retired by 2016. 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.

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.

Tampa Electric Company:

Phillip Ellis
State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Blvd
Tallahassee, FL 32399
Page 3 of 3

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. In addition, there is mention of a possible fuel conversion to biodiesel at the Phillips Station located in Highlands County, which was placed in long term reserve standby in 2009.

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 and 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.

The proposed expansions/potential sitings as identified 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,

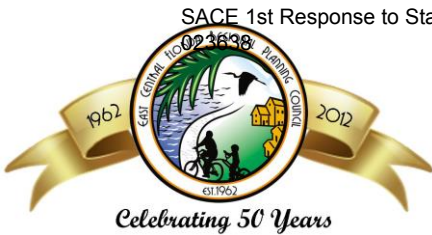


Marisa M. Barmby, AICP
Senior Planner

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.
 Executive Director



MEMORANDUM

To: Phillip Ellis, Florida Public Service Commission

From: Hugh W. Harling, Jr., Executive Director
 Tara M. McCue, AICP, Director of Planning and Community Design

Date: August 1, 2013

Subject: 2013 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 2013 Ten-Year Site Plans for the agencies listed above. Staff comments to each utility are italicized below.

Florida Power and Light (FPL)

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.

Orlando Utilities Commission (OUC)

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.

Progress Energy Florida (PEF)

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

Executive Committee

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 Gubernatorial Appointee
 Seminole County

Vice Chair

Patty Sheehan
 City Commissioner
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Secretary

Chuck Nelson
 County Commissioner
 Brevard County

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Welton Cadwell
 County Commissioner
 Lake County

Member at Large

Cheryl L. Grieb
 City Commissioner
 City of Kissimmee



July 16, 2013

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, 2013 - 2022
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 2022 to be located within Gilchrist County. The combined summer electrical generating capacity of the stations will be 1,770 megawatts, while the combined winter electrical generating capacity of the stations will be 2,080 megawatts. The ten-year site plan notes that 385 megawatts of the summer generating capacity and 456 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.

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by coordinating growth management, protecting regional resources,
promoting economic development and providing technical services to local governments.

Letter to Mr. Phillip Ellis
Page 2
July 16, 2013

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

**North
Central
Florida
Regional
Planning
Council**



APPENDIX A
Serving

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2009 NW 67th Place, Gainesville, FL 32653-1603 • 352.955.2200

REGIONAL CLEARINGHOUSE INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 7-16-13

PROJECT DESCRIPTION

#60 - Seminole Electric Cooperative, Inc., Ten-Year Site Plan 2013 -2022

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

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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REGIONAL CLEARINGHOUSE INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 7-16-13

PROJECT DESCRIPTION

#58 - Progress Energy Florida, Inc. Ten-Year Site Plan, 2013 - 2023

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

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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2009 NW 67th Place, Gainesville, FL 32653-1603 • 352.955.2200

REGIONAL CLEARINGHOUSE INTERGOVERNMENTAL COORDINATION AND RESPONSE

Date: 7-16-13

PROJECT DESCRIPTION

#59 - Gainesville Regional Utilities - 2013 Ten-Year Site Plan

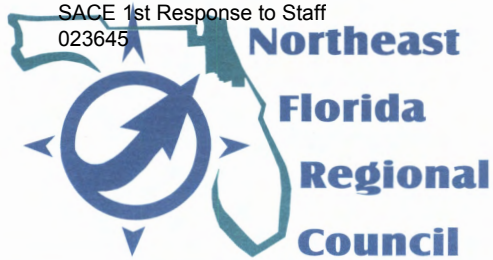
TO: Mr. Phillip Ellis
Division of Regulatory Analysis
Florida Public Service Commission
540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

COMMENTS ATTACHED

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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promoting economic development and providing technical services to local governments.



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June 7, 2013

Ms. Jeanette Sickel
Florida Public Service Commission
Division of Economic Regulation
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850

Dear Ms. Sickel:

Please find attached the Northeast Florida Regional Council's review for JEA's ten-year site plan.

JEA Ten-year Site Plan: The ten-year site plan, as required by Section 186.801 of the Florida Statutes (F.S.), was reviewed by the Northeast Florida Regional Council staff.

Action taken: Staff's review was approved by the Council and authorized for transmittal to the Florida Public Service Commission.

If you have any further requests or questions, please contact Ms. Ameera Sayeed, Senior Regional Planner, (904) 279-0885, ext. 151 or asayeed@nefrc.org.

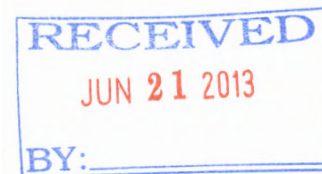
Sincerely,

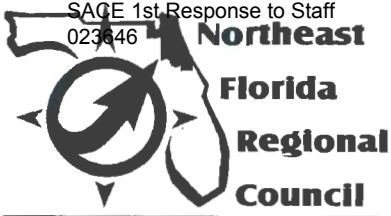
A handwritten signature in blue ink that reads "Edward Lehman".

Edward Lehman
Director of Planning & Development

Attachment

EL/ag





Bringing Communities Together

Baker • Clay • Duval • Flagler • Nassau • Putnam • St. Johns

MEMORANDUM

DATE: May 31, 2013

TO: Northeast Florida Regional Council

THRU: Planning and Growth Management Policy Committee

FROM: Ameera F. Sayeed, GISP, Senior Regional Planner

RE: Review of JEA Ten-Year Power Plant Site Plan 2013-2022

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. The purpose of the ten-year site plan is to disclose the general location of proposed power plant sites and facilitate coordinated planning efforts. Pursuant to Section 186, Florida Statutes, Council staff reviewed the most recent ten-year site plan prepared by the Jacksonville Electric Authority (JEA). The purpose of this report is to summarize JEA's plans for future power generation and provide comments for transmittal to the Florida Public Service Commission (Commission).

Statutory Authority

Section 186.801, Florida Statutes, requires that all major generating electric utilities in Florida submit a *Ten-Year Site Plan* to the Commission for review. Each *Ten-Year Site Plan* contains projections of the utility's electric power needs for the next ten years and the general location of proposed power plant sites and major transmission facilities. In accordance with the statute, the Commission performs a preliminary study of each *Ten-Year Site Plan* and must determine whether it is "suitable" or "unsuitable". In conducting its review, the Commission considers the views of appropriate local and state agencies. The Northeast Florida Regional Council reviews electric utility Ten-Year Site Plans within the region and submits comments to the Commission for review. The Commission forwards the *Ten-Year Site Plan* review, upon completion, to the Florida Department of Environmental Protection (DEP) for use in subsequent power plant siting proceedings. To fulfill the requirements of Section 186.801, Florida Statutes, the Commission has adopted Rules 25-22.070 through 25-22.072, Florida Administrative Code. Electric utilities must file the *Ten-Year Site Plan* by April 1st.

Board Memorandum
May 31, 2013

Purpose

The intent of the *Ten-Year Site Plans* is to give state, regional, and local agencies advance notice of proposed power plants and transmission facilities. However, the *Ten-Year Site Plans* are not a binding plan of action on electric utilities. As such, the Commission's classification of a *Ten-Year Site Plan* as suitable or unsuitable has no binding effect on the utility. Such a classification does not constitute a finding or determination in docketed matters before the Commission. The Commission may address any concerns raised by a utility's *Ten-Year Site Plan* at a public hearing. Because the *Ten-Year Site Plans* are planning documents containing tentative data, they may not contain sufficient information to allow regional planning councils, water management districts, and other reviewing agencies to evaluate site-specific issues within their jurisdictions. Each utility is responsible for providing detailed data, based on in-depth environmental assessments, during Power Plant Siting Act or Transmission Line Siting Act certification proceedings.

Summary of the Plan

JEA is the seventh largest municipally owned electric utility in the United States in terms of number of customers. JEA's electric service area covers most of Duval County and portions of Clay and St. Johns counties. JEA's service area covers approximately 900 square miles and serves approximately 420,000 customers. The evaluation has revealed that JEA has included in this ten-year plan the necessary analysis. The existing JEA electric supply resources, forecasts of customer energy requirements and peak demands, forecasts of fuel process and availability, and an analysis of alternatives for resources that would meet JEA's future capacity and energy needs were reported in the ten-year plan. JEA forecasts accounted for the system peak demand growth and energy consumption resource plan; in addition to cost considerations, environmental and land use considerations were amply factored into the ten-year plan. JEA had provided population estimates in previous ten-year site plans and it appears that the current plan no longer includes the population forecast and accompanying discussion.

JEA consists of three separate entities: The JEA Electric system, the St. Johns River Power Park and the Robert W. Scherer system. Collectively, these plants consist of two dual-fired (petroleum coke/coal) Circulating Fluidized Bed steam turbine-generator units (Northside steam Units 1 and 2); one dual-fired (oil/gas) steam turbine-generator unit (Northside steam Unit 3); five dual-fired (gas/diesel) combustion turbine-generator units (Kennedy GT1 and GT8, and Brandy Branch GT1, CT2, and CT3); two natural gas-fired combustion turbine-generator units (GEC GT1 and GT2); four diesel-fired combustion turbine-generator units (Northside GTs 3, 4, 5, and 6); and one combined cycle heat recovery steam generator unit (Brandy Branch steam Unit 4). The St. Johns River Power Park (SJRPP) is jointly owned by JEA (80 percent) and Florida Power and Light (FPL) (20 percent). SJRPP consists of two nominal 638 MW bituminous coal fired units located north of the Northside Generating Station in Jacksonville, Florida.

Nuclear Generation

In March 2008, JEA approved the policy of pursuing nuclear energy partnerships with the goal of providing 10 percent of JEA's power from nuclear sources. In June 2008, JEA entered into a purchase power agreement with the Municipal Electric Authority of Georgia (MEAG) for a portion of MEAG's entitlement to the Vogtle Units 3 and 4, which are proposed new nuclear units. These two new nuclear units are under construction at the existing Plant Vogtle location in

Board Memorandum
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Burke County, GA. JEA is entitled to net firm capacity of 206 MW from the proposed units. JEA assumes they will have available capacity beginning in the year 2017 from Unit 3 and additional capacity from Unit 4 beginning in the year 2018.

Clean Power and Renewable Energy

JEA has pursued several clean power initiatives and is in the process of evaluating potential renewable energy resources. JEA has worked with the Sierra Club of Northeast Florida, the American Lung Association and local environmental groups to establish a process to maintain an action plan entitled "Clean Power Action Plan". This Plan includes an advisory Panel that is comprised of community representatives. Also, JEA has included in their review and planning installation of solar photovoltaic, solar thermal, landfill and wastewater treatment biogas capacity and wind capacity. Progress has extended to include installation of clean power systems, unit efficiency improvements, commitment to purchase power agreements (including nuclear power), legislative and public education activities, and research into and development of clean power technologies.

Solar

JEA has installed 35 solar PV systems, totaling 222 kW, on public high schools in Duval County, as well as many of JEA's facilities, and the Jacksonville International Airport. JEA implemented the Solar Incentive Program in early 2002. This program continues to provide rebates for the installation of solar thermal systems. In addition to the solar thermal system incentive program, JEA established a residential net metering program to encourage the use of customer-sited solar PV systems, which was revised as the Tier 1 & 2 Net Metering policy in 2009, to include all customer-owned renewable generation systems up to and equal to 100 kW. In 2011, JEA established the Tier 3 Net Metering Policy for customer-owned renewable generation systems greater than 100 kW up to 2 MW. JEA signed a purchase power agreement with Jacksonville Solar, LLC in May 2009 to provide energy from a 15.0 MW DC rated solar farm, which began operation in summer 2010.

Landfill

JEA owns three internal combustion engine generators that are fueled by the methane gas produced by the landfill. JEA also receives landfill gas from the North landfill, which is fed to the Northside Generating Station and is used to generate power at Northside Unit 3.

Wind

JEA purchases 10MW of wind capacity from NPPD's (Nebraska Public Power District) and in turn the NPPD buys back the energy at specified on/off peak charges. JEA receives environmental credits associated with green projects. JEA entered into a 20-year agreement with Nebraska Public Power District to continue to participate in the wind generation project located in Ainsworth, Nebraska.

Biomass

JEA owns three internal combustion engine generators located at the Girvin Road landfill. This facility was placed into service in July 1997, and is fueled by the methane gas produced by the landfill. The facility originally had four generators, with an aggregate net capacity of 3 MW. Gas

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generation has declined, and one generator was removed and placed into service at the Buckman Wastewater Treatment facility.

In 2011, JEA started a co-firing biomass in the Northside Units 1 and 2, utilizing wood chips from JEA tree trimming activities as a biomass energy source. Northside 1 and 2 has produced a total of 2,154 MWh of energy from wood chips during 2011 and 2012. JEA has received bids from local sources to provide sized biomass for potential use for Northside Units 1 and 2.

Plug-in Electric Vehicle Peak Demand

In 2012, JEA developed the PEV demand and energy forecast for the service territory using the 2011 information from the Electric Power Research Institute (EPRI), the Edison Electric Institute (EEI), the U.S. Census Bureau, and the Bureau of Economic and Business Research (BEBR). JEA's baseline forecast of the number of plug-in vehicles in the area was determined from BEBR's forecasted population growth rate, the U.S. Census Bureau's 2010 estimated number of vehicles, and EPRI's forecasted low scenario PEV penetration rate. JEA forecasted the average usable battery capacity per vehicle using the upcoming plug-in vehicle model rollouts from Toyota, Honda, Ford, and General Motors, and grew the capacity by 1 kWh per year. The baseline forecast assumed that charging would initially be uncontrolled at home until the mid-2020s when public infrastructure became feasible and available. When comparing Pike's 2012 PEV forecasted vehicle sales with JEA's 2012 forecast, JEA's baseline projections were 63 percent higher than Pike. Because of this difference, JEA shifted the start of its PEV forecast back 5 years to 2017. Because Pike did not provide forecast data for Duval County, JEA maintained the previously forecasted annual increases.

Staff Evaluation

The JEA forecasts are much more statistically sound. In the past JEA used regression analyses, which would not necessarily account for statistical anomalies. To address the variability, in recent year with the demand, JEA also used historical data, growth rates and established regression analyses for the 13-year progression to establish periods of economic downturn and prerecession periods. JEA forecasted the Net Energy Load to increase at an average of 1.17 percent per year during the last ten-year period. JEA views demand to decline in 2012 and hence over the 13 years the average annual growth rate for total energy is expected to be at 0.73 percent and 0.49 percent for net energy.

Council staff supports JEA and the State of Florida's efforts to continue to develop new programs to: 1) reduce the reliance on coal and oil as energy sources; 2) increase conservation activities to offset the need to construct new power plants; and 3) plan to develop an environmentally sound power supply strategy that may provide reliable electric service at the lowest practical cost.

Recommendation

Staff recommends that the Committee and Council approve this report and authorize its transmittal to the Florida Public Service Commission.

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

June 7, 2013

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

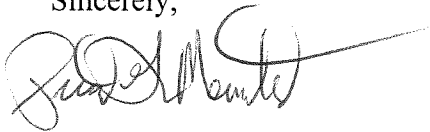
Subject: 2013 Ten Year Power Plant Site Plans

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 May 17, 2013. The report concludes that the FPL Ten Year Power Plant Site Plan, 2013-2022 is inconsistent with **Strategic Regional Policy Plan Goal 9.1**, decreased vulnerability of the region to fuel price increases and supply interruptions. 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,



Peter G. Merritt, Ph.D.
Assistant Director

Attachment

cc: Nick Blount, FPL

TREASURE COAST REGIONAL PLANNING COUNCIL

Report on the

Florida Power & Light Company Ten Year Power Plant Site Plan, 2013-2022

May 17, 2013

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 (Exhibit 1). FPL is proposing to add a total of about 2,267 megawatts (MW) of summer capacity to its system from 2013 to 2022. FPL plans to obtain additional electricity through: 1) power purchases from qualifying facilities, utilities, and other entities; 2) upgrades to existing facilities; 3) addition of an existing municipal facility; 4) modernization of existing FPL facilities; and 5) construction of a new generating unit. 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;
- 2016 – place in service the Port Everglades Next Generation Clean Energy Center (1,277 MW) in the City of Hollywood; and
- 2022 – place in service Turkey Point Nuclear Unit 6 (1,100 MW) in Miami-Dade County

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

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

6. Northeast Okeechobee County site in Okeechobee County; and
7. Palatka Plant site in Putnam County.

Also, FPL has identified 5 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. Manatee Plant site in Manatee County;
4. An unidentified location in Martin County for a photovoltaic (PV) facility; and
5. An unidentified location in Putnam County.

The ten year site plan describes eight factors that are influencing FPL's resource planning work. These factors include:

1. Maintaining/enhancing fuel diversity in the FPL system.
2. Maintaining a balance between load and generating capacity in southeastern Florida, particularly in Miami-Dade and Broward counties.
3. FPL will begin serving the City of Vero Beach's electrical load beginning January 1, 2014.
4. An updated projection of mandatory efficiency standards for appliances, lighting, and other electrical equipment will result in significant reductions in FPL peak load and net energy for load in 2022.
5. FPL's projected increasing dependence upon demand side management resources to maintain system reliability.
6. The timing of when the Nuclear Regulatory Commission will issue a new schedule for its review of FPL's application for a Combined Operating License for the Turkey Point Units 6 and 7 nuclear units and the potential impact that schedule may have on the overall project schedule.
7. Potential changes in environmental regulations for air emissions could affect FPL's resource plan.
8. The possibility of establishment of a Florida standard for renewable energy or clean energy.

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 one preferred site and one potential site for future power generating facilities in the Treasure Coast Region (Exhibit 2). The preferred site is the Riviera Beach 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 Beach 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 Florida Department of Environmental Protection, and is expected to start commercial operation in 2014.

Palm Beach County Department of Environmental Resources Management (ERM) has provided comments on the FPL Ten Year Power Plant Site Plan (Exhibit 4). The comments include a discussion of concerns associated with the development and operation of the Riviera Beach Energy Center, which is currently under construction. The concerns are related to thermal pollution of the Lake Worth Lagoon; potential impacts to manatees; potential impacts to organisms from the facility's cooling water intake; stormwater retention; oil spill prevention plans; climate change vulnerability; and sea turtle lighting compliance. Council recommends that FPL meet with representatives from Palm Beach County ERM to discuss how these issues are addressed in the FPL Riviera Beach Energy Center Conditions of Certification and determine if additional actions are necessary to satisfy these concerns.

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.

New in the 2013, the ten year site plan indicates FPL will begin serving the City Vero Beach's electrical load beginning January 1, 2014. In early 2013, FPL came to an agreement with the City of Vero Beach to purchase the City's electric utility system. FPL is expected to begin providing electric service to more than 34,000 customers formerly served by the City of Vero Beach. As part of FPL's acquisition of Vero Beach's electric utility system, FPL will take ownership of Vero Beach's five existing generating units starting January 2014. The current plan is to immediately retire three of these older generating units and operate the remaining two, which supply approximately 44 MW (Summer) of combined cycle capacity, for a maximum of three years.

The ten year site plan also indicates that FPL is currently evaluating the possibility of serving the electrical loads of several entities, including the City of 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 70.6 percent (4.3 percent from coal, 0.2 percent from oil, and 66.1 percent from natural gas) of FPL's electric generation in 2013. The plan predicts fossil fuels will account for 68.7 percent (5.4 percent from coal, 0.1 percent from oil, and 63.2 percent from natural gas) of FPL's electric generation in 2022. During the same period, nuclear sources are predicted to change from 24.0 percent in 2013 to 25.6 percent in 2022. Solar sources are predicted to decline from 0.2 percent in 2013 to 0.1 percent in 2022.

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.

In addition to the three solar facilities noted above, the plan indicates that FPL is currently in the process of identifying other potential solar sites in the state. FPL is evaluating existing generation sites along with other sites within FPL's service territory. Council continues to support FPL's existing solar projects and encourages FPL to develop additional projects based on renewable resources.

Conclusion

The FPL ten year site plan is inconsistent with **Strategic Regional Policy Plan Goal 9.1**, decreased vulnerability of the region to fuel price increases and supply interruptions, because the plan predicts continued heavily reliance on only two primary fuel types, natural gas and nuclear fuel. The plan predicts a very slight decrease in the reliance on fossil fuels and a slight increase in the reliance on nuclear energy during the next ten years. This outcome is an incremental step toward consistency with **Strategy 9.1.1**, reduce the Region's reliance on fossil fuels. However, this shift in fuel supply is not sufficient to decreased vulnerability of the region to fuel price increases and supply interruptions. Council recommends that FPL adopt a more balanced portfolio of fuels that includes a significant component of renewable energy sources. Council remains concerned that the ten year site plan does not predict an increase in the use of renewable energy during the next decade. Council continues to encourage the Florida Legislature to adopt a Renewable Portfolio Standard in order to provide a mechanism to expand the use of renewable energy in Florida.

Council recommends that FPL consider new strategies to expand reliance on renewable sources. FPL should consider expanding its solar rebate programs for customers who install PV and solar water heating systems on their homes and businesses. This program is part of a five-year pilot program authorized by the FPSC to promote clean solar power and reduce energy consumption. The program should be expanded because demand far exceeds the availability of funds. Also, the application period should be coordinated with the Solar and Energy Loan Fund (SELF) so that participants in this program would have the option of receiving a rebate. SELF is a low interest rate loan program that provides financing for clean energy solutions. The current schedule for rebate applications makes it difficult for SELF participants to take part in the FPL rebate program.

FPL should also consider developing 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 sources. The phasing in of PV and other locally available energy sources will help Florida achieve a sustainable future.

Attachments

EXHIBIT 1

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

Projected Capacity Changes for FPL ⁽¹⁾			
Year	Projected Capacity Changes	Net Capacity Changes (MW)	
		Winter ⁽²⁾	Summer ⁽³⁾
2013	Changes to Existing Purchases ⁽⁴⁾	(545)	(425)
	Port Everglades Units 3 & 4 retired for Modernization	(765)	(761)
	Turkey Point Unit 2 operation changed to synchronous condenser	(394)	(392)
	Sanford Unit 5 CT Upgrade	—	9
	Turkey Point Unit 4 Uprate - Completed	—	115
	Turkey Point Unit 4 Uprate - Outage ⁽⁵⁾	(717)	—
	Sanford Unit 4 CT Upgrade	—	16
	Manatee Unit 2	(3)	—
	Scherer Unit 4	(28)	—
	Cape Canaveral Next Generation Clean Energy Center ⁽⁶⁾	—	1,210
	Manatee Unit 1 ESP - Outage ⁽⁷⁾	(822)	—
	Martin Unit 1 ESP - Outage ⁽⁷⁾	—	(826)
	2014	Sanford Unit 5 CT Upgrade	19
Cape Canaveral Next Generation Clean Energy Center ⁽⁶⁾		1,355	—
Changes to Existing Purchases ⁽⁴⁾		22	37
Manatee Unit 1 ESP - Outage ⁽⁷⁾		822	—
Sanford Unit 4 CT Upgrade		16	—
Vero Beach Combined Cycle ⁽⁸⁾		46	44
Martin Unit 1 ESP - Outage ⁽⁷⁾		(832)	826
Martin Unit 2 ESP - Outage ⁽⁷⁾		—	(826)
Manatee Unit 3 CT Upgrade		—	19
Turkey Point Unit 5 CT Upgrade		—	33
Turkey Point Unit 4 Uprate - Completed ⁽⁵⁾		115	—
Riviera Beach Next Generation Clean Energy Center ⁽⁶⁾		—	1,212
2015		Manatee Unit 3 CT Upgrade	39
	Martin Unit 1 ESP - Outage ⁽⁷⁾	832	—
	Martin Unit 2 ESP - Outage ⁽⁷⁾	—	826
	Turkey Point Unit 5 CT Upgrade	33	—
	Changes to Existing Purchases ⁽⁴⁾	70	70
	Ft. Myers Unit 2 CT Upgrade	—	51
	Riviera Beach Next Generation Clean Energy Center ⁽⁶⁾	1,344	—
2016	Changes to Existing Purchases ⁽⁴⁾	(858)	(928)
	Ft. Myers Unit 2 CT Upgrade	51	—
	Port Everglades Next Generation Clean Energy Center ⁽⁶⁾	—	1,277
2017	Turkey Point Unit 1 operation changed to synchronous condenser	(398)	(396)
	Changes to Existing Purchases ⁽⁴⁾	(37)	(37)
	Vero Beach Combined Cycle ⁽⁸⁾	(46)	(44)
Port Everglades Next Generation Clean Energy Center ⁽⁶⁾	1,429	—	
2018	Changes to Existing Purchases ⁽⁴⁾	(388)	(381)
2019	—	—	—
2020	—	—	—
2021	Changes to Existing Purchases ⁽⁴⁾	180	180
2022	Turkey Point Nuclear Unit 6 ⁽⁸⁾	—	1,100

(1) Additional information about these resulting reserve margins and capacity changes are found on Schedules 7 & 8 respectively.
(2) Winter values are forecasted values for January of the year shown.
(3) Summer values are forecasted values for August of the year shown.
(4) 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.
(5) Outages for uprate work.
(6) 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.
(7) Outages for ESP work.
(8) This unit will be added as part of the agreement that FPL will serve Vero Beach's electric load starting January, 2014. This unit is expected to be retired within 3 years.

EXHIBIT 2 Treasure Coast Region Significant Energy Facilities

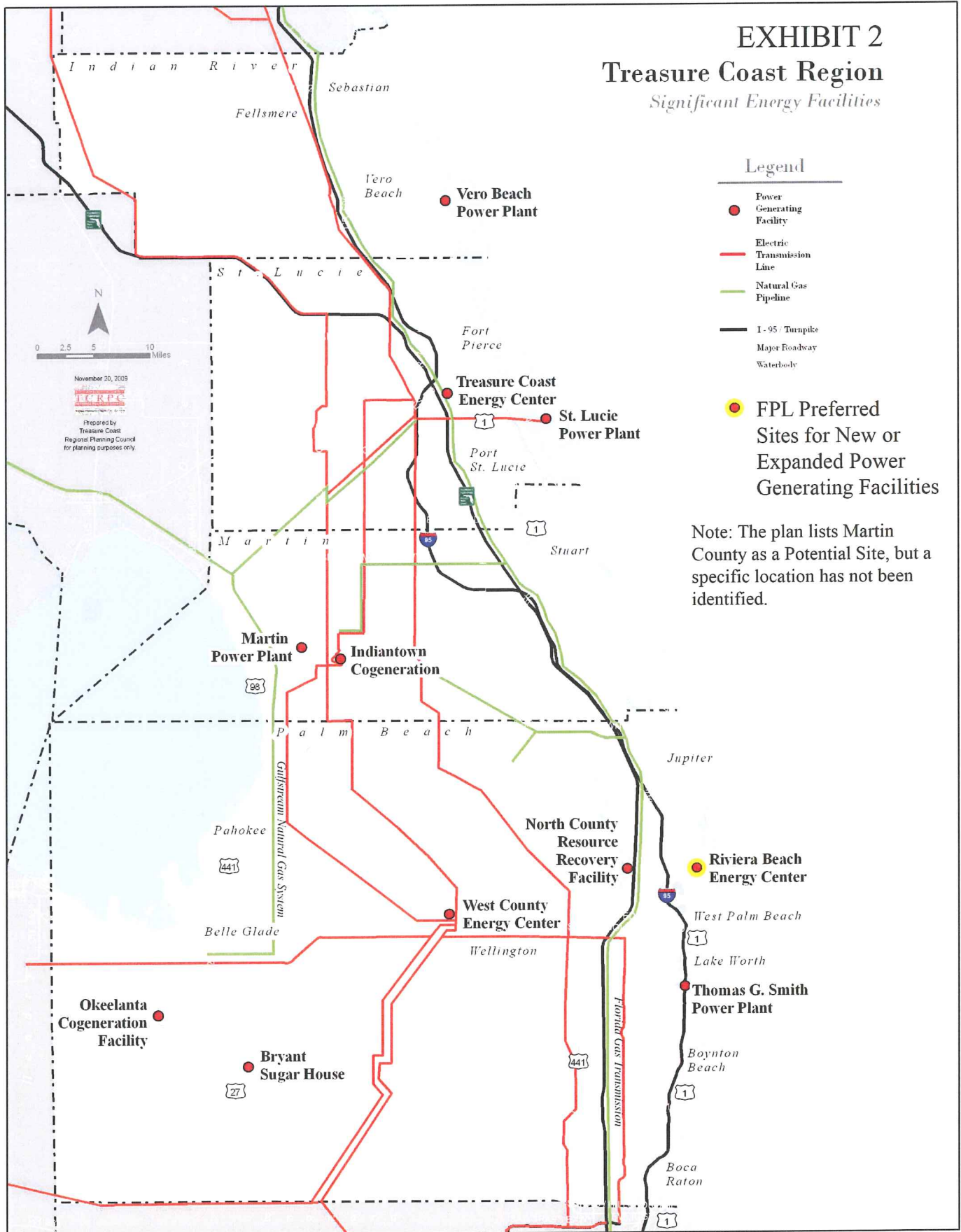


EXHIBIT 3

Schedule 6.2
Energy Sources % by Fuel Type

Energy Source	Units	Actual ^{1/}		Forecasted									
		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
(1) Annual Energy Interchange ^{2/}	%	5.3	4.7	1.9	2.3	2.5	1.0	0.1	0.0	0.0	0.0	0.0	0.0
(2) Nuclear	%	19.1	15.3	24.0	23.4	23.1	23.2	22.7	22.2	22.5	21.9	21.6	25.6
(3) Coal	%	5.0	4.3	4.3	4.4	4.9	4.4	4.9	4.8	5.2	5.3	5.5	5.4
(4) Residual (FO6) -Total	%	0.6	0.3	0.2	0.2	0.3	0.3	0.1	0.2	0.1	0.2	0.2	0.1
(5) Steam	%	0.6	0.3	0.2	0.2	0.3	0.3	0.1	0.2	0.1	0.2	0.2	0.1
(6) Distillate (FO2) -Total	%	0.1	0.0	0.0	0.0	0.0	0.1	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	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
(9) CT	%	0.0	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	%	66.1	72.6	66.1	66.3	65.4	66.9	68.0	68.9	66.9	67.0	67.1	63.2
(11) Steam	%	4.8	5.0	0.2	0.1	0.2	0.4	0.3	0.4	0.3	0.4	0.4	0.3
(12) CC	%	60.8	67.3	65.8	66.1	65.1	66.5	67.6	68.4	66.5	66.5	66.6	62.8
(13) CT	%	0.6	0.3	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(14) Solar ^{3/}	%	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1
(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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17) Other ^{5/}	%	3.6	2.6	3.3	3.3	3.7	4.0	4.0	3.7	5.1	5.4	5.5	5.6
		100	100	100	100	100	100	100	100	100	100	100	100

1/ Source: A Schedules and Actual Data for Next Generation Solar Centers Report

2/ The projected figures are based on estimated energy purchases from SJRPP, the Southern Companies (UPS contract), and other utilities.

3/ Represents output from FPL's PV and solar thermal facilities.

4/ For 2011, the Martin 8 Solar Thermal GWh output is rolled into row (12) for reporting purposes. In 2012, the GWh output is presented in row (16). The projected GWh contributions for 2013-2022 are also provided 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.



EXHIBIT 4

Department of Environmental
Resources Management
2300 North Jog Road, 4th Floor
West Palm Beach, FL 33411-2743
(561) 233-2400
FAX: (561) 233-2414
www.pbcgov.org/enn

May 2, 2013

RECEIVED
MAY - 6 2013
TREASURE COAST
REGIONAL PLANNING COUNCIL

Ms. Liz Gulick, Administrative Supervisor
Treasure Coast Regional Planning Council
421 SW Camden Avenue
Stuart, Florida 34994

Dear Ms. Gulick:

**SUBJECT: PALM BEACH COUNTY COMMENTS FOR THE FPL
10 YEAR POWER PLANT SITE PLAN**

Palm Beach County Department of Environmental Resources Management (ERM) staff has reviewed the information contained in the site plan and have the following concerns:

- The Florida Power & Light (FPL) Power Plant will utilize Lake Worth Lagoon water as a cooling source and discharge it in the Lagoon. Thermal pollution remains a concern since it can potentially affect dissolved oxygen and cause increased stress to aquatic organisms and seagrass. Confirmation is requested that increased thermal stress is not expected from the new plant.
- One of the impacts of the thermal pollution is that the discharge has developed into a warm water refuge for up to 800 manatees and thus any disruption to the operation schedule could have the potential for negative impacts to manatees. Changes in manatee distribution have been evident in recent years due to the intermittent operation of the temporary heating system. We expect that the operation schedule of the new plant will be similar to the old plant and provide a more continuous and dependable warm water source which should reduce potential manatee impacts. It is understood that there is a working group evaluating plans for alternative warm water sources to reduce the dependence of manatees on this artificial source.
- The plant is projected to use 600 million gallons of lagoon water daily. The biological impact due to impingement and entrainment of fish and planktonic invertebrates drawn into a facility's cooling water intake is expected to be significant and may be the primary impact to the Lake Worth Lagoon (LWL). This is particularly critical given the biologically unique location of LWL and its fish and invertebrate diversity which is a function of its proximity to the Gulfstream Palm Beach County would like to be provided with an assessment of those impacts and a summary of steps to minimize any adverse environmental impacts.

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Paulette Burdick

Shelley Vana

Mary Lou Berger

Jess R. Santamaria

County Administrator

Robert Weisman

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Ms. Liz Gulick
May 2, 2013
Page 2

- Increasing stormwater retention from stormwater runoff above the minimum requirements is recommended due to the critical location of the plant to sensitive resources and to reduce the chance of an inadvertent release of pollutants.
- The site plan does not appear to address the potential discharge from the oil fuel pipeline when a fuel delivery is made. No details of the length of the pipeline or Spill Prevention plans have been provided in this report in the case of an accidental release.
- Sea Level Rise could have at least two potential impacts on the proposed Plant: inundation as result of rising waters that could be enhanced when combined with storm surges; and the possibility of salt water intrusion into the Surficial Aquifer, which will be used as one of the water sources for the plant's operations. ERM suggests that climate change vulnerability be incorporated into the plants operational protocols.
- The plan should demonstrate compliance with Palm Beach County's Sea Turtle Lighting criteria by including shields for light fixtures to decrease skyglow which is known to result in hatchling disorientation in this area.

Should you have further inquiries regarding this issue please contact me at (561) 233-2400, or Bob Kraus at (561) 233-2476.

Sincerely,



Robert Robbins, Department Director
Environmental Resources Management

rr:pd:rk

cc: Robert Banks, Assistant County Attorney
Palm Beach County Attorney's Office
Rebecca Caldwell, Executive Director
Palm Beach County Planning, Zoning & Building
Lorenzo Aghemo, Planning Director
Palm Beach County Planning, Zoning & Building
Isaac Hoyos, Principal Planner
Palm Beach County Planning, Zoning & Building
Paul Davis, Division Director, Environmental Enhancement & Restoration
Palm Beach County Department of Environmental Resources Management

Water Management Districts

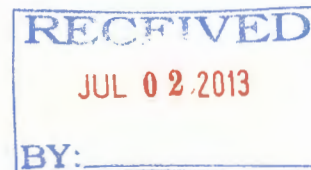
- South Florida Water Management District
- Southwest Florida Water Management District
- St. John's River Water Management District
- Suwannee River Water Management District



SOUTH FLORIDA WATER MANAGEMENT DISTRICT

June 28, 2013

Mr. Phillip Ellis
Engineering Specialist III
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850



Dear Mr. Ellis:

Subject: 2013 Ten-Year Site Plans for Florida Electric Utilities

Thank you for your May 21, 2013 letter requesting that the South Florida Water Management District (District) review the 2013 Ten-Year Site Plans for the Florida Power & Light Company (FPL), Progress/Duke Energy Florida (DEF), and Tampa Electric Company (TECO). The District has completed its review of the site plans.

The ten-year site plans provided by DEF and TECO do not include existing or proposed facilities within the boundaries of the District. The District forwards no comments regarding these proposed sites.

The District finds the ten-year site plan provided by FPL suitable as a planning document. The District offers the following comments to assist electric utilities with ongoing planning.

In planning for siting future facilities, utilities should recognize that water availability is limited in specified areas by the District's Restricted Allocation Area rule. The criteria associated with the Restricted Allocation Area Rule can be found in Section 3.2.1 of the Basis of Review for Water Use Permit Applications within the South Florida Water Management District (October 23, 2012).

For assistance or additional information, please contact John Morgan, Lead Policy Analyst, at (561) 682-2288 or jmorganj@sfwmd.gov.

Sincerely,

A handwritten signature in blue ink, appearing to read "Sharon M. Trost".

Sharon M. Trost, P.G., AICP
Director, Regulation Division
South Florida Water Management District

SMT/jm



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Southwest Florida Water Management District

2379 Broad Street, Brooksville, Florida 34604-6899

(352) 796-7211 or 1-800-423-1476 (FL only)

On the World Wide Web at WaterMatters.org

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 U.S. 301 North
Tampa, Florida 33637-6759
(813) 985-7481 or
1-800-836-0797 (FL only)

June 11, 2013

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

Subject: Electric Utility 2013 Ten-Year Site Plans

Dear Mr. Ellis:

In response to your request, the Southwest Florida Water Management District (District) has completed its review of the 2013 Ten-Year Site Plans (Site Plan) for Progress/Duke Energy Florida (DEF) and Tampa Electric Company (TECO). The District's review is being conducted pursuant to Section 186.801(2)(e), Florida Statutes, which requires that the Public Service Commission consider "the views of the appropriate water management district as to the availability of water and its recommendation as to the use by the proposed plant of salt water or fresh water for cooling purposes."

Both DEF and TECO indicate in their Site Plans that new generating facilities are proposed within the ten-year planning horizon. The Site Plan for DEF indicates that two new combined cycle units are proposed in 2018 and 2020 at undesignated sites. The Site Plan for TECO indicates that conversion of the Polk Power Station's simple cycle combustion turbines (Units 2-5) to a natural gas combined cycle unit is currently undergoing site certification review and is proposed for 2017. The Site Plan for TECO also indicates that a new combustion turbine is proposed in 2020 at an undesignated site.

With the exception of the TECO Polk Power Station Units 2-5 project, which is currently undergoing site certification review, no information was provided for the other TECO project and the two DEF projects concerning identification of the proposed project sites, water sources, and water demands. Without this information, the District's ability to comment on the "suitability" of the Site Plans is extremely limited.

Please note that, pursuant to Section II.A.1.f of the current Operating Agreement between the Florida Department of Environmental Protection (DEP) and the District concerning the division of responsibility for management and storage of surface waters regulation and wetland resource regulation under Chapter 373, Part IV, Florida Statutes, the DEP is responsible for conducting the Environmental Resource Permit-related review and for taking final agency action for power plants, electrical distribution and transmission lines, and other facilities related to the production, transmission, and distribution of electricity.

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Vice Chair, Hillsborough

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Polk

Vacant
Charlotte, Sarasota

Vacant
Citrus, Lake, Levy, Sumter

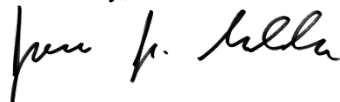
Blake C. Guillory
Executive Director

Based on the information provided in the Site Plans, the District offers the following technical assistance comments for your consideration:

- 1) During the site certification or permitting process, consideration must be given to the lowest quality water available which is acceptable for the proposed use. If a lower quality of water is available and is environmentally, technically and economically feasible for all or a portion of the proposed use, this lower quality water must be used.
- 2) For new generating facilities proposed in the southern and much of the central portions of the District, there are additional water use restrictions. These areas have been designated as Water Use Caution Areas. This designation has occurred in response to water resource impacts, such as salt water intrusion, lowered lake levels and reduced stream flows, which have been caused by excessive ground water withdrawals. Regional recovery strategies are being implemented to address the adverse water resource impacts. Consequently, the District has heightened concerns regarding potential impacts due to future groundwater demands and availability within these areas.
- 3) The most water conserving practices must be used in all processes and components of the power plant's water use that are environmentally, technically and economically feasible for the activity, including reducing water losses, recycling, and reuse.

We appreciate this opportunity to participate in the review process. If you have any questions or require further assistance, please do not hesitate to contact me at (352) 796-7211, extension 4790, or james.golden@watermatters.org.

Sincerely,



James J. Golden, AICP
Senior Planner

JG



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.

July 17, 2013

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

Re: Review of the 2013 Ten-Year Site Plans for Florida's Electric Utilities

Dear Mr. Ellis:

St. Johns River Water Management District (District) staff have reviewed the Ten-Year Site Plans (TYSPs) for Florida Power & Light Company (FPL), Progress / Duke Energy Florida (DEF), Gainesville Regional Utilities (GRU) and JEA relative to suitability as planning documents, as requested in your letter dated May 21, 2013. 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. As planning documents, TYSPs do not contain detailed information relative to projected water demand. However, when locating or expanding a site for a power facility, FPL, DEF, GRU, and JEA should consider the availability of water to meet the projected demands of the facility and potential impacts due to facility water use, including the cumulative impacts. In general, the District requires that all consumptive use permit (CUP) applications for new uses and requested increases in CUP allocations demonstrate use of the 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.

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

Sincerely,

A handwritten signature in blue ink, appearing to read 'Jeff Cole', is written over a blue horizontal line.

Jeff Cole
Chief of Staff

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SUWANNEE RIVER WATER MANAGEMENT DISTRICT

August 1, 2013

Phillip Ellis
Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399

DON QUINCEY, JR.
Chairman
Chiefland, Florida

Subject: Review of the 2013 Ten-Year Plans for Florida's Electric Utilities

ALPHONAS ALEXANDER
Vice Chairman
Madison, Florida

Dear Mr. Ellis:

RAY CURTIS
Secretary / Treasurer
Perry, Florida

The following are comments as requested in your May 21st letter.

KEVIN BROWN
Alachua, Florida

Progress/Duke Energy Florida (DEF):

The Suwannee River Generating Plant (SRGP) is located directly on the banks of the Suwannee River near Ellaville. The Suwannee River provides cooling water for the SRGP. The SRGP is not located within a Water Resource Caution Area; therefore current demand is not anticipated to exceed supply in the next twenty years.

GEORGE COLE
Monticello, Florida

Gainesville Regional Utilities (GRU):

The Deerhaven Generating Station (DGS) is located on the border between the Upper Santa Fe Water Resource Caution Area (WRCA) and the Lower Santa Fe WRCA. In both of these caution areas, the projected demands will exceed the available supply within the next twenty years.

VIRGINIA H. JOHNS
Alachua, Florida

GARY F. JONES
Old Town, Florida

The District is currently establishing minimum flows and levels (MFLs) for the Lower Santa Fe River, Ichetucknee River and associated priority springs. In conjunction with MFL establishment, the District is developing strategies to prevent the Ichetucknee River and associated priority springs flows and levels from falling below established minimums. For the Lower Santa Fe River and priority springs, the District is developing strategies to recover flows and levels. The prevention and recovery strategies will employ water conservation, alternative water supplies, water resource development projects, and regulation of consumptive uses of water. Facility plans should be coordinated with District staff during the development of these strategies and the water supply planning process.

VIRGINIA SANCHEZ
Old Town, Florida

GUY N. WILLIAMS
Lake City, Florida

ANN B. SHORTELL, Ph.D.
Executive Director
Gainesville, Florida

Seminole Electric Cooperative (SEC):

Seminole Electric Cooperative currently does not have an active plant within the District. There is a proposed generating station in Gilchrist County to be located near Bell. This generating station is located in a basin which contributes to the Lower Santa Fe River. The comments in the previous paragraph are applicable here.

Sincerely,


Ann B. Shortelle, Ph.D.
Executive Director

TS/Im

Water for Nature, Water for People

Local Governments

- Citrus County



Board of County Commissioners
DEPARTMENT OF PLANNING AND DEVELOPMENT
3600 W. Sovereign Path, Lecanto, FL 34461-8070
Toll Free (352) 489-2120 TTY (352) 527-5312
Web Address: www.bocc.citrus.fl.us

In reply, refer to:

DS-13-022

July 23, 2013

Phillip Ellis
Engineer Specialist III
State of Florida Public Service Commission
Capital Circle Office Center
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

RE: Review of the 2013 Ten-Year Site Plans for Progress/Duke Energy Florida (DEF)

Dear Mr. Ellis:

This Department has reviewed the Progress/Duke Energy Florida Ten-Year Site Plan dated April 2013 and does not find any conflicts with growth management policies as specified in the Citrus County Comprehensive Plan.

It is noted that this document focuses on environmental and land use information for sites within the Progress /Duke Energy Florida system that are primarily located outside of Citrus County. The Plan notes the retirement of the Crystal River Nuclear Units 1, 2, and 3, and planned installation of combined cycle facilities in 2018 and 2020 at sites that have not yet been identified.

Thank you for the opportunity to review the Plan. If you require additional feedback, please do not hesitate to contact this office.

Sincerely,

Vincent A. Caetero, AICP
Director
Department of Planning and Development

VAC/JBC/rls

CC: Ken Frink, P.E., Assistant County Administrator
Jenette Collins, AICP, Director, Land Development Division
Jim Faulkner, Director, Geographic Resources and Community Planning Division

(F)

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STATE OF FLORIDA



DIVISION OF ENGINEERING
TOM BALLINGER
DIRECTOR
(850) 413-6910

Public Service Commission

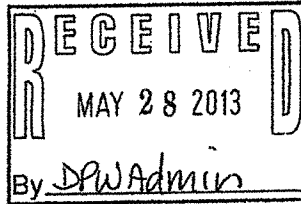
RECEIVED

MAY 23 2013

May 21, 2013

ADMIN

Mr. Brad Thorpe
County Administrator
Citrus County
110 N. Apopka Drive
Inverness, FL 34450



Fwd: TO C.P., K.F
UNICE C. SHOULD
LOOK AT THIS
BLAD
5-24-13

Dear Mr. Thorpe:

Re: Review of the 2013 Ten-Year Site Plans for Florida's Electric Utilities

Pursuant to Section 186.801, Florida Statutes, the Florida Public Service Commission (Commission) is responsible for reviewing and classifying each electric utility's Ten-Year Site Plan as "suitable" or "unsuitable." As part of the annual review in accordance with Rule 25-22.071, Florida Administrative Code, the Commission must provide a copy of the relevant Ten-Year Site Plans and solicit the views of appropriate state, regional, and local agencies. To this end, the Commission has made available on its website electronic copies of the 2013 Ten-Year Site Plans for all the Florida electric utilities at the following link:

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

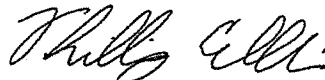
Below is a list of those electric utilities that have identified preferred or potential plant sites in your jurisdiction. Please review these Ten-Year Site Plans and provide comments, along with a brief summary if possible, on their suitability as planning documents. Please note that these plans are not designed to give information about proposed facilities in such detail as would be required for a development permit or other formal process.

Relevant 2013 Ten-Year Site Plans

- Progress / Duke Energy Florida (DEF)

Please forward all comments by August 1, 2013, including an electronic copy to my e-mail address below. If you have any questions, require additional time to file comments, or would like to receive a hardcopy of the Ten-Year Site Plans, please feel free to contact me at (850)-413-6626 (pellis@psc.state.fl.us). Thank you for your assistance.

Regards,



Phillip Ellis
Engineering Specialist III

POE

cc: Office of Commission Clerk (Cole)
Division of Engineering (Ballinger, Vickery)
Office of the General Counsel (Murphy)

Other Organizations

- Sierra Club and Earthjustice

Mr. 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
tmatthew@psc.state.fl.us

Re: Comments on 2013 Ten-Year Plan Submittals

Dear Mr. Ellis and Ms Matthews:

Thank you for accepting these comments on behalf of the Sierra Club and its nearly 27,000 Florida members and on behalf of Earthjustice. We appreciated the opportunity to participate in the Public Service Commission (PSC)'s Ten-Year Plan review process in 2012, and are happy to continue our participation this year.

In last year's comments,¹ we asked that the PSC consider the implications of the retirement of Duke (then Progress) Energy's Crystal River Units 1 & 2, and of Gulf Power's Lansing Smith Units 1 & 2. We advised the PSC that the units had significant environmental compliance obligations which rendered them noneconomic to run in the near-term, but that neither company had included full analysis of that possibility in its submittal.

We appreciate that the PSC addressed these retirement issues in its review of the 2012 plans. *See, e.g., PSC, Review of the 2012 Ten-Year Site Plans ("2012 Review")* at 3. We respectfully submit that that analysis should continue in further depth this year because both utilities have now confirmed our retirement predictions from last year. Duke has committed to retiring Crystal River 1 & 2 for economic reasons and Gulf, though it has not made a final decision, has deferred further environmental compliance work on Lansing Smith and has requested PSC approval for transmission upgrades which would allow for Lansing Smith 1 & 2 to shut down.

In its review, the PSC assumed that the capacity of these retiring units would be replaced by natural gas, which would increase natural gas's share in Florida's electric generation to 62.9% by 2022 (up from 56.7% without the retirements, and from 57.7% in 2011). *Id.* The PSC states that it views "the growing lack of fuel diversity" within Florida as a "major strategic concern." *Id.* at 39. Although we certainly welcome the retirements of these dangerous coal plants, we share this fuel diversity concern: Undue dependence on natural gas leaves the state overly vulnerable to fuel price volatility, even as potential LNG exports and other shifts in the gas market seem likely to increase gas prices in the medium term. For this reason, we strongly suggest that the PSC consider planning scenarios which employ other, less risky, resources to make up some or all of the share of generation now served by the retiring plants.

¹ Attached as Exhibits 1 & 2, for your reference.

In particular, we believe that demand-side management measures, including energy efficiency, other demand response programs, and demand-side renewable energy, can make up a significant portion of any resource gap left by the likely retirements. Increased supply side renewable energy can also increase the diversity of the state's resource mix. Because the PSC will be considering new goals for both Duke and Gulf under the Florida Energy Efficiency and Conservation Act (FEECA) this year, this is a particularly good time to develop the data needed for sensible planning.

I. Coal Retirements

Both Duke and Gulf have confirmed that retirement is likely in the cards for their economically vulnerable plants, though Duke has gone further and confirmed that Crystal River 1 & 2 will certainly retire. Duke appears to be planning to address these retirements largely through adding new generating capacity. Gulf intends to rely on power imports in the near term.

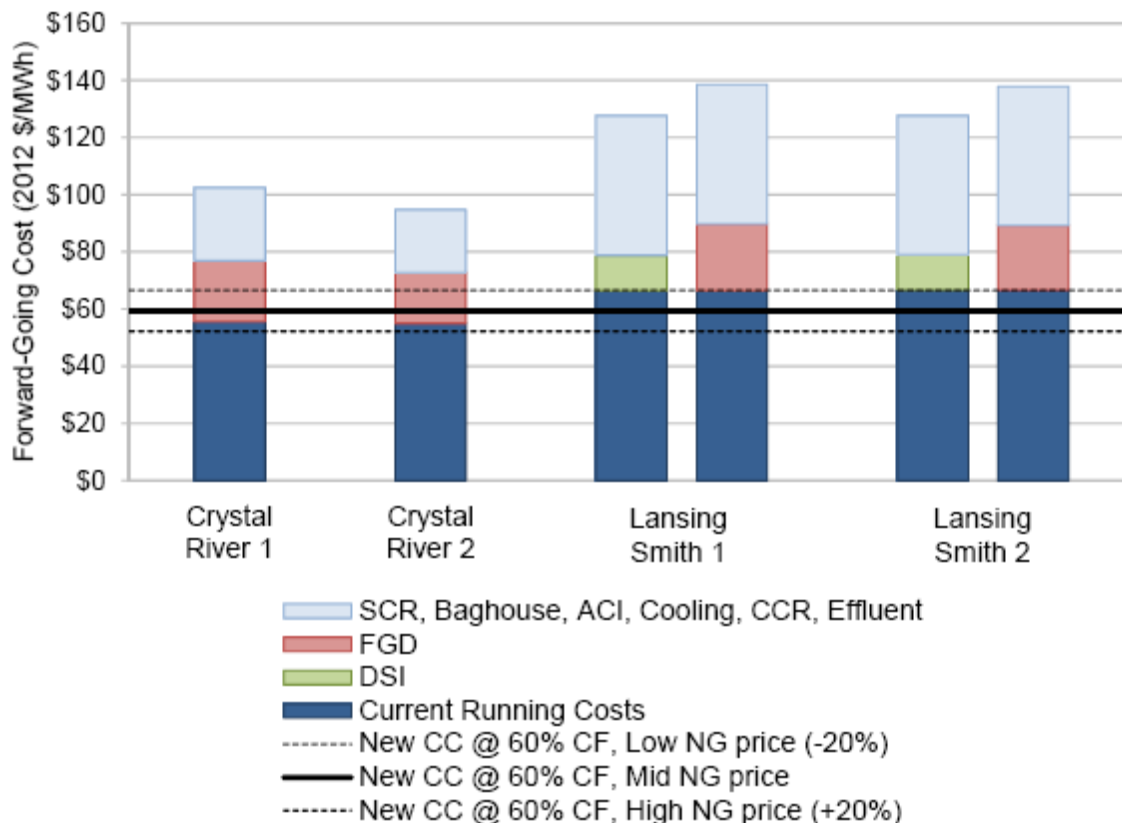
Duke/Progress

Duke has confirmed "expected retirement of Crystal River 1 & 2 in 2016." Duke TYSP at 3-2. As Duke explains in testimony filed in the Environmental Cost Recovery Docket, the lifecycle projected system cost for retiring units 1 & 2 is far lower than the cost of retrofitting the units to comply with environmental compliance obligations: The difference between the retirement and retrofit scenarios is \$ 1.32 billion in Duke's base case analysis; retrofit is unfavorable only in the extremely unlikely case of very high gas prices and no CO₂ regulation. Direct Testimony of Benjamin M. H. Borsch on Behalf of Progress Energy Florida (Apr. 1, 2013) at 4, Docket No. 130007-EI; *see also* Progress Energy Florida, *Review of Integrated Clean Air Compliance Plan* (Apr. 1, 2013) ("*Duke Compliance Plan*") at 25-26.

To be sure, Duke has held out the option of making short-term fuel mix adjustments which might allow the units to continue operating, perhaps as long as 2020. *Duke Compliance Plan* at 21. Continued operation would plainly be economically imprudent. As we demonstrated in our comments and workshop presentation on last year's plan, and as the figure below shows, the Crystal River units already verge on noneconomic when compared even against the substantial expense of constructing a new combined cycle natural gas plant to replace their capacity, much less against more sensible options, including demand side programs.²

² This figure is drawn from our 2012 workshop presentation and is based on work by Synapse Energy Economics, using public cost estimates from the Energy Information Administration's cost reporting forms and the EPA's Integrated Planning Model, developed by Sargent & Lundy.

Forward Going Costs of Existing Coal Units and Probable Environmental Controls



Because Crystal River 1 & 2 are uneconomic by almost any measure (as Duke acknowledges), the pertinent question is how best to replace any portion of their 965 MW in nameplate capacity which will be required going forward. (In practice, this lost capacity is smaller: both units have been relatively little used in recent years.) Lost capacity from the 860 MW Crystal River 3, the retired nuclear unit at the site, will also play a substantial role in system planning, of course.

Over the period from 2013 to 2022, Duke expects its firm summer peak demand to grow by 1287 MW, TYSP at 3-7, and increase of just shy of 15% over the next decade, or about 1.5% per year. At present, Duke reports that it intends to make up necessary capacity to match this growth through “planned power purchases from 2016 through 2020 and planned installation of combined cycle facilities in 2018 and 2020 at undesignated sites.” *Id.* at 3-2. According to Duke, these energy imports are likely to grow an additional 1470 MW above its current ~ 1900 MW of imported capacity, *id.* at Schedule 7.1. The addition of a 1307 MW (winter capacity) combined cycle facility in 2018, and a second 1307 MW facility in 2020 then replaces these imports. *See id.* at 3-7, 3-10 – 3-11. This additional capacity is 764 MW greater than the capacity which Duke is losing, leading to a 21% reserve margin by 2022.

As we discuss below, Duke’s strategy of increasing its built generating capacity substantially in response to projected growth, and relying on natural gas generation to do so, is not the prudent one for either the company or for Florida.

Gulf Power

As the figure above indicates, Lansing Smith 1 & 2 are even less economically attractive to operate than the uncontrolled Crystal River coal units. Gulf has not yet committed to retirement publicly, but its filings in this docket and in the Environmental Cost Recovery docket make clear that it is preserving that option.

Specifically, Gulf has requested the PSC approve a \$77 million transmission upgrade project, which it explains is necessary to ensure that Lansing Smith is not a must run unit. Gulf Power, *Third Supplemental Petition of Gulf Power Company Regarding its Environmental Compliance Program*, Docket No. 13007-EI (Mar. 29, 2013) at 8. According to Gulf, these upgrades will allow Plant Smith to run at lower levels or to close, and would be “required if these units retire or are controlled as a result of [the mercury and air toxics rule.]” *Id.* at 8. Gulf, thus, maintains that it intends to “reserve the decision to install ... controls or to retire the two units for a future time when more is known with regard to costs of compliance requirements associated with additional environmental regulations.” *Id.*

Because Gulf Power – unlike Duke – has not shared cost information with the public comparing the cost of controlling versus retiring the plant, *see* Gulf Power, *Environmental Compliance Program Update*, Docket No. 13007-EI (Mar, 29, 2013) at 22-27, it is clear that it anticipates considerable additional compliance obligations at Plant Smith, including additional air, water, and waste rules. *Id.* at 22. Although Gulf has not provided economic analysis of a retirement option, it is clear that operating costs from the mercury rule alone would “greatly increase the variable operating cost of Smith Units 1 and 2,” *id.* at 23, enough so that spending \$77 million on transmission to reduce the operating need for the plant is more economic than continuing to run it, *id.* at 26.

We certainly agree that it is better to run Plant Smith less. The truth, however, is that Plant Smith is not economic to run *at all* under current conditions. It is certainly not economic to run going forward as environmental compliance costs increase. The appropriate course for Gulf Power is to retire the facility, rather than simply building transmission which will allow it to operate the costly plant somewhat less. Its transmission project, apparently, will enable that retirement, which remains an option. We urge the PSC to continue to analyze retirement possibilities.

In this regard, Gulf’s Ten Year Site Plan submission does not clearly discuss all the implications of Plant Smith. It acknowledges, again, that “potential incremental capital expenditures for compliance may be substantial,” Gulf TYSP at 3, but does not yet appear to provide a straightforward retirement analysis. Gulf anticipates 575 MW in summer peak demand growth by 2022 (about 20% growth over that period, or, according to Gulf, a 1.9% annual increase over the next decade). *See* Gulf TYSP at Schedule 3.1.

Gulf’s plan indicates that capacity additions are not necessary to manage this projected growth. Gulf reports that a power purchase agreement (PPA) which it has signed with Shell Energy for use of 885 MW of capacity from an existing gas combined cycle plant will meet its needs through 2023, after which it will construct additional in-system capacity. *Id.* at 2-3. For this reason, the PSC’s projection last year that Lansing Smith’s retirement will lead to gas generation increases in Florida appears to be incorrect in the near term. As with Crystal River’s retirement, however, we believe that demand-side

options and other non-gas resources should be emphasized to meet any capacity needs that eventually arise.

II. Implications for the Ten-Year Plan and FEECA Goal-Setting Processes

Because the PSC will shortly move fully into the FEECA goal-setting process for the next five years, this is a particularly appropriate time to consider alternate futures for the Duke and Gulf power networks, with an emphasis on resources which the Legislature designed FEECA to encourage. The cost of adding new fossil capacity will almost always be higher than the cost of demand-side measures. The savings possible through an efficiency-focused strategy, coupled with efficiency's potential to help Florida avoid the undue dependence on natural gas which the PSC is seeking to avoid, argue strongly for a careful analysis of these questions in this year's Ten-Year Site Plan Review.

The Legislature has determined that it is "critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. A study commissioned by the Legislature this past year confirmed these findings, concluding that "FEECA appears to provide a positive net benefit to ratepayers." Galligan *et al.*, *Evaluation of Florida's Energy Efficiency and Conservation Act* (Dec. 7, 2012) ("FEECA Study") at 9.

Despite these benefits, the PSC has, in the past, opted to suspend further program expansion for Duke and FPL, on cost grounds. *See, e.g., Re: Progress Energy Florida, Inc.*, Docket No. 1000160-EG, 2001 WL 3659327 (Aug. 6, 2011). The PSC should revisit this position during this year's goal-setting process in view of the positive findings of the legislative study, and the pressing need to address the retirements of vulnerable coal units in ways that best protect the ratepayers from further risk from fossil fuel price shifts and regulatory uncertainty. Ratepayers will face costs associated with new capacity and loss of fuel supply diversity which are far greater than those imposed by demand-side programs --- programs which the legislative study have determined have net *benefits*.

In particular, the PSC should view with skepticism Duke's proposal to construct 2614 MW of natural gas generation in just the next few years in order to cope with a 1.5% annual average growth rate in its predicted demand. Initially, Duke has a history of significant positive errors in its forecasts. As the PSC explained in its 2012 Ten Year Site Plan Review, Duke overestimated net energy for load forecasts by 11.36% on average between 2007 and 2011, and by 6.17% between 2006 and 2010. *2012 Review at 19*. Certainly the recession contributed to some of this overage, but the size of the error should give the PSC pause.

More importantly, however, the 1.6% demand growth rate which Duke forecasts, even if accurate, is within the range of load growth rates which demand-side management can address. According to the legislative FEECA study, many states require annual reductions far greater. *See FEECA Study at 177-180*. States requiring savings of at least 1% a year, according to that study, include Arizona, Indiana, Maine, Maryland, Michigan, Minnesota, New York, Ohio, and Texas, with many other states not far behind (still other states, including California, are listed as having very large reduction goals, but a percentage reduction is not specified). *See id.* Such reduction rates would entirely offset Duke's projected load growth, obviating the need for much, if not all, of its projected capacity needs in light of the Crystal River retirements.

Duke plainly has the potential to greatly expand its programs. It reports that only 25% (405,000 customers out of 1.6 million) take part in its demand response program, for instance. Duke TYSP at 1-1. This low participation is likely one reason that Duke is well below its FEECA goals for summer MW and annual GWh reductions – missing the annual target by more than 60%. *See* PSC, *Annual Report on Activities Pursuant to [FEECA]* (Feb. 2013) at 19. Duke has told the PSC that it was unable to reach its performance levels because “of the Commission decision to not approve a new DSM plan” for the company. *Id.* at 20. Thus, if the PSC engages with Duke to approve an improved plan, Duke may well be able to increase efficiency programs sufficiently to greatly decrease its capacity needs.

This analysis also applies to Gulf. Although Gulf does not plan new capacity for the next decade, it, too, has potential for further improvements, failing to meet even its modest existing FEECA goal by 12%. *Id.* at 19. If Gulf were performing at the level of nationally leading utilities – saving more than 1.5% of its demand per year – it could likely avoid those projected capacity additions.

Such enhanced performance could help Florida, as a whole, to meet the Legislature’s directive in FEECA. At present, Florida ranks in the bottom half of the states with regard to energy efficiency. *See* American Council for an Energy-Efficient Economy, *State Scorecard 2012* (ranking Florida #29).³ The coal retirements before the PSC provide a strong incentive to do better.

We understand that the PSC will be conducting substantial analysis on this front during its FEECA goal-setting process, *see* Section 366.82, F.S., which requires careful consideration of the “full technical potential” of demand-side programs. We suggest that the PSC conduct that analysis in tandem with its Ten-Year Site Plan review, valuing demand-side programs as a resource which can be used to address capacity and energy issues arising from the coal retirements announced or likely in the site plan docket. Thus, in its 2013 Ten-Year Site Plan Review, the PSC could profitably evaluate the several different scenarios post-retirement, including scenarios in which capacity is replaced with more aggressive demand side measures. Other scenarios should also, of course, explore the potential of other energy sources, including enhanced in-state renewables, including solar, and out-of-state PPAs for renewable (and hence zero fuel cost) energy. In the FEECA process, meanwhile, the PSC can consider the costs and benefits of such measures, especially as compared with costly and risky new gas capacity. The two processes can and should reinforce each other as the PSC works to find ways to minimize risks and costs to ratepayers.

III. Conclusion

Last year, we cautioned that a significant amount of coal-fired capacity in Florida was set for retirement. That process has continued. To manage any ratepayer risk from these retirements and the possible over-dependence on natural gas which they may promote, the PSC should emphasize demand-side management options as alternatives to gas-fired capacity. We look forward to working with the Commission to ensure that Florida ratepayers secure healthier air and a more reliable and efficient electricity system.

Sincerely,

³ Available at: <http://aceee.org/energy-efficiency-sector/state-policy/aceee-state-scorecard-ranking>.

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July 2, 2012

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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 SO₂, 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 SO₂ 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 SO₂ NAAQS

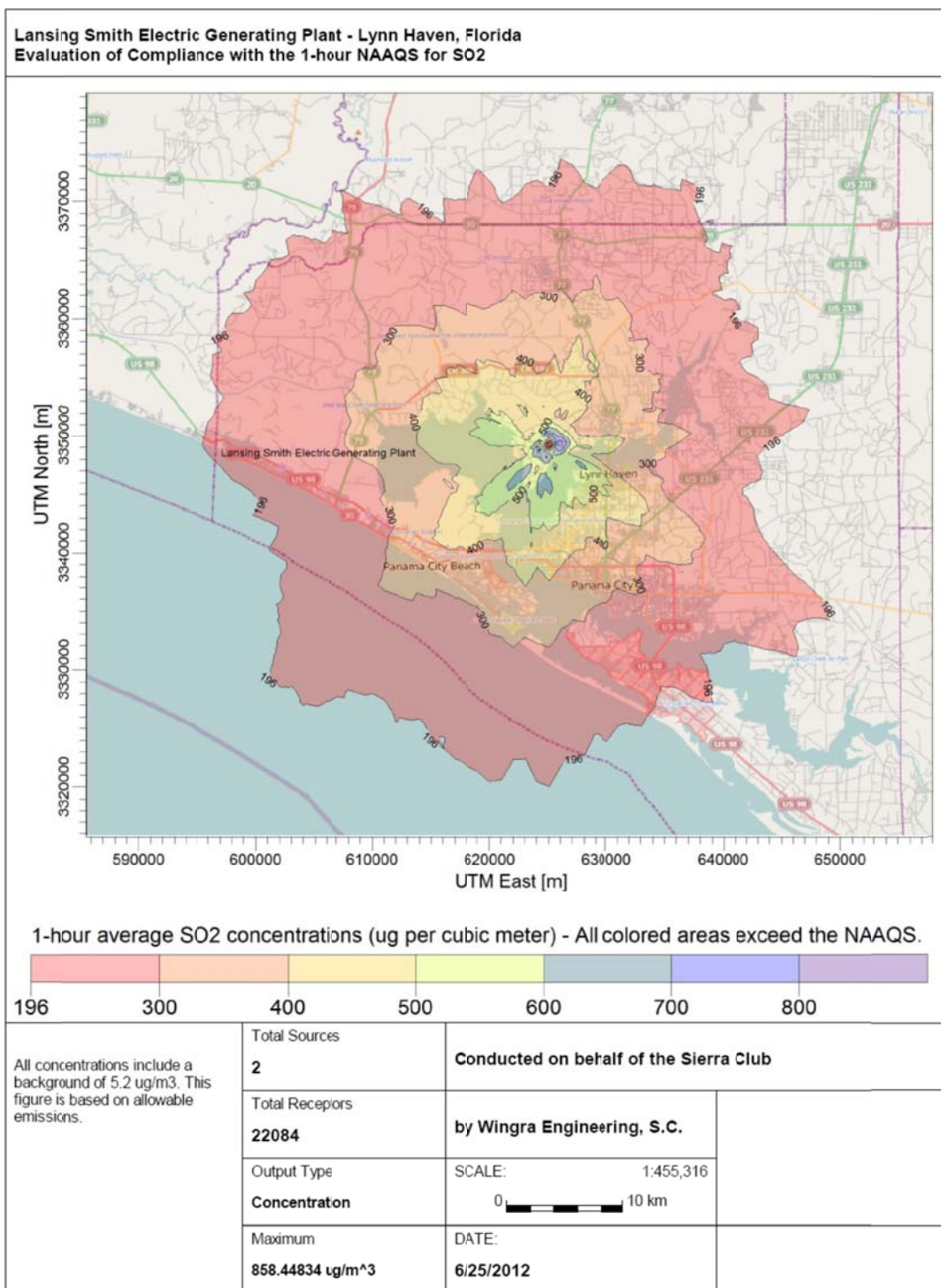
Just five minutes of exposure to SO₂ can make people sick; in fact, the causal link between this pollution and asthma attacks and other respiratory problems is the “strongest” such link which the EPA’s scientific advisory board can identify. 75 Fed. Reg. 35,520, 35,525 (June 22, 2010). To protect the 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 SO₂ to a maximum allowable exposure of 75 ppb (a concentration equivalent to 196.2 µg/m³) 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 SO₂ 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 µg/m³, Lansing Smith’s permit allows pollution levels to soar to 858.4 µg/m³, 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 SO₂ concentrations reach 346.5 µg/m³, which is nearly double the safe value. See Ex. 2 at Table 1.

Indeed, Lansing Smith's SO₂ 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 SO₂ 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 SO₂, 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 SO₂ 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 SO₂ 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 in 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂ 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, SO₂ 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, 2012⁴, 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

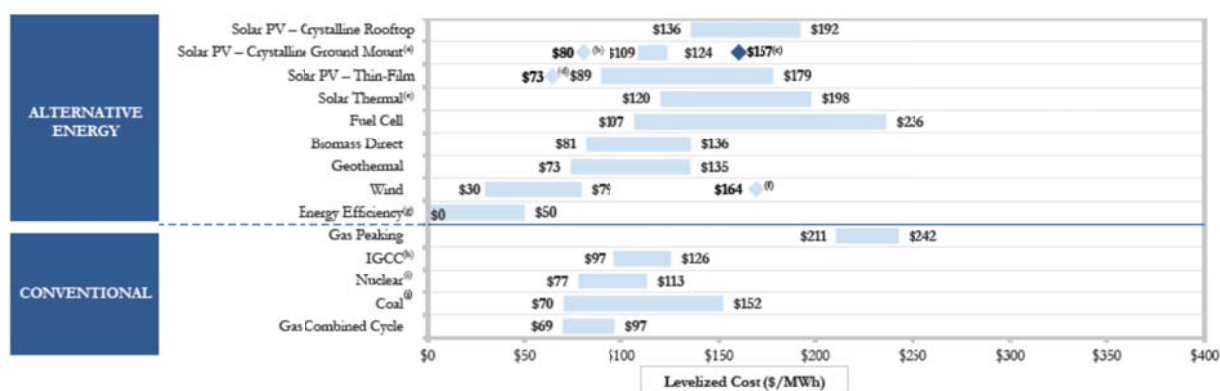
⁶ *See* EPA's plans for this rule at http://water.epa.gov/scitech/wastetech/guide/steam_index.cfm

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 unsupported: 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,

s/ Craig Holt Segall

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Re: Comments on Progress Energy'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 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 SO₂, 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 SO₂ National Ambient Air Quality Standards (“NAAQS”), 40 C.F.R. § 50.17, the Mercury and Air Toxics Standards (“MATS”), 40 C.F.R. Subpt. UUUU, and the Regional Haze Rule, 40 C.F.R. § 51.308.

i. The SO₂ NAAQS

Just five minutes of exposure to SO₂ 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 SO₂ to a maximum allowable exposure of 75 ppb (a concentration equivalent to 196.2 µg/m³) 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.

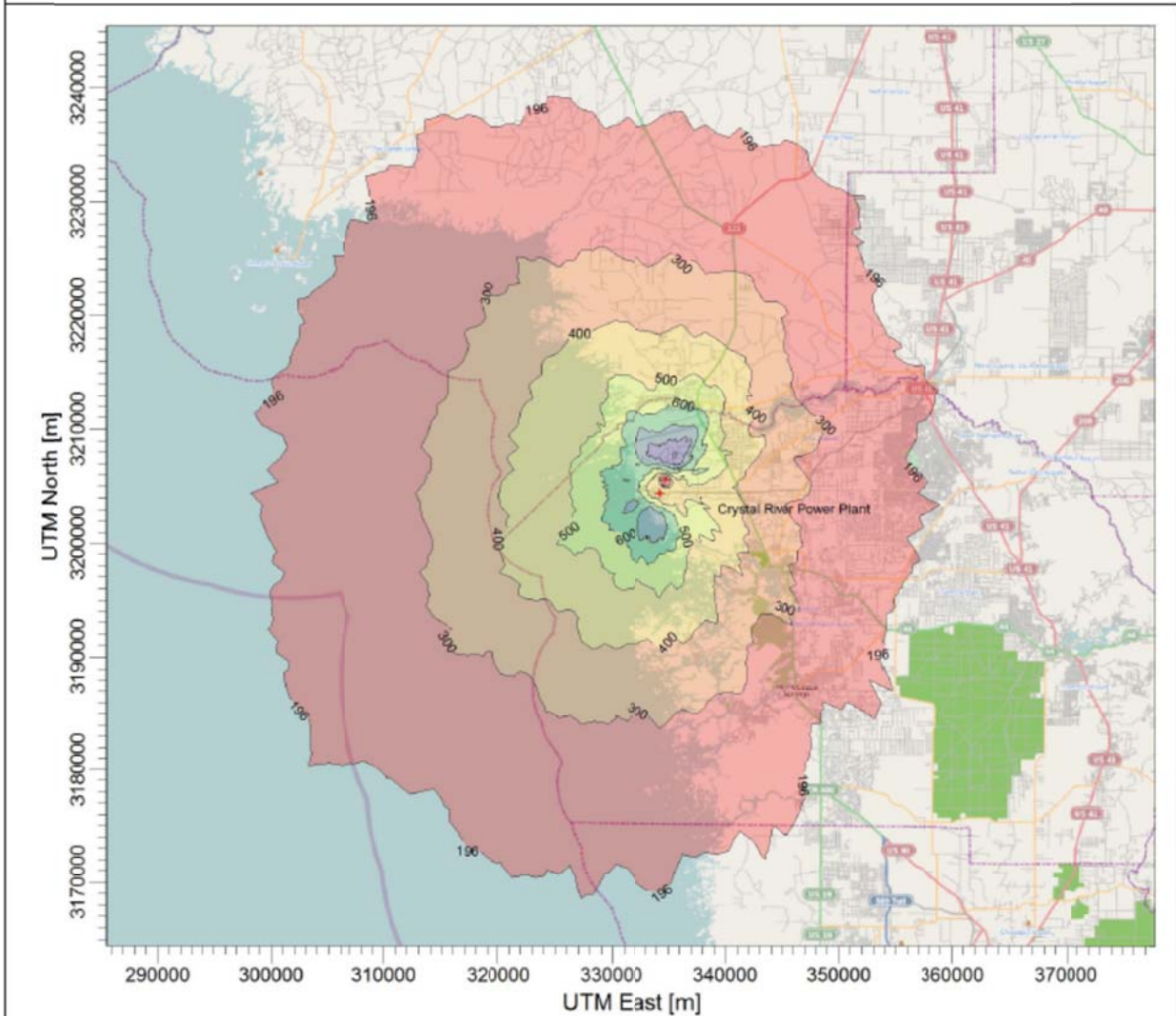
This tight timeline is directly relevant to the Commission’s review of Progress Energy’s plans because the Crystal River plant is causing violations of the NAAQS, and so will have to install controls under any legal SIP. Sierra Club engaged an expert air modeler, Steve Klafka of Wingra Engineering, to 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 SO₂ 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 µg/m³, Crystal River's permit allows pollution levels to soar to a maximum of 921.0 µg/m³, 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



1-hour average SO₂ concentrations (ug per cubic meter) - All colored areas exceed the NAAQS.



All concentrations include a background of 5.2 ug/m ³ . 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	
	Maximum	921.02714 ug/m³		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 SO₂ concentrations reach 534.6 µg/m³, 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 SO₂ 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 SO₂ 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 SO₂ 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 SO₂, 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.

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 SO₂ 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 SO₂ 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, SO₂ 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-

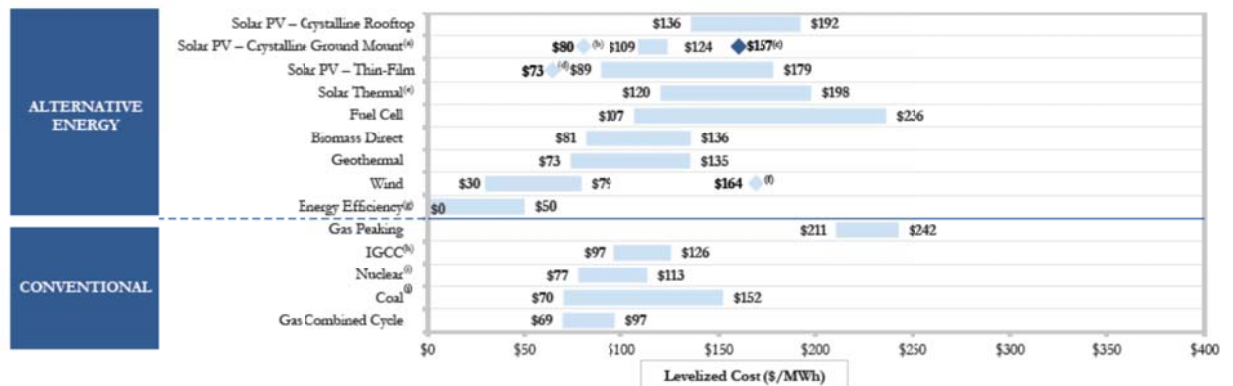
⁷ *See* Ex. 2, *supra*.

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

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,
s/ Craig Holt Segall
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From: Tom Larson <tlarson@cleanenergy.org>
Sent: Wednesday, October 09, 2013 10:21 AM
To: Phillip Ellis
Cc: Office Of Commissioner Edgar; George Cavros
Subject: Exemplary IRPs
Attachments: Risk-Aware Electricity Regulation-Ceres 120419.pdf;
RAPSynapse_WilsonBiewald_BestPracticesinIRP_2013_JUN_21.pdf

Follow Up Flag: Follow up
Flag Status: Flagged

Dear Mr. Ellis:

At the recent TYSP workshop, Ms. Edgar invited SACE to provide for PSC consideration references to IRPs of utilities that we see demonstrating good modeling practices, more fully considering risk, evaluating alternative resources on a level playing field, and providing greater transparency to the community.

Respecting risk assessment, PacifiCorp and to a lesser extent Avista, both in the NWPCC territory which I mentioned, are leading examples of IOU adoption. Also TVA has done good good work, in our estimation. I offer a few links here to information these utilities have posted:

<http://www.pacificorp.com/es/irp.html>

<http://www.avistautilities.com/inside/resources/irp/electric/Pages/default.aspx>

<http://www.tva.com/environment/reports/irp/>

Also, the Regulator Assistance Project recently conducted a couple studies on IRP practices (one with funding provided by SACE and supported by Ceres); copy of each is attached for your convenience.

Please share this information with all of the commissioners as proper and customary.

Regards,

Tom Larson | Florida Energy Policy Manager



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Re: Supplemental Information Following 2013 Ten-Year Site Plan Workshop

Dear Mr. Ellis and Ms. Matthews:

Thank you for the opportunity to present to the Commission at the September 25, 2013, Ten-Year Site Plan Workshop. At the Workshop the Commissioners raised a number of questions in response to our presentation and we agreed to provide supplemental information to more fully address those questions. This letter transmits and explains that supplemental information.

As discussed at the Workshop, the information supports deferring plan approval until the utilities provide a comparative analysis of the costs and quantified risks of all relevant energy resources, including supply side and demand side. Substantiating the cost-effectiveness of planned investments in this way is squarely within the utilities' ten-year site plan data requirements. See F.A.C. § 25-22.072 (incorporating by reference Form PSC/RAD 43-E (11/97), requiring evidence of "lowest cost possible" planned energy). Yet the utilities' plans lack the requisite comparative analysis of the costs and risks of the various energy resources available to Florida. Without this analysis by the utilities, the Commission cannot meaningfully review the plans for enumerated statutory criteria, such as "possible alternatives to the proposed plan," nor can the Commission evaluate and plan for risks like "disrupted energy supplies or unexpected prices surges." F.S. § 186.801 (citing State Comprehensive Plan, F. S. § 187.201). For these reasons, the information herein supports the Commission deferring plan approval, including approval of planned new gas-burning capacity, until the utilities provide the missing comparative cost-risk analysis to substantiate the cost-effectiveness of their proposed investments.

Moreover, the Sierra Club urges the Commission to follow the regulatory best practice of making the comparative cost-risk analysis available for public comment. Doing so would provide the Commission with a fuller critique of the options for addressing pressing issues, including the need to: (1) plan for significant coal and nuclear retirements; (2) appropriately minimize Florida's exposure to natural gas price shocks and supply disruptions; (3) evaluate and seize opportunities to pursue cost competitive energy resources; and 4) hedge against the costs and risks of fossil fuel-burning generation capacity.

I. A Comparative Analysis of Costs and Quantified Risks of All Relevant Resources (Supply Side and Demand Side) Is Critical for Prudent Resource Planning.

Prudent resource planning minimizes costs and risks. To minimize not just the present value of revenue requirements—alone, a limited focus of resource planning—but also risk, planners generally evaluate a wide range of scenarios (not just the scenario deemed most likely, the "reference

case”). Planners do this through a number of different methods. Many planners use probabilistic modeling and sensitivity analyses for inputs including but not limited to: load growth, fuel prices, electricity spot prices, market structure, environmental regulations, and other risk factors. In addition, some planners also rely on other analytic aids, including market reports, requests for proposals, and stakeholder feedback. This section addresses the Commissioners’ questions about planning for cost and risk with examples and explanations of emerging best practices.

a. CERES Report—Guidance Primarily for Commissions

Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know offers guidance that is especially relevant to states like Florida that are “facing substantial coal generation retirements and evaluating a spectrum of resource investment options.” Ron Binz & CERES, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (2012) (“*Risk-Aware*”) at iii, Ex. 1. Like other reports discussed below, this report reviews existing practices and makes recommendations for valuing and selecting plans to minimize risk. What sets this report apart, and why the Sierra Club has highlighted it, is its focus on the role of state regulatory utility commissions in the planning process.

Risk-Aware urges commissions to proactively identify and address risks. *See, e.g., id.* at 14. This includes gathering information on all relevant future conditions and investment alternatives, not only the conditions and investments identified by the utilities. *Id.* at 46. Further, by fostering transparency and stakeholder engagement throughout the planning processes, commissions are able to build trust and enhance understanding of energy options among all interested parties. *Id.* at 11.

During the Workshop, Commissioner Graham expressed interest in risk assessment methodology. *Risk-Aware* shows one way that planners can systematically assess risk. The report draws on decades of relevant energy regulation and finance experience to develop a composite cost-risk analysis showing the relative cost and relative risk among a wide range of investment alternatives (e.g., nuclear, natural gas combined cycle, solar, efficiency programs). *See id.* at iii, Figures 14 and 15. Spurring commissions to develop tailored assessments like this for their respective jurisdictions, *see id.* at 34, *Risk-Aware* describes its risk assessment methodology in a step-by-step fashion. First, *Risk-Aware* examines twenty-two resources across seven risk categories, wherein the report describes and then quantifies the risks associated with each resource. *See id.* at 30 – 34; *see also id.* at Figures 13, 16. Next, *Risk-Aware* establishes composite risk indices for each resource. *Id.* at 34 – 36. Finally, *Risk-Aware* compares relative risk and relative cost. *Id.* at Figure 17.

b. Nicholas Institute Report—Risk Assessment Made Easier

Least-Risk Planning for Electric Utilities, recently published by the Nicholas Institute for Environmental Policy Solutions at Duke University, presents another relatively easy way to address risks in resource plans. *See* David Hoppock & Patrick Bean, *Least-Risk Planning for Electric Utilities* (2013) (“*Least-Risk Planning*”), Ex. 2. *Least-Risk Planning* emphasizes that “**evaluating a wide range of potential scenarios [such as 10 to 15] that fully capture the realistic range of all relevant sources of uncertainty is critical.**” *Id.* at 11 (emphasis added). Picking up where traditional scenario analysis leaves off, *Least-Risk Planning* suggests that modeling outputs like production costs and fixed costs can be used to compare the costs and quantified risks of investment alternatives. *Id.* at 14. *Least-Risk Planning* illustrates how, with three, then four investment alternatives (deliberately simplified examples), it reviews the steps by which a utility would identify trends, risks, and the hedge value of

energy efficiency programs and renewable resources like wind and solar. *Id.* at 8, 14. *Least-Risk Planning* maintains that utility planners and state regulators would find this method “attractive” (no new tools or modeling required), “sensible” (not too pessimistic or too optimistic about risks), and complementary to traditional scenario analysis. *Id.* at 5, 6. Indeed, some utilities like the Tennessee Valley Authority have adopted a similar risk assessment method already. *Id.* at 6 (citing 2011 TVA Integrated Resource Plan).

c. Regulatory Assistance Project & Synapse Report—A Survey of Several States

Best Practices in Electric Utility Integrate Resource Planning, recently commissioned by the Regulatory Assistance Project and prepared by Synapse Energy Economics, reviews emerging best practices in several states’ resource planning processes. See Bruce Biewald & Rachel Wilson, *Best Practices in Electric Utility Integrate Resource Planning* (2013) (“*Best Practices*”), Ex. 3. To be sure, many other reports examine resource planning best practices, and *Best Practices* cites some of these reports. However, the strength of *Best Practices* is its breadth and depth of coverage, as it reviews the practices of several states from across the Nation and prepares case studies on three states in particular—Arizona, Colorado, and Oregon.

Overall, *Best Practices* recommends active commission oversight, stakeholder engagement, and transparency. See *id.* at 26, 27. For example, commissions in Arkansas and Hawaii promote transparency and robust stakeholder engagement through their planning rules. *Id.* at 26, 27. The Kentucky and Colorado commissions also allow interveners to file, and require utilities to respond to, written interrogatories and comments. *Id.* at 21, 27. In turn, the supplemental information from the interveners and utilities supports these commissions’ planning oversight. *Id.*

Best Practices stresses transparent modeling because “[m]odeling in general is only as good as the *input assumptions* used to generate the portfolios.” *Id.* at 25. Specifically, the report suggests: “A proper [resource plan] will include discussion of the inputs and results, and appendices with full technical details. Only items that are truly sensitive business information should be treated as confidential, because such treatment can hinder important stakeholder input processes.” *Id.* at 32. Further, the best practice for commissions is to “take an active role in assessing the validity of inputs used by the utilities in their filings, the resulting outcomes, and whether these are consistent with both the [relevant state] rules and the state’s energy policies and goals.” *Id.* at 27. Limiting transparency hinders a commission’s ability to perform this oversight. See, e.g., *id.* at 25.

Best Practices also offers several insights on how to optimize modeling results. The first insight is to avoid “inadvertently exclud[ing] combinations of options that deserve consideration.” *Id.* at 31. This could happen when utilities define (potentially biased) future resource portfolios, rather than deferring to models to select the portfolios. See *id.* Alternatively, this could happen when “users constrain optimization models so that a model may not, given the cost, select the quantity of a specific resource that [the user] may want,” such as where a utility may limit the amount of a resource that a model can consider—for instance, limiting investments in energy efficiency to the minimum level that a state policy may require, rather than allowing the model to consider larger investments in energy efficiency that the model may otherwise identify as the least-cost, least-risk means of addressing energy needs. *Id.* at 27. Against such defects, the report offers this cure:

The best [resource plans] create levelized cost curves for demand-side resources that are comparable to the levelized cost curves for supply-

side resources. ... By developing cost curves for demand-side options, planners allow the model to choose an optimum level of investment. So if demand-side resources can meet customer demand for less cost than supply-side resources, as is frequently the case, this approach may result in more than the minimum investment levels required under other policies.

Id. at 29 (emphasis added) (quoting State and Local Energy Efficiency Action Network, *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures* (2011), at 6, Ex. 4).

Best Practices also identifies the risks that are commonly addressed by scenario or sensitivity analyses in resource plans. These include: “fuel prices (coal, oil, and natural gas), load growth, electricity spot prices, variability of hydro resources, market structure, environmental regulations, and regulations on carbon dioxide (CO₂) and other emissions.” *Best Practices* at 5. The case studies on Arizona, Colorado, and Oregon illustrate how resource plans incorporate risk, as discussed below.

- ◊ **Arizona:** During the state’s 2012 planning process, the Arizona utility modeled low and high scenarios for what it deemed to be “major cost inputs,” including: natural gas prices, CO₂ prices, production and investment tax credits for renewable resources, energy efficiency costs, and monetization of SO₂, NO_x, PM, and water. *See id.* at 16. During the modeling, the utility monitored certain metrics to compare and evaluate potential resource investment alternatives. *Id.* at 16-17. In addition to revenue requirements, these metrics included: fuel diversity, capital expenditures, natural gas burn, water use, and CO₂ emissions. *Id.* at 16. Arizona’s final 2012 resource plan and materials from five stakeholder meetings are available at www.aps.com/en/ourcompany/ratesregulationsresources/resourceplanning/Pages/resourceplanning.aspx.
- ◊ **Colorado:** During the state’s 2011 planning process, the Colorado utility evaluated its baseline case and eight alternative cases under several sensitivity scenarios, altering the price of CO₂ emissions, renewable tax incentives, natural gas prices, and level of sales. *See Best Practices* at 19-22. Notably, per an intervenor’s recommendation the Colorado Public Utilities Commission asked the utility to adopt higher energy efficiency goals. *Id.* at 27 (citing Colorado Public Utilities Commission, Decision No. C11-0442; Docket No. 10A-554EG (2011)). The utility incorporated the new goals into its calculation of resource need in subsequent modeling. *See Public Service Company of Colorado, 2011 Electric Resource Plan* (2011), available at www.xcelenergy.com/About_Us/Rates_&_Regulations/Resource_Plans/PSCo_2011_Electric_Resource_Plan.
- ◊ **Oregon:** Of the three case studies, Oregon’s planning process was the most comprehensive. *Best Practices* at 23. During the state’s 2012 planning process, the Oregon utility defined 67 input scenarios including: alternative transmission configurations, CO₂ price levels and regulation types, natural gas prices, and renewable resource policies. *Id.* at 24. Sensitivity cases examined additional incremental costs for coal plants, alternative load forecasts, renewable generation costs and incentives, and demand-side management resource availability. *Id.* Top resource portfolios were identified through a combination of lowest average portfolio cost and worst-case portfolio cost resulting from 100 simulation runs. *Id.* Final portfolios were selected after considering such criteria as risk-adjusted portfolio cost, 10-year customer rate impact, CO₂ emissions, supply

reliability, resource diversity, and uncertainty and risk surrounding greenhouse gas and renewable portfolio standard policies. *Id.*; *see also* PacifiCorp, 2011 *Integrated Resource Plan*, available at www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/2011IRP-MainDocFinal_Vol1-FINAL.pdf.

II. The Commission Should Not Approve the Utilities’ Ten-Year Site Plans: The Commission Cannot Determine What the Reliable, Least-Cost Energy Mix Is Because the Utilities’ Plans Are Missing the Requisite Comparative Analysis of Costs and Quantified Risks of All Relevant Energy Resources, Including Supply Side and Demand Side.

Commissioner Brown requested clarification of the Sierra Club’s recommendations for further action by the Commission. In short, we recommended that the Commission defer approval of the plans until the utilities provide the requisite comparative analysis of the costs and quantified risks of all relevant energy resources, including supply side and demand side. As discussed below, the missing analysis is legally required, and it will put the Commission—and the public—in a better position to ensure low-cost, low-risk power for Florida, and to understand the reasoning behind the investments that are ultimately selected. Moreover, subjecting such analysis to public notice and comment will provide the Commission with a fuller critique of the strengths and weaknesses of the plans.

a. The Utilities’ Ten-Year Site Plans Must Provide an Analysis of the Relative Cost and Relative Risk of All Relevant Energy Resources that is Sufficient to Allow the Commission to Classify the Plans as Suitable or Unsuitable, Suggest Alternatives to the Plans, and Ensure a Reliable, Least Cost Power Supply for Florida.

Ten-year site plans are Florida’s primary vehicle for collecting information about, and preparing for future conditions related to, the state’s power supply. The Commission established the legally required data requirements in Form PSC/RAD 43-E (11/97), “Electric Utility Ten-Year Site Plan Information and Data Requirements” (“Form”). *See also* F.A.C. § 25-22.072 (incorporating the Form by reference). Notably, the Form requires utilities to describe their planning assumptions, modeling methods, and outcomes. *See* Form at 4-6 (enumerating these requirements in the section titled “Other Planning Assumptions and Information”). Moreover, each plan must “provide sufficient information to assure the Commission that an adequate and reliable supply of electricity at the lowest cost possible is planned for the state’s electric needs.” *Id.* at 4. Here, cost should be considered over the life of the investment, and to ensure a robust understanding of potential costs, the plans should quantify the risks that could materially affect the costs, including factors identified above that are routinely considered by other commissions, such as fuel price surges and regulatory risks.

This reading of cost is supported by the governing Florida statutory provisions, F. S. § 186.601 (Ten-Year Site Plans) and § 187.201(11)(b)(10) (State Comprehensive Plan), which call for such circumspect planning. Under mandatory statutory criteria, the Commission must review each utilities’ ten-year site plan for, among other things, “possible alternatives to the proposed plan,” and must evaluate and prepare for risks like “disrupted energy supplies or unexpected price surges.” *See* F.S. § 186.801 (citing State Comprehensive Plan, F.S. § 187.201). Without a comparative cost-risk analysis, the Commission lacks the prerequisite information to perform this statutorily required

planning oversight. Moreover, as discussed at the Workshop and in our comments, the missing analysis hinders the Commission's ability to fulfill its over-arching statutory duty to maintain "sufficient, adequate, and efficient service" and "fair and reasonable rates" for all Floridians. *See, e.g.*, F.S. § 366.03; *see also* Sierra Club, Comments on 2013 Ten-Year Plan Submittals Comments (2013) ("Sierra Club Comments"), Ex. 5.

b. The Utilities' Ten-Year Site Plans Fail to Provide the Required Analysis of the Relative Cost and Relative Risk Among the Relevant Energy Resources Available to Florida.

Our comments and Workshop presentation demonstrated how two utilities in particular have failed to include sufficient cost and risk information in their plans. To recap, Gulf Power and Duke Energy Florida's plans do not show the following:

- ◇ Alternative load forecasts, accounting for significant positive errors in historic forecasts;
- ◇ Implications, costs, and expected timelines of upcoming retirement/retrofit decisions;
- ◇ Alternative investment scenarios beyond the selected "reference case" or "base expansion case";
- ◇ A sensitivity analysis of fuel price, carbon price, supply disruptions, and other risks;
- ◇ A direct comparison of levelized cost curves for demand-side and supply-side resources;
- ◇ A direct comparison of the relative risk among all potential energy resource investment; and
- ◇ A full accounting of energy efficiency and renewable resource options, including (but not limited to) renewable energy contracts and self-build options for utility scale solar systems.

Without the missing analysis, the Commission cannot meaningfully verify whether the proposed investments—such as Duke's "planned power purchases from 2016 through 2020 and planned installation of combined cycle facilities in 2018 (1,307 MW, winter capacity) and 2020 (another 1,307 MW) at undesignated sites," Progress (now Duke) Energy Florida TYSP at 3-2—do in fact provide reliable, least-cost power.

c. The Commission Should Require the Utilities to Conduct a Comparative Cost-Risk Analysis and Subject the Analysis to a Public Comment Period.

As discussed at the Workshop, Florida's energy system is at a crossroads and planning presents a critical opportunity to enhance the understanding of energy options among all interested parties. The Sierra Club urges the Commission to require the utilities to conduct a comparative cost-risk analysis and invite interveners' comments on this analysis. Doing so now would help the Commission address pressing issues, including the need to: (1) plan for significant coal and nuclear retirements; (2) appropriately minimize Florida's exposure to natural gas price shocks and supply disruptions; (3) evaluate and seize opportunities to pursue cost competitive energy resources; and 4) hedge against the costs and risks of fossil fuel-burning generation capacity.

i. The Utilities Should Provide a Full Retirement/Retrofit Analysis of Existing Generation Capacity to Ensure an Accurate and Meaningful Cost-Risk Comparison of Energy Options Going Forward.

While Gulf Power and Duke Energy Florida have confirmed the Sierra Club's retirement predictions from last year, we expect (but have not seen plans that address) more coal-burning unit retirements within the planning horizon, such as Lansing Smith 1 and 2. As we have seen, the Federal

Government has and may well continue to ratchet down power plant emissions under the Clean Air Act to address public health and welfare concerns. These regulations could impact the economic viability of certain fossil-fuel burning capacity in Florida. Indeed, the Florida Reliability Coordinating Council (FRCC) has acknowledged “potential multiple generation retirements from the same site, starting as early as April 2015.” FRCC, 2013 Load & Resource Reliability Assessment Report (2013). In any event, we continue to urge the Commission to require the utilities to provide a straightforward retirement/retrofit analysis, including decommissioning costs and timelines for existing generating capacity, as well as their implications for the utilities’ generating needs. This information is critical for developing an accurate cost-risk comparison of all relevant energy resources available to Florida going forward.

ii. The Utilities Should Identify and Analyze Options to Minimize Florida’s Exposure to Natural Gas Price Shocks and Supply Disruptions.

One of the utilities’ plans most troubling defects is their unwarranted reliance on more natural gas imports—channeling money out-of-state and worsening Florida’s exposure to natural gas price shocks and supply disruptions. As the Sierra Club has stressed, nowhere do the plans substantiate that proceeding this way is cost effective or necessary. For example, Duke and Gulf Power forecasted load growth near 1% per year over the planning horizon, which is well within the range that demand-side management could address at a lower cost. *See* Sierra Club Comments.

Moreover, natural gas-burning capacity is risky in ways that alternative (zero fuel cost) energy is not. Here, we recap three sources of risk. First, the U.S. Energy Information Administration (EIA) dramatically revised downward its estimates of the domestic shale gas reserves, by 42% nationally, and by 66% in the Marcellus. *See* EIA, *Advanced Energy Outlook 2012 Early Release Overview* (2012) at 9. Second, the natural gas industry is moving quickly to export liquefied natural gas. *See, e.g.*, Federal Energy Regulatory Commission, *Proposed/Potential North America LNG Import/Export Terminals*, available at www.ferc.gov/industries/gas/indus-act/lng/lng-proposed-potential.pdf (last visited October 11, 2013). Both of these factors—declining supply and increasing demand at international market prices—create a risk of materially higher natural gas prices in the future. To be sure, numerous studies examine the implications of natural gas exports, and at the Workshop we highlighted EIA’s higher risk case predicting that rapid expansion of gas exports could drive up domestic natural gas prices at the wellhead by as much as 54% (\$3.23/Mcf) by 2018. Whether or not this particular rate of price increase comes to pass, it certainly suggests that the Commission would benefit from a transparent analysis of price shock risks before it approves further natural gas generation in Florida—an analysis which is lacking in the plans.

Third, Florida’s limited natural gas transport infrastructure raises the specter of supply disruptions. Planning should address such risks and should include the costs of building additional infrastructure, such as additional natural gas pipelines, in evaluating energy investment options. For all these reasons, the Commission should instruct the utilities to identify in their cost-risk comparisons all relevant energy resource investment options that minimize Florida’s exposure to natural gas prices shocks and supply disruptions.

iii. The Utilities Should Identify and Justify How They Value and Select Alternative Energy Resources, Including the Value that Renewable Energy And Energy Efficiency Provide For Capacity and Energy Needs,

and As A Hedge Against the Risks and Costs of Further Natural Gas Generation.

As we identified at the Workshop, alternative energy investments are low-cost, low-risk, and compare favorably to conventional generation. The Commission would benefit from a full analysis of such resources in the utilities' ten-year site plans. Duke Energy Florida's plan has served as our example of just how little information the utilities have provided on alternative energy investments. This dearth of information prevents the Commission from verifying that cost-effective alternative energy investments (demand side and supply side) have been appropriately valued and incorporated into the plans. Duke's plan states that by March 2013 the utility's ongoing Request for Renewables logged over 310 responses—responses that are not disclosed or described in Duke's plan. *See* Duke TYSP at 3-21. Duke's plan also omits the option of self-building renewable energy projects. The plan plainly lacks the requisite comparative cost-risk analysis, and even lacks the statutorily required "statement describing how the production and purchase of renewable energy resources impact the utility's present and future capacity and energy needs." *See* F.S. § 186.801(2)(j).

The Commission should not approve such defective plans, especially since the 2012 legislative study determined that Florida has a track record of cost-effective alternative energy investments that have yielded net benefits to Florida's ratepayers. *See* Galligan et al., *Evaluation of Florida's Energy Efficiency and Conservation Act* (Dec. 7, 2012) ("*FEECA Study*") at 9, 10. Instead, we continue to strongly recommend that the Commission instruct the utilities to provide analyses that identify: (1) how they valued and selected alternative energy resources, (2) how these resources impact the utilities' capacity and generation needs, and (3) how the utilities have captured the hedge value of alternative energy resources against the risks associated with further expansion of fossil fuel-burning generation, especially of natural gas.

III. The Commission Should Demand a Clear and Thorough Analysis of the Comparative Costs and Risks of Energy Resources, Including Enhanced Energy Efficiency and Renewable Energy Investments, Because in Today's Market, the Analysis May Well Show that it is More Prudent to Invest in Energy Efficiency and Renewable Energy than Natural Gas.

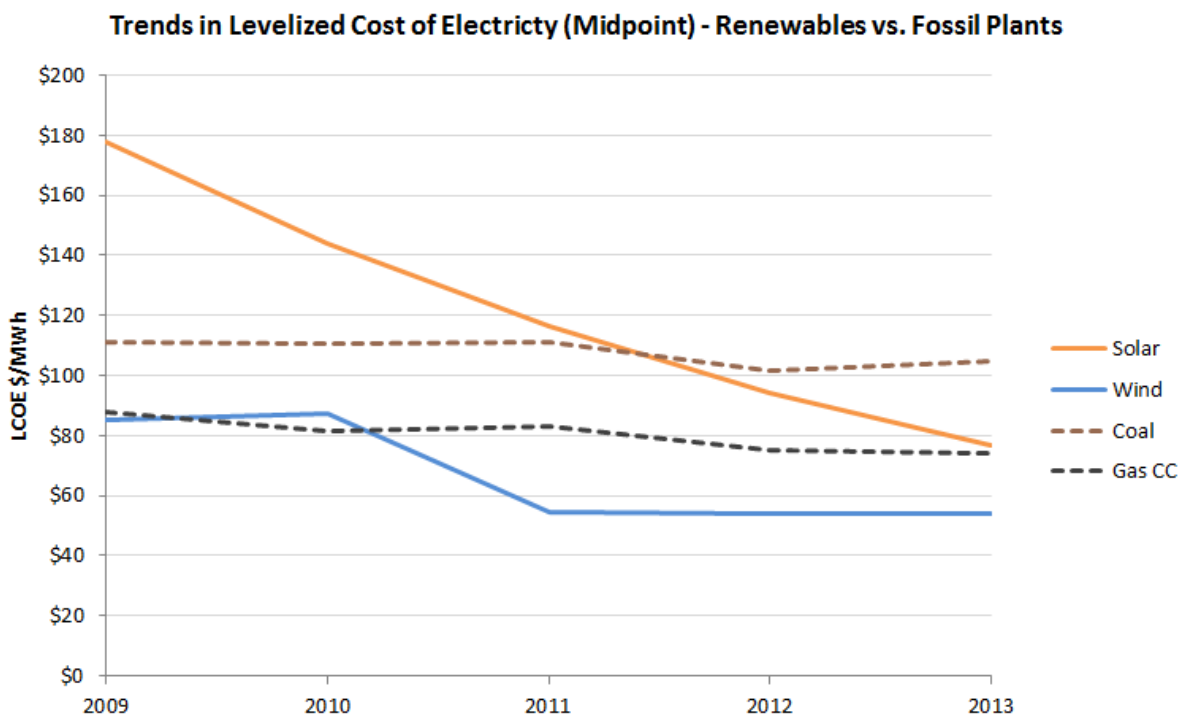
Although at the Workshop we spent a considerable amount of time addressing risks of further natural gas development, the other half of a cost and risk analysis is cost. As discussed at the Workshop, energy markets—and the costs of various types of energy resources, both supply and demand—are rapidly changing. Renewable energy generation continues to plummet in price, while coal and nuclear generation continue to increase, and natural gas is showing clear and increasing signs of significant upward pressure. In this mix, energy efficiency continues to be by far the cheapest energy resources in the market today.

As we noted at the Workshop, there are any number of ways to evaluate such costs. Below we identify some of the more common means of evaluating costs, and reiterate information indicating what those costs are in today's market.

a. Levelized Cost of Electricity Is One Common Comparative Metric of The Costs of Energy Resources.

Levelized cost of electricity (LCOE) is one key metric for comparing resource costs, and one commonly cited source of LCOE data is the international advisory and asset management firm Lazard Ltd, *Lazard’s Levelized Cost of Energy Analysis—Version 7.0* (2013) (“*Lazard’s Analysis*”). At the Workshop we emphasized that national LCOE data can reveal cost trends, while resource planning best practice is for utilities to create (generally using models) levelized cost curves for demand-side resources that are comparable to the levelized cost curves for supply-side resources available within the context of the regional grid. See, e.g., State and Local Energy Efficiency Action, *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures* (2011) at 7.

Since we have not seen evidence of such side-by-side levelized cost comparisons in the ten-year site plans, we have cited *Lazard’s Analysis*: Energy efficiency programs average \$0-\$50 MWh, or better, since these figures do not fully account for the opportunity cost of foregone consumption due to demand response. See *Lazard’s Analysis* at 4. Renewable resources are becoming increasingly cost competitive. Utility-scale solar photovoltaic systems are approaching “grid parity” without tax subsidies and may currently reach “grid parity” under certain conditions. *Id.* As discussed at the Workshop, the graph reproduced below plots Lazard’s levelized cost of electricity data from 2009 to 2013 to show cost trends of renewable resources like solar and wind versus conventional fossil fuel-burning resources like coal and natural gas.



Source: Lazard 2009-2013.

The trends shown in this graph favor investments in renewable resources like wind and solar because they are already cost-competitive with conventional generation resources like coal and gas, and their prices keep falling fast—thanks largely to technological advances, such as larger wind turbines and cheaper components for solar-power arrays. As we have noted, the opposite is true for

fossil fuel-burning generation; costs are generally increasing due to increasingly stringent pollution controls, fuel price volatility, and supply disruption risks.

a. Given Rapidly Changing Electricity Markets, Requests for Proposals are a Common, But Not Exclusive, Way of Identifying Resource Costs.

Commissioner Balbis requested clarification of the Sierra Club's suggestion of using requests for proposals (RFPs) to test resource costs for ten-year site planning purposes. In short, we suggested that, as an initial step, the Commission should obtain from the utilities more information about the renewable energy bids that they received in response to existing RFPs. Duke's plan, for example, states that the utility's ongoing Request for Renewables returned over 310 bids by March 2013. Bids like these are a potential trove of cost information that would enhance the understanding of energy options among all interested parties. *See* Duke TYSP at 3021. Indeed, the 2012 legislative study found that Florida jurisdictional utilities are missing opportunities to share information and best practices on saving energy. *See FEECA Study* at 13. Ten-year site planning is where the utilities can start to remedy this, and the Commission should instruct the utilities to make the bid information, other than the truly sensitive business information, available to the public.

Further, at the Workshop we suggested that a review of existing RFPs and responsive bids may well reveal opportunities for further market testing, perhaps through RFPs, to identify the cost-effective resources available to Florida. For instance, Connecticut recently issued an RFP to identify cost-effective resources for meeting that state's energy policy goals. *See* Connecticut Department of Energy and Environmental Protection, *Request for Proposals for Long Term Energy Contracts* (2013), available at www.ct.gov/deep/cwp/view.asp?a=4405&Q=527812&deepNav_GID=2121. Notably, *Power Purchase Agreement Checklist for States and Locals Governments*, produced by that National Renewable Energy Laboratory, offers guidance on developing RFPs for solar photovoltaic (PV) power purchase agreements in particular. *See* National Renewable Energy Laboratory, *Power Purchase Agreement Checklist for States and Locals Governments* (2009), Ex. 6.

Alternatively, as we discussed at the Workshop, the Commission could identify resource costs by reviewing examples of recent electricity purchase or production decisions, such as the new solar photovoltaic generation in Georgia and Colorado. *See* Georgia Public Service Commission, *PSC Approves Agreement to Resolve Georgia Power 2013 Integrated Resource Plan and Expands the Use of Solar Energy* (Aug. 2013); Xcel Energy, *Xcel Energy Proposes Adding Economic Solar, Wind to Meet Future Customer Energy Demands* (Sept. 2013). Additional cost data—especially from local or regional electricity markets—is essential for prudent planning, and the Commission should require the utilities to include sufficient cost data in their plans to substantiate the cost-effectiveness of their proposed investments.

IV. Conclusion

For all these reasons, the Commission should defer ten-year site plan approval, including approval of planned new gas-burning capacity, until the utilities provide the missing comparative cost-risk

analysis. Moreover, the Sierra Club urges the Commission to follow the best practice of making the comparative cost-risk analysis available for public comment.

Sincerely,

/s/

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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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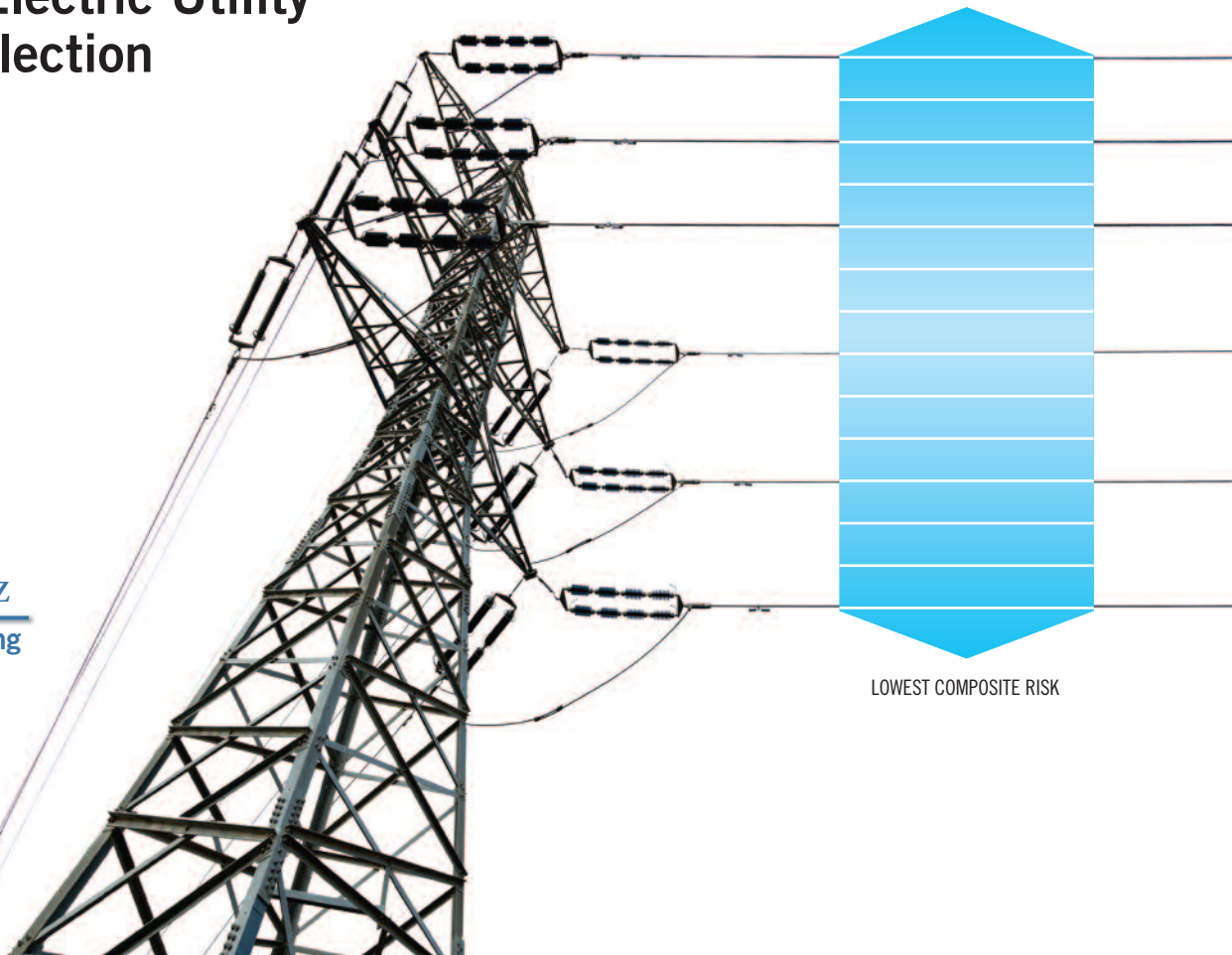
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HIGHEST COMPOSITE RISK

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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.

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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.

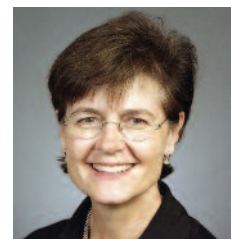
At its heart, this report is a call for “risk-aware regulation.” With an estimated \$2 trillion of utility capital investment in long-lived infrastructure on the line over the next 20 years, regulators must focus unprecedented attention to risk—not simply keeping costs down today, but minimizing overall 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.

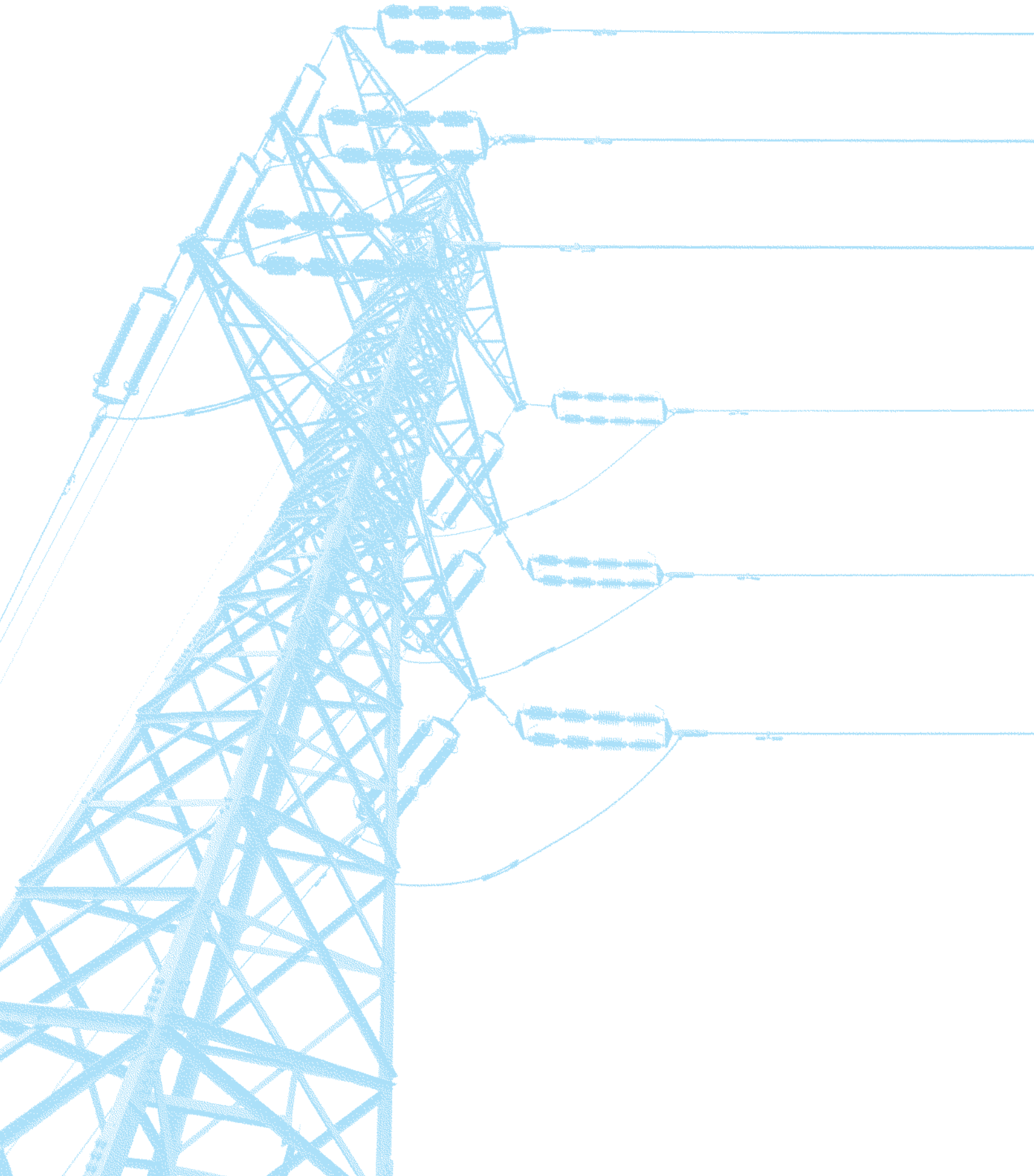
This report offers some good news amid pervasive uncertainty: the authors point out that planning the lowest-cost, lowest risk investment route aligns with a low-carbon future. From a risk management standpoint, diversifying utility portfolios today by expanding investment in clean energy and energy 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
Managing Principal
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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 years⁴—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	
<i>Cost-related</i>	<i>Time-related</i>
› 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.nbrgroup.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.uccusa.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

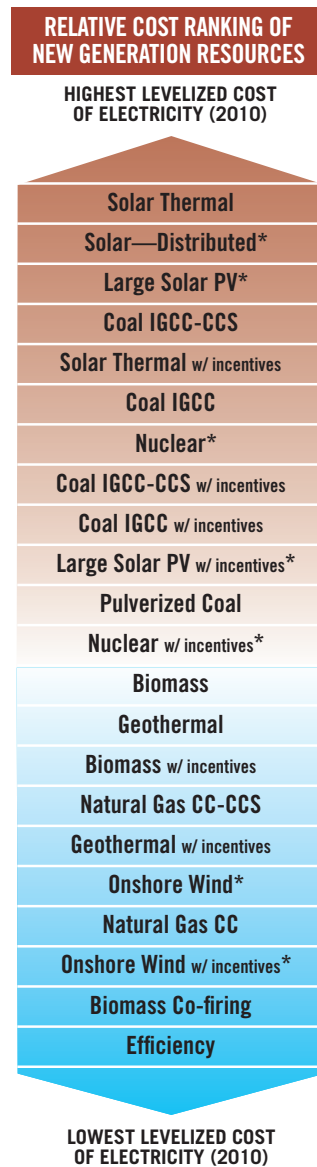
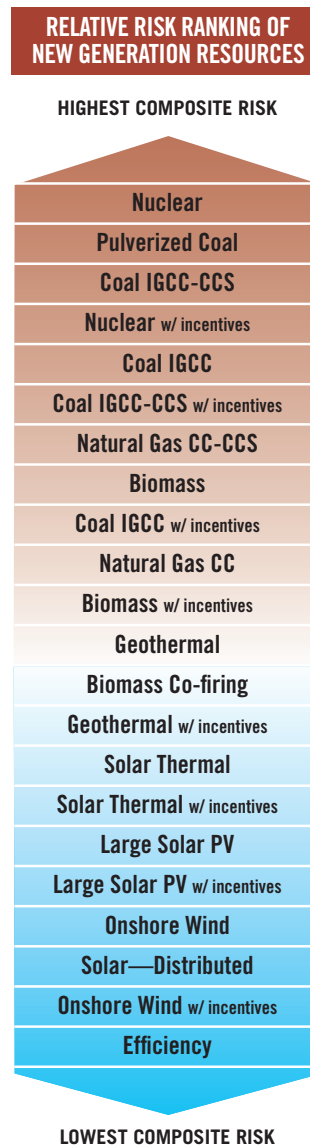


Figure ES-3



* 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:

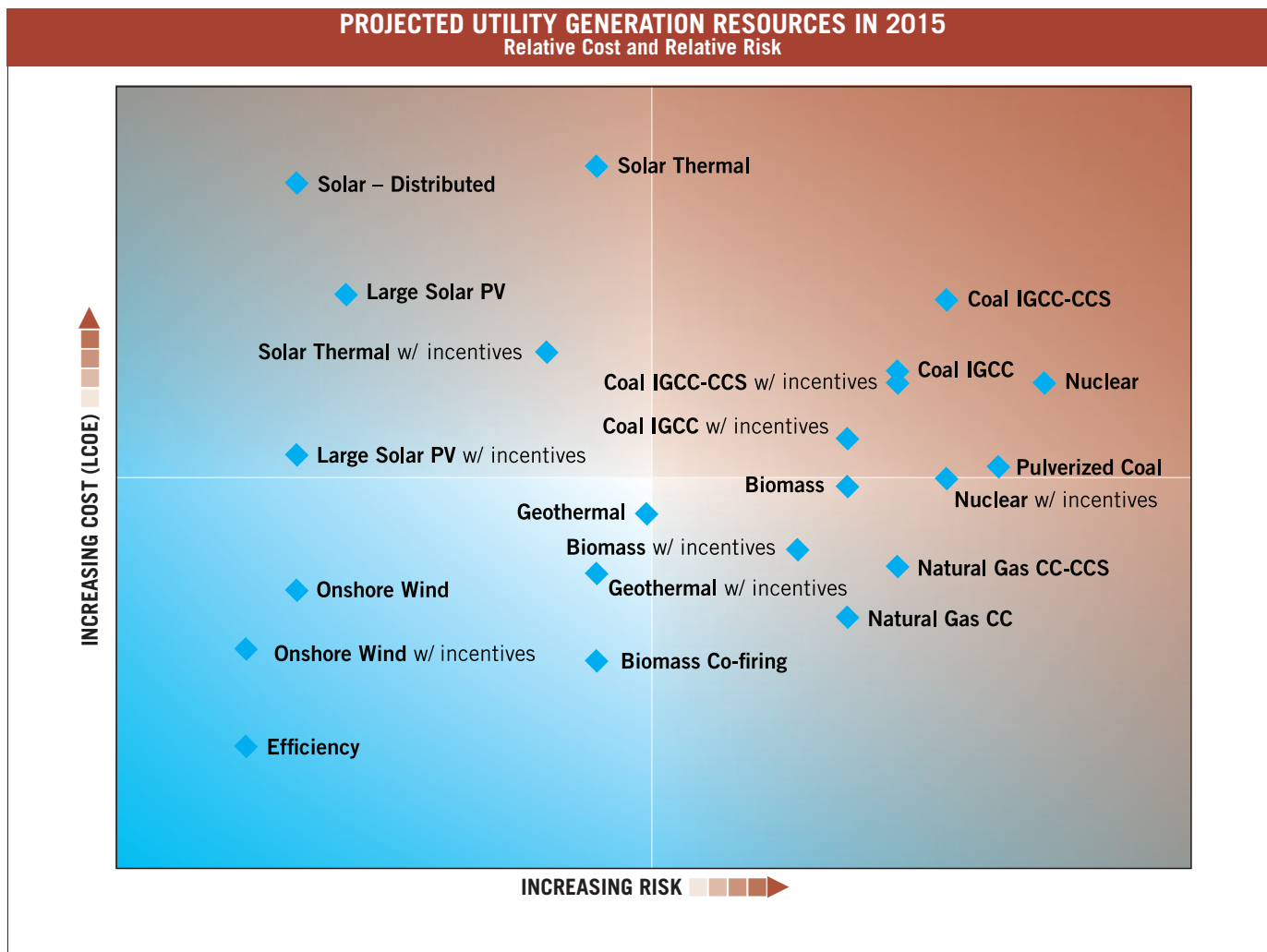
- ⚡ **Construction Cost Risk:** includes unplanned cost increases, delays and imprudent utility actions
- ⚡ **Fuel and Operating Cost Risk:** includes fuel cost and availability, as well as O&M cost risks
- ⚡ **New Regulation Risk:** includes air and water quality rules, waste disposal, land use, and 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



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

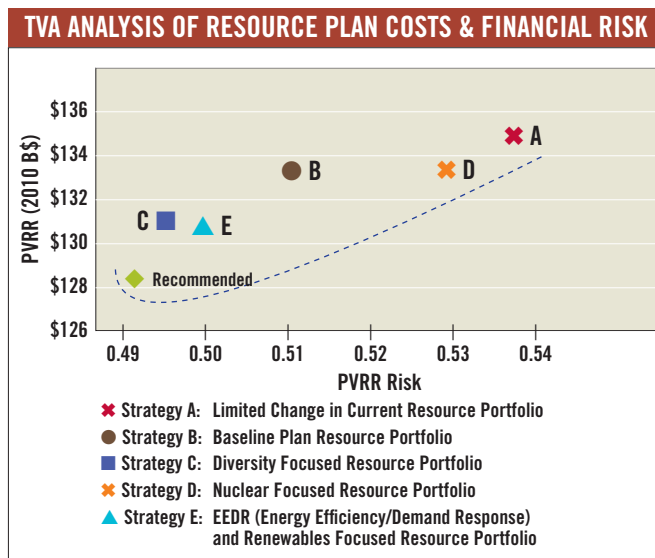
MANAGING RISK INTELLIGENTLY IS ARGUABLY THE MAIN DUTY OF REGULATORS WHO OVERSEE UTILITY INVESTMENT. EFFECTIVELY MANAGING RISK IS NOT SIMPLY ACHIEVING THE LEAST COST *TODAY*, BUT RATHER IS PART OF A STRATEGY TO *MINIMIZE OVERALL COSTS OVER THE LONG TERM*. WE IDENTIFY SEVEN ESSENTIAL STRATEGIES THAT REGULATORS 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 portfolio¹⁵ 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



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.

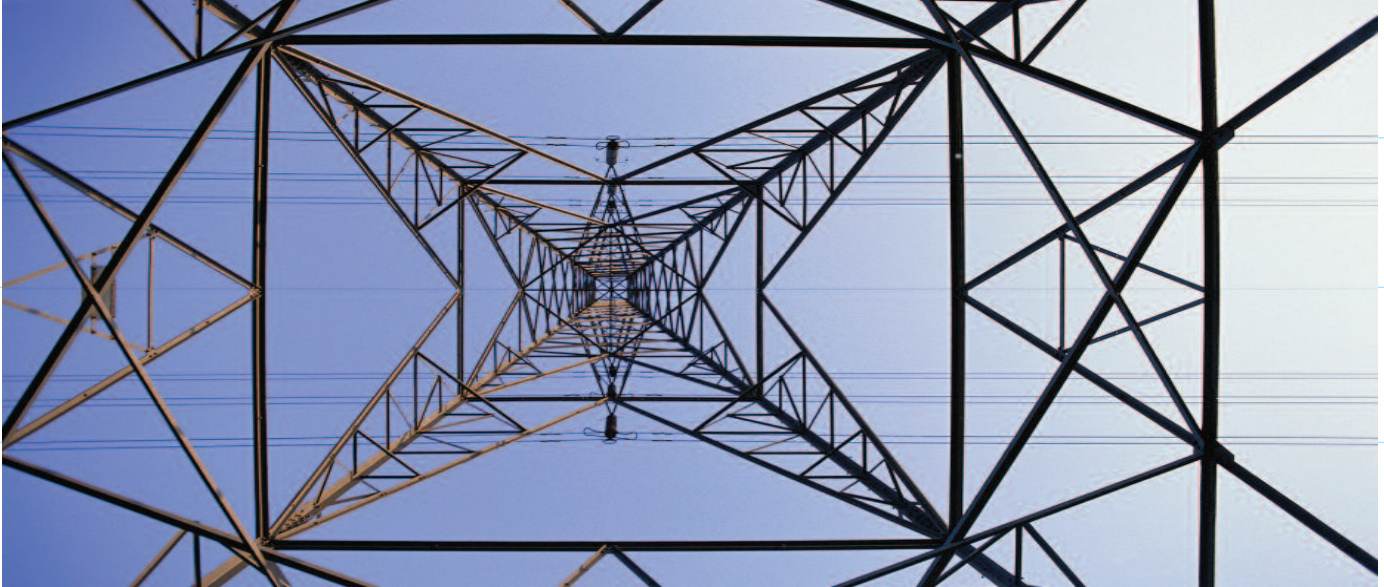
Regulators must recognize the incentives and biases that attend traditional regulation, and should review and reform their approaches to resource planning, ratemaking and utility cost recovery accordingly. Utilities must endorse regulatory efforts to minimize investment risks on behalf of consumers and 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

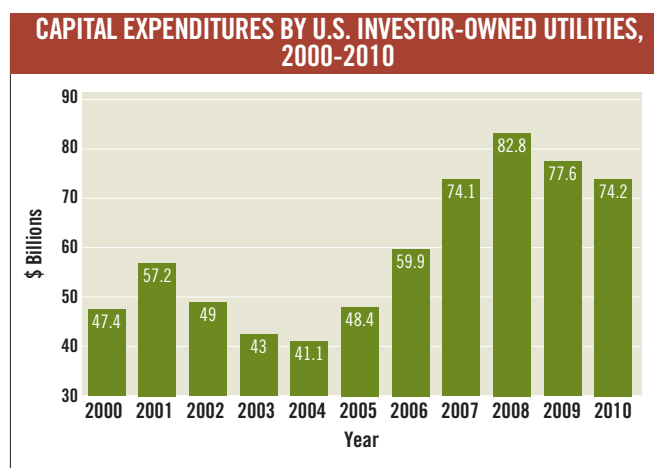
THE INVESTMENT CHALLENGE

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



16 See footnote 2.

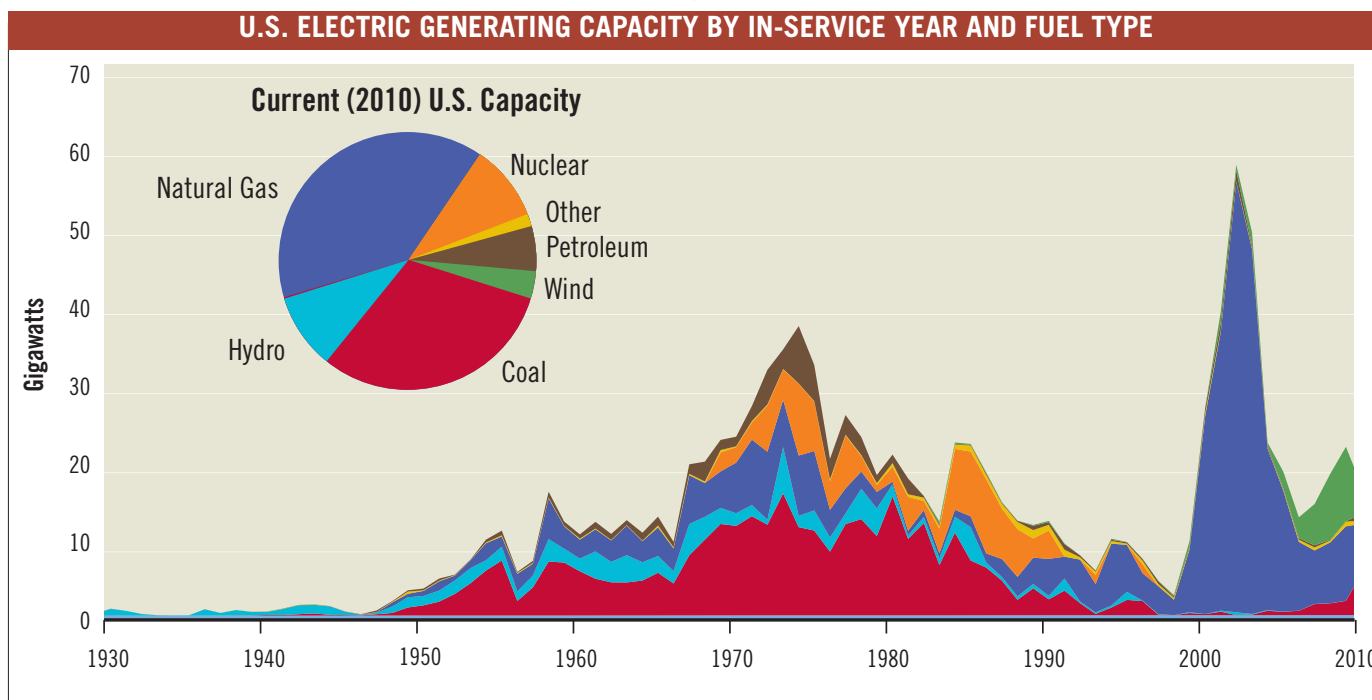
17 Peter Fox-Penner, *Smart Power* (Washington DC: Island Press, 2010). The “first revolution” was triggered by George Westinghouse, Thomas Edison, Nicola Tesla, Samuel Insull and others more than a century ago.

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



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*.

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.



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.

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

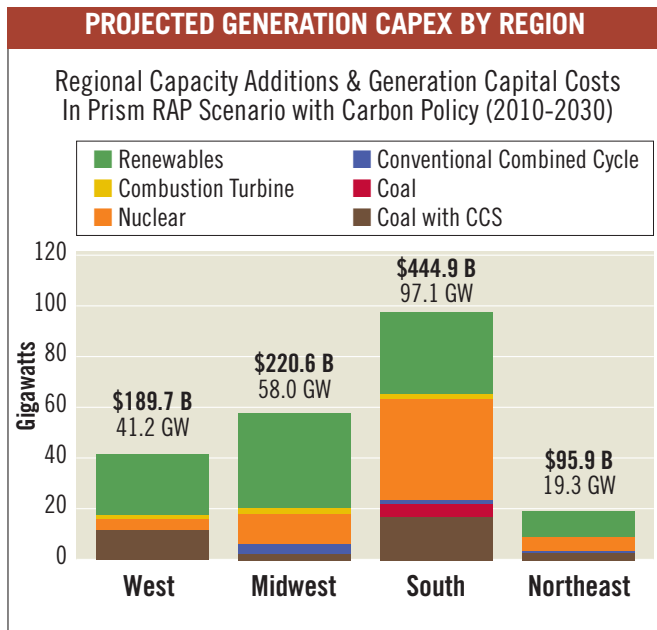


Figure 3 shows the Brattle Group’s investment projections for new generating capacity for different U.S. regions,²⁴ while Figure 4 predicts capacity additions for selected U.S. states. Importantly, the Brattle Group noted that some of this investment in new power plants could be avoided if regulators 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.

Figure 4

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%

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.

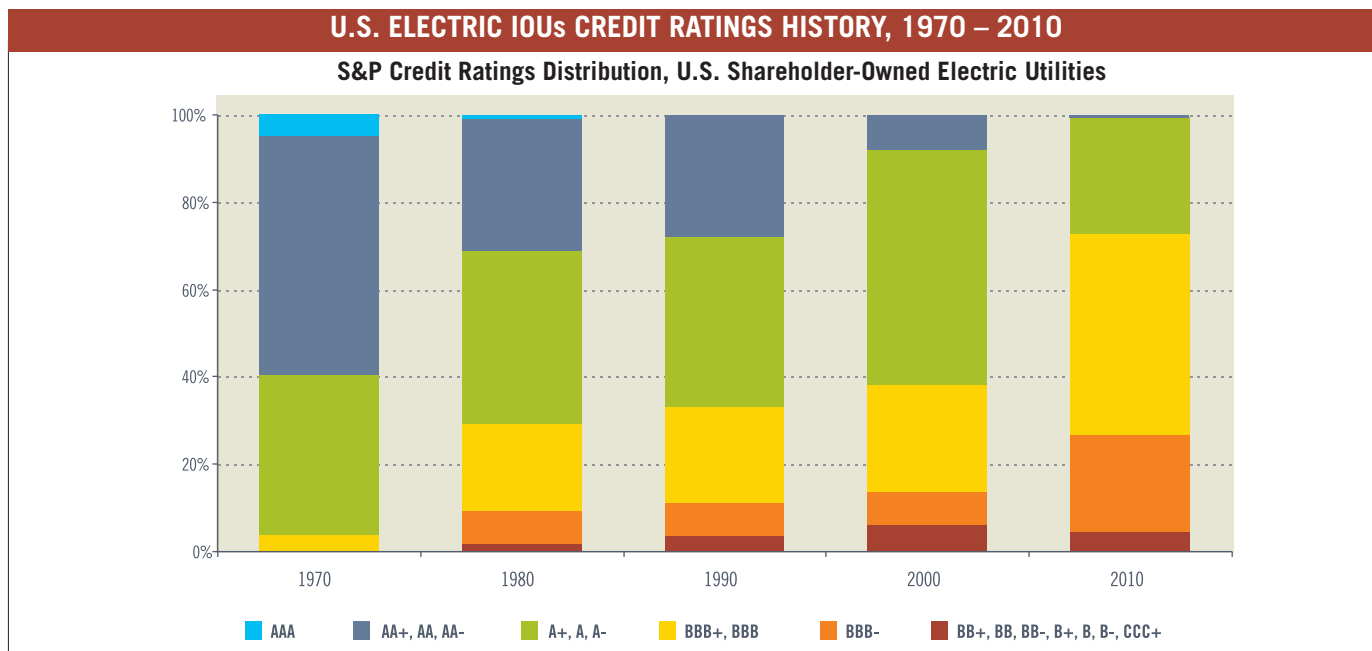
28 U.S. Energy Information Administration, *AEO2012 Early Release Overview* (Washington DC: U.S. Energy Information Administration, 2012), 9, [http://www.eia.gov/forecasts/aeo/er/pdf/0383er\(2012\).pdf](http://www.eia.gov/forecasts/aeo/er/pdf/0383er(2012).pdf).

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



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.

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.

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32 Cortright, “Testimony.”

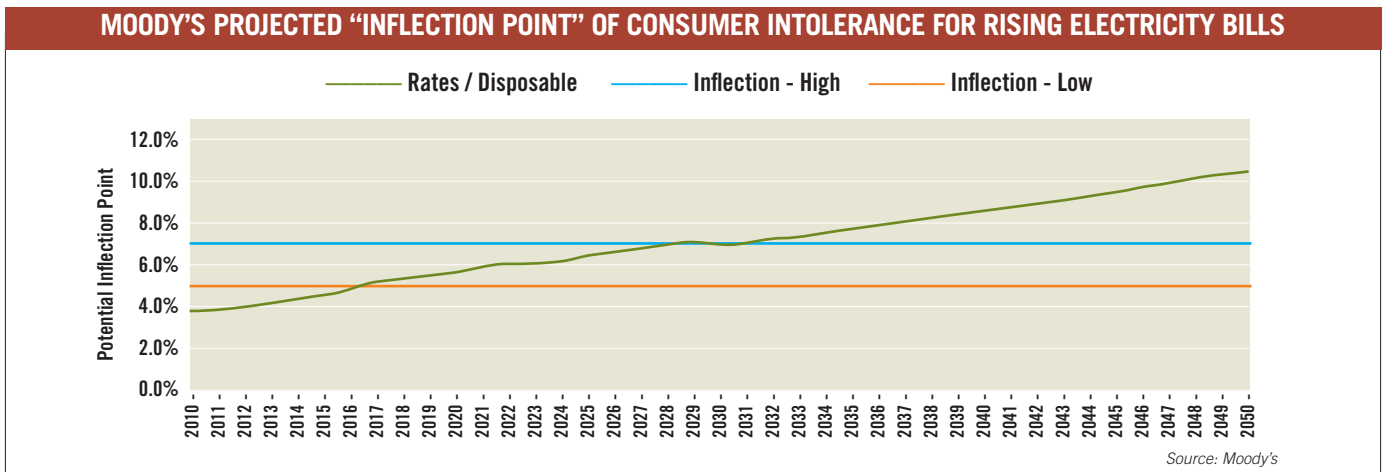
33 Standard & Poor’s, *The Top 10 Investor Questions for U.S. Regulated Electric Utilities in 2012* (New York: Standard & Poor’s, 2012).

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



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:

$$\text{Risk} = \sum_j \text{Event}_j \times (\text{Probability of Event}_j)$$

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>.

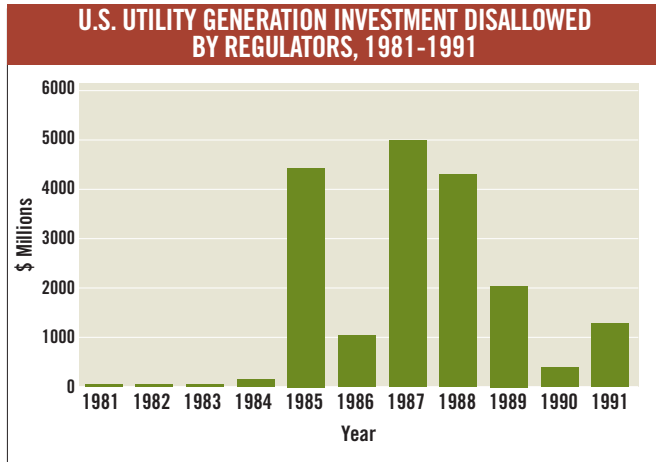
40 The natural gas build-out of the 1990s and early 2000s was led by independent power producers, not regulated utilities.

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



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

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).

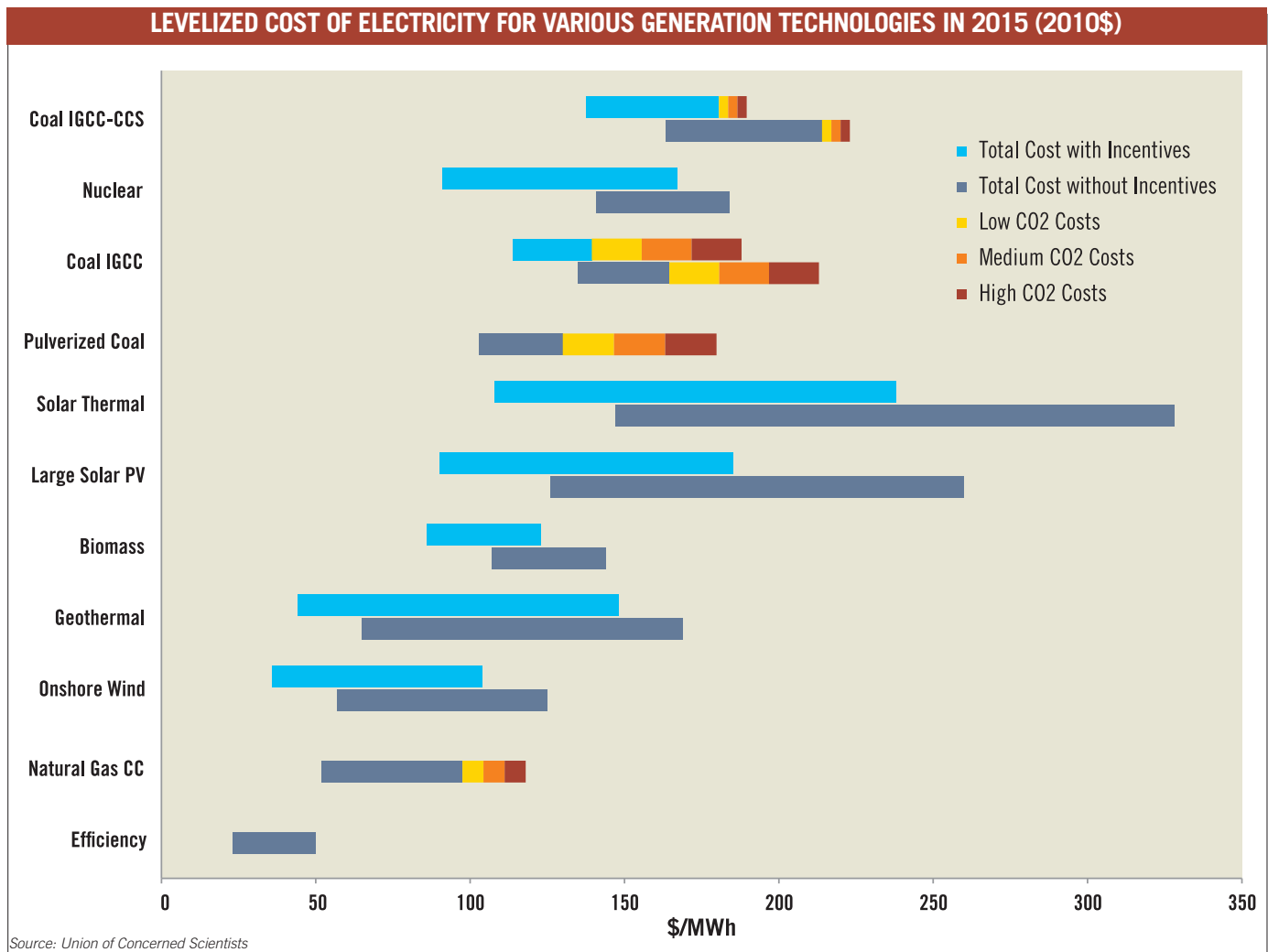
Generation resources also vary widely in their design lives and exposure to climate regulations, among other differences.

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



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**).

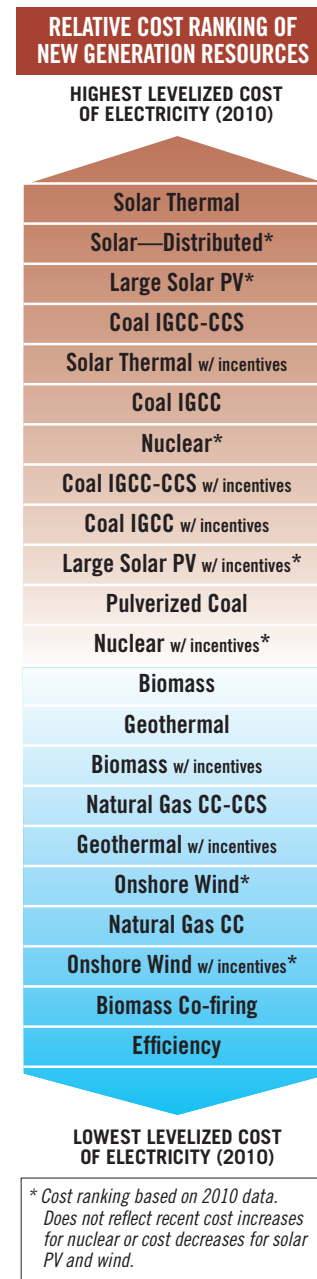
For consistency, we use UCS's data compilation, which is based on 2010 cost estimates, without modification. But the actual cost of nuclear power in 2015 is likely to be sharply higher than this estimate following the Fukushima nuclear accident and recent experience with new nuclear projects. For wind 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



 **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 Wisser 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

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.

technologies (e.g., biomass) and resources with familiar construction regimes (e.g., gas and coal thermal plants).

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-portfolios-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.

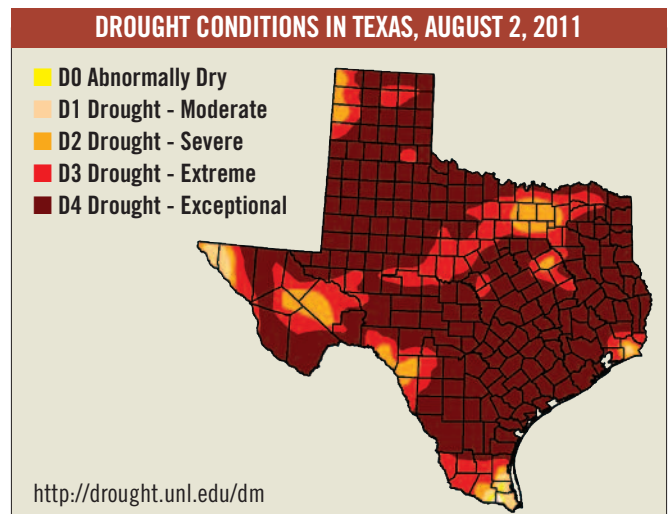
The tools we describe in this report for new resources apply equally well to these situations. Regulators should treat this much like an IRP proceeding (see “Utilizing Robust Planning Processes” on p. 40). Utilities should be required to present multiple different scenarios for their disposition of coal 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



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

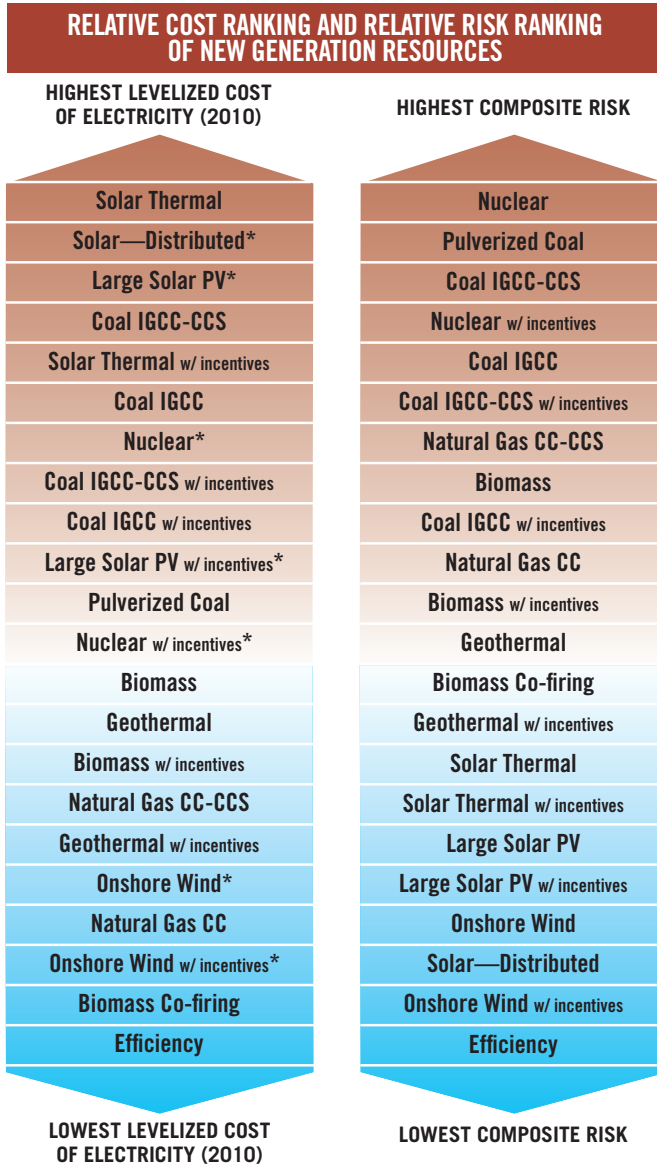
RELATIVE RISK EXPOSURE OF NEW GENERATION RESOURCES							
Resource	Initial Cost Risk	Fuel, O&M Cost Risk	New Regulation Risk	Carbon Price Risk	Water Constraint Risk	Capital Shock Risk	Planning Risk
Biomass	Medium	Medium	Medium	Medium	High	Medium	Medium
Biomass w/ incentives	Medium	Medium	Medium	Medium	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

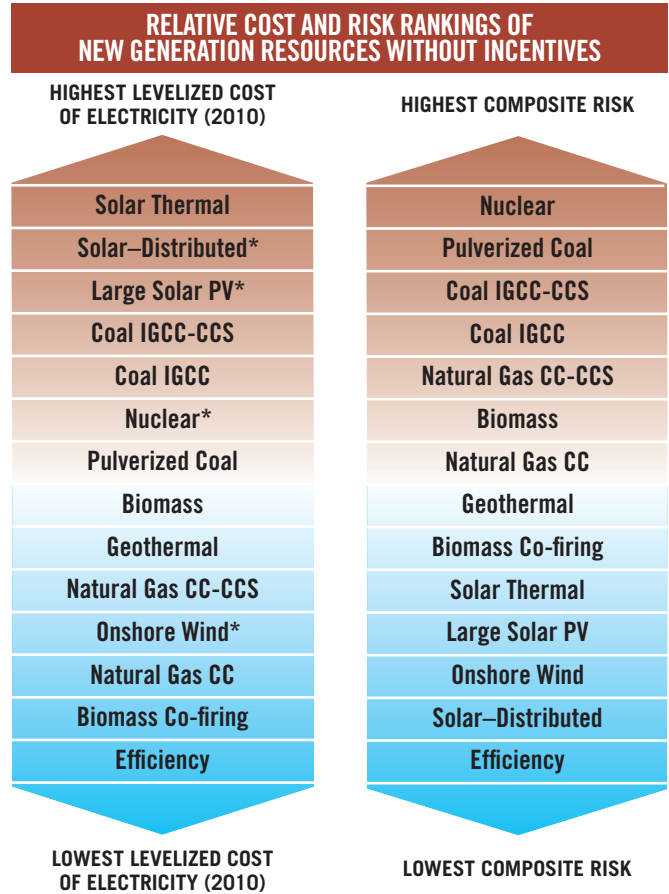


* Cost ranking based on 2010 data. Does not reflect recent cost increases for nuclear or cost decreases for solar PV and wind.



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.

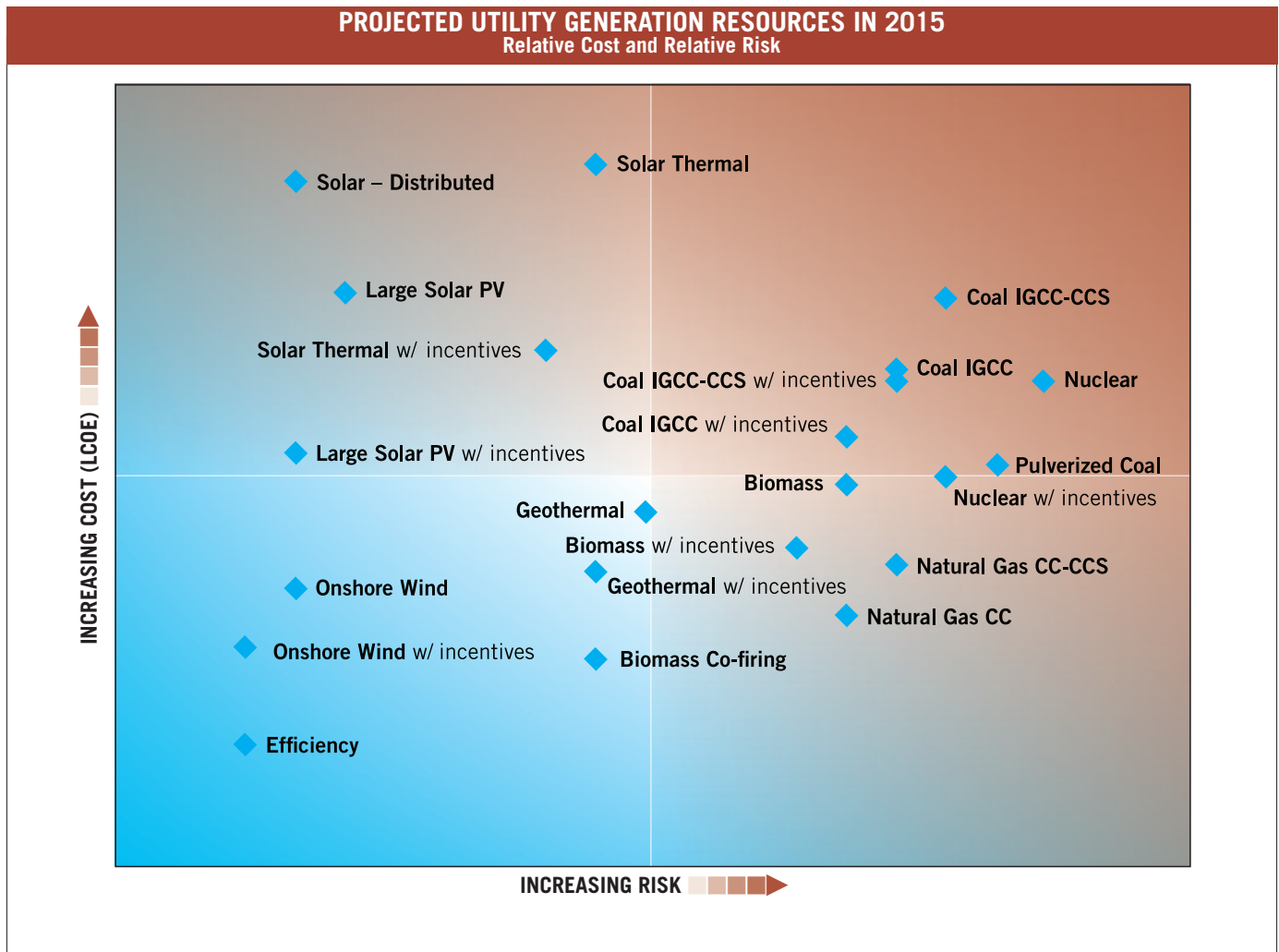
To test the robustness of the composite risk ranking, we also examined two rankings where the scores were weighted. In one case, the environmental factors were given double weight; in the other, the cost factors were given double weight. As before, the scores were renormalized so that the highest-scoring 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.



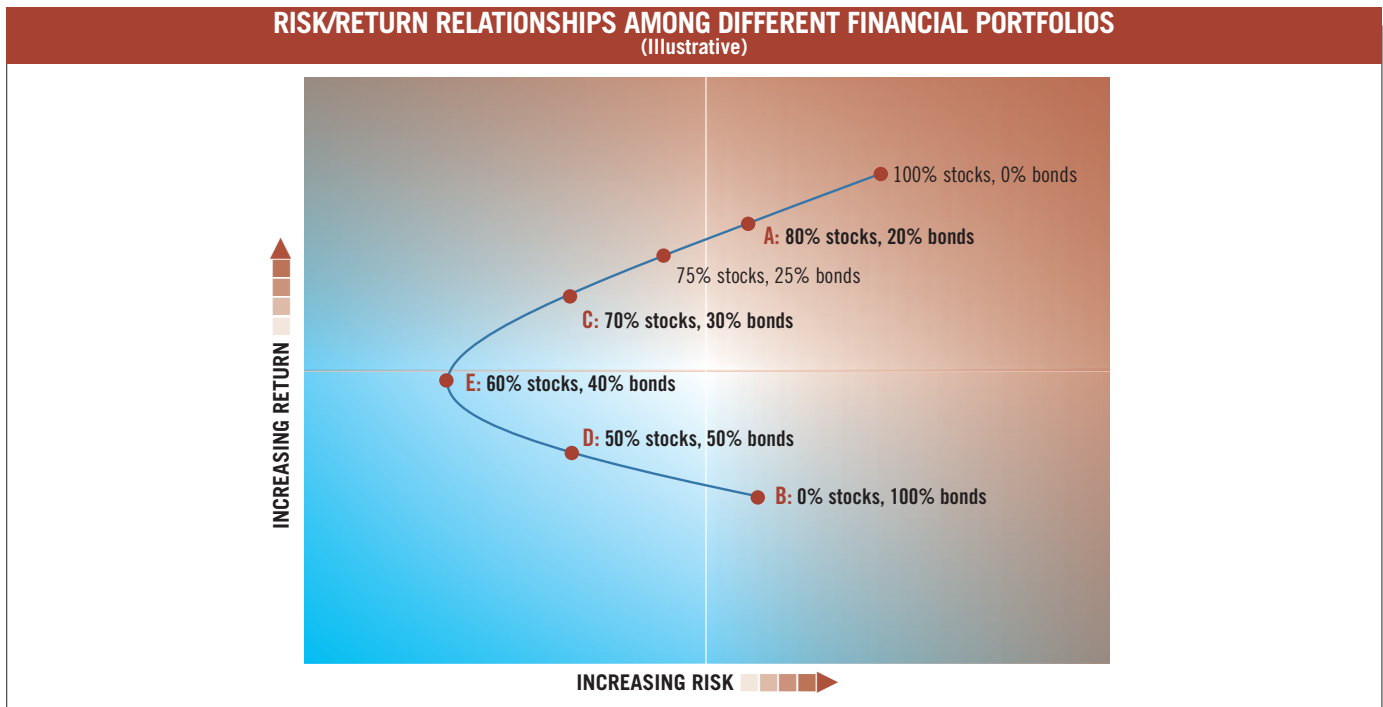
An overlooked strategy (that usually lacks an advocate) is to reduce overall risk to everyone.



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



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 Portfolio⁶⁸
- 🔑 **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

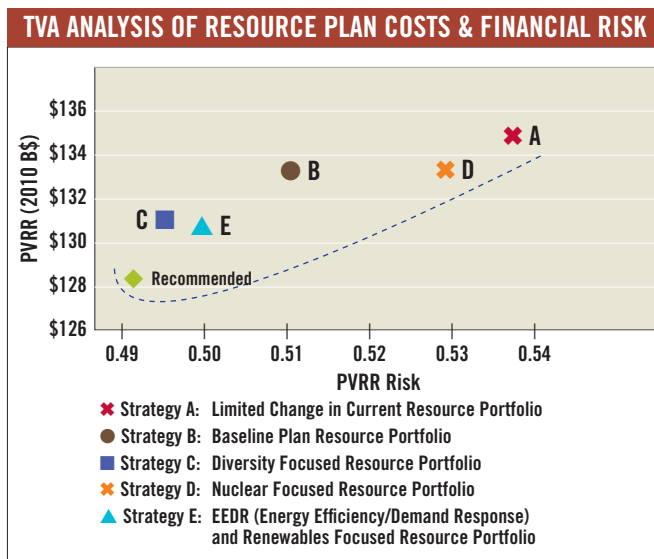


Figure 19 illustrates how these strategies mapped out along an “efficient frontier” according to TVA’s analysis of cost and risk.⁶⁹ The lowest-cost, lowest-risk strategies were the ones that diversified TVA’s resource portfolio by increasing TVA’s investment in energy efficiency and renewable energy.⁷⁰ 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.

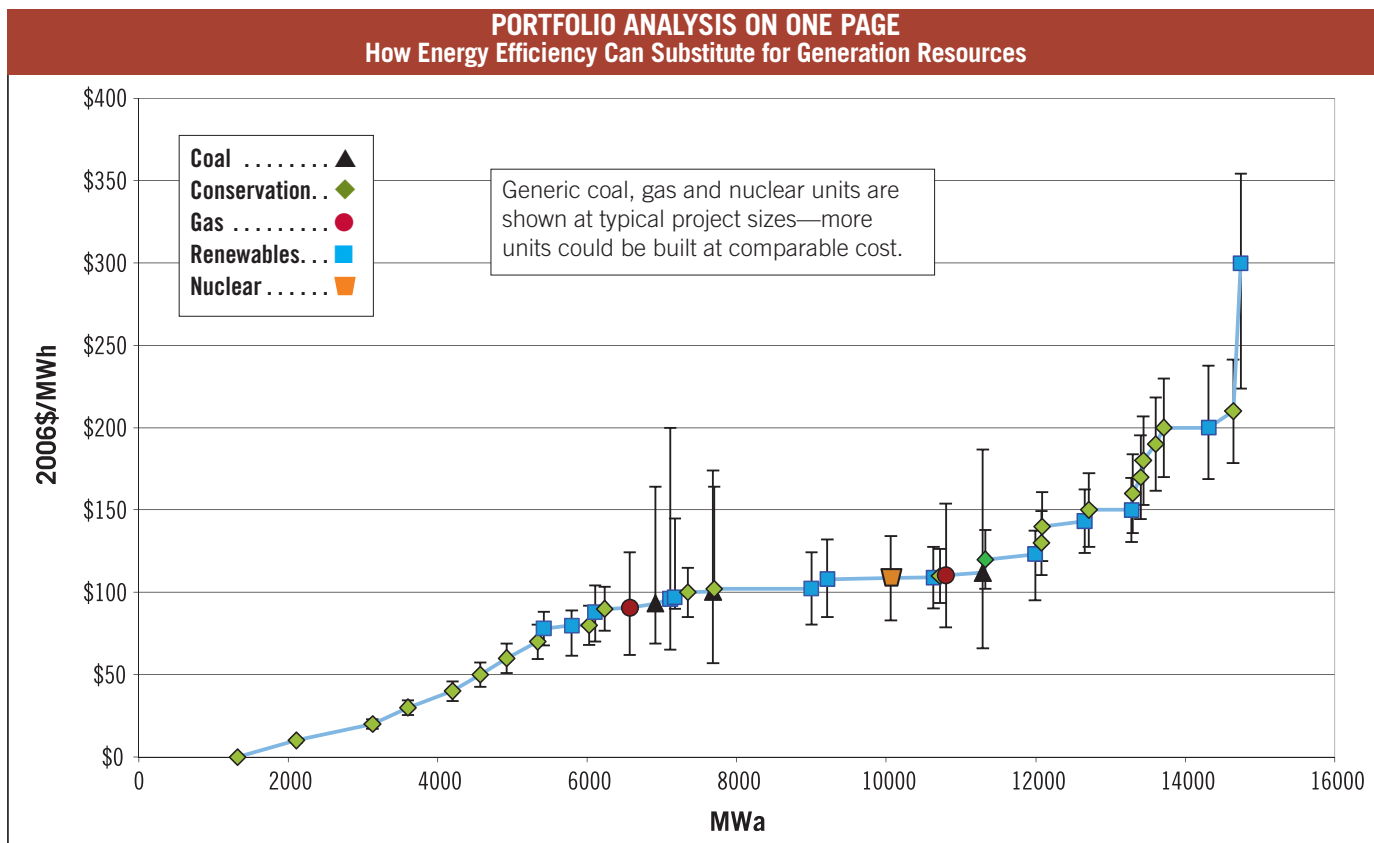
⚡ Stakeholder involvement. There are at least two good reasons to encourage broad stakeholder involvement in an IRP process. First, parties besides the utility will bring new ideas, close scrutiny and contrasting analysis to the IRP case, all of which helps the regulator to make an informed, independent 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.



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⚡ 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



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 a 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		Primary Scenario High DSM (130% Goal) Medium Section 123 (200 MW) Base Load											
Portfolios 1-12		Portfolio Number											
Key Portfolio Characteristic		1	2	3	4	5	6	7	8	9	10	11	12
		Portfolio Rank within Scenario (PVRR)											
		1	2	3	4	5	6	7	8	9	10	11	12
PVRR & Rank	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												
PVRR rank	5	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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LEAST-RISK PLANNING FOR ELECTRIC UTILITIES

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INTRODUCTION

Electric utility capital investments often entail significant risk.¹ They are typically large, irreversible investments, with long lifetimes and many alternatives.² They often lead to uncertain cost outcomes relative to investment alternatives.³ In addition to this inherent risk, electric utilities and utility regulators face uncertainty regarding near-term and long-term fuel prices, demand growth, environmental regulations, climate policy, and technology development.⁴ Given the \$1.5 to \$2 trillion dollars in capital investments that electric utilities are projected to make over the next 20 years, these conditions imply that electric utilities and utility regulators must make difficult decisions in an environment of significant uncertainty.⁵ Poor investment decisions could cause ratepayers to face significant rate increases and potentially burden utilities with unrecoverable costs.

Most electric utility planning methods in traditionally regulated, vertically integrated markets strive to determine the least-cost investment—or series of investments—to reliably meet load. To accomplish this goal, electricity generation planners typically use scenario analysis to account for a range of potential futures. However, determining optimal investments is difficult if least-cost investments vary widely across scenarios, as is often the case during a time of unprecedented uncertainty in the industry and given a wide range of potential market futures. An investment that is least cost in one scenario (or future) may be high cost and high risk in another. As a result, utilities and regulators may regret investments, and customers could be saddled with higher costs. The wrong investment can reverberate through the local economy and ultimately lead to shuttering of incumbent industries and failure to attract new customers.

Perhaps the most prominent example of a regrettable electricity generation decision is the Shoreham nuclear power plant in New York. Long Island Lighting Company (LILCO) conceived the project during the 1960s due to growing concerns with fossil fuel supplies. The plant took 20 years to construct and cost approximately \$6 billion.⁶ Nearly 100 times over budget, the plant was mothballed before entering

¹ Risk is defined here as the potential for a loss or negative outcome from an uncertain event.

² Electricity sector capital investments tend to have low salvage values, meaning most costs are sunk and unrecoverable if the investment does not operate as planned. See Elizabeth Olmsted Teisberg, “Capital Investment Strategies under Uncertain Regulation,” *The RAND Journal of Economics* 24, no. 4 (Winter 1993): 591-604, <http://www.jstor.org/stable/2555747>. Also see Table 8-1, EPA’s IPM Base Case v.4.10 Financial Assumptions, U.S. Environmental Protection Agency, <http://www.epa.gov/airmarkets/progsregs/epa-ipm/docs/v410/Chapter8.pdf>.

³ Dalia Patino Echeverri and David Hoppock, Southeastern Association of Regulatory Utility Commissioners 2013 Annual Conference, Asheville, North Carolina, June 9, 2013, <http://www.naruc.org/Grants/Documents/SEARUC%202013%20Risk%20Workshop.pdf>.

⁴ Fuel prices: Mark Bolinger, *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*, Lawrence Berkeley National Laboratory (March 2013). Demand growth: Peter Fox-Penner, *Smart Power: Climate Change, the Smart Grid, and the Future of Electric Utilities* (Washington D.C.: Island Press, 2011); Gregory Aliff, *The Math Does Not Lie: Factoring the Future of the U.S. Electric Power Industry*, Deloitte Center for Energy Solutions (2012). Environmental regulations and climate policy: Ron Binz, Richard Sedano, Denise Furey, and Dan Mullen, *Practicing Risk-Aware Electricity Regulation: What Every State Regulator Needs to Know* (Boston: CERES, 2012). Technology development: Gregory Aliff, *The Math Does Not Lie*.

⁵ NARUC President Philip Jones, 2012 NARUC Annual Conference, <http://www.narucmeetings.org/Presentations/2012jonesspeech.pdf>. Ron Binz et al., *Practicing Risk-Aware Electricity Regulation*.

⁶ Massoud Simnad, “Has the Nuclear Power Industry Risen and Fallen or Will It Rise Again?” *Energy* 21 (1996): 1095–1111.

commercial operation.⁷ By the time it was decommissioned in 1995, electricity rates for LILCO customers had increased to among the highest in the country. As a result, LILCO was dissolved into several entities, including the Long Island Power Authority.⁸ Customers are still paying off an estimated \$3.5 billion worth of debt related to the project.⁹

Given current risks and uncertainties, the potential for today’s generation decisions to have similarly long-lasting negative impacts is high. For example, the decision to invest in an existing coal plant to comply with environmental regulations may be least cost in the near term but high cost over a longer horizon, depending on how the federal government regulates greenhouse gas emissions. Similarly, an investment in a natural gas plant may be least cost, assuming low natural gas price projections are realized, but the investment can significantly increase electricity rates if natural gas prices spike or return to the price volatility seen 5 to 10 years ago (Figure 1). Utilities can make investments in renewable generation, for example, to hedge against fuel price and other risks, but these investments are often relatively high cost in the near term. Moreover, estimating their hedging value with traditional utility planning methods is challenging.¹⁰

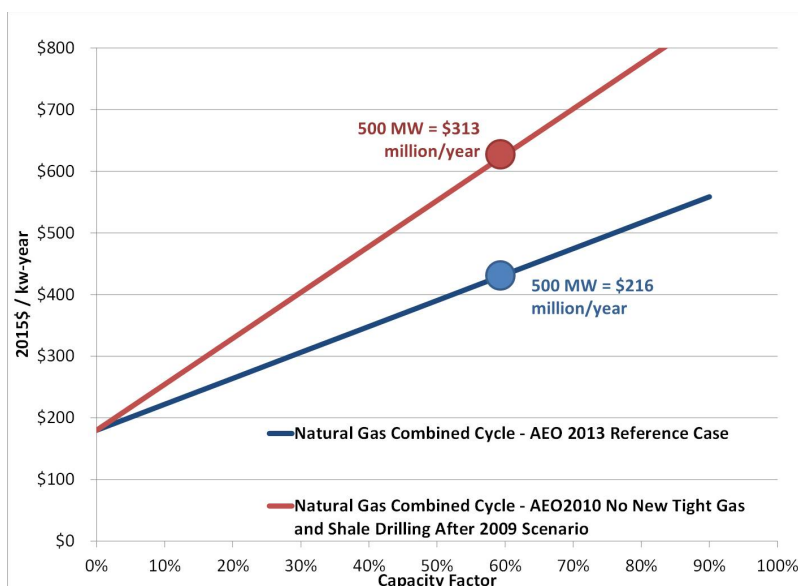


Figure 1. Levelized annual revenue requirements for natural gas combined cycles given high and low natural gas fuel price forecasts. A 500 MW combined cycle operating at 60% capacity factor would cost \$216 million annually if fuel prices from the Energy Information Administration’s (EIA) AEO2013 Reference Case are realized. In comparison, annual costs are almost \$100 million higher given natural gas prices from the EIA’s AEO2010 “No New Tight Gas and Shale Drilling after 2009” scenario.

To deal with a range of least-cost investments across scenarios, decision makers sometimes assign greater weight to certain scenarios, ignore results from scenarios they view as less likely, or choose the

⁷ Malcolm Grimston. *The Importance of Politics to Nuclear New Build* (London: Chatham House, 2005).

⁸ H. Carl McCall, *Staff Study: Disposition of the Shoreham Nuclear Power Plant*, State of New York Office of the State Comptroller Division of Management Audit, Report 95-D-38, 1995.

⁹ Abby Gruen, “Rating agencies to NY governor on LIPA privatization: Do the math,” *SNL Energy*, January 9, 2013.

¹⁰ Mark Bolinger, *Revisiting the Long-Term Hedge Value of Wind Power in an Era of Low Natural Gas Prices*, Lawrence Berkeley National Laboratory, March 2013.

investment option that is least cost (or low cost) over the greatest range of scenarios. However, an investment option that is least cost over a range of scenarios can create considerable risk in one or more of the remaining scenarios.

One option for overcoming the uncertainty associated with identifying optimal investments is to change the planning objective from least cost to a metric that accounts for the wide range of potential outcomes. A *least-risk* metric that also assures low relative costs by “minimizing the maximum regret” of generation plans is a potentially attractive alternative approach. Identifying investments for generation plans that are low cost and low risk across all scenarios is a strategy utility planners—including those at the Tennessee Valley Authority— have begun to use to avoid making decisions that could cause significant regret in the future.¹¹ Given the current environment of economic and regulatory uncertainty, utility planners and state utility regulators may want to supplement their existing planning methods with a least-risk approach to determine optimal generation plans.

ALTERNATIVES TO TRADITIONAL SCENARIO ANALYSIS PLANNING

To overcome the difficulties associated with traditional scenario analysis and decision making under uncertainty, utility planning experts, academics, and others have developed methodologies and other tools to optimize decision making under uncertainty while quantifying and minimizing risks. These tools include robust decision making, real options analysis, utility scenario planning for least-risk outcomes, expected value analysis using probabilities, and other stochastic optimization methods.¹² Some of these methods require utility planners and regulators to learn new processes and models.¹³ The least-risk metric introduced here can complement current planning methods and is compatible with existing models and traditional scenario analysis.

Utility planners and regulators can create a simple metric to estimate the risk of a decision by calculating the “regret” of a decision for each scenario using the outputs of traditional scenario analysis. Minimizing the maximum regret is a decision analysis methodology that minimizes forecast regret for the range of

¹¹ In its 2011 Integrated Resource Plan, TVA states, “When faced with a challenge like planning the power system for the next 20 years, a ‘no-regrets’ decision-making framework is generally the best approach. A ‘no-regrets’ framework is one in which decision makers... weigh the likelihood and consequence of the risks and challenges that could surface so that decisions have a high likelihood of being sound in many possible states of the world.” TVA, *Integrated Resource Plan: TVA’s Environmental & Energy Future* (2011), http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf.

¹² Robust decision-making: Robert J. Lempert, Steven W. Popper, and Steven C. Banks, *Shaping the Next 100 Years: New Methods for Long-Term, Quantitative Policy Analysis* (Santa Monica, CA: RAND, 2003). Real options analysis: Avinosh K. Dixit and Robert S. Pindyck, *Investment under Uncertainty* (Princeton, NJ: Princeton University Press, 1994). Utility scenario planning: David M. Boonin, *Utility Scenario Planning: Always Acceptable vs. the Optimal Solution*, National Regulatory Research Institute (March 2011), http://www.nrri.org/pubs/multiutility/NRRI_utility_scenario_planning_mar11-07.pdf. Expected value analysis using probabilities: David Hoppock, Dalia Patino Echeverri, and Etan Gumerman, *Determining the Least-Cost Investment for an Existing Coal Plant to Comply with EPA Regulations under Uncertainty*, Nicholas Institute for Environmental Policy Solutions at Duke University (February 2012), <http://nicholasinstitute.duke.edu/climate/lowcarbontech/determining-the-least-cost-investment-for-an-existing-coal-plant-to-comply-with-epa-regulations-under-uncertainty#.UdTWY9LvtJQ>.

¹³ Given significant uncertainty in the utility sector and the scale of the investment decisions, use of new methodologies and models is worth exploring.

investment options and scenarios analyzed.¹⁴ In other words, minimizing the maximum (minimax) regret identifies a generation plan that is relatively low cost for the utility—and ultimately, ratepayers—no matter how the future unfolds.

Decision theory states that investment decisions should reflect the risk preferences of the decision maker.¹⁵ Therefore, minimizing potential regrets is a particularly attractive approach for regulated utilities and is compatible with their objectives and those of utility regulators. In traditionally regulated states, utility rates of return on capital investments are authorized by state regulators and assessed on prudently incurred investments.¹⁶ Because the utility's return on investment is set by the state and based on costs and performance, the objective of the utility is to minimize the total cost of service while maintaining a high level of reliability, rather than attempting to maximize profit. Moreover, electric utilities provide an essential service to society and the economy. The expected and required reliability of the bulk power system in the United States makes end-use customers and utility regulators wary of high-risk investments and is important in attracting low-cost capital for investments. Thus, traditionally regulated utilities are typically risk averse, because their investments are capital intensive, long lived, and subject to scrutiny by regulators and ratepayers, including post-investment prudence review.

Minimax regret analysis is considered a sound decision-making method under uncertainty, because it is neither too optimistic nor too pessimistic about future outcomes.¹⁷ Some utilities have begun moving toward this method of planning. For example, the 2011 Integrated Resource Plan of the Tennessee Valley Authority (TVA) used a similar “no regrets” analysis that “balances competing objectives while reducing costs and risk and retaining the flexibility to respond to future risks and opportunities.”¹⁸ The approach overcomes the decision-making dilemma many utilities and regulators face when evaluating numerous scenarios and

□ **Minimizing the Maximum Regret**

Step 1: Calculate the net present value of total system cost (net present value revenue requirement) for each investment option or investment portfolio across all scenarios.

Step 2: Create a matrix of total costs for each investment option in every scenario. Determine the least-cost investment option in each scenario.

Step 3: Calculate a regret score for each investment option across all scenarios by subtracting the least-cost option from each investment option within each scenario. Create a matrix of regret scores.

Step 4: Determine the maximum regret of each investment option by selecting the maximum regret score for each investment option across all scenarios. Determine the investment option with the lowest maximum regret. This option minimizes the maximum forecast regret.

¹⁴ David R. Anderson, Dennis J. Sweeney, Thomas A. Williams, and Kipp Martin, *An Introduction to Management Science: Quantitative Approaches to Decision Making*, 12th ed. (Mason, Ohio: Thomson South-western, 2008).

¹⁵ Robert T. Clemen and Terence Reilly, *Making Hard Decisions* (Pacific Grove, CA: Duxbury, 2001).

¹⁶ Utility regulators do not set a guaranteed profit; they set a rate of return based on a test year. Actual returns vary on the basis of sales and cumulative costs.

¹⁷ A. Colman, *Game Theory and Its Applications* (New York: Routledge Press, 1995).

¹⁸ TVA. *Integrated Resource Plan: TVA's Environmental and Energy Future* (2011), http://www.tva.com/environment/reports/irp/pdf/Final_IRP_complete.pdf.

investment alternatives: is this significant investment in the best interest of our ratepayers, or will we come to regret the decision?

MINIMIZING MAXIMUM REGRET

Although utilities and state regulators typically evaluate large electric system investment decisions using scenario analysis, they do not use the scenario analysis outputs to forecast potential regrets, even though the calculation is relatively easy. A simplified example illustrates the methodology. In this example, a utility evaluates three investment alternatives across four scenarios of future market conditions.¹⁹ It simulates system operations resulting from Investment A in scenarios 1-4, and then those for investments B and C. Utility planners then typically create a matrix populated with the net present value (NPV) total system costs over 20 years for each investment and scenario combination (Table 1).

Table 1. An example of a typical utility generation planning scenario analysis output, depicting NPV total system costs over 20 years for each investment scenario combination.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Investment A	\$ 100 B	\$120 B	\$125 B	\$140 B
Investment B	\$103 B	\$123 B	\$127 B	\$131 B
Investment C	\$110 B	\$125 B	\$128 B	\$130 B

In Table 1, Investment A appears to be the best choice, because it is the least-cost option in three of the four scenarios. Investment B is never the least-cost alternative, and Investment C is only least cost in one scenario.

The utility in this simplified example has several investment options—but in reality, utilities choose from dozens if not hundreds of generation plan alternatives. Although they can choose their investments, they cannot control future market conditions, and therein lies the uncertainty and decision maker’s dilemma. Although Investment A is the least-cost alternative in three of the four scenarios, is it really the utility’s best choice?

Manipulating the matrix with a minimax regret analysis to determine the lower-risk, least regrettable decision yields a different answer. To calculate the regrets of each investment, utility planners would identify the least-cost outcome in each scenario (Table 2).

¹⁹ The four scenarios represent a set of assumptions about and forecasts for key variables, such as fuel prices, environmental regulations, and electricity demand.

Table 2. The least-cost investment for each future scenario is highlighted in red.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Investment A	\$ 100 B	\$120 B	\$125 B	\$140 B
Investment B	\$103 B	\$123 B	\$127 B	\$131 B
Investment C	\$110 B	\$125 B	\$128 B	\$130 B

The regret of each investment in a scenario is calculated as the difference between an investment’s cost and the lowest-cost option in the same scenario. For example, Investment A has a regret of \$0 in Scenario 1, because it resulted in the best possible outcome for that particular future (\$100 B – \$100 B). Investment B yields a \$3 billion regret (\$103 B – \$100 B), and Investment C results in a \$10 billion regret (\$110 B – \$100 B). In other words, if the utility made Investment B or C, and the future ends up as forecast in Scenario 1, it would regret the decision, because a cheaper alternative existed, and ratepayers ultimately paid higher prices than they could have.

Populating a regret matrix makes identifying potential risks relatively easy. Although Investment A is the least-cost option in three scenarios, Table 3 shows that it can also result in a maximum regret of \$10 billion. Investment C is the least-cost option in the remaining scenario, but it can also result in a regret of up to \$10 billion. Costs for Investment B, on the other hand, never deviate significantly from the least-cost option and do not exceed a regret of \$3 billion. Therefore, according to a minimax regret analysis, Investment B is the optimal investment, because it minimizes the maximum regret of the decision. It may not be the least-cost option, but its additional cost acts as a hedge and results in stable, relatively predictable costs for customers.

Table 3. A regrets (additional cost above the optimal investment in each scenario) table derived from tables 1 and 2 quantifies the potential risk for each investment and identifies the alternative that minimizes the maximum regret.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Maximum Regret of Each Investment
Investment A	\$ 0 B	\$0 B	\$0 B	\$10 B	\$10 B
Investment B	\$3 B	\$3 B	\$2 B	\$1 B	\$3 B
Investment C	\$10 B	\$5 B	\$3 B	\$0 B	\$10 B

Applying minimax regret analysis to utility planning

Minimizing the maximum regret is not only a simple approach compatible with existing tools and data, but also a useful method for identifying trends, risks, and opportunities related to various generation plans (such as building new units and retiring others) and future market conditions. The value of this planning method can be illustrated with a more detailed set of generation plan options and scenarios for a hypothetical electric utility.

Model Background and Assumptions

For this example, the 20-year NPV total system costs of four generation plans is calculated for four scenarios for a total of 16 assessments. The total costs are the discounted revenue requirements for the utility, which include system production costs (fuel, variable operations and maintenance, emissions) and fixed costs (costs of new power plants or retrofits, including financing charges to cover debt payments and returns for equity investors). Utilities simulate their systems and quantify their costs in this manner. After a total cost matrix is created, a regret matrix is developed to compare generation plans and understand risks and opportunities associated with different assets.

For this analysis, a simplified production cost model was developed using Microsoft Excel's Solver tool.²⁰ The resulting linear program optimizes the economic dispatch of a generation portfolio to minimize annual production costs over a 20-year period given a set of unit characteristics and 8,760 hours/year load data. Unit characteristics include heat rate, variable operations and maintenance (O&M) costs, emissions rate, and availability (to account for annual maintenance and outage rates, or in the case of solar and wind, the availability of the resource). Fuel and emissions costs assumptions were included to develop different scenarios and to calculate each unit's production cost rate in dollars per megawatt-hour (\$/MWh). The optimization was subject to constraints of unit availability and needed to meet load obligations while maintaining a 15% reserve margin.

Following each model run, the annual production cost output was added to the annual fixed costs for the electricity generating system. Fixed costs include fixed O&M for existing and new units and the annual stream of revenue required for building and financing new power plants or environmental controls. Assumptions for unit characteristics, new unit capital costs and O&M, and environmental control costs were based on Energy Information Administration (EIA) and Edison Electric Institute estimates.²¹ The annual sum of fixed and variable revenue requirements was discounted by a weighted after-tax cost of capital of 8.36% to determine the 20-year NPV of total system costs for the utility and its ratepayers.²²

The hypothetical electric utility included 29 units with a total installed capacity of about 6,800 megawatts (MW) in 2013. Unit types included coal, nuclear, diesel combustion turbines (CTs), natural gas CTs, natural gas combined cycle turbines (CCs), wind, solar, hydro, and demand-side resources. Wind capacity and solar capacity were discounted for reserve margin purposes to account for their intermittency and probable availability during peak demand periods.²³

²⁰ The authors did not have access to proprietary production cost models typically used by electric utilities.

²¹ EIA unit assumptions are from *Updated Capital Cost Estimates for Utility Scale Electricity Generating Plants* (2013), http://www.eia.gov/forecasts/capitalcost/pdf/updated_capcost.pdf. EEI environmental control cost assumptions are from EEl/ICF, *Potential Impacts of Environmental Regulation on the U.S. Generation Fleet* (2011), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2011IRP/EEI_ModelingReportFinal-28January2011.pdf.

²² The after-tax weighted cost of capital assumes a 50:50 ratio of debt and equity financing, with a 6% debt interest rate, 13% return on equity, and a 38% corporate tax rate.

²³ Installed wind capacity received 15% credit toward the reserve margin, and solar capacity received 35% credit. See <http://www.wind-energy-the-facts.org/en/part-2-grid-integration/chapter-6-wind-power-contribution-to-system-adequacy/capacity-credit-of-wind-power/capacity-credit-values-of-wind-power.html> for example wind capacity credits in Germany. *An Evaluation of Solar Valuation Methods Used in Utility Planning and Procurement Processes* (LBNL 2012) presents a range of solar capacity credits used by U.S. utilities in recent planning documents.

Using several years of publicly available load data from the PJM interconnection, an indicative 8,760 hourly load shape was developed for the hypothetical system.²⁴ For all scenarios, peak demand was assumed to be 5,500 MW in 2013 and to grow 0.5% annually.

Generation Plans Evaluated

Four generation plans were developed to simulate the wide variety of choices available to utilities and to identify a low-risk plan. Because peak demand in each scenario remains static, each generation plan adds the same amount of reserve margin capacity during the same periods. For risk-based assessments like this, utilities typically analyze only their near- to medium-term generation decisions, for example, a decision in 2013 to build a combined cycle unit that comes online in 2018 or a nuclear unit that begins commercial operation in 2020. Decisions about what to build to satisfy expected demand far in the future are deferred to allow the utility to adapt to changing market conditions. However, to simplify the present analysis and to illustrate the impacts of shifting to distinct generation portfolios over time, expansion plan decisions are exogenously determined for later years.

The four generation plans vary in terms of coal retirements and types and quantities of resources added in the future (Table 4). Generation plans 1 and 3 rely solely on natural gas units to satisfy future needs. Generation plans 2 and 4 have more diversified expansion plans that augment new natural gas capacity with other resources. Generation Plan 2 adds new wind, nuclear, energy efficiency, and demand response as well as natural gas CCs and CTs. Generation Plan 4 does not build new nuclear capacity, and instead supplements the portfolio with greater wind, solar, energy efficiency, and demand response, along with new natural gas capacity.

Table 4. Generation plan assumptions. FGD = flue gas desulfurization; SCR = selective catalytic reduction; CCR = coal combustion residuals.

	Generation Plan 1	Generation Plan 2	Generation Plan 3	Generation Plan 4
Coal fleet assumptions	850 MW Retire in 2015 425 MW Install SCR/FGD in 2016 925 MW CCR Upgrades in 2018	850 MW Retire in 2015 425 MW Install SCR/FGD in 2016 925 MW CCR Upgrades in 2018	1275 MW Retire in 2015 500 MW CCR Upgrades in 2018	1275 MW Retire in 2015 500 MW CCR Upgrades in 2018
New Unit Assumptions				
2016	300 MW Natural Gas CT 700 MW Natural Gas CC	275 MW Natural Gas CT 600 MW Natural Gas CC 250 MW Wind 50 MW Energy Efficiency 50 MW Demand Response	400 MW Natural Gas CT 1000 MW Natural Gas CC	600 MW Natural Gas CT 475 MW Natural Gas CC 50 MW Solar 200 MW Wind 125 MW Energy Efficiency 150 MW Demand Response
2020	300 MW Natural Gas CC	300 MW Nuclear	300 MW Natural Gas CC	100 MW Demand Response 150 MW Energy Efficiency 100 MW Solar 300 MW Wind
2029	150 MW Natural Gas CT	150 MW Natural Gas CT	150 MW Natural Gas CT	50 MW Energy Efficiency 100 MW Natural Gas CT

The capacity mix of each generation plan changes significantly over the 20-year study period (Figure 2) even though natural gas-fired capacity dominates the mix from the beginning to the end of each plan. The resource diversity differences among plans are evident when comparing plans 1 and 3 with plans 2 and 4.

²⁴ Hourly historical load data for the PJM Interconnection and associated electric distribution companies are available from <http://www.pjm.com/markets-and-operations/ops-analysis/historical-load-data.aspx>.

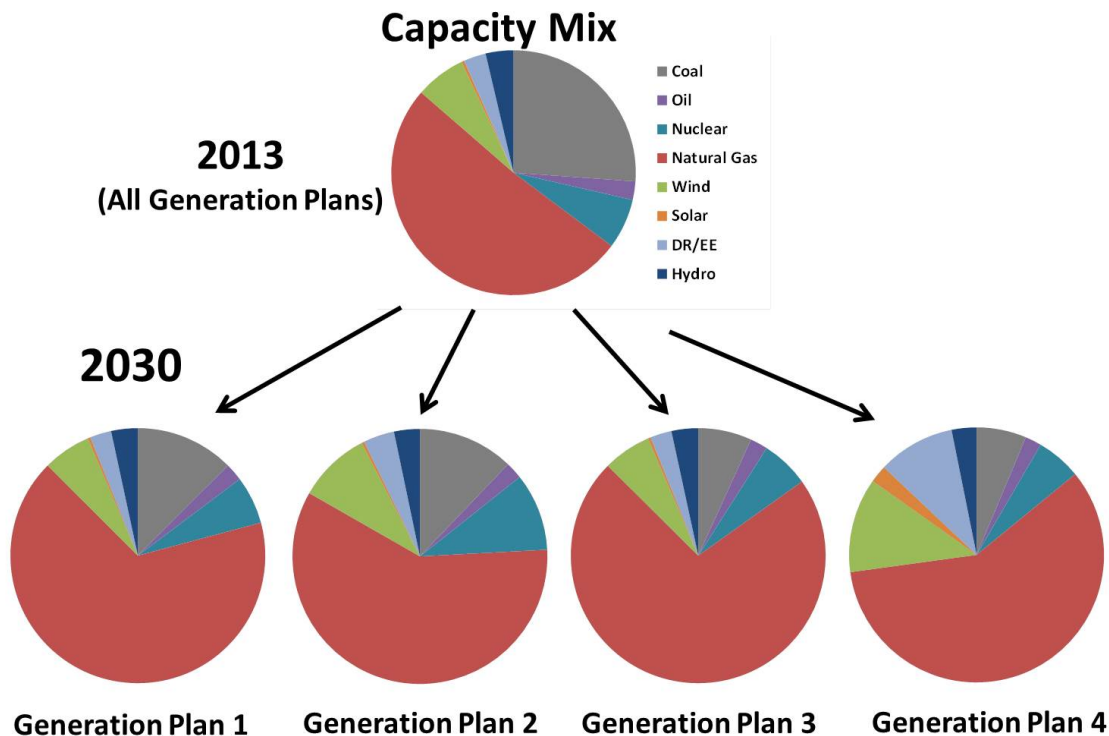


Figure 2. Installed capacity mix in 2013 and 2030 for each generation plan.

Scenarios

Scenario selection is important in minimax regret analysis, because if the selected scenarios do not capture the plausible range of futures for all investment options, the inclusion or exclusion of certain scenarios can predetermine the regret calculations. For example, a minimax regret analysis with a high natural gas price scenario but without a scenario with nuclear cost escalation or other implementation difficulties would lead to high regret scores for natural gas generation investments and likely to low regret scores for a nuclear investment. Therefore, evaluating a wide range of potential scenarios that fully capture the realistic range of all relevant sources of uncertainty is critical.

To simplify the present analysis, each generation plan was simulated through four scenarios of future market conditions. The scenarios and their associated fuel and emissions price data are from the EIA’s *Annual Energy Outlook 2013* (AEO).²⁵ The first scenario is the AEO “Reference Case,” which portrays a business-as-usual future. Because natural gas prices are having a profound impact on the electric industry and will play a growing role in the sector, the analysis includes two scenarios with natural gas prices above and below the Reference Case prices. These scenarios are based on the AEO “High Oil & Gas Potential” case and “Low Oil & Gas Potential” case. Also included is the AEO “Greenhouse Gas \$25” case. This scenario shows the indicative impacts of carbon prices.

Results

To simulate how each generation plan performs in each potential future, scenario fuel and emissions price assumptions were embedded into the production cost model, along with each generation plan, resulting in

²⁵ EIA, *Annual Energy Outlook 2013*, [http://www.eia.gov/forecasts/aeo/pdf/0383\(2013\).pdf](http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf).

16-generation plan-scenario combination model runs. For example, the analysis “hard codes” Generation Plan 1 into the production cost model and then optimizes its economic dispatch in a Reference Case world, in high and low natural gas price environments, and with a GHG policy. The process is repeated with each generation plan, and the subsequent production cost outputs are added to each generation plan’s fixed costs to calculate a 20-year NPV of total cost—or revenue requirements (Table 5).

Table 5. Twenty-year NPV of total cost for each generation plan and scenario combination.

	AEO 2013 Reference Case	AEO 2013 High Oil & Gas Resources (Low Prices)	AEO 2013 Low Oil & Gas Resources (High Prices)	AEO 2013 Greenhouse Gas \$25
Generation Plan 1	\$ 14,130,000,000	\$ 12,050,000,000	\$ 15,590,000,000	\$ 20,570,000,000
Generation Plan 2	\$ 15,000,000,000	\$ 13,230,000,000	\$ 16,220,000,000	\$ 20,860,000,000
Generation Plan 3	\$ 13,950,000,000	\$ 11,790,000,000	\$ 15,610,000,000	\$ 20,280,000,000
Generation Plan 4	\$ 14,050,000,000	\$ 12,260,000,000	\$ 15,430,000,000	\$ 19,720,000,000
Least-Cost Generation Plan in Each Scenario	\$ 13,950,000,000	\$ 11,790,000,000	\$ 15,430,000,000	\$ 19,720,000,000

Determining the least-cost option among the four plan options would be difficult if cost were the only consideration. Generation Plan 3 is the least-cost option in the Reference Case and in the low natural gas price environment, whereas Generation Plan 4 is the least cost option in the remaining two scenarios. Utility planners and regulators may approve Generation Plan 3, because they view the Reference Case and low gas price scenarios as most plausible. However, low-probability events—“black swans”—typically have greater impacts. By failing to account for the less plausible high gas price and greenhouse gas price scenarios, the utility and its regulators may leave customers at risk for higher costs in the future.²⁶

To quantify the risks of regret for each generation plan, a regrets matrix is created by subtracting the lowest-cost plan in every scenario from the cost of each generation plan in that same scenario (Table 6). Generation Plan 1, for example, can result in a regret of \$180 million given the Reference Case future. The regret is the additional cost borne by ratepayers as a result of the utility not choosing the optimal plan for that particular future. This method reveals that the maximum regret for generation plans 1, 2, 3, and 4 are \$850 million, \$1.44 billion, \$560 million, and \$470 million, respectively, for the given scenarios.

²⁶ Nassim Nicholas Taleb, *The Black Swan* (New York: Random House, 2007).

Table 6. Regrets matrix showing the risks of incremental costs (regrets) of each generation plan.

	AEO 2013 Reference Case	AEO 2013 High Oil & Gas Resources (Low Prices)	AEO 2013 Low Oil & Gas Resources (High Prices)	AEO 2013 Greenhouse Gas \$25	Maximum Regret of Each Generation Plan
Generation Plan 1	\$ 180,000,000	\$ 260,000,000	\$ 160,000,000	\$ 850,000,000	\$ 850,000,000
Generation Plan 2	\$ 1,050,000,000	\$ 1,440,000,000	\$ 790,000,000	\$ 1,140,000,000	\$ 1,440,000,000
Generation Plan 3	\$ -	\$ -	\$ 180,000,000	\$ 560,000,000	\$ 560,000,000
Generation Plan 4	\$ 100,000,000	\$ 470,000,000	\$ -	\$ -	\$ 470,000,000

Therefore, Generation Plan 4 is the optimal investment, because it has the lowest possible regret across the scenarios. Moving forward with this plan may not yield the lowest cost in a reference case or low gas price environment, but its costs do not deviate widely from the lowest-cost option, and it will not yield the highest costs.

Why does Generation Plan 4 perform well across all scenarios? The diversity and flexibility of its resources. A minimax regret analysis essentially optimizes the system to create a portfolio that hedges against a range of risks and avoids the perils that can arise from overreliance on a particular resource.²⁷ Generation Plan 4 allows the utility to respond to changing market conditions by switching generation from one fuel resource to another. Thus, the utility can mitigate risks associated with rising fuel prices or take advantage of falling fuel prices. Generation Plan 4 does not build enough natural gas capacity to take full advantage of a low gas price environment, but it does offer protection against rising fuel prices and potential GHG rules. The portfolio in essence becomes a hedge. The additional costs of Generation Plan 4 in certain scenarios can be viewed as an insurance premium for cost certainty and reduced cost volatility.

Using this methodology also ensures a balance between capital cost and operating cost risks. The majority of risks with fossil fuel plants like coal and natural gas are on the operating side of the equation. If natural gas prices increase, customers will pay higher prices. With renewables like wind and solar, however, the risk is on the capital cost, because production costs are predictable and close to \$0/MWh. Because the analysis takes into account the total costs of building and operating an electric system, it ensures that utilities and their regulators do not overbuild wind and solar resources. Doing so would increase the capital cost requirements of their plan and potentially lead to regrets, as evidenced by Generation Plan 2, which called for an expansion plan similar to that of Generation Plan 4. However, Generation Plan 2 included a nuclear investment, which increased the capital costs and total cost of the plan, leading to greater possible regrets than Generation Plan 4.

²⁷ In a minimizing the maximum regret analysis, failing to include scenarios that cover the full range of uncertainties for all investment options and generation portfolios will likely result in undervaluation of the risk of select investment options and generation portfolios.

Generation Plan 4 reflects the optimal mix of renewables, energy efficiency, and traditional resources as well as the optimal mix of capital and operating costs. It highlights the innate hedging capabilities of wind, solar, and energy efficiency resources—capabilities that regret scores can quantify, unlike traditional scenario analysis. By capturing the hedging value of wind, solar, and energy efficiency, a minimax regret analysis can increase adoption of these resources.

CONCLUSIONS

Current lowest-cost planning techniques adopted by utilities and utility regulators may inadequately account for potential future cost risks. Identifying a single least-cost plan using traditional planning methods is often impossible given uncertain and quickly evolving conditions in the electric power sector. The least-cost plan in one scenario can lead to high costs in another scenario. Utilities and their regulators may come to regret some of the investments they make today and ultimately saddle ratepayers with higher costs than they otherwise would have.

Shifting the planning approach from a lowest-cost metric to a lowest-risk metric can reduce risks of regrets and incremental ratepayer costs. Some uncertainty planning methods, such as stochastic optimization and robust decision-making, require new tools and methodologies. By contrast, a minimax regret analysis is compatible with existing planning techniques. It takes outputs, such as production costs and fixed costs, from existing scenario analyses and evaluates them in light of a balance of low-cost and low-risk considerations, rather than from the perspective of a least-cost objective.

The example above shows how utilities and regulators can adopt this method and indicates the benefits of doing so. By analyzing several potential generation plan options across a wide range (such as 10 to 15) scenarios, utilities and regulators can avoid making investments that reduce the flexibility of the electric system to respond to changing market conditions. Utilities and regulators may find minimax regret analysis is an attractive approach to supplement their current planning efforts.

Minimax regret analysis can identify the optimal blend of resources to create a diverse, resilient portfolio that ensures utilities do not rely too heavily on one resource over another. Even if the optimal plan in a minimax regret analysis does not result in the lowest-cost option, it will give utilities, regulators, and ratepayers increased price certainty, because it will reduce cost volatility. Moreover, that cost certainty can help attract new businesses and industries by allowing them to efficiently plan their own investments.

Minimizing the maximum regret is also a useful tool for assessing the risk-reduction benefits of energy efficiency programs, renewable resources like wind and solar, and generation diversity in general. In some regions, these investments have difficulty overcoming the least-cost barrier due to their upfront capital costs, which are higher than those of traditional electricity generating facilities. The minimax regret analysis accounts for these higher capital costs but also highlights the value that the investments add by hedging fuel price risks and creating a resilient system.



Energy solutions
for a changing world

Best Practices in Electric Utility Integrated Resource Planning

Examples of State Regulations
and Recent Utility Plans

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The Regulatory Assistance Project (RAP) is a global, non-profit team of experts focusing on the long-term economic and environmental sustainability of the power and natural gas sectors. RAP has deep expertise in regulatory and market policies that promote economic efficiency, protect the environment, ensure system reliability, and allocate system benefits and costs fairly among all consumers.

RAP works extensively in the European Union, the US, China, and India. We have assisted governments in more than 25 nations and 50 states and provinces. In Europe, RAP maintains offices in Brussels and Berlin, with a team of more than 10 professional experts in power systems, regulation, and environmental policy. For additional information, visit the RAP website www.raonline.org.

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Executive Summary

An integrated resource plan is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. For utilities, integrated resource planning is often quite time- and resource-intensive. Its benefits are so great, however, particularly to consumers, that utilities are frequently required by state legislation or regulation to undertake planning efforts that are then reviewed by state public utilities commissions (PUCs). (In this document, the acronym IRP is used, depending on the context, to denote either an integrated resource plan or the process of integrated resource planning.)

IRP rules governing utilities have been created in a number of ways. Bills that mandate integrated resource planning have been passed into law by state legislatures; rules have been codified under state administrative code; and state utility commissions have adopted IRP regulations as part of their administrative rules, or have ordered it to be done as a result of docketed proceedings. Although some state IRP rules have remained unchanged since they were first implemented, other states have amended, repealed, and in some cases reinstated their IRP rules. Examples can be found in the rules of Arizona, Colorado, and Oregon. Rules that have been amended recently often reflect current concerns in the electric industry—e.g., fuel costs and

volatility, the effects of power generation on air and water, issues of national security, electricity market conditions, and climate change, as well as individual state concerns.

There are, however, certain subject-matter areas that are essential to resource planning on which state regulations are silent. Utilities must use their discretion in determining how best to address these areas in their resource plans. This paper provides utilities, commissions, and legislatures with guidance on these subject-matter areas. Section III summarizes three recent utility IRPs from the states mentioned above, in an effort to determine both best practices in integrated resource planning and ways in which utilities can improve their planning processes and outcomes. Section IV then presents a series of recommendations, developed from these examples, for integrated resource planning and its resulting plans.

For an IRP process to be deemed successful, it should include both a meaningful stakeholder process and oversight from an engaged public utilities commission. A successful utility's resource plan should include consideration in detail of the following elements: a load forecast, reserves and reliability, demand-side management, supply options, fuel prices, environmental costs and constraints, evaluation of existing resources, integrated analysis, time frame, uncertainty, valuing and selecting plans, action plan, and documentation. Section IV describes in detail the elements of both the process and the plan.

Introduction

As energy demand across the United States rises and falls and the generation fleet ages, utilities must plan to add and retire resources in the most cost-effective manner while meeting regional reliability standards. Integrated resource planning began in the late 1980s, as states looked for a way to respond to the oil embargos and nuclear cost overruns of the previous decade—and ever since, it has been an accepted way in which utilities can create long-term resource plans. State requirements for resource plans vary in terms, among other things, of planning horizon, the frequency with which plans must be updated, the resources required to be considered, stakeholder involvement, and the actions that public utilities commissions should take in reference to the plan (review, acknowledge, and accept or reject the plan).

As the electric industry began to restructure in the mid-1990s, integrated resource planning rules in many states were repealed or ignored. Some states have since made an effort to update IRP rules to make them applicable to current industry conditions, while other states have continued to use rules that are now out of date. This report describes IRP requirements in three states that have recently updated their regulations governing the planning process, and it reviews the most recent resource plan

from the largest utility in each of those states. Rules from Arizona, Colorado and Oregon are described in detail, in order to demonstrate ways in which states can require comprehensive planning processes and resource plan outcomes from the utilities under their jurisdictions.

These particular states were chosen not only because their rules have recently been updated, but also because the guidance they provide to electric utilities offers examples of best practices in integrated resource planning. The updated rules have been designed to give thoughtful consideration to specific resources that have traditionally been ignored, and to produce outcomes that are in the best interests of both ratepayers and society as a whole. Utility resource plans from Arizona Public Service, Public Service Company of Colorado, and PacifiCorp utilize progressive methodologies and contain modern elements that contribute to the production of high-quality plans that are useful examples of superior resource planning efforts.

This report is intended to be helpful to policymakers, public utility commissions and their staff, ratepayer advocates, and the general public as they each consider the ways in which utility resource planning can best serve the public interest.

I. The Purpose and Use of Integrated Resource Planning

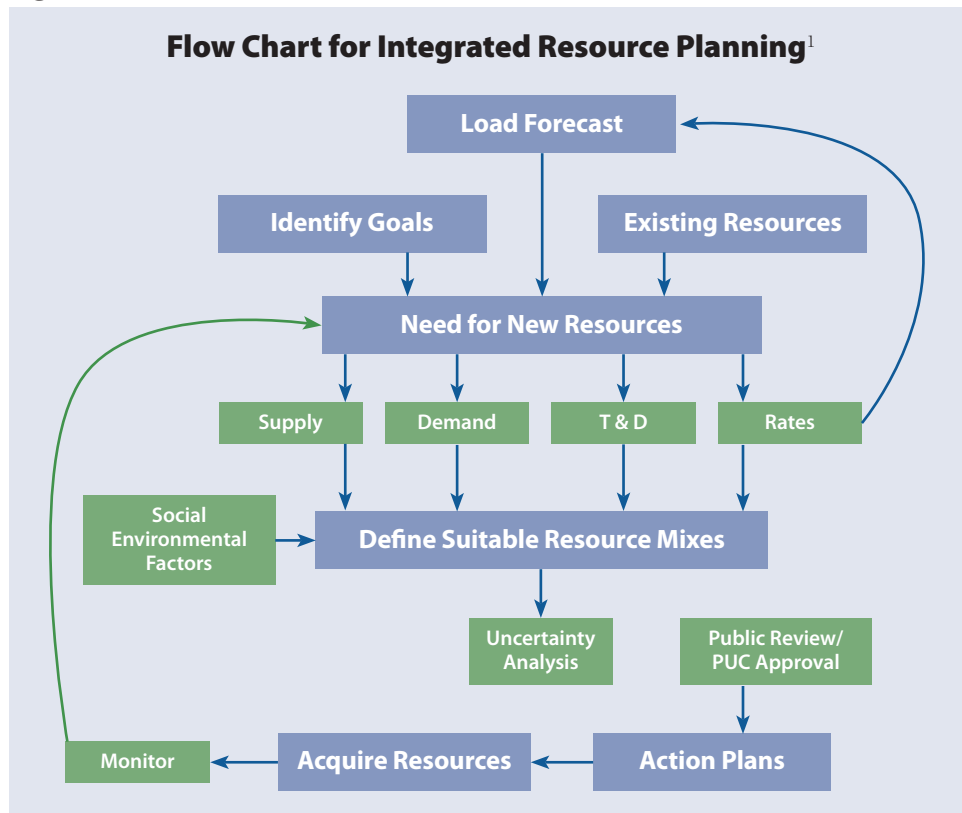
An integrated resource plan, or IRP, is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. Steps taken in the creation of an IRP include:

- forecasting future loads,
- identifying potential resource options to meet those future loads,
- determining the optimal mix of resources based on the goal of minimizing future electric system costs,
- receiving and responding to public participation (where applicable), and
- creating and implementing the resource plan.

Figure 1 shows these steps in a flow chart.

Integrated resource planning has many benefits to consumers, and other positive impacts on the environment. This is a planning process that, if correctly implemented, locates the lowest practical costs at which a utility can deliver reliable energy services to its customers. IRP differs from traditional planning in that it requires utilities to use analytical tools that are capable of fairly evaluating and comparing the costs and benefits of both demand- and supply-side resources.² The result is an opportunity to achieve lower overall costs than might result from considering only supply-side options. In particular, the inclusion of demand-side options presents more possibilities for saving fuel and reducing negative environmental impacts than might be possible if only supply-side options were considered.³

Figure 1



- 1 Hirst, E. A Good Integrated Resource Plan: Guidelines for Electric Utilities and Regulators. Oak Ridge National Laboratory. December 1992. Page 5. As it appears in Harrington, C., Moskovitz, D., Austin, T., Weinberg, C., & Holt, E. Integrated Resource Planning for State Utility Regulators. The Regulatory Assistance Project. June 1994.
- 2 Integrated Resource Planning for State Utility Regulators. Available at: <http://www.raponline.org/document/download/id/817>
- 3 Kushler, M. & York, D. Utility Initiatives: Integrated Resource Planning. July 2010. American Council for an Energy-Efficient Economy. Available at: <http://aceee.org/policy-brief/utility-initiatives-integrated-resource-planning>

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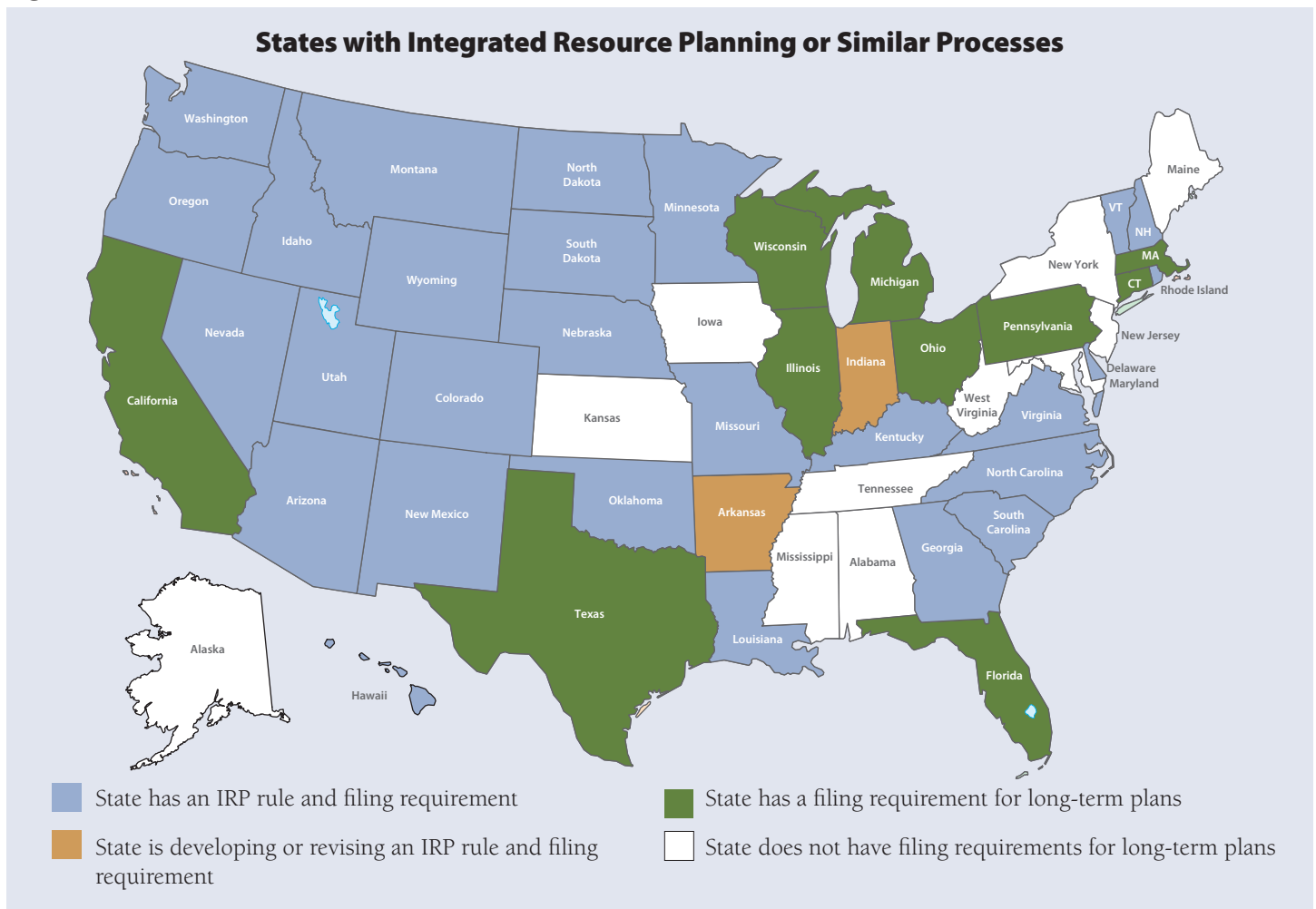
In general, IRP focuses on minimizing customers’ bills rather than on rates—but an overall reduction in total resource cost achieved through the efficient use of energy will lower average energy bills. As a result, all customers benefit from the lower system costs that IRP achieves.⁴

Alternatives examined by system planners in an IRP setting include adding generating capacity (thermal, renewable, customer-owned, or combined heat and power), adding transmission and distribution lines, and implementing energy efficiency (EE) and demand response programs. Common risks that are addressed by scenario or sensitivity analyses

in IRPs include fuel prices (coal, oil, and natural gas), load growth, electricity spot prices, variability of hydro resources, market structure, environmental regulations, and regulations on carbon dioxide (CO₂) and other emissions.⁵

Resource planning requirements exist in many states, but may differ significantly from state to state. Utilities that create more than one resource plan in the same state may have different processes for creating those plans and may arrive at significantly different conclusions, despite being governed by the same regulations. Figure 2 shows the states that have IRP or long-term planning requirements.⁶

Figure 2



4 Id footnote 2.

5 Hopper, C. & Goldman, N. Review of Utility Resource Plans in the West. Lawrence Berkeley National Laboratory. Presentation at the New Mexico PRC IRP Workshop, Santa Fe. June 8, 2006. Slide 17.

6 For a complete list of the rules and regulations associated with integrated resource planning in the states, see Appendix 1.

II. Examples of State Integrated Resource Planning Statutes and Regulations

State IRP rules have been established in a number of ways. In certain states, legislatures have passed bills into law mandating that utilities engage in resource planning; in others, IRP rules have been codified under state administrative code. Some state utility commissions have adopted integrated resource planning regulations as part of their administrative rules, or have ordered it through docketed proceedings. Rules can also be developed through a combination of these processes. Various state IRP rules and their individual requirements are discussed in the sections below.

A. IRP Planning Horizons

Integrated resource plans are long-term in nature, but these planning periods vary according to state regulations. Table 1 lists the length of planning horizons typically found in IRP rules, as well as the states that have implemented

Table 1

Planning Horizons Found in IRP Rules	
Planning Horizon	States with Specified Planning Horizon
10 years	Arkansas, Delaware, Oklahoma, South Dakota, Wyoming
15 years	Arizona, Kentucky, Minnesota, North Carolina, South Carolina, Virginia
20 years	Georgia, Hawaii, Idaho, Indiana, Louisiana, Missouri, Nebraska, Nevada, New Mexico, North Dakota, Oregon, Utah, Vermont, Washington
Multiple periods	Montana
Utility determined	Colorado
Not specified	New Hampshire

these various planning horizons as a part of their rules.

The most common planning horizon spans a 20 year period, with half of the IRP states mandating this planning period.

B. Frequency of Updates

Utility integrated resource plans must be updated periodically to reflect changing conditions with respect to load forecasts, fuel prices, capital costs, conditions in the electricity markets, environmental regulations, and other factors. IRP updates are typically required every two to three years, as shown in Table 2, below.

Montana appears twice in Table 2, as traditional utilities are required to file IRPs every two years, while restructured utilities are required to file updates every three years. There are some exceptions to the typical update requirements of

Table 2

Frequency of IRP Updates, as Determined by State Rules	
Planning Horizon	States with Specified Planning Horizon
Every two years	Arizona, Delaware, Idaho, Indiana, Minnesota, Montana, New Hampshire, North Carolina, North Dakota, Oregon, South Dakota, Utah, Virginia, Washington
Every three years	Arkansas, Georgia, Hawaii, Kentucky, Louisiana, Montana, Missouri, Nevada, New Mexico, Oklahoma, South Carolina, Vermont
Every four years	Colorado
Every five years	Nebraska
Not specified	Wyoming

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two to three years. Nebraska, for example, has a five year requirement for updates and is the only state to be made up entirely of public power utilities, many of which are customers of the Western Area Power Administration (WAPA). Pursuant to the Energy Policy Act of 1992, municipally-owned utilities are required to prepare resource plans every five years, but do not have to make those plans publicly available. Most Nebraska utilities must comply with both WAPA IRP requirements as well as state IRP requirements.

C. Resources Evaluated in Integrated Resource Planning

Generally, state rules mandate that utilities consider all feasible supply-side, demand-side, and transmission resources that are expected to be available within the specified planning period. Many state IRP requirements make no specifications for resources that must be evaluated beyond this. Other states have gone into further detail about the resources that should be investigated, including:

- **Delaware** – utilities shall identify and evaluate all resource options, including: generation and transmission service; supply contracts; short and long-term procurement from demand-side management (DSM), demand response (DR) and customer sited generation; resources that utilize new or innovative baseload technologies; resources that provide short or long-term environmental benefits; facilities that have existing fuel and transmission infrastructure; facilities that utilize existing brownfield or industrial sites; resources that promote fuel diversity; resources or facilities that support or improve reliability; and resources that encourage price stability.⁷
- **Indiana** – utilities shall examine: all existing supply and demand-side resources and existing transmission; all potential new utility electric plant options and transmission facilities; all technologies and designs expected to be available within the twenty-year planning period, either on a commercial scale or demonstration scale; and a comprehensive array of demand side measures, including innovative rate design.⁸
- **Kentucky** – utilities shall evaluate improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities.⁹

There are state IRP rules that specify not only the resources that must be evaluated, but also the amount of weight given to a particular resource by either the utilities or the Public Service/Utilities Commissions. Colorado is one such state, and is described in more detail in later sections.

In almost all cases, state integrated resource planning rules have specific requirements for the planning horizons that should be covered, the frequency with which utility plans must be updated, and the generating resources that should be considered. Some states require nothing more, while others might also require, for example: 1) a certain number or a certain type of scenario analysis; 2) that certain types of resource cost tests be used to evaluate demand-side management policies; or 3) that externalities be considered by utilities when creating resource plans. Requirements for generating unit retirements and associated decommissioning costs are another example of something that some states might include in integrated resource planning rules, while others might not. The next section describes the discussion of this type of requirement in state IRP regulations.

D. Retirements and Decommissioning

Integrated resource planning is generally understood to be primarily concerned with the addition of resources in order to meet growing demand for electricity, and very few IRP rules mandate that utilities address end-of-life issues for generating units in their resource plans. In a summary document on integrated resource planning, the Regulatory Assistance Project states that “as utilities compare the cost of each supply- and demand-side option, they need to capture the entire life-cycle cost. This life-cycle cost means the fixed and variable costs incurred over the life of the investments: construction, operation, maintenance, and fuel costs.”¹⁰ This description does not represent the full

-
- 7 HB 6, the Delaware Electric Utility Retail Customer Supply Act of 2006.
 - 8 170 Indiana Administrative Code 4-7-1: Guidelines for Integrated Resource Planning by an Electric Utility.
 - 9 Kentucky Administrative Regulation 807 KAR 5:058: Integrated resource planning by electric utilities.
 - 10 Harrington, et al. Integrated Resource Planning for State Utility Regulators. The Regulatory Assistance Project. June 1994. Page 14.

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life of the investment, however, as it does not specifically include the costs associated with the retirement and decommissioning of a resource.

State IRP rules and utility filings reflect this incomplete assessment of life-cycle costs. Twenty-seven states have IRP rules and 20 of them are silent with respect to unit retirements. Utah and Colorado require that utility filings include information about the life expectancies of the generating units in the resource plans. Three states – New Mexico, North Carolina, and South Dakota – are slightly more specific, and mandate that utilities provide expected retirement dates for generating facilities. Specifically, the utilities in each of the states are required to do the following:

- **Utah** – include the life expectancy of generating resources
- **Colorado** – provide the estimated remaining useful lives of existing generation facilities without significant new investment or maintenance expense
- **New Mexico** – give the expected retirement dates for existing generating units
- **North Carolina** – provide a list of units to be retired from service (applies to both existing and planned generating facilities), with the location, capacity and expected date of retirement
- **South Dakota** – include those facilities to be removed from service during the planning period, along with the projected date of removal from service and the reason for removal

There are only two state rules that make any mention of decommissioning costs:

- Arizona rules state that if the discontinuation, decommissioning, or mothballing of any power source or the permanent derating of any generating facility is expected, the utility must provide:
 - i. Identification of each power source or generating unit involved,
 - ii. The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating, and
 - iii. The reasons for each discontinuation, decommissioning, mothballing, or derating.”¹¹
- Georgia laws and rules state that “Total cost estimates for proposed projects must include construction and non-construction related costs incurred through commercial operation, including decommissioning/dismantlement costs.”¹²

Rather than being addressed in utility integrated resource plans, generating unit retirements and associated decommissioning costs are largely left to be dealt with in other cases and proceedings that are brought before Public Utilities/Service Commissions.

E. Long-term Procurement Planning Requirements

As the electric industry began to restructure in the mid-1990s, many states that had integrated resource planning requirements either repealed them with restructuring laws, or simply began to ignore them. Some states eventually replaced integrated resource planning laws with rules for resource procurement plans. A document designed to inform California’s 2010 Long-Term Procurement Plan (LTPP) requirement surveys the ways in which utilities in other states create their resource plans. The document states that “[w]hile California utilities have not undertaken a full integrated resource planning effort in many years, the 2010 LTPP proceeding is considering the appropriate role of utility resource planning in procuring the resources needed to meet state policy goals.”¹³

Requirements for procurement plan filings differ from requirements for integrated resource plans. Planning periods are typically ten years, with some states requiring only a five year planning period. Procurement plans are usually required to be updated every year. Because utilities

- 11 Arizona Corporation Commission Decision No. 71722, in Docket No. RE-00000A-09-0249. June 3, 2010. Page 13. Amends Arizona Administrative Code Title 14, Chapter 2, Article 7, “Resource Planning.” Available at: <http://images.edocket.azcc.gov/docketpdf/0000112475.pdf>
- 12 Integrated Resource Planning Act of 1991 (O.C.G.A. § 46-3A-1), Amended. See also: Georgia Public Service Commission, General Rules, Integrated Resource Planning 515-3-4. Available at: http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1
- 13 Aspen Environmental Group and Energy and Environmental Economics, Inc. Survey of Utility Resource Planning and Procurement Practices for Application to Long-Term Procurement Planning in California - DRAFT. Prepared for the California Public Utilities Commission. September 2008. Page 1.

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in these states operate in a deregulated market and do not own generation, procurement plans evaluate purchases for capacity and energy, as well as energy efficiency and other demand-side management programs.

Connecticut is one such state that used to have an integrated resource planning requirement, and now has a requirement for procurement plans. The state had IRP regulations in place by the late 1980s, but this requirement was repealed when the restructuring law (Public Act 98-28) was passed in 1998. A long-term procurement planning law then became effective in 2007 (Public Act 07-242). Plans submitted to the Connecticut Energy Advisory Board in compliance with the 2007 law have much in common with utility IRPs and have even been called “Integrated Resource Plans,” though they are technically long-term procurement plans.

The following section describes the ways in which IRP rules have been made in Arizona, Colorado, and Oregon, and presents some of the specifics of each of those rules.

1. Arizona

The Arizona Corporation Commission (ACC) has been given both constitutional and statutory authority to oversee the operations of electric utilities, and to engage in rulemaking that includes the establishment of IRP regulations. Article 15 of the Arizona Constitution created the ACC, which oversees the operations of all public service corporations in the state, including investor-owned electric utilities. The Commission is given exclusive authority to establish rates, enact rules that are reasonably necessary in ratemaking, and determine what sort of regulation is reasonably necessary for effective ratemaking,¹⁴ as established in Article 15, §3:

The Corporation Commission shall have full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the State for service rendered therein, and make reasonable rules, regulations, and orders, by which such corporations shall be governed in the transaction of business within the State... and make and enforce reasonable rules, regulations, and orders for the convenience, comfort, and safety, and the preservation of the health, of the employees and patrons of such corporations...

Utility practices in Arizona are not governed by legislation or by statute, but rather through administrative

code created by rulemaking proceedings of the Arizona Corporation Commission. Renewable energy requirements, distributed energy resource requirements, and integrated resource planning reporting requirements have all been established in this way.

The ACC has the authority to require that electric utilities provide reports concerning both past business activities and future plans. Integrated resource plans fall into this category. Article 15, §13 of the Arizona Constitution states that “[a]ll public service corporations... shall make such reports to the Corporation Commission, under oath, and provide such information concerning their acts and operations as may be required by law, or by the Corporation Commission.” Arizona Revised Statute §40-204(A) expands on this requirement, stating that:

Every public service corporation shall furnish to the Commission, in the form and detail the Commission prescribes, tabulations, computations, annual reports, monthly or periodical reports of earnings and expenses, and all other information required by it to carry into effect the provisions of this title and shall make specific answers to all questions submitted by the Commission.

Regulating and requesting information regarding the resource portfolios of electric utilities is one way in which the ACC meets its constitutional and statutory obligations to ensure that just and reasonable rates are being charged to consumers of electricity. In this pursuit, the ACC adopted the state’s first Resource Planning and Procurement Rules in February 1989, requiring that utilities owning electric generation facilities file historical data every year, and 10-year resource plans every three years. The rules also provide for a Commission hearing to review these filings. In accordance with the rules, the first round of utility IRPs were filed in 1992 and hearings were held. In 1995, however, the Commission suspended the obligation of the electric utilities to file future resource plans until IRP rules could be modified to be consistent with impending electric industry competition and the passage of the retail electric competition rules.¹⁵

14 Arizona Corporation Comm’n v. Woods, 171 Ariz. 286, 294 (“Woods”).

15 The Commission adopted retail electric competition rules in Decision No. 59943, dated December 26, 1996.

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In revising the IRP rules, Commission staff were required to hold workshops, open to all stakeholders and to the public, on specific resource planning topics. These workshops:

*Were to focus on developing needed infrastructure and a flexible, timely, and fair competitive procurement process; and were to consider whether and to what extent competitive procurement should include consideration of a diverse portfolio of purchased power, utility-owned generation, renewables, demand-side management, and distributed generation.*¹⁶

Following the workshops, a docket was opened for proposed rulemaking regarding resource planning, and on June 3, 2010 in Decision No. 71722, the Commission amended the Arizona Administrative Code Title 14, Chapter 2, Article 7, Resource Planning. In the most significant changes, compared to the original rules, the revised IRP rules:

- Extend the forecasting and planning horizon from 10 years to 15 years;
- Require submissions of utility IRPs every even-numbered year rather than every third year;
- Require load-serving entities to include, in their IRP, data regarding air emissions, water consumption, and tons of coal ash produced;
- Require that environmental impacts related to air emissions, solid waste, and other environmental factors and reduction of water consumption be analyzed and addressed in utility plans;
- Require that plans address costs for compliance with current and projected environmental regulations;
- Require that the resource plans include energy efficiency, to meet Commission-specified percentages;
- Require that the resource plans include renewable resources, to meet the specified percentages in Arizona Administrative Code R14-2-1804;
- Require that the resource plans include distributed energy resources, to meet the specified percentages in Arizona Administrative Code R14-2-1805;
- Require that utilities submit a work plan in every odd year that outlines the upcoming 15-year resource plan, and lays out: 1) the utility's method for assessing potential resources; 2) the sources of its current assumptions; and 3) a general outline of the procedures it will follow for public input, which includes an outline of the timing and extent of public

participation and advisory group meetings that will be held before the resource plan is completed and filed.¹⁷ Before they file the resource plan, utilities are required to provide an opportunity for public input. ACC practice also allows for public comment on the completed resource plan after it has been filed by the utility.

In the revised rulemaking proceedings emphasis was placed on diversifying the resource base in utilities' generation portfolios; on lowering costs through decreased reliance on volatile fossil-fuel based generation; and on considering and addressing environmental impacts, such as air emissions, coal ash, and water consumption.¹⁸ Utilities must also submit a set of analyses to identify and assess the errors, risks, and uncertainties in: demand forecasts; the costs of DSM measures and power supply; the availability of sources of power; the costs of compliance with current and future environmental regulations; fuel prices and availability; construction costs, capital costs and operating costs; and any other factors the utility wishes to consider. This assessment should be done using sensitivity analysis and probabilistic modeling analysis.¹⁹ The utility should provide a description of the ways in which these errors, risks, and uncertainties can be managed (e.g., by obtaining additional information, limiting risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects), along with a plan to do so.²⁰

Following the review of the utility IRP, the Commission is required to file an order that either acknowledges the resource plan (with or without amendment) or states the reasons for not acknowledging it.

The first electric utility IRPs filed under the revised rules were submitted to the ACC in 2012. The filing from Arizona Public Service (APS) is discussed in later sections.

16 Arizona Corporation Commission. Decision No. 71722. Docket No. RE-00000A-09-0249. June 3, 2010.

17 Id.

18 Id. Page 12.

19 Arizona Corporation Commission. Decision No. 71722. Docket No. RE-00000A-09-0249. June 3, 2010. Exhibit A: Notice of Proposed Rulemaking. Page 42.

20 Id. Page 43.

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2. Colorado

Title 40 of the Colorado Revised Statutes establishes the state Public Utilities Commission and gives it authority to regulate the public utilities located within the state, specifically with regard to “the adequacy, installation, and extension of the power services and the facilities necessary to supply, extend, and connect the same.”²¹ Title 40 also contains all of the legislative requirements with which Colorado’s public utilities must comply, and prescribes the general methods by which the PUC should evaluate compliance.

The evaluation process is described in more detail in 4 Code of Colorado Regulations (CCR) 723-3: Rules Regulating Electric Utilities. This section of the code describes the rules promulgated by the Public Utilities Commission to establish the process for determining the need for additional electric resources by those electric utilities subject to the Commission’s jurisdiction, and for developing cost-effective resource portfolios to meet such need reliably.²² The rules, in their current form, were adopted in 2003 and were referred to as *least-cost planning* rules. Beginning in 2003, utilities were required to file resource plans every four years, and may file an interim plan if changed circumstances justify the filing.

Utilities may choose their own planning period, but that period must be at least 20 and no more than 40 years. Utilities may also specify the resource acquisition period they will follow, which will be between the first six and ten years of the planning period. The planning period is both the time frame for which the resource plan is developed, and the long-term period over which the net present value of revenue requirements is calculated. The resource acquisition period represents the near-term period in which the utility must actually acquire resources to meet system energy and demand requirements. For any resources they propose to acquire, utilities file needs assessments and draft requests for proposals (RFPs). The PUC may approve, deny, or order modifications to utility plans. Following PUC approval, utilities then begin the competitive bidding process to acquire the new resources needed to meet load and reserve requirements.

Over the past decade, the PUC has opened several docketed proceedings and issued emergency rules revising the least-cost planning rules to provide specific guidelines for utilities, and to ensure compliance with new legislation adopted by Colorado state government.

In Decision No. C07-0829 of September 19, 2007, the PUC adopted emergency rules modifying LCP rules as required by bills enacted in the 2006 and 2007 sessions of the Colorado Legislature. In general, these bills required the PUC to consider not only the costs of new generation resources as prescribed in least-cost planning rules, but also various benefits, requiring more technical expertise and involvement from the PUC in the resource selection process.²³

Specifically, the following bills required the associated changes:

- HB07-1037 establishes requirements for energy efficiency and demand-side management resources, and requires the PUC to shift from a least-cost planning standard to a more subjective consideration of multiple criteria “which will require substantially more Commission involvement in the resource selection process.”²⁴ The criteria shift applies to the evaluation of all resources, not only demand-side management (DSM)²⁵ measures.
- HB07-1281 increases the renewable energy resources that electric utilities must acquire, necessitating greater integration between the resource planning rules and the new Renewable Energy Standards.
- SB07-100 is intended to improve the economic viability of rural renewable resources. The bill provides for the designation of energy resource zones, and for the construction of transmission infrastructure to bring energy from these zones to load centers.
- HB06-1281 requires the Commission “to give the fullest possible consideration to new clean and energy efficient technologies... (and) provides an

21 Colorado Revised Statutes 40-1-103.

22 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3601.

23 Colorado Public Utilities Commission. Decision No. C07-0829. Docket No. 07R-0368E. September 19, 2007.

24 Id. Page 7.

25 Demand-side management , or DSM, measures involve reducing electricity use through activities or programs that promote electric energy efficiency or conservation, or more efficient management of electric energy loads.

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example of how the Commission can give such consideration to resources that may be in the public interest when accounting for the benefits of advancing the development of a particular resource, or when accounting for other benefits outside of a strict cost perspective.”²⁶

The statutory language describes some of those benefits:

*The Commission shall give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies in its consideration of generation acquisitions for electric utilities, bearing in mind the beneficial contributions such technologies make to Colorado’s energy security, economic prosperity, environmental protection, and insulation from fuel price increases. The Commission shall consider utility investments in energy efficiency to be an acceptable use of ratepayer moneys.*²⁷

As a result of the various bills described above, the PUC chose to strike the term “least-cost” from the rules in all instances, changing their title to Resource Planning Rules. It also introduced the term cost-effective into the rules, defining it as “the reasonableness of costs and rate impacts in consideration of the benefits offered by new clean energy and energy-efficient technologies.”²⁸ These and other emergency rules were adopted on a permanent basis in Decision No. C07-1101 in Docket No. 07R-419E.

Other significant changes to the Resource Planning Rules were adopted by the PUC in 2010 in response to the passage of HB10-1365, known as the Clean Air-Clean Jobs Act (CACJA). The legislative declaration of the Act states that:

*The general assembly hereby finds, determines, and declares that the federal “Clean Air Act,” 42 U.S.C. sec. 7401 et seq., will likely require reductions in emissions from coal-fired power plants operated by rate-regulated utilities in Colorado. A coordinated plan of emission reductions from these coal-fired power plants will enable Colorado rate-regulated utilities to meet the requirements of the federal act and protect public health and the environment at a lower cost than a piecemeal approach. A coordinated plan of reduction of emissions for Colorado’s rate-regulated utilities will also result in reductions in many air pollutants and promote the use of natural gas and other low-emitting resources to meet Colorado’s electricity needs, which will in turn promote development of Colorado’s economy and industry.*²⁹

The Act required that all utilities owning or operating

coal-fired generating units in Colorado file an emissions reductions plan, which may include the following elements: emission control equipment, retirement of coal-fired units, conversion of coal units to natural gas, long-term fuel agreements, new natural gas pipelines, increased utilization of existing natural gas resources, and new transmission infrastructure. The CO Department of Public Health and the Environment and the PUC were tasked with reviewing the utility filings.

Approval of the plans is contingent on several factors, including whether required emissions reductions would be achieved; whether the plan promotes economic development in the state; whether reliable electric service is preserved; and the degree to which the plan increases the utilization of natural gas or relies on energy efficiency or other low-emitting resources. Plans were to be filed by August 15, 2010, and full implementation is to occur by December 31, 2017.³⁰

While required emissions reduction plans were separate from Electric Resource Plans, the PUC opted to revise and clarify Electric Resource Planning (ERP) rules to make them more consistent with the CACJA. The PUC adopted revised rules on July 29, 2010 in Decision No. C10-0958 as part of Docket No. 10R-214E. Significant changes to the rules include:

- Adoption as the policy of the state of Colorado that the PUC give the fullest possible consideration to the cost-effective implementation of new clean energy and energy-efficient technologies.
- Inclusion in the resource plan of the annual water withdrawals and consumption for each new resource, and the water intensity of the generating system as a whole.
- Inclusion of the projected emissions of sulfur dioxide, nitrogen oxides, particulate matter, mercury, and

²⁶ Id. Page 9.

²⁷ Colorado Revised Statutes 40-2-123(1)(a).

²⁸ Colorado Public Utilities Commission. Decision No. C07-0829. Docket No. 07R-0368E. September 19, 2007. Page 20.

²⁹ Colorado Revised Statutes 40-3.2-203(1).

³⁰ General Assembly of the State of Colorado. House Bill 10-1365.

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carbon dioxide for new and existing generating resources.

- The Commission must consider the likelihood of new environmental regulations, and the risk of higher future costs associated with greenhouse gases, when it considers utility proposals.
- Descriptions of at least three alternate resources plans that meet the same resource need as the base plan but include proportionally more renewable energy or demand-side resources. For the purpose of risk analysis, a range of possible future scenarios and input sensitivities should be proposed for testing the robustness of the alternative plans.
- Permission for the utilities to implement cost-effective demand-side resources to reduce the need for additional resources that would otherwise need to be obtained through a competitive acquisition process.³¹

Colorado's IRP rules do not mandate public participation prior to the filing of the IRP. The rules are, however, unique in requiring that the utility, Commission staff, and the Office of Consumer Counsel agree upon an entity to act as an independent evaluator (paid for by the utility) and advisor to the Commission. The independent evaluator reviews all documents and data used by the utility in developing its resource plan, and submits a report to the Commission that contains its analysis of "whether the utility conducted a fair bid solicitation and bid evaluation process, with any deficiencies specifically reported."³²

Following the filing of the utility's resource plan, the IRP rules state that parties in the proceeding have 45 days to file comments on the plan and on the independent evaluator's report. The utility has a chance to respond to comments, after which the Commission is required to issue a written decision approving, conditioning, modifying, or rejecting the utility's preferred cost-effective resource plan, "which decision shall establish the final cost-effective resource plan."³³ In 2011 the Colorado electric utilities filed the first electric resource plans that were consistent with these revised rules. The plan from Public Service Company of Colorado ("Public Service") is discussed in section III of this report.

3. Oregon

Oregon's IRP rules are the most straightforward of the three states examined here. The state first established resource planning rules in 1989, in Public Utility Commission Order 89-507. The order directs all energy

utilities in Oregon to undertake least-cost planning, which the Commission defines in a somewhat unique way, stating that:

Least-cost planning differs from traditional planning in three major respects. It requires integration of supply and demand side options. It requires consideration of other than internal costs to the utility in determining what is least-cost. And it involves the Commission, the customers, and the public prior to the making of resource decisions rather than after the fact. ...Least-cost planning as mandated by this order will allow the public as well as the Commission to participate in the planning process at its earliest stages.³⁴

The PUC thus identifies one of the key procedural elements of least-cost planning as allowance for significant involvement from the public and other utilities in the preparation of the resource plan, which includes opportunities for the public to contribute information and ideas as well as to receive information. The Commission's order states that "the open and collaborative character of least-cost planning may foster elevated confidence among those affected by the decisions and may make the process more responsive to demonstrated needs."³⁵ Substantive elements of least-cost planning are similar to those found in other states, with the PUC emphasizing the evaluation of conservation in a manner that is consistent and comparable to that of supply-side resources,³⁶ and with the analysis of economic, environmental, and social uncertainties.

The order also includes a concurring opinion from Commissioner Myron B. Katz, in which he discusses whether commissions, in the context of least-cost planning, should be interested in costs to utilities and ratepayers alone, or in overall costs to society. Katz suggests that utilities should seek to determine the costs for resources that include any externalities associated with those

31 Colorado Public Utilities Commission. Decision No. C10-0958. Docket No. 10R-214E. July 29, 2010.

32 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3613(b).

33 4 Code of Colorado Regulations 723-3. Part 3: Rules Regulating Electric Utilities. Electric Resource Planning: 3613(e).

34 Public Utility Commission of Oregon. Order No. 89-507. Docket No. UM 180. April 20, 1989.

35 Id. Page 3.

36 Id. Page 7.

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resources, stating that “[a] resource should be deemed cost-effective and thus eligible for selection if its costs are lower than the costs of alternative resources assuming a market in which all costs, including environmental costs, are reflected in resource price tags.”³⁷

Subsequent PUC Orders 07-002, 08-339, and 09-041 (which became O.A.R. 860-027-0400) updated planning guidelines and requirements, and changed least-cost planning terminology to integrated resource planning, in recognition of the fact that there are many risks and uncertainties associated with any portfolio that must be weighed, and that least-cost is not the only criterion for selecting the best resource portfolio. This emphasis on the importance of risk in integrated resource planning is one way in which Oregon differs from some other states. The emphasis is placed in the forefront of the revised rules, with Guideline 1(b) stating that “(r)isk and uncertainty must be considered.”³⁸ *Risk* is defined as a measure of the bad outcomes associated with a resource plan, while *uncertainty* is a measure of the quality of information about an event or outcome. Recognizing risks that are general to the electric industry and those that are specific to Oregon, the rules specify that, at a minimum, the following sources of risk must be considered in utility resource plans: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gases, as well as any additional sources of risk and uncertainty.³⁹

In order to quantify these risks, utilities should calculate two different measures of the present value of revenue requirement risk (PVRR). The first should measure the variability of resulting PVRR costs under the different scenarios, and the second should measure the severity of any bad outcomes.⁴⁰ The primary goal of Oregon’s IRP planning process is thus “the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.”⁴¹ A portfolio of resources with the lowest expected cost before the inclusion of various risks may in fact have higher costs than other resource portfolios once those risks are considered.

The goal of the Oregon PUC in amending its rules was for utilities to identify the lowest-cost resource plan over the specified planning horizon by balancing both cost and risk. The Commission declines to mandate how the measures of PVRR risk be defined, instead leaving it up to

the utilities and to “the interactive process of developing an IRP to make the best assessment of appropriate risk measures.”⁴² Unlike in Arizona, which requires that utilities create a plan to manage specific risks, Oregon requires that utilities take risks, their probabilities of occurrence, and the likelihood of bad outcomes into their choice of preferred resource plan.

These subsequent orders make few other substantive changes to the rules established in order 89-507, but instead add detail on the information and analysis that the PUC wanted in order to acknowledge utility resource plans. Notable changes include:

- The requirement that each utility ensure that a conservation potential study is done periodically for its entire service territory.
- The requirement that demand response and distributed generation be evaluated similarly to more traditional supply-side resources.
- The requirement that utilities include the expected regulatory compliance costs for various pollutants, that a range of potential CO₂ costs be analyzed,⁴³ and that sensitivity analyses be performed on a range of costs for nitrogen oxides, sulfur oxides, and mercury, if applicable.⁴⁴

Order 07-002 also details the nature of public involvement in the IRP process, stating that the public and other utilities should be allowed significant involvement in the preparation of an IRP—that they should be allowed to contribute information and ideas, and to make relevant inquiries of the utility formulating the plan. The utility should also make a draft IRP available for public review

37 Id. Page 12.

38 Public Utility Commission of Oregon. Order No. 07-002. Docket No. UM 1056. January 8, 2007. Appendix A. Page 1.

39 Id.

40 Id. Appendix A. Page 2.

41 Id. Appendix A. Pages 1-2.

42 Id. Page 7.

43 From zero to \$40 (1990\$), as established in Order No. 93-695.

44 Public Utility Commission of Oregon. Order No. 07-002. Docket No. UM 1056. January 8, 2007.

45 Id. Page 8.

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and comment before filing a final version with the PUC.⁴⁵

Following submission of the integrated resource plan, intervening parties and Commission staff have six months to complete and file written comments on it. In advance of the deadline for written comments, the utility must also present the results of its resource plan to the Commission at a public meeting. The Commission then acknowledges the plan or returns it to the utility with comments. It may allow the utility to revise its resource plan before issuing an acknowledgement order.⁴⁶

The IRP rules are careful to point out that acknowledgement of the IRP does not guarantee

favorable ratemaking treatment later on, but that the acknowledgement simply means the plan seemed reasonable at the time it was reviewed by the Commission.⁴⁷ PacifiCorp, operating in Oregon as Pacific Power, is expected to file its 2013 IRP this year, but that plan was not available in time for inclusion in this paper. PacifiCorp's 2011 IRP is discussed in later sections.

46 Id. Page 9.

47 Id. Page 2.

III. Examples of Best Practices in Utility Integrated Resource Plans

A. Arizona Public Service

Arizona Public Service (APS) is the state's largest electric utility, and has been serving retail and wholesale consumers since 1886. In March 2012, APS filed the first formal resource plan in 17 years with the Arizona Corporation Commission. This IRP was also the first to be filed under the ACC's revised rules, as described in section II.A.

From the time when the Corporation Commission issued the final IRP rules to the date that APS filed its resource plan, the utility was “engaging key stakeholders to gain an understanding and appreciate of their areas of concern.”⁴⁸ A series of workshops held during 2010 and 2011 sought to both inform and gather input from interested stakeholders on future resource decisions. The workshop topics included the resource fleet and transmission system; load forecasts; energy efficiency; smart grid; demand response; utility water consumption; fuel supplies and markets; technology options and costs; externalities; resource procurement; portfolios and sensitivities; and metrics and monetization costs for water, sulfur oxides, particulate matter, and nitrogen oxides. Approximately 35 to 50 stakeholders participated in each meeting, and several stakeholders were also invited to give presentations in some of the topic areas mentioned above.⁴⁹

APS also contracted with the Morrison Institute at Arizona State University to conduct a series of four “Informed Perception Project” surveys on customer preferences and concerns regarding the energy resource options available to APS. Results showed that APS customers “favored an increase in the use of renewable energy resources, such as solar and wind, and were interested in both the environmental impacts and reliability of energy choices.”⁵⁰

Over the course of the 15-year planning period, with the assumption that migration to the state and individual electricity consumption will return to historic highs,

APS has forecast 3% average annual growth in nominal electricity requirements through 2027. Energy efficiency and distributed generation, in the form of rooftop solar installations, will help offset some of this growth, but APS expects that it will need to add additional conventional supply-side resources, in the form of natural gas-fired generation, in 2019. APS created four resource portfolios to evaluate: a base case, a “four corners contingency,” an “enhanced renewable” case, and a “coal retirement” case. Figure 3 shows the details of those plans.

Each of the resource plans created by APS were analyzed using a production simulation model, PROMOD IV, which dispatches the energy resources in each of the portfolios and generates system costs, or the likely future revenue requirements, associated with each. Calculation of system revenue requirements demonstrated that the APS base case portfolio was the most cost-effective of the resource plans evaluated. APS also monitors specific metrics to provide a context for comparing and evaluating the portfolios. In addition to revenue requirements, those metrics include fuel diversity, capital expenditures, natural gas burn, water use, and CO₂ emissions.

APS selected major cost inputs and evaluated several sensitivity scenarios, setting the assumptions for these variables higher and/or lower to test the impacts on the specific metrics being evaluated. These major cost inputs include natural gas prices, CO₂ prices, production and investment tax credits for renewable resources, energy efficiency costs, and monetization of SO₂, NO_x, PM, and water. APS also created low-cost and high-cost scenarios,

48 Arizona Public Service. 2012 Integrated Resource Plan. March 2012. Page 2.

49 Id. Page 25.

50 Id.

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Figure 3:

Portfolios Considered in the APS 2012 IRP⁵¹				
	Base Case (2012 Resource Plan)	Four Corners Contingency	Enhanced Renewable	Coal Retirement
Description	<i>Plan includes APS closing Four Corners units 1-3 and purchasing SCE's share of units 4-5; continues the current trajectory of EE and RE compliance</i>	<i>Contingency plan depicting the retirement of the Four Corners coal-fired plant; energy replaced by additional natural gas resources</i>	<i>Assumes 30% (after EE/DE) of energy needs met by renewable resources; include the consummation of the Four Corners transaction</i>	<i>Assumes APS retires all coal-fired generation; energy replaced with a combination of natural gas and renewable resources</i>
Resource Contributions (2027 Peak Capacity Contribution/ % Energy Mix)				
Nuclear	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh	1,146 MW 18.7% MWh
Coal	1,932 MW 26% MWh	962 MW 12.7% MWh	1,932 MW 26% MWh	0MW 0MWh
Natural Gas and Demand Response	7,424 MW 26.3% MWh	8,394 MW 39.6% MWh	7,138 MW 20.7% MWh	9,188 MW 46.3% MWh
Renewable Energy (RE) & Distributed Energy (DE)	1,141 MW 13.7% MWh	1,141 MW 13.7% MWh	1,427 MW 22.8% MWh	1,308 MW 19.7% MWh
Energy Efficiency (EE)	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh	1,525 MW 15.4% MWh

which incorporate the low and high values for all of the variables mentioned above rather than testing them on an individual basis. The results of the sensitivity analysis showed that the four corners contingency and coal retirement portfolios have the most variability in terms of net present value of revenue requirements, which fluctuate 11-12% as compared to 6-7% for the base case and enhanced renewable portfolios. Natural gas price changes caused the largest impact on sensitivity results.

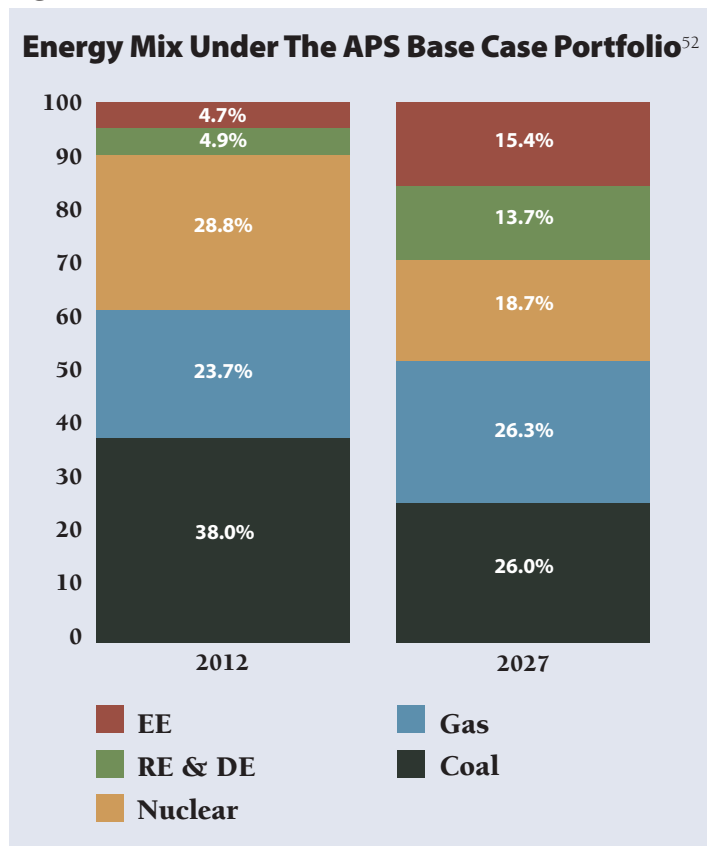
Under the base case plan, APS achieves compliance with energy efficiency requirements and slightly exceeds compliance levels for renewable energy. Consistent with the intent of the revised rules, APS's reliance on coal-fired generating resources drops by 12% between 2012 and 2027. Use of natural gas increases slightly over the course of the planning period under this scenario, but by 2027, no single fuel source makes up more than approximately 26% of the APS resource mix. Figure 4 shows the energy mix in 2027 compared to 2012 under the base case portfolio.

APS had approximately 600 MW of excess capacity in 2012, heading into the summer peak. In the short term—over the next three years—the company planned to continue to pursue energy efficiency and renewable energy resources. During the intermediate term, years four to 15 of the planning period, APS plans to add 3,700 MW of natural gas capacity and 749 MW of renewable capacity. However, “[i]n the event that solar, wind, geothermal, or other renewable resources change in value and become a

51 Id. Page 44. Arizona Public Service Company hired Black and Veatch Corporation to conduct a Solar Photovoltaic (PV) Integration Cost Study report that provides the company with an estimate for the incremental operating reserves necessary to integrate geographically diverse PV development in the APS service territory, and quantifies the anticipated incremental cost to provide the reserve capacity and energy services. “Solar Photovoltaic Integration Cost Study,” B&V Project No. 174880 (November 2012).

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Figure 4



more viable and cost-effect option than natural gas, future resource plans may reflect a balance more commensurate to the enhanced renewable portfolio.”⁵³

APS should be commended for several elements of its 2012 IRP. The first of those is the comprehensive stakeholder process, which included workshops covering most, if not all, of the topic areas that are vital to comprehensive integrated resource plans. Not only were stakeholders invited to listen and offer feedback, they were also invited to present their points of view on a subset of these important issues. In the IRP itself, APS provides all non-confidential input and output data for stakeholder review.

Second, APS continues to pursue energy efficiency, renewable energy, and distributed generation resources in each of the resource portfolios it analyzed, meeting or exceeding ACC-specified goals and consistent with the Commission finding that:

Continued reliance on fossil generation resources without the addition of renewable generation resources is inadequate and insufficient to promote and safeguard the security,

*convenience, health, and safety of electric utilities’ customers and the Arizona public and is thus unjust, unreasonable, unsafe, and improper.*⁵⁴

APS has also analyzed portfolios that meet the Commission goals of promoting fuel and technology diversity as the utility lowers its reliance on coal-fired generation and increases its use of energy efficiency and renewable energy resources.

Third, APS takes environmental costs into account when evaluating its resource plans. The company uses a CO₂ adder consistent with the assumption that federal regulation of CO₂ will occur within the 15-year planning period. In sensitivity scenarios, APS analyzes alternative prices for CO₂ emissions, and also includes adders for SO₂, NO_x, PM, and water. Emissions cost and water consumption are also two metrics by which APS evaluates its resource portfolios. Water in particular is a resource that has not been given much consideration in utility integrated resource planning in past decades, in this and in other jurisdictions—but it is especially important for Arizona and other states in the arid parts of the country, as it may at times act as a constraining resource on electric power generation.

While APS has indeed done an admirable job in its 2012 Integrated Resource Plan, there are several areas in which the utility can still improve. The first is with respect to its load forecast. APS assumes a return to very high levels of load growth, at 3% per year for a total of 55% growth in energy consumption over the planning period. Load growth is one variable that can be highly uncertain. APS even states that “weather, population growth, economic trends, and energy consumptions behaviors are among the key variables that impact the Company’s view of future resource needs. Accurately forecasting any one of these variables over a 15-year period is a challenge. Accurately forecasting them all is impossible.”⁵⁵

52 Id. Page 45.

53 Id. Page 64.

54 Arizona Public Service. 2012 Integrated Resource Plan. Page 13.

55 Id. Page 18.

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Changes in the forecast can lead to significant changes in the quantity and type of resources needed in a utility's portfolio. For this reason, utilities engaged in resource planning typically analyze sensitivity cases that use at least two (low and high) alternative load forecasts. APS admitted that "a challenge more specific to the APS service territory is load-growth uncertainty,"⁵⁶ and yet the company analyzed only a single load forecast—one that the company admits is more than triple the average growth of electricity demand in the United States.⁵⁷

The second improvement that APS could make to its IRP process relates to the creation of the utility's resource portfolios. Often, in integrated resource planning, utilities will use resource optimization models—e.g., EGEAS, Strategist, or System Optimizer—to create resource portfolios. The user inputs data on peak and energy demand, reserve margins, fuel prices, emissions prices, capital and operating cost of both supply and demand resources, etc., and the optimization model will select the number and type of resources to be added over time to make up the least-cost plan. These models will also perform a simplified system dispatch in order to generate system revenue requirements over the planning period. Rather than using an optimization model to select the ideal resource portfolios, APS hand-selected the resource mix for each portfolio. Under this method, it is possible that a lower-cost resource plan exists that APS has not identified.

This is particularly true in the sensitivity analyses that the company conducted. As described above, natural gas prices led to the greatest variance in system revenue requirements in the sensitivity analyses. Had an optimization model been used to evaluate scenarios with high natural gas prices, one might see the model select fewer natural gas-fired resources in favor of increased renewable or energy efficiency. Similarly, in sensitivity scenarios that look at decreased costs for energy efficiency, an optimization model might select additional quantities of energy efficiency to be added to the resource mix. Some of the supply-side resources selected using base EE costs might then not be required, as additional EE would lower both peak and energy demand.

On page 104 of its IRP, APS presents a table of residential and non-residential EE programs that were rejected because program costs were higher than benefits. In sensitivity scenarios where lower EE costs were evaluated, some of

these measures that were rejected may have met cost-effectiveness tests and been selected for inclusion in utility resource portfolios.

B. Public Service Company of Colorado

The October 2011 IRP filing from Public Service Company of Colorado ("Public Service") was filed shortly after the company's filing that addressed the Clean Air-Clean Jobs Act. In the CACJA plan ultimately approved by the Colorado PUC, Public Service will retire 600 MW of base-load coal generation, fuel switch from coal to natural gas at another 450 MW of coal generation, and install emission controls at three other coal units by the year 2017. Additionally, as part of two separate filings, the company planned for the installation of 900 MW of additional wind and 30 MW of new solar by the end of 2012. These additions, repowerings, and retirements, along with the current weak growth in Colorado's economy, led Public Service to project a resource need of only 292 MW of additional generation capacity by 2018.

Public Service developed a "least-cost baseline case" resource portfolio, designed to meet resource needs during the Resource Acquisition Period from 2012 to 2018 at the lowest measurement of present value of revenue requirements. The utility also developed eight alternative plans that evaluate increasing amounts of renewable and distributed generation resources. These resource portfolios were evaluated using the Strategist model from the period of 2011-2050, and are shown in Figure 5.

Public Service evaluated the baseline case and the eight alternative cases under several sensitivity scenarios, altering the price of CO₂ emissions, renewable tax incentives, natural gas prices, and level of sales. Figure 6 shows the results of the analysis for the first three variables.

Public Service concludes from its analysis that existing and planned resources would be sufficient to meet the forecasted energy requirements of its system, but that natural gas-fired combustion turbines (CTs) would be required to provide the capacity necessary to maintain reserve margins. The company also concludes that adding

56 Id. Page 20.

57 Id. Page 18.

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Figure 5

Least-Cost Baseline Case and Alternative Plans During the Resource Acquisition Period (RAP) From Public Service Company of Colorado's 2011 IRP⁵⁸									
		Level A				Level B			
RAP Resource	1 Baseline	A2 Wind	A3 PV	A4 Battery	A5 Solar Thermal	B2 Wind	B3 PV	B4 Battery	B5 Solar Thermal
Thermal Resources	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	2 CTs 346 MW	1 CT 173 MW	1 CT 173 MW	1 CT 173 MW
Wind		200 MW	200 MW	200 MW	200 MW	800 MW	800 MW	800 MW	800 MW
Solar			25 MW	25 MW	25 MW		100 MW	100 MW	100 MW
Battery				25 MW				100 MW	
Solar Thermal					50 MW				125 MW

Figure 6

Sensitivity Results for CO₂, Tax Incentives, and Gas Prices From Public Service Company of Colorado's 2011 IRP⁵⁹									
		Level A				Level B			
		A2 Wind	A3 PV	A4 Battery	A5 Solar Thermal	B2 Wind	B3 PV	B4 Battery	B5 Solar Thermal
Alternative Plan 2011-2050 PVRR Deltas from Baseline Case (\$Millions)									
Starting Assumptions		\$98	\$105	\$160	\$298	\$427	\$489	\$672	\$881
CO₂ 3-Source Low Esc		\$9	\$10	\$65	\$182	\$75	\$113	\$297	\$455
CO₂ 3-Source		\$7	\$8	\$62	\$178	\$63	\$101	\$285	\$441
CO₂ Early (\$20 in 2017)		(\$36)	(\$38)	\$17	\$124	\$117	\$92	\$98	\$223
Low Gas		\$164	\$179	\$238	\$393	\$671	\$760	\$979	\$1,204
High Gas		\$21	\$19	\$72	\$183	\$151	\$176	\$369	\$503
PTC Wind		(\$97)	(\$90)	(\$35)	\$103	\$312	(\$251)	(\$67)	\$142
10% ITC Solar PV		\$98	\$119	\$174	\$312	\$427	\$546	\$729	\$938
30% ITC Solar Thermal		\$98	\$105	\$160	\$235	\$427	\$489	\$672	\$741

58 Public Service Company of Colorado. 2011 Electric Resource Plan: Volume 1. October 31, 2011. Pp. 1-38.

59 Id. Pp. 1-41.

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renewable generating resources would increase system costs under both baseline and sensitivity assumptions.⁶⁰ The results of the sensitivity analysis shown in Figure 6 seem to indicate, however, that if the production tax credit (PTC)⁶¹ for wind were to be extended, there would be some benefit to adding additional wind generation, as shown by the decline in present value of revenue requirements in this scenario relative to the base case.

Given the results of the resource analysis, Public Service proposes to utilize a competitive All-Source Solicitation to acquire the resources needed to meet planning reserve margin targets. The solicitation would seek both short-term and long-term power supply proposals, with a preference for short-term contracts. Public Service lists several uncertainties that it will face over the coming years: future environmental regulations, changing technology costs, tax credits that impact the relative costs of generation alternatives, fuel prices, and economic growth in its service territory.⁶² Given these uncertainties and the relatively small resource need, the shorter-term power purchase agreements would allow the utility to wait and see if and how uncertainties can be resolved before adding new generation facilities to its resource mix. The company will also offer enough self-build power supply proposals into the solicitation process to meet the needs over the resource acquisition period.

These proposals would ensure that at least one portfolio could be developed with company-owned facilities, and that generating capacity will be expanded at existing sites. Public Service requests that the PUC allow it to conduct periodic solicitations for additional renewable energy, if and when markets become most favorable to customers; but it reports no plans to add additional renewables over the acquisition period. The company states that, “[t]o the extent the Commission desires to see portfolios from the Phase 2 process that contain increasing levels of renewable or Section 123 Resources the Commission should direct the Company to do so in its Phase 1 order.”⁶³

Public Service’s 2011 IRP is comprehensive, thorough, and a good example of effective resource planning. Resource planning in Colorado is driven by: 1) the state Legislature, as statutes dictate the content of state IRP rules; 2) by interveners, whose comments and suggestions during IRP processes can lead to changes in both rules and content of utility resource plans; and 3) by the PUC, which oversees the process and may require that utilities revise resource

plans in specific ways prior to receiving Commission approval. The input and oversight from these three entities, combined with the utilities’ expertise, leads to the inclusion of several notable elements in the resource plan that demonstrate additional issues of concern in Colorado.

First, recognizing that acquiring necessary resources does not always go according to plan, the utility creates and describes a series of the more common contingency events—e.g., bidders withdrawing proposals, transmission development delays, higher than anticipated electric demand, etc.—and develops plans to address them if they occur.⁶⁴

Second, Public Service acknowledges that its planned volume of wind installations (2,100 MW by 2012) creates specific challenges and requirements that much lower volumes of renewables would not. Because wind output can be variable and uncertain, there may be additional flexibility requirements on an electric system—i.e., there must be a certain amount of generation that can be brought on-line within a 30-minute period in order to respond to changes in renewable output. Public Service conducts an assessment of the need for flexible resources in its IRP’s general assessment of need.

Flexibility studies are not a part of traditional integrated resource planning, but Public Service is responding to unique circumstances in its service territory by incorporating this type of study in its resource planning. Utilities sometimes cite the variability and uncertainty of wind and other renewables as reasons *not* to pursue these types of resources in their portfolios; Public Service shows,

60 Id. Pp. 1-43.

61 The federal renewable energy production tax credit (PTC) provides a per-kilowatt-hour tax credit for electricity generating by various types of renewable energy resources and sold by the taxpayer to an unrelated person during the taxable year. The PTC was originally enacted in 1992 and has been extended several times, most recently in January 2013 as part of the American Taxpayer Relief Act of 2012 (H.R. 6, Sec 407). Currently, the PTC for wind resources for which construction began prior to December 31, 2013 is 2.3 cents/kWh.

62 Id. Pp. 1-5.

63 Id. Pp. 1-49.

64 Id. Pp. 1-59.

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however, that these challenges can be planned for in a reasonable way and are not a reason to avoid renewable additions.

Finally, traditional integrated resource planning does not pursue short-term strategies, such as market purchases that may buy time in the hope that some uncertainties will be resolved.”⁶⁵ The Public Service IRP does just that, however, by making shorter-term resource acquisition decisions and preserving “decisions involving new generation facilities to a point in the future when we see how these uncertainties are resolved.”⁶⁶

While Public Service should be applauded for its integration of renewables to date, it is unclear from the company’s IRP whether it truly views renewable generating technologies as a system resource as opposed to an obligation established by the state legislature and the PUC. As mentioned above, Public Service has no plans to pursue additional renewable acquisitions during the next seven years, even though sensitivity analyses show that additional wind generation may be beneficial to ratepayers if the production tax credit were to be extended. The company does ask that it be granted permission to conduct solicitations for renewables outside of the resource planning process if it determines that market conditions are “favorable,” but it gives no indication as to what favorable market conditions might look like. An evaluation of the market conditions favorable to renewables would be very helpful in the context of resource planning, and could be

included in future IRPs or updates from Public Service.

C. PacifiCorp

Of the three utilities examined here, PacifiCorp is unique in that it operates across six states—Oregon, Washington, California, Idaho, Utah, and Wyoming, five of which have IRP or other long-term planning requirements.⁶⁷ This gives PacifiCorp the additional challenge of planning on a system-wide basis while meeting each of the resource-acquisition mandates and policies in the states where it operates. The company evaluates a 20-year study period, but focuses on the first ten years (2011-2020) in its assessment of resource need.

In that ten-year planning period, PacifiCorp forecasts that system peak load will grow at 2.1% per year (2.4% for

65 Chupka, M., Murphy, D. & Newell, S. *Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches*. Brattle Group. 2008. Page 2.

66 Public Service Company of Colorado. *2011 Electric Resource Plan: Volume 1*. October 31, 2011. Pp. 1-5.

67 Wyoming does not have its own IRP obligation, but instead mandates that any utility serving in the state that is required to submit an IRP in another jurisdiction also file that IRP with the Wyoming PSC.

68 *Id.* Page 8.

Figure 7

Resource Additions in the Preferred Portfolio—PacifiCorp’s 2011 IRP⁶⁸

Resource	Capacity (MW)										Total
	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	
CCCT F Class	-	-	-	625	-	597	-	-	-	-	1,222
CCCT H Class	-	-	-	-	-	-	-	-	475	-	475
Coal Plan Turbine Upgrades	12	19	6	-	-	18	-	8	-	-	63
Wind, Wyoming	-	-	-	-	-	-	-	300	300	200	800
CHP-Biomass	5	5	5	5	5	5	5	5	5	5	50
DSM, Class 1	6	70	57	20	97	-	-	-	-	-	250
DSM, Class 2	108	114	110	118	122	124	126	120	122	125	1,189
Oregon Solar Programs	4	4	4	3	3	-	-	-	-	-	18
Micro Solar – Water Heating	-	4	4	4	4	4	4	4	-	-	28
Firm Market Purchases	350	1,240	1,429	1,190	1,149	775	822	967	695	995	N/A

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the eastern system peak and 1.4% for the western system peak), and that energy requirements will grow by 1.8% per year. Resource deficits will begin in the first year, with PacifiCorp being short 326 MW in 2011. This deficit grows to 3,852 MW by 2020. In the near-term, shortages will be met with DSM, renewables, and market purchases, but new baseload and intermediate generating units begin to be added to the resource mix in 2014.⁶⁹ Figure 7 shows the proposed resource additions.

If PacifiCorp were to proceed with these proposed resource additions, by 2020 its capacity mix would be as shown in Figure 8. In this scenario, traditional thermal resources still make up two-thirds of PacifiCorp’s capacity mix; DSM makes up just over 13%, and renewables make up 2.6%.

As Figure 9 shows, PacifiCorp’s energy mix looks slightly different under its preferred portfolio. The percentage of total energy generated from coal-fired resources drops by 26% between 2011 and 2020, while the amount of

Figure 8

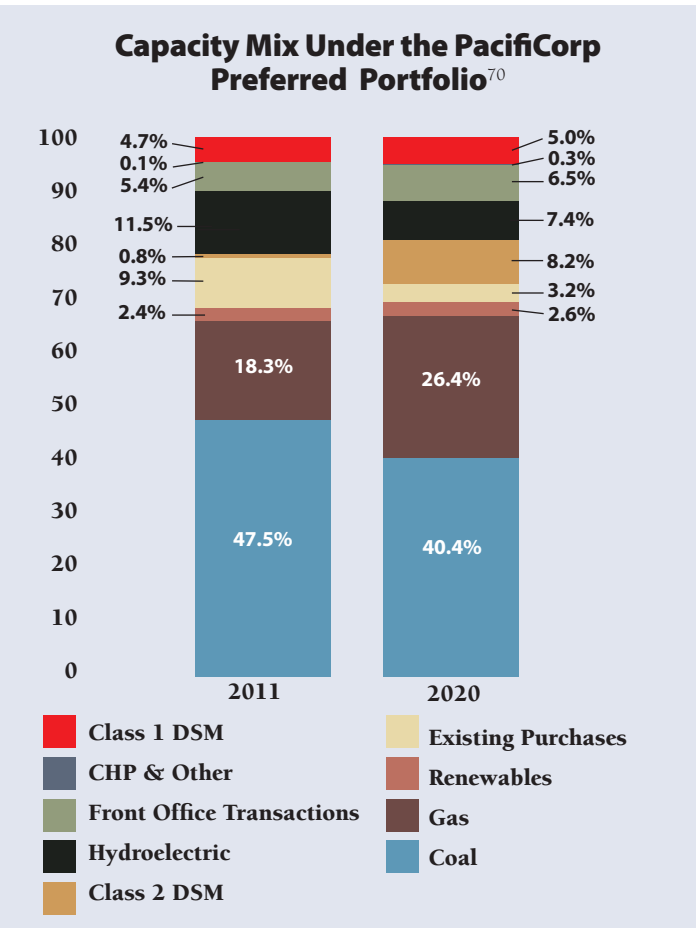
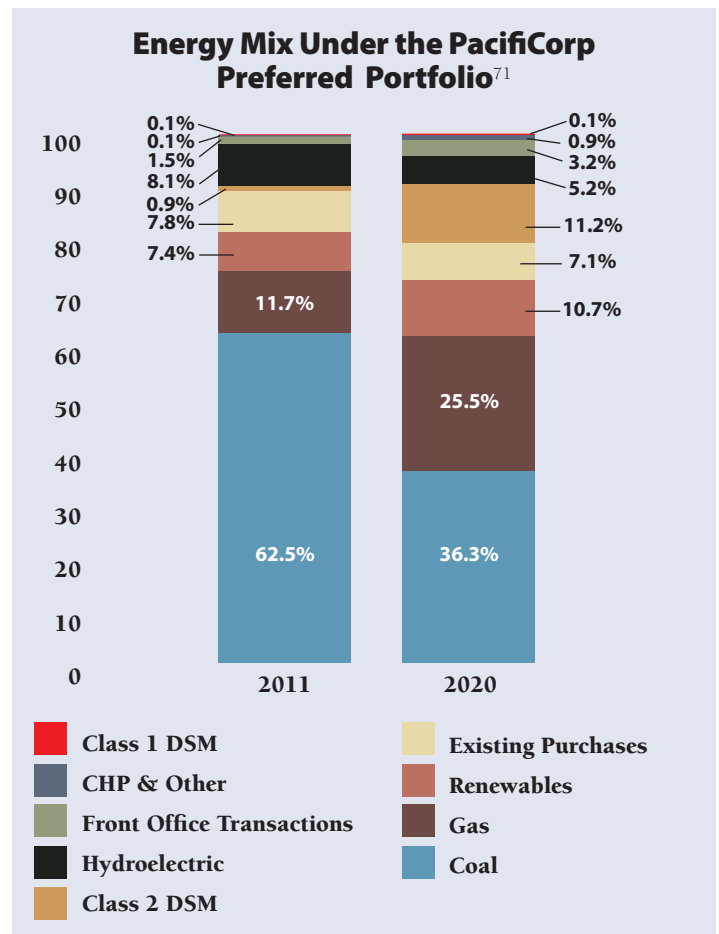


Figure 9



energy from gas-fired resources more than doubles. Even with the significant drop in generation from coal, energy from thermal resources makes up 61% of PacifiCorp’s total energy. DSM makes up 11% of the energy mix, with another 11% coming from renewable resources. Hydroelectric power and energy purchases make up the bulk of the remaining energy.

Of the three utilities examined in this report, PacifiCorp’s portfolio modeling process is the most comprehensive. It uses a model called System Optimizer, which has the capability to determine capacity expansion plans, to run a production cost simulation of each optimized portfolio, and to perform a risk assessment on these portfolios.

69 PacifiCorp. 2011 *Integrated Resource Plan: Volume 1*. March 31, 2011. Page 83.

70 Id. Page 10.

71 Id. Page 13.

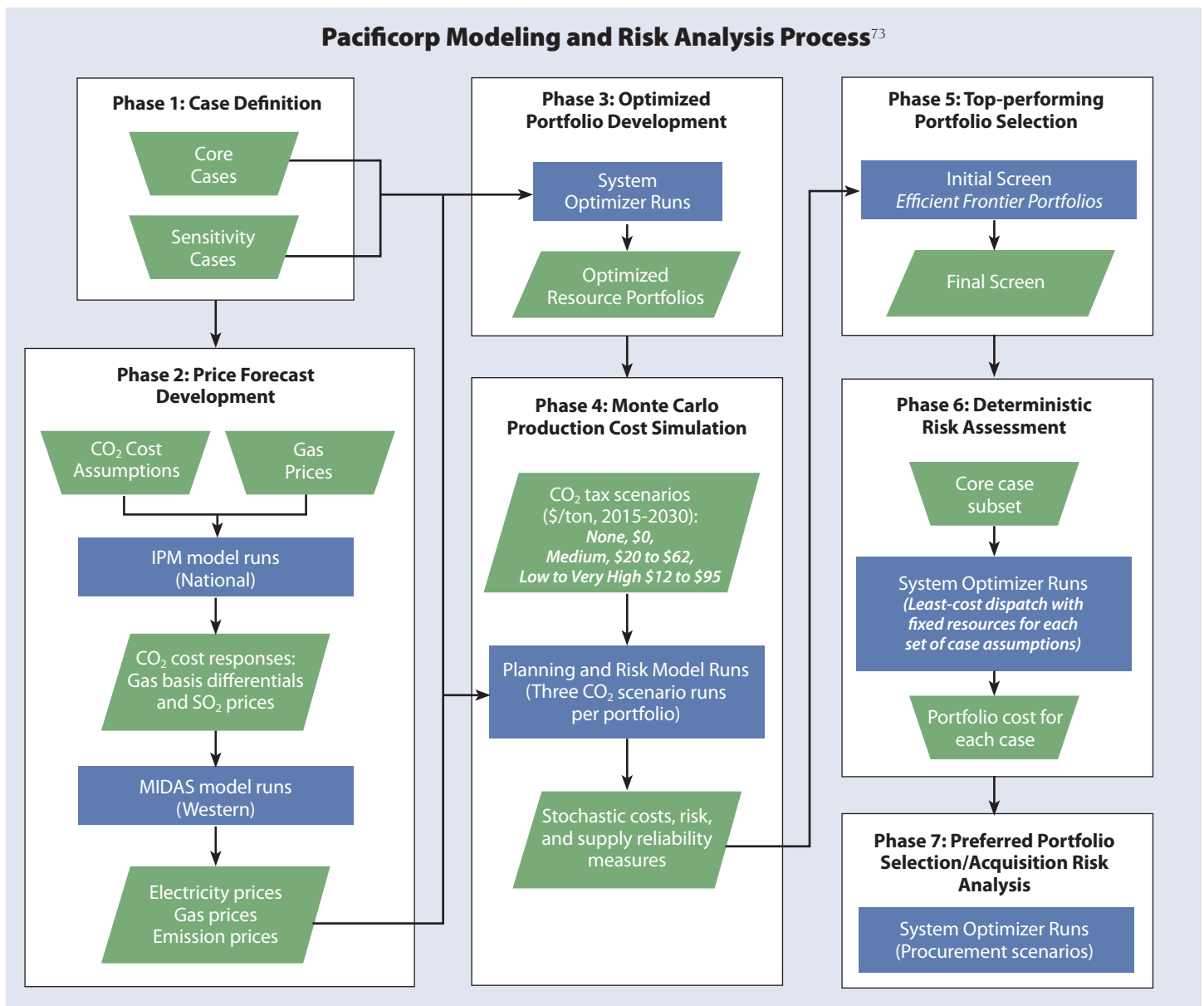
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Altogether, PacifiCorp defined 67 input scenarios for portfolio development. These looked at alternative transmission configurations, CO₂ price levels and regulation types, natural gas prices, and renewable resource policies. Sensitivity cases examined additional incremental costs for coal plants, alternative load forecasts, renewable generation costs and incentives, and DSM resource availability. Top resource portfolios were determined on the basis of the combination of lowest average portfolio cost and worst-case portfolio cost resulting from 100 simulation runs. Final portfolios were selected after considering such

criteria as risk-adjusted portfolio cost, 10-year customer rate impact, CO₂ emissions, supply reliability, resource diversity, and uncertainty and risk surrounding greenhouse gas and RPS policies.⁷²

Figure 10 shows PacifiCorp’s schematic of its modeling process. PacifiCorp is one of the only utilities in the country that models energy efficiency resources as supply-side resources, rather than as load modifiers. The utility provides the model with specific quantities of energy efficiency at given costs, and allows those efficiency resources to compete against the other resources from

Figure 10



72 Id. Page 153.

73 Id. Page 155.

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which the model is able to select. PacifiCorp's efficiency resource information in its 2011 IRP is based on a 2010 energy efficiency potential study that provided an estimate of the size, type, timing, location, and cost of the demand-side resources that are technically available in PacifiCorp's service territory. Data for more than 18,000 measures were available after the resources were separated by customer segment, facility type, and unique EE measures.

Energy efficiency measures are called Class 2 DSM, while capacity-based measures are separated into two categories: Class 1 DSM includes dispatchable demand-response programs, and Class 3 DSM includes pricing programs. Focusing on Class 2 DSM measures, PacifiCorp consolidated them into nine cost bundles grouped by levelized cost for inclusion in the modeling, and 1,400 supply curves were modeled for the IRP.⁷⁴

Energy efficiency measures performed well in the modeling, representing the largest resource added through 2030 across all portfolios with cumulative capacity additions exceeding 2,500 MW in the preferred portfolio. The inclusion of such large quantities of energy efficiency creates huge cost savings to ratepayers. If energy efficiency were not included in PacifiCorp's resource portfolio, the utility would have to meet electric load by adding 2,500 MW of supply-side resources at much greater cost.

Although PacifiCorp's portfolio modeling process is comprehensive and well-executed, system resource modeling in general is only as good as the *input assumptions* used to generate the portfolios. The most significant area in need of improvement in the PacifiCorp IRP process relates to the input assumptions and analysis regarding the company's coal fleet—or, rather, the lack of analysis presented on this in the IRP. This lack of analysis began during the stakeholder process. In comments that it submitted, the Sierra Club states that it actively participated in the stakeholder input process, and raised many of the issues discussed in those comments. “The company did not respond to any requests for data related to the topics addressed in these comments, choosing instead to provide only a small amount of materials in the final draft, just days before the company submitted the final IRP.”⁷⁵

PacifiCorp's 26 coal-fired boilers make up almost two thirds of its generation. To keep these units running while meeting stricter federal air pollution standards,

the company would have to spend \$1.57 billion in environmental capital cost from 2011 to 2020, in addition to \$1.2 billion that it invested before 2011. Operating costs would raise the total cost to customers to \$4.2 billion, or \$360 million on an annual basis by 2030.⁷⁶ PacifiCorp, however, makes no mention of these current compliance obligations or any future costs in the 2011 IRP or its appendices. The utility failed to disclose the costs that would be faced by its coal fleet in its 2011 IRP, and failed to do a comprehensive analysis of the economics of each of its coal-fired generating units. Absent this analysis, the resource portfolios analyzed by the company cannot be considered to be truly “optimized.”

It is highly likely that PacifiCorp could add additional renewable resources to its portfolio. As discussed above, Public Service Company of Colorado had 2,100 MW of wind capacity alone on its system at the end of 2012, and they are a single utility operating in one state. PacifiCorp's territory covers portions of six states, many with large amounts of renewable potential. PacifiCorp's service territory also borders other states with large amounts of renewable potential, and the company could enter into long-term contracts for renewable energy. The company states in the IRP that it commissioned a study on geothermal potential, yet its resource portfolio does not include any anticipated geothermal energy or capacity during the study period.

74 Lamont, D. & Gerhard, J. The Treatment of Energy Efficiency in Integrated Resource Plans: A Review of Six State Practices. Regulatory Assistance Project. January 2013. Pp. 6-8.

75 Sierra Club's Preliminary Comments in the Matter of PacifiCorp 2011 Integrated Resource Plan before the Public Utility Commission of Oregon. LC 52. August 25, 2011.

76 Opening Comments of the Citizens' Utility Board of Oregon in the Matter of PacifiCorp 2011 Integrated Resource Plan before the Public Utility Commission of Oregon. LC 52.

IV. Recommendations for Prudent Integrated Resource Planning

Prudent integrated resource planning involves both the process of creating and sharing the resource plan with stakeholders, and the elements that are analyzed and included in the plan itself.

This section provides recommendations, for both the IRP process and the resulting resource plan, that are designed to result in responsible and comprehensive utility integrated resource plans.

A. Integrated Resource Planning Process

Integrated resource planning processes differ from state to state. The ideal process begins with the determination of the IRP guidelines or rules. Integrated resource planning rules were first established in many states in the late 1980s or early 1990s; Oregon's first rules, for example, were established by PUC order in 1989. Significant changes have occurred since then. During the mid- to late 1990s, electric restructuring moved many utilities away from traditional resource planning in favor of market-based provision of electric supply; and today, climate change, national security, and volatility in fuel and commodity markets can make it difficult to determine the best way in which to supply electricity to consumers. Integrated resource planning rules should thus be reexamined periodically, to make sure they reflect the current conditions and challenges associated with providing reliable electric service at reasonable costs.

Arizona began the process of changing its rules after retail competition was instituted in the state by the Corporation Commission—and although the rules took over a decade to be revised and put into effect, the current regulations have been designed to address the issues that are of concern today. When IRP rules are reexamined, state commissions should open proceedings that are open to the public, and stakeholders should be allowed to offer input on the ways in which rules should be revised, as well as to review and comment on any draft documents that are issued. All three of the state IRP rules examined here have gone through this process, and in drafting

revised rules, each of the state commissions carefully considered the feedback offered by interveners and adopted recommendations from both public interest groups and utilities.

1. Resource Plan Development

Stakeholder group involvement is equally important when it is time for a utility to develop its integrated resource plan. As was discussed in section III.A., APS detailed its stakeholder process in its 2012 IRP. During the two-year period that preceded the filing of the plan, the utility held various workshops where stakeholders received updates on the inputs to be used, and were able to offer feedback and even give presentations on these various inputs. Stakeholders were also surveyed to determine their preferences with regard to the energy resources selected by APS. Not only does this stakeholder process inform the content of the resource plan that is ultimately filed by the utility; it can also help to inform the review process once the filing has been made.

Other states have also recognized the benefits of stakeholder involvement in IRP and developed model processes. In its *Resource Planning Guidelines for Electric Utilities*, the Arkansas Public Service Commission suggests that utilities establish a Stakeholder Committee to assist in preparing resource plans that “should be broadly representative of retail and wholesale customers, independent power suppliers, marketers, and other interested entities in the service area.”⁷⁷ The members of this committee would review utility objectives, assumptions, and estimated needs early in the planning cycle, and would submit a report along with the utility's resource plan. Committee members may also submit additional comments to the Commission, which may

77 Arkansas Public Service Commission. *Resource Planning Guidelines for Electric Utilities*. June 2007.

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require the utility to re-evaluate its plan to address these comments.⁷⁸

In Hawaii, IRP rules were designed to attempt to maximize public participation in the planning process. In each county within its service territory, the utility is required to organize advisory groups made up of representatives of public and private entities whose interests are affected by the utility's resource plan—including state and county agencies and environmental, cultural, business, and community interest groups. The rules specify that "(a)n advisory group should be representative of as broad a spectrum of interests as possible."⁷⁹

Whether required by IRP rules or not, it is good practice for a utility to convene a stakeholder group, or to hold public meetings that are open to all interested parties, before creating and submitting its resource plan. These meetings are useful both to provide information and invite feedback on the input assumptions and the process that the utility is using in its resource planning, and to help ensure that the resulting plan is relevant and reflects the interests of ratepayers and the general public.

2. Resource Plan Review

Many state utility commissions are quasi-judicial boards that rely on the rules of civil procedure and allow for participation and intervention from different organizations and members of the public (provided they have standing in the proceeding, or an ability to assist the commission in making decisions). After a utility has filed its resource plan, the state PUC should open a proceeding that allows stakeholders to review and submit written comments on the filing. This feedback should be taken into account during the review by the PUC and its staff. Commissions should take an active role in assessing the validity of the inputs used by the utilities in their filings, the resulting outcomes, and whether these are consistent with both the IRP rules and the state's energy policies and goals.

In Kentucky, for example, the IRP rules specify that once a utility's IRP has been received, the Commission should develop a procedural schedule allowing for submission of written interrogatories to the utility by commission staff and any interveners, written comments by staff and interveners, and responses to these interrogatories and comments by the utility. The Commission may convene conferences to discuss the filed IRP if it wishes to do so. Following a review of the plan and intervener comments,

Commission staff will issue a report summarizing its review and offering recommendations to the utility for subsequent IRP filings.⁸⁰

Of the states examined in this report, the Colorado PUC has taken on a particularly active role in determining whether utility resource choices were in the public interest. The PUC did so, for example, in its review of Public Service Company of Colorado's 2010 DSM Plan, when it rejected the energy efficiency goals proposed by the company and instead asked that the utility adopt goals recommended by an intervener—the Southwest Energy Efficiency Project—that were approximately 130% of the goals in place at the time.⁸¹ These EE goals were then incorporated into the 2011 IRP, in the calculation of resource need as one of the input modeling assumptions.⁸²

Many states, though not all, require that utility plans be available to interveners and/or members of the public for review and participation in resource planning dockets. This signals to both stakeholders and utilities that the IRP process should be collaborative, and that stakeholders can and do offer valuable insights and opinions into resource planning that should be taken into account by utilities when developing their plans. Active oversight and participation by the state PUC is critical to ensuring that comments and proposals by interveners are reviewed, considered fully, and incorporated into utility resource plans when reasonable.

78 Id.

79 Public Utilities Commission, State of Hawaii. *A Framework for Integrated Resource Planning*. Revised May 22, 1992.

80 807 KAR 5:058. Integrated Resource Planning by Electric Utilities.

81 Colorado Public Utilities Commission. Decision No. C11-0442. Docket No. 10A-554EG. March 30, 2011.

82 *The Treatment of Energy Efficiency in Integrated Resource Plans*. Page 15.

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B. Integrated Resource Plans

A good electric system IRP should include, at a minimum:

Load forecast

A company's load forecast (annual peak and energy) is one of the major determinants of the quantity and type of resources that must be added in a utility's service territory over a given time period, and has always been the starting point for resource planning. Projections of future load should be based on realistic assumptions about local population changes and local economic factors⁸³ and should be fully documented. Resource needs can rise or fall dramatically over a short period of time, and frequent, up-to-date load forecasts are necessary for utilities to be able to adequately assess the quantity and type of additional resources that might be needed in a specific planning period.

In Colorado, for example, at the time of Public Service's CACJA filing in mid-2010, the company was projecting a resource need of approximately 1,000 MW by 2018. At the time of its IRP filing in October 2011, the projection of resource need had dropped to 292 MW as a result of the economic recession and the success of DSM and solar programs.⁸⁴ In order to help plan for any future changes in load, utilities should model a range of possible load forecasts, not just a reference case.

Reserves and reliability

Reliability is typically defined as having capacity equal to the forecasted peak demand, plus a reserve margin during the hours in which that peak demand is expected to occur. Reserve requirements should provide for adequate capacity based on a rigorous analysis of system characteristics and

proper treatment of intermittent resources. The system characteristics affecting reliability and reserve requirements include load shape, generating unit forced-outage rates, generating unit maintenance-outage requirements, number and size of the generating units in a region or service territory, transmission inerties with neighboring utilities, and availability and effectiveness of intervention procedures.⁸⁵

Demand-Side Management

Many state IRP statutes or regulations include in the definition of integrated resource planning an evaluation of energy conservation and efficiency. Even so, "[w]hile demand-side resources have always been a conceptual part of IRP, in practice they have not always been an important focus."^{86, 87} As generation from traditional supply-side resources is growing more costly and energy efficiency measures are becoming less expensive, however, demand-side alternatives have gained a greater number of advocates across the United States.

Not only is energy efficiency often the lowest-cost resource available to system planners, it can also mitigate a variety of risks, such as that of impending carbon legislation and other environmental regulations affecting air and water quality. In addition to offsetting energy consumption, implementing EE measures can lead to a deferral in costly transmission and distribution investments.⁸⁸

In the IRPs of most utilities, demand-side resources are included only up to the point that statutory goals are met, or mandatory levels of investment are included. Resource planners often incorporate the effects of those demand-side policies as adjustments ("decrements") to their forecasts of future load requirements. However,

83 State and Local Energy Efficiency Action Network. *Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures*. September 2011. Page 5.

84 Public Service Company of Colorado. *2011 Electric Resource Plan: Volume 1*. October 31, 2011. Pp. 1-5.

85 Biewald, B. & Bernow, S. *Electric Utility System Reliability Analysis: Determining the Need for Generating Capacity*. Boston: Energy Systems Research Group. 1988.

86 Chupka, M., Murphy D. & Newell, S. *Reviving Integrated Resource Planning for Electric Utilities: New Challenges and Innovative Approaches*. Brattle Group. 2008. Page 3.

87 Demand response, which is another type of demand-side resource, is considered in utility IRPs even less frequently than is efficiency. A full discussion of how demand response is included or excluded in IRPs is beyond the scope of this report.

88 *The Treatment of Energy Efficiency in Integrated Resource Plans*. Page 15.

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“The best IRPs create levelized cost curves for demand-side resources that are comparable to the levelized cost curves for supply-side resources. ... By developing cost curves for demand-side options, planners allow the model to choose an optimum level of investment. So if demand-side resources can meet customer demand for less cost than supply-side resources, as is frequently the case, this approach may result in more than the minimum investment levels required under other policies.”⁸⁹

The three integrated resource plans discussed in this report each deal with energy efficiency in different ways. In Arizona, the Corporation Commission has set a demand-side management standard, and each of the portfolios analyzed in the IRP from Arizona Public Service assume full compliance with that standard.⁹⁰ Public utilities are required to achieve annual energy savings of at least 22% by 2020, and savings (measured as a percent of retail energy sales) should increase incrementally in each calendar year prior to 2020.⁹¹ In its IRP, APS has calculated the number of MWh of energy savings needed to be compliant with Commission standards, and has imported these targets into the IRP as a load decrement over the planning horizon.

Colorado’s Energy Efficiency Resource Standard (EERS) was established by Colorado House Bill 07-1037 and codified under the Code of Colorado Regulations §40-3.2-104. The law requires that the Colorado Commission set savings goals for energy and peak demand for the state’s investor-owned utilities, but specifies minimum savings goals of at least 5% of both retail energy sales and peak demand from a 2006 baseline. Utilities are required to

submit DSM plans, which are then reviewed and approved by the Commission, or approved with modifications. The plan that is ultimately approved may require levels of DSM that are higher than the minimum savings goals that have previously been established. Similar to APS, in its most recent IRP, Public Service took the most recent utility-specific DSM goals approved by the Commission and imported them into the IRP process as a load decrement, reducing the resource need over the planning period.

PacifiCorp is subject to EERS requirements in Washington and California. In 2006 in Washington, voters passed Initiative 937, which requires that electric utilities serving more than 25,000 customers undertake all cost-effective energy conservation. Beginning in 2010, utilities must do an assessment of all the achievable cost-effective conservation potential in even-numbered years.⁹² Alternatively, efficiency targets may be based on a utility’s most recent integrated resource plan, provided that plan is consistent with the resource plan for the Northwest Power and Conservation Council.⁹³

California Assembly Bill 2021, enacted in 2006, called for a 10% reduction in electricity consumption within 10 years. It also required that the California Energy Commission (CEC), California Public Utilities Commission (CPUC), and other interested parties develop a statewide estimate of all cost-effective electricity savings, develop efficiency and demand reduction targets for the next 10 years, and update the study every three years. Goals were developed by the CPUC in 2008 for years 2012 through 2020, and each of the three investor-owned utilities in the state has distinct requirements for electricity savings and demand reduction.⁹⁴

89 State and Local Energy Efficiency Action Network. Using Integrated Resource Planning to Encourage Investment in Cost-Effective Energy Efficiency Measures. September 2011. Page 6.

90 Arizona Public Service. 2012 Integrated Resource Plan. March 2012. Page 36.

91 Arizona Corporation Commission. Decision No. 71819. Docket No. RE-00000C-09-0427. August 10, 2010.

92 Chapter 19.285 of the Revised Code of Washington (RCW): Energy Independence Act.

93 The Northwest Power and Conservation Council (NWPCC) is a regional entity that helps the states in the Pacific

Northwest ensure an affordable and reliable energy system while maintaining fish and wildlife health in the Columbia River Basin. One responsibility of the NWPCC is to publish a 20-year electric plan that serves as a guide for Bonneville Power and its customer utilities in the region. The regional plan drives best practices in energy efficiency and is a reference against which utility plans may be measured. In the Sixth Power Plan, published in 2010, the NWPCC recommended that energy efficiency be deployed aggressively such that it meets 85% of new demand for electricity over the next 20 years.

94 California Public Utilities Commission. Decision 08-07-047. Rulemaking 06-04-010. July 31, 2008.

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In California, PacifiCorp is also subject to a separate “loading order” requirement that requires utilities to first meet growth in energy demand through energy efficiency and demand response. Only after all cost-effective demand-side measures have been taken should the utilities consider adding conventional generation technologies.⁹⁵ PacifiCorp’s 2011 IRP creates leveled cost curves for demand-side resources, as described above and in previous sections, and is a good example of this type of energy efficiency modeling effort. This type of modeling may be too costly to be feasible for some utilities, but it is important that consideration of various levels of DSM savings be given in integrated resource planning in order to give stakeholders confidence that all cost-effective DSM has been included in utility resource plans.

Supply options

A full range of supply alternatives should be considered in utility IRPs, with reasonable assumptions about the costs, performance, and availability of each resource. There can be uncertainties regarding the availability and costs of raw materials and skilled labor, construction schedules, and future regulations. Because these cost uncertainties can affect technologies in different ways, it is prudent to model a range of possible costs and construction lead times for supply alternatives. And because planning periods examined in IRPs are typically a decade or more, it is also prudent to evaluate supply technologies that are not currently feasible from a cost perspective, but may become so later in the planning period.

Fuel prices

Coal prices have been on the rise in recent years, and natural gas prices have historically been quite volatile. Fuel prices can shift as a result of demand growth, climate legislation, development of export infrastructure, and supply conditions.⁹⁶ It is thus extremely important to use reasonable, recent, and consistent projections of fuel prices in integrated resource planning.

Environmental costs and constraints

Utility IRPs should include a projection of environmental compliance costs—including recognition, and evaluation where possible—of all reasonably expected future regulations. At this time, the EPA has announced several upcoming environmental regulations. A final version of the

Mercury and Air Toxics Standards (the “MATS” Rule) has been released, and rules are pending for Coal Combustion Residuals (“CCR”), cooling water intake structures under the Clean Water Act (“316(b)”), updates to the National Ambient Air Quality Standards (“NAAQS”), and new Effluent Limitation Guidelines.

Within the next three to five years, certain generating units may also become subject to new requirements under the Clean Air Act’s Regional Haze Program, sometimes known as the BART rule because it requires installation of “best available retrofit technology.” The Cross-State Air Pollution Rule, which would have required emissions reductions of SO₂ and NO_x in many states but was vacated by the US Court of Appeals for the DC Circuit in 2012, may return in a revised form at some point in the future.⁹⁷ Finally, greenhouse-gas emissions limits for electric generating units may come into effect in the next decade.⁹⁸

These rules, both individually and in combination, have the potential to dramatically change the electric power industry. Utilities, in their IRP filings, need to acknowledge these rules and prepare for them as best they can through evaluations of emissions allowance costs, emission controls, and changes to resource portfolios. Few utilities now do this in a comprehensive manner. Of those discussed here, APS does the best job in its IRP by providing a discussion of each of the rules and its potential impacts on APS operations. The process could be improved through analysis of different compliance strategy scenarios.

Existing resources

Examination of existing resources in utility IRPs has become especially important as the mandated emission

95 See California Assembly Bills 1890 and 995. Similar loading order requirements exist in a few other states. See for example Connecticut Public Act No. 07-242, Section 51: An Act Concerning Electricity and Energy Efficiency.

96 *Reviving Integrated Resource Planning*. Page 6.

97 Colburn, K., et al. “Least-Risk Planning: The Homer City Decision Increases Uncertainty—but Rewards Forward Thinking.” *Public Utilities Fortnightly*, November 2012.

98 EPA has proposed but not yet finalized greenhouse gas emission limits for newly constructed power plants. After those rules are finalized, EPA is required under the Clean Air Act to develop standards for existing power plants.

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reductions associated with the MATS rule, discussed above, have led to utility decisions across the country to install pollution control retrofits, repower, or retire their coal units. PacifiCorp drew the ire of stakeholders and the Oregon PUC by not including this type of analysis for its coal-fired units in its 2011 IRP. All types of modifications to existing resources should be included in a utility's analysis of the optimum resource portfolio.

Integrated analysis

There are various reasonable ways to model plans, generally requiring the use of optimization or simulation models. Common models used throughout the industry include Strategist, EGEAS, System Optimizer, MIDAS, AURORA, PROMOD, and Market Analytics. These models are supplied to utilities by various third-party vendors.

It is important that the integrated model does not inadvertently exclude combinations of options that deserve consideration. This might occur in one of two ways. The first is in the instances that future resource portfolios are user-defined, rather than selected by an industry model. This is one of the criticisms of the Arizona Public Service IRP: the use of production cost modeling without an optimization component may have resulted in a less than optimal addition of supply- and demand-side resources over time.

The second way in which this may occur is if users constrain optimization models so that a model may not, given the cost, select the quantity of a specific resource that it may want. For example, a utility may constrain a model in such a way that it is only allowed to add 100 MW of wind generation over the resource planning period; but depending on the nature of the utility's electric system, the

model may want to add additional wind resources. In this way, a combination of resources that deserves consideration may be excluded.

Time frame

The study period for IRP analysis should be sufficiently long to incorporate much of the operating lives of any new resource options that may be added to a utility's portfolio—typically at least 20 years—and should consider an “end effects” period to avoid a bias against adding generating units late in the planning period. Arizona rules require a 15-year planning period, Oregon a 20-year planning period, and Colorado a utility-specified planning period of between 20 and 40 years. Of the rules examined here, only Oregon explicitly states that an end effects period should be considered.

Uncertainty

At a minimum, important and uncertain input assumptions should be tested with high and low cases to assess the sensitivity of results to changes in input values. These assumptions include, but are not limited to, load forecasts, fuel prices, emissions allowance prices, environmental regulatory regimes, costs and availability of demand-side management measures, and capital and operating costs for new generating units.⁹⁹ The types of inputs listed are common to most utilities across the United States, but there are additional input assumptions that are regional or local in nature.

As discussed in the section on Oregon's IRP rules, its PUC requires utilities to model cases that vary the amount of hydroelectric output in the region. Utilities in states like Arizona, New Mexico, or Florida may want to examine

99 Decisions in the face of uncertainty come with degrees of risk. A recent study by CERES entitled, “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) concludes that 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.” According to CERES, “risk arises when there is potential

harm from an adverse event that can occur with some degree of probability.” Risks for electric system resources have both time-related (i.e., 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) and cost-related aspects (the possibility that an investment will not cost what one expects, or that cost recovery for the investment will differ from expectations). Practicing Risk-Aware Regulation (April 2012) at 20-21 <http://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation>

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cases that vary the amount of solar output when doing long-term planning. Utilities located in arid regions, or those owning a significant number of generation assets that are dependent on the availability of a water source for power plant cooling, may want to analyze scenarios where water is scarce or is at too high a temperature to be useful for cooling. Individual utilities must determine those input assumptions that are subject to variability, and model sensitivity cases accordingly to properly account for risks and uncertainties that they face.

Performing single-factor sensitivities may not, however, be very informative. Many cases may warrant more sophisticated techniques, such as probabilistic techniques or those that combine uncertainties. “Testing candidate resource solutions against scenarios that address the range of plausible future trajectories of external factors, and their interrelationships, can more effectively support planning in an uncertain environment.”¹⁰⁰

Valuing and selecting plans

There are often multiple stages of running scenarios and screening in developing an IRP, and there are various reasonable ways to approach this. Traditionally, the present value of revenue requirements is the primary metric that is analyzed, and minimized, in utility IRPs. This metric alone may not, however, sufficiently address uncertainties. It may be useful also to evaluate plans along other dimensions like environmental cost or impact, fuel diversity, impact on reliability, rate or bill increases, or minimization of risk.

It is essential that the IRP process be executed in a manner that applies the selected metrics in a reasonably transparent and logical manner, without inappropriately screening out resources options or plans that deserve consideration at the next stage. Note also that it is highly

unlikely that a single resource portfolio will be the best choice on every metric evaluated. A resource portfolio that performs well across several metrics, but perhaps is not the top performer on any single metric, may in fact be the best choice for utility planners.

Action plan

Even though IRPs should have a longer study period, a good plan will include a specific discussion of the implications of the analysis for near-term decisions and actions, and will also include specific plans for getting those near-term items accomplished. Demand-side measures take time to implement, and supply-side resources require months or years of lead time to permit and construct. Utilities must thus provide a thorough discussion of the steps they plan to take to implement, acquire, or construct resources that will meet energy and peak demand needs in their service territories in the three- to five-year period after the plan is filed. The availability of these near-term resources has a direct effect on the resources needed throughout the remainder of the planning period; so it is prudent for the utility to detail the ways in which it will go about acquiring the resources described in its IRP.

Documentation

A proper IRP will include discussion of the inputs and results, and appendices with full technical details. Only items that are truly sensitive business information should be treated as confidential, because such treatment can hinder important stakeholder input processes.

100 Reviving Integrated Resource Planning. Page 4.

V. Conclusion

Utility integrated resource planning has been in effect in various parts of the United States for more than 25 years. While some utilities are regulated by the original IRP rules developed more than a decade ago, many states have updated their IRP rules to reflect current conditions and concerns in regional and national electricity markets. In states where this has occurred, IRPs filed by utilities tend to be more comprehensive and to exhibit more of the “best practices”

in utility resource planning that have been described in this report.

Nonetheless, there are still many ways in which utilities can improve both their resource planning processes and the plans that are generated as a result of these processes. Engaged stakeholders and state public utilities commissions can provide oversight to this process, helping to promote resource choices that lead to positive outcomes for society as a whole.

Appendix: State IRP Statutes and Rules

Arizona

Arizona Corporation Commission Decision No. 71722, in Docket No. RE-00000A-09-0249. June 3, 2010.¹⁰¹

Arkansas

Arkansas PSC. “Resource Planning Guidelines for Electric Utilities.” Approved in Docket 06-028-R. January 4, 2007.¹⁰² Rules are currently under review and updates have been proposed.

Colorado

Colorado PUC. 4 CCR 723-3, Part 3: Rules Regulating Electric Utilities. Decision No. C10-1111. Docket No. 10R-214E. November 22, 2010.¹⁰³

Delaware

HB 6, the Delaware Electric Utility Retail Customer Supply Act of 2006.¹⁰⁴

Georgia

Integrated Resource Planning Act of 1991 (O.C.G.A. § 46-3A-1), Amended.¹⁰⁵

Georgia Public Service Commission. General Rules. Integrated Resource Planning 515-3-4.¹⁰⁶

Hawaii

Public Utilities Commission, State of Hawaii, A Framework for Integrated Resource Planning, March 9, 1992.¹⁰⁷

Idaho

Idaho Public Utilities Commission Order No. 22299, in Case No. U-1500-165.¹⁰⁸

Indiana

170 Indiana Administrative Code 4-7-1: Guidelines for Integrated Resource Planning by an Electric Utility. New draft rules have been proposed in docket IURC RM 11-07.¹⁰⁹

Kentucky

KY Administrative Regulation 807 KAR 5:058. Integrated Resource Planning by Electric Utilities. Relates to KRS Chapter 278.¹¹⁰

Louisiana

Louisiana Public Service Commission Corrected General Order. Docket No. R-30021. Decided at the Commission's March 21, 2012 Business and Executive Session.¹¹¹

Minnesota

MN Statute §216B.2422.¹¹²

MN Rules Part 7843.¹¹³

Missouri

Rules of Dept. of Economic Development. Division 240 - PSC. Chapter 22—Electric Utility Resource Planning (4 CSR 240.22).¹¹⁵

Montana

Montana's Integrated Least-Cost Resource Planning and Acquisition Act (§§ 69-3-1201-1206, Montana Code Annotated).¹¹⁶

Administrative Rules of Montana 38.5.2001-2016, adopted by the Montana PSC, for traditional utilities.¹¹⁷

Administrative Rules of Montana 38.5.8201-8227, adopted by the Montana PSC, for restructured utilities.¹¹⁸

Nebraska

Nebraska Revised Statute 66-1060.¹¹⁹

Nevada

NRS 704.741.¹²⁰

New Hampshire

Title XXXIV Public Utilities, Chapter 378: Rates and Charges, Section 38: Least Cost Energy Planning.¹²¹

New Mexico

Integrated Resource Plans for Electric Utilities, Title 17, Chapter 7, Part 3.¹²²

North Carolina

North Carolina Utilities Commission Rule R8-60: Integrated Resource Planning and Filings.¹²³

North Dakota

North Dakota PSC Order issued on January 27, 1987 in Case No. 10,799. Amended on March 11, 1992 in Case No. PU-399-91-689.¹²⁴

Oklahoma

Title 165: Oklahoma Corporation Commission. Chapter 25: Electric Utility Rules, Subchapter 37: Integrated Resource Planning.¹²⁵

Oregon

Oregon PUC Order No. 07-002, Entered January 8, 2007.¹²⁶

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South Carolina

Code of Laws of South Carolina, Chapter 37, Section 58 37 40. Integrated resource plans.¹²⁷

Public Service Commission of South Carolina Order No. 91-885 in Docket No. 87-223-E. October 21, 1991.¹²⁸

South Dakota

SL 1977, Ch. 390, § 23. Chapter 49-41B-3.¹²⁹

Administrative Rule Chapter 20:10:21, Energy Facility Plans.¹³⁰

Utah

Report and Order on Standards and Guidelines. Docket No. 90-2035-01. Issued June 18, 1992.¹³¹

Vermont

30VSA Sec 218c - Statute establishing least-cost integrated resource planning.¹³²

Public Service Board Order of 4/16/1990 initiating the IRP progress (Docket No. 5270).¹³³

Public Service Board Order of 7/16/2002 (Docket No. 6290).¹³⁴

Virginia

Code of Virginia § 56-597 - § 56-599.¹³⁵

Washington

Washington Administrative Code 480-100-238: Integrated Resource Planning.¹³⁶

Wyoming

Wyoming Public Service Commission Rule 253 (submitted July 22, 2009), and associated Guidelines for Staff Review.¹³⁷

101 This Decision amends Arizona Administrative Code, Title 14, Chapter 2, Article 7: Resource Planning. It is available at: <http://images.edocket.azcc.gov/docketpdf/0000112475.pdf>

102 Arkansas guidelines available at: http://www.sosweb.state.ar.us/elections/elections_pdfs/register/june_07/126.03.07-003.pdf

103 Colorado PUC Decision available at: https://www.dora.state.co.us/pls/efi/EFI.Show_Docket?p_session_id=&p_docket_id=10R-214E

104 Delaware legislation available at: [http://legis.delaware.gov/LIS/lis143.nsf/vwLegislation/HB+6/\\$file/legis.html?open](http://legis.delaware.gov/LIS/lis143.nsf/vwLegislation/HB+6/$file/legis.html?open)

105 Georgia annotated code available at: <http://www.lexisnexis.com/hottopics/gacode/Default.asp>

106 Georgia PSC rules available at: http://rules.sos.state.ga.us/cgi-bin/page.cgi?g=GEORGIA_PUBLIC_SERVICE_COMMISSION%2FGENERAL_RULES%2FINTEGRATED_RESOURCE_PLANNING%2Findex.html&d=1

107 Hawaii PUC Framework available at: http://www.heco.com/vcmcontent/Integrated%20Resource/IRP/PDF/IRP_Framework_052292.pdf

108 Idaho PUC Order available at: <http://www.puc.state.id.us/search/orders/dtsearch.html>

109 Indiana Administrative Code available at: <http://www.in.gov/legislative/iac/title170.html>

110 Indiana docket RM#11-07 available at: <http://www.in.gov/iurc/2689.htm>

111 Kentucky Administrative Regulation available at: <http://www.lrc.ky.gov/kar/807/005/058.htm>

112 Louisiana PUC Order available at: Rules from Arizona, Colorado and Oregon are described in detail in order to demonstrate ways in which states require comprehensive planning processes and resource plan outcomes from the utilities under their jurisdictions.

113 Minnesota Statute available at: <https://www.revisor.mn.gov/statutes/?id=216B.2422>

114 Minnesota rules available at: <https://www.revisor.mn.gov/rules/?id=7843>

115 Missouri rules available at: <http://www.sos.mo.gov/adrules/csr/current/4csr/4c240-22.pdf>, Final Order of Rulemaking was issued on March 3, 2011, as part of the Missouri Public Service Commission Rulemaking Case No. EX-2010-0254. That amendment is available at: https://www.efis.psc.mo.gov/mpsc/commoncomponents/view_itemno_details.asp?caseno=EX-2010-0254&attach_id=2011015905

116 Montana Annotated Code available at: http://data.opi.mt.gov/bills/mca_toc/69_3_12.htm

117 Montana Administrative Rules available at: <http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=38.5>

118 Montana Administrative Rules available at: <http://www.mtrules.org/gateway/ChapterHome.asp?Chapter=38.5>

119 Nebraska Statute available at: <http://nebraskalegislature.gov/laws/statutes.php?statute=66-1060>

120 Nevada Statute available at: <http://www.leg.state.nv.us/nrs/NRS-704.html#NRS704Sec741>

121 New Hampshire Statute available at: <http://www.gencourt.state.nh.us/tsa/html/NHTOC/NHTOC-XXXIV-378.htm>

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- 122 New Mexico PRC Rule available at: http://www.pnm.com/regulatory/pdf_electricity/irp_electricity.pdf
- 123 North Carolina PUC Rule available at: <http://ncrules.state.nc.us/ncac/title%2004%20-%20commerce/chapter%2011%20-%20utilities%20commission/04%20ncac%2011%20r08-60.pdf>
- 124 North Dakota PSC Order available at: http://www.raponline.org/docs/RAP_NDElectricResourceLongRangePlanningSurvey2005_09_17.pdf
- 125 Oklahoma Rule available at: <http://www.occeweb.com/rules/2010Ch35ElectricpermanentMasterRuleseff7-11-10searchable.pdf>
- 126 Oregon PUC Order available at: <http://apps.puc.state.or.us/orders/2007ords/07-002.pdf>
- 127 South Carolina Code available at: www.scstatehouse.gov/code/t58c037.docx
- 128 South Carolina PSC Order available at: <http://dms.psc.sc.gov/pdf/orders/DF4FC4A9-EB41-2CB4-D44614AD02D02B8D.pdf>
- 129 South Dakota Statute available at: <http://legis.state.sd.us/statutes/DisplayStatute.aspx?Statute=49-41B-3&Type=Statute>
- 130 South Dakota Rule available at: <http://legis.state.sd.us/rules/DisplayRule.aspx?Rule=20:10:21>
- 131 Utah Order available at: http://www.airquality.utah.gov/Public-Interest/Current-Issues/Regionalhazesip/RegionalHazeTSDdocs/Utah_PSC_Integrated_Planning_Rules.pdf
- 132 Vermont Statute available at: <http://www.leg.state.vt.us/statutes/fullsection.cfm?Title=30&Chapter=005&Section=00218c>
- 133 Public Service Board Orders issued prior to 1996 are not available online.
- 134 Vermont PSB Order available at: <http://www.state.vt.us/psb/orders/2002/files/6290phaseIIextensionorder.pdf>
- 135 Virginia Statute - content begins at: <http://leg1.state.va.us/cgi-bin/legp504.exe?000+cod+56-597>
- 136 Washington Administrative Code available at: <http://apps.leg.wa.gov/wac/default.aspx?cite=480-100-238>
- 137 Wyoming PSC Rule available at: <http://legisweb.state.wy.us/ARULES/2009/AR09-043.htm>; Guidelines for Staff Review available at: <http://psc.state.wy.us/htdocs/electric/ElectricIRPGuidelines7-10.pdf>



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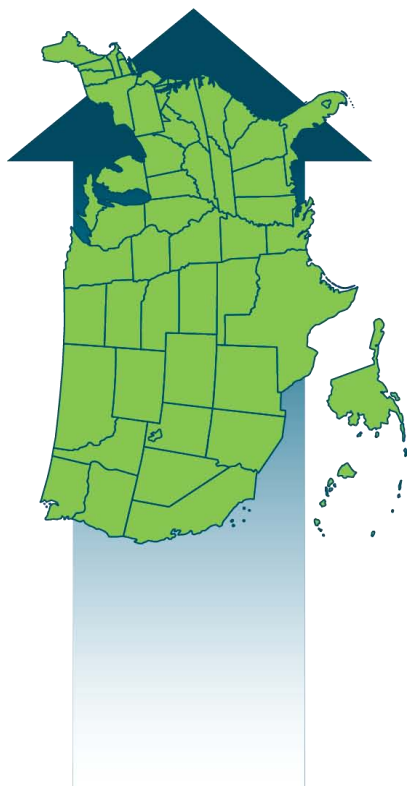
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List of Acronyms

BPA	Bonneville Power Administration
EPA	Environmental Protection Agency
IRP	integrated resource plan
MW	megawatt
NYSERDA	New York State Energy Research and Development Authority
PM	portfolio management
PUC	Public Utility Commission



Executive Summary

An integrated resource plan (IRP) is a long-range utility plan for meeting the forecasted demand for energy within a defined geographic area through a combination of supply side resources and demand side resources. Generally speaking, the goal of an IRP is to identify the mix of resources that will minimize future energy system costs while ensuring safe and reliable operation of the system.

Thirty-four states currently require some sort of IRP process for electricity planning. Thirteen of those states also use IRP processes for natural gas planning. Significant variation exists concerning whether IRPs are acknowledged or approved by each state's public utility commission (PUC) and the authority accorded to the plans.


In the process of developing an IRP for electricity, planners may consider adding generation capacity, encouraging customer-owned generation and combined heat and power facilities, adding transmission and distribution lines, reducing line losses in the transmission and distribution system, implementing demand response programs, and investing in energy efficiency programs to reduce future demand. Analogous supply side and demand side options exist for natural gas planning.

An IRP can be a powerful impetus for energy efficiency and other demand management alternatives to new supply, especially where the planning process is mandatory and overseen by a PUC, because the IRP may require utilities to consider demand side resources that benefit ratepayers even if those resources do not benefit utility shareholders. The availability of energy efficiency and other demand side resources at very low costs and in significant quantities was often ignored in traditional planning processes that focused exclusively on supply side resources.

For an IRP process to successfully encourage all cost-effective energy efficiency, the process must at a minimum be built upon credible load forecasts; use credible information about the costs and availability of new generation assets, transmission and distribution lines, and demand side measures; and evaluate demand side resources equally and fairly in relation to supply side resources. In addition, the very best IRP processes employ most or all of the practices in the left-hand column of Table 1. The right-hand column shows resources for more information on the best practices.

Table 1. Best Practices to Encourage All Cost-Effective Energy Efficiency in an IRP Process

Best Practices	Resources for More Information
<p>Credible load forecasts: model a range of possible load forecasts, not just the reference case</p>	
<p>Generation resources: model a range of possible costs for each supply side technology, considering uncertainties</p>	<p>Webinar:</p> <ul style="list-style-type: none"> • <i>“Integrating the Impact of Energy Efficiency Programs into Resource Planning”</i>
<p>Transmission and distribution resources: consider new transmission lines as a possible resource, but also consider distribution system improvements as a way to reduce line losses and reduce the need for generation</p>	<p>Publications:</p> <ul style="list-style-type: none"> • <i>National Action Plan for Energy Efficiency Guide to Resource Planning with Energy Efficiency</i>
<p>Energy efficiency and other demand side resources: create levelized cost curves for demand side resources that are comparable to the levelized cost curves for supply side resources and allow the model to choose an optimum level of investment</p>	<ul style="list-style-type: none"> • <i>National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change</i>
<p>Modeling: use simulation models that evaluate the cost and risk of multiple possible resource portfolios under dozens or hundreds of future scenarios, where risk is measured by looking at how often each portfolio ends up being one of the most expensive of all the portfolios</p>	<ul style="list-style-type: none"> • <i>National Action Plan for Energy Efficiency Guide for Conducting Energy Efficiency Potential Studies</i>
<p>Environmental Regulations: assess the compliance costs associated with a range of possible future environmental regulations and consider those costs in their modeling</p>	<ul style="list-style-type: none"> • <i>State and Local Energy Efficiency Action Network Setting Energy Savings Targets for Utilities</i>
<p>Stakeholder participation: engage stakeholders early and in meaningful ways</p>	<ul style="list-style-type: none"> • <i>Energy Portfolio Management: Tools and Resources for State Public Utility Commissions</i>
<p>Scale: model at a regional scale or otherwise acknowledge that utilities operate within the context of a regional electricity grid</p>	



Federal and state policies can strongly influence the extent to which IRPs and other similar planning processes are used as well as how effective they are at promoting energy efficiency. As of the end of 2009, only six states had active policies in place that required fair consideration of demand side resources, not just in electric generation planning but also in electric transmission and distribution planning and natural gas planning. In addition to considering state policy changes, all stakeholders can seek to improve existing planning processes by replicating the best practices described above and by learning from successful examples of IRP processes in other jurisdictions.

IRP processes are not appropriate for all utility types, but alternative planning processes exist to effectively promote energy efficiency services in those cases. In the fifteen states that have restructured their electric industry to promote retail competition, consumers may choose from whom to buy their power. Regulated distribution utilities—as the “default” provider or the “provider of last resort”—are typically responsible for procuring power on behalf of consumers who do not choose a competitive generation supplier. Because of the more limited responsibilities of utilities in competitive retail markets, comprehensive IRP processes are generally not appropriate. Instead, distribution utilities in these markets can effectively promote energy efficiency through at least three alternative, but similar, planning processes:

- One option is for the distribution utility to use a “portfolio management” process for default services, whereby energy needs are planned for and procured by evaluating a variety of demand side and supply side resources, or energy suppliers are required to include demand side resources in their offers. Under this option, only default service customers may receive energy efficiency services.
- A second option is for the distribution utility to employ a scaled-down version of IRP, where demand side resources are evaluated as alternatives to transmission and distribution facilities.
- The third option is for the distribution utility to be responsible for implementing cost-effective energy efficiency programs relative to generation, transmission, and distribution facilities, regardless of the fact that generation services are provided through the competitive market. This option can be combined with the second option and enables all utility customers to participate in energy efficiency.

Three successful efforts are summarized to provide examples of best practices.

- The Northwest Power and Conservation Council developed an IRP in 2010 for the Bonneville Power Administration after evaluating the costs and risks of thousands of possible resource portfolios against 750 different future scenarios, all over a 20-year planning horizon. Through the IRP process, the council determined that 85% of its projected growth in demand over the next 20 years can be met through energy efficiency.
- PacifiCorp, a utility serving 1.7 million customers, filed its latest IRP with regulators in six western states in 2011. This IRP is based on recent (2010) potential studies that developed levelized cost curves for the agricultural, residential, commercial, and industrial sectors specific to each state served by the company, and here again energy efficiency represents the largest resource added through 2030.
- Con Edison provides an example of a successful alternative planning process from a distribution utility that operates in a competitive retail market. In 2003, Con Edison saw that specific parts of its distribution network were approaching capacity limits while load continued to grow. Even though the utility was not subject to an IRP or similar planning mandate, managers decided that demand side resources should be compared on an equal basis to supply side resources. Following a request for proposals, Con Edison contracted with energy service companies that succeeded in procuring 89 megawatts (MW) of targeted savings and saved over \$223 million in capital expenditures.

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The Purpose and Use of Integrated Resource Planning

The National Action Plan for Energy Efficiency (the Action Plan) was developed by a broad group of stakeholders in 2008 because “improving the energy efficiency of homes, businesses, schools, governments, and industries—which consume more than 70% of the natural gas and electricity used in the United States—is one of the most constructive, cost-effective ways to address the challenges of high energy prices, energy security and independence, environmental concerns, and global climate change in the near term.”¹ The State and Local Energy Efficiency Action Network (SEE Action) builds on the foundation of the Action Plan and broadens the effort, with a goal of taking energy efficiency to scale and achieving all cost-effective energy efficiency by 2020. The primary goal of this paper is to explain how integrated resource planning can serve as an effective tool for promoting energy efficiency and other demand side resources. Some of the alternatives to an integrated resource plan (IRP) that have proven effective in states with competitive retail markets are also briefly explained.

What is an Integrated Resource Plan?

An IRP is a long-range utility plan for meeting the forecasted demand for energy within a defined geographic area through a combination of supply side resources and demand side resources.² Generally speaking, the goal of an IRP is to identify the mix of resources that will minimize future energy system costs while ensuring safe and reliable operation of the system.

IRP processes are commonly used to analyze alternatives for meeting future demand for electricity. Less commonly, IRP processes are used to ensure that adequate, reliable, and affordable supplies of natural gas will be available as well. Because the planning process is more complex with respect to electricity, most of the emphasis in this paper will be on IRPs for electricity.

An IRP may be developed by a utility or power marketing administration for its service territory in one or more states, by a utility commission for its entire state, or by a regional transmission organization or independent transmission system operator (ISO) for a multistate region. In some states, utility plans serve as a blueprint for resource acquisition decisions and are subject to approval by the public utility commission (PUC). Plans covering a multistate area are more likely to be used for educational purposes only.

What Kinds of Alternatives are Considered in an IRP?

In the process of developing an IRP, planners may consider a wide range of alternatives to meet future energy needs. For electricity plans, the alternatives can include adding generation capacity, encouraging customer-owned generation and combined heat and power facilities, adding transmission and distribution lines, reducing line losses in the transmission and distribution system, and implementing demand response programs. But the primary focus of this paper is another alternative, which is now included in IRP processes in more than 30 states, and that is investing in energy efficiency programs to reduce future demand when it is cost effective to do so. Analogous supply side and demand side options exist for natural gas planning.³

In planning to meet future energy needs, nearly all utilities and utility regulators across the country have practiced least-cost resource planning for decades. In many cases, these least-cost resource plans exclusively considered procurement of supply side resources. The availability of energy efficiency and other demand side resources at very low costs and in significant quantities was often ignored in the planning process. An IRP can be very similar to a traditional least-cost resource plan, with the distinction that a process or plan that doesn't consider demand side resources is not an IRP.

¹ National Action Plan for Energy Efficiency, Vision for 2025: A Framework for Change, available at <http://www.epa.gov/cleanenergy/documents/suca/vision.pdf>.

² Demand side resources can include energy efficiency, demand response, and customer-owned generation sized to meet the customer's needs. The term demand side management (DSM) has essentially the same meaning and is commonly used, but that term may hinder one of the goals of this paper, which is to encourage planners to treat demand side and supply side resources equally.

³ Not every IRP considers every alternative listed. The alternatives considered will vary based on state and local regulatory requirements and based on what type of entity is developing the plan.

Distinction between Uses of IRP as a Regulatory or Non-regulatory Planning Tool

Resource planning requirements are not consistent across the United States. Some states require utilities to develop IRPs, whereas others do not. Planning requirements may be embodied in state statutes, administrative rules, or PUC orders. It should also be understood that all utilities do some sort of long-range planning based on least-cost procurement of resources, and some may develop an IRP even in the absence of a regulatory requirement. Figure 1 indicates those states that have adopted IRP requirements.

The 34 states shown in blue in Figure 1 require IRP or some sort of similar process for electricity planning. Although not indicated on the map, thirteen (13) of those states also use IRP processes for natural gas planning.⁴

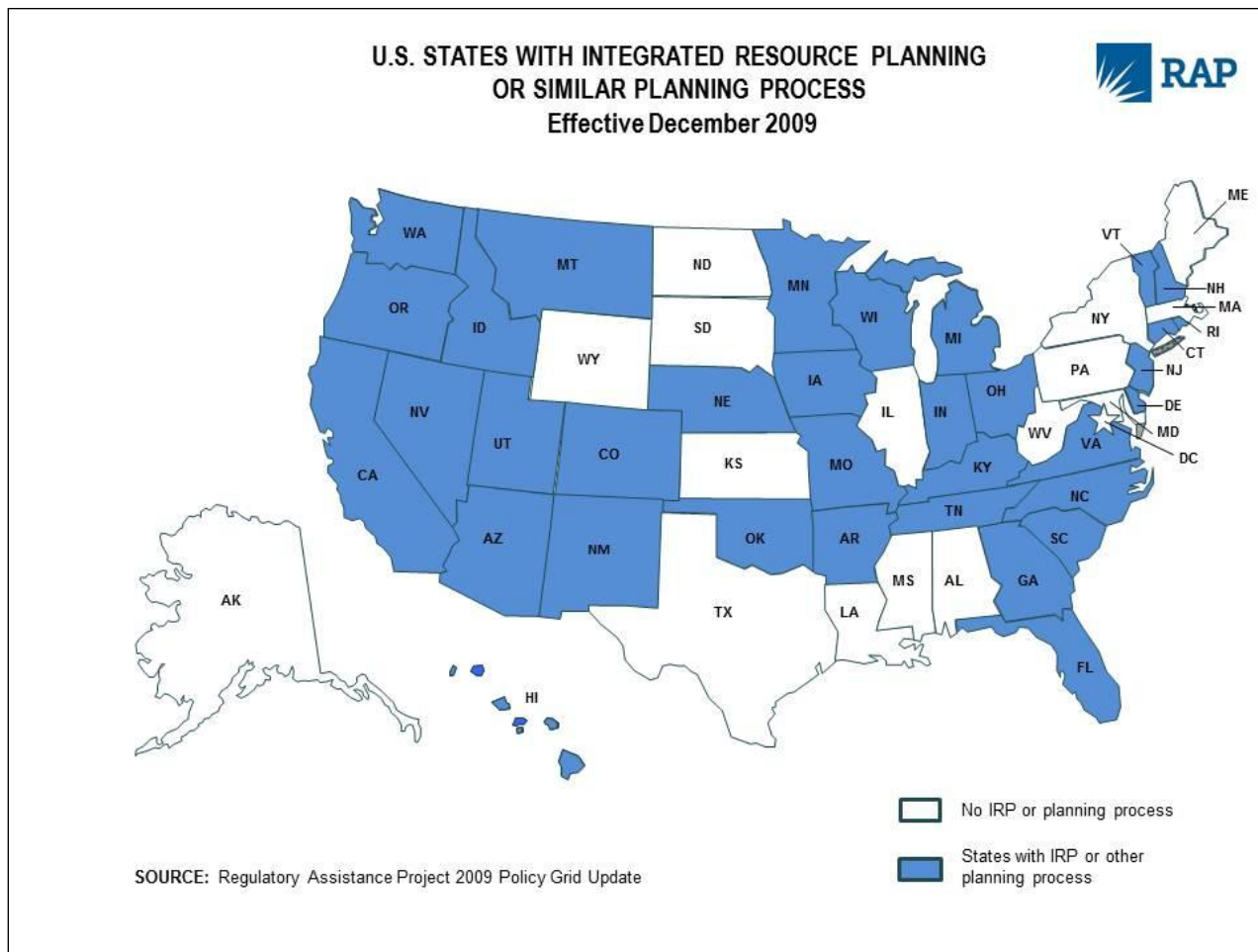


Figure 1. States with integrated resource planning or similar processes⁵

In states that require some form of IRP, there is significant variation in the role assigned to the PUC. The PUC may perform any of the following:

⁴ Some of the states that do not require an IRP process nevertheless have strong energy efficiency policies. IRP is only one of many effective policy tools for encouraging energy efficiency.

⁵ Source: <http://raponline.org/document/download/id/4447>. Because actual requirements vary widely from state to state, readers are encouraged to refer to the source document for details.

- Develop an IRP based on data provided by utilities
- Acknowledge receipt of IRPs developed by utilities
- Approve IRPs filed by utilities, with modifications if necessary
- Convene an IRP process with opportunities for stakeholders to intervene prior to a PUC decision

Another area of significant variation is the official status or treatment of an IRP that has been approved or acknowledged by a PUC. At one end of the spectrum is Nevada, where PUC approval of an IRP is tantamount to approval for the utility to construct or acquire the resources (supply side or demand side) described in the plan.

More commonly, IRP approval by the PUC does not relieve a utility from the need to ultimately demonstrate that its investments are optimal and consistent with the plan given actual (as opposed to forecast) conditions. PUC approval may, however, convey a rebuttable presumption that the projects described in the plan are necessary and prudent. In Oregon, for example: "Consistency with the plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment. Similarly, inconsistency with the plan will not necessarily lead to unfavorable rate-making treatment, although the utility will need to explain and justify why it took an action inconsistent with the plan."⁶ Similarly, in Idaho the PUC stated that it would "continue to hold that the plans are not to be given the force and effect of law, [but] we presume that utilities intend to follow the plans after they have been filed for our acceptance. Deviations from the integrated resource plans must be explained. The appropriate place to determine the prudence of an electric utility's plan or the prudence of an electric utility's following or failing to follow a plan will be in general rate case or other proceeding in which the issue is noticed."⁷

Finally, there are states in which a PUC-acknowledged IRP serves more as a reference document than as an actual plan. In Wisconsin, for example, utility IRPs are not required, but funding levels for mandatory utility investments in energy efficiency are determined by the Public Service Commission through a quadrennial planning process. The results of that process are then incorporated into biennial, statewide Strategic Energy Assessments developed by the Commission with input from utilities and other stakeholders. These assessments evaluate most of the same supply, demand, and transmission questions that underlie an IRP. They guide the Commission in a variety of general policy discussions, and they provide the public with useful information. But utility supply side resource investments are reviewed in separate cases, and Wisconsin statutes ensure that the Strategic Energy Assessments have no binding significance in those cases.

How IRPs Can Promote Energy Efficiency and other Demand Side Resources

An IRP can be a powerful impetus for promoting energy efficiency and other demand management alternatives to new supply. Although the amount of available cost-effective energy efficiency will vary based on local circumstances, some quantity will probably always be available at a lower levelized cost per megawatt-hour than supply side alternatives.⁸ Thus, because of this basic economic fact, any planning process that requires utilities to consider demand side resources as part of an integrated strategy to meet customer demand is likely to promote energy efficiency. This is especially true where IRP processes are mandatory and overseen by a PUC, because the IRP requirement may require utilities to consider demand side programs that benefit ratepayers even if the programs do not benefit shareholders. In some circumstances, cost-effective energy efficiency measures may even be available in sufficient quantities to satisfy all of the projected load growth within the planning timeframe.⁹

⁶ Oregon PUC Order No. 89-507 at 7.

⁷ Order 25260 from Case #GNR-E-93-3.

⁸ See, for example, the Lazard estimates presented to the National Association of Regulatory Utility Commissioners in June 2008, available at [http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20\(2\).pdf](http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf).

⁹ The Vermont Energy Investment Corporation, which administers ratepayer-funded programs throughout that state, reported in 2008 that energy efficiency measures had for the first time turned load growth negative in 2007. Since very few states even attempt to achieve all cost-

Approaches for Including Demand Side Resources in an IRP

Planners can use at least three different approaches for including demand side resources in an IRP. The first two approaches incorporate these resources in forecasts of future demand for energy, whereas the third approach treats these resources as assets that can be deployed to meet forecasted demand if doing so is less costly than deploying supply side resources.

One way for planners to include demand side resources in the future load forecast is to build in the effects of an energy efficiency policy as a defined model input. For example, if a state has a requirement that utilities achieve annual energy savings equal to 1% of the prior year's load, planners can adjust their future demand forecast to ensure that the results of the policy are included. This approach is the simplest of the three approaches described in this paper and may be the best option in cases where planners have limited information about the costs of demand side resources. This approach, however, will not necessarily result in the least-cost resource plan, because it presupposes a certain level of demand side resources before evaluating the cost-effectiveness of all options for meeting demand. It also will not encourage investments in energy efficiency beyond the minimum level specified by the policy.

A better option for including demand side resources in the future load forecast is to evaluate supply side options against *multiple* load forecasts. For example, planners can develop one forecast based on the minimum level of efficiency investments required by state policies, another forecast based on increased investments, and a third based on investing in all cost-effective efficiency measures. The costs of "minimum efficiency," "more efficiency," or "all cost-effective efficiency" are then added to the costs of supply side resources to evaluate plans. This approach is preferable to the first option because it allows planners to consider the overall system cost implications of different levels of energy efficiency investments; it presupposes, however, that credible information is available on the costs of achieving each level of load reduction.

Finally, planners can develop a forecast of future energy demand that assumes no demand side resource investments beyond the ongoing impacts of existing policies and programs. Instead, additional demand side investments are treated as resources that can "generate" negative energy and demand at specified costs. Thus, a kilowatt of demand or a kilowatt-hour of energy can be served through either demand side resources or supply side resources. This approach will not only result in a true least-cost plan and (in most cases) high levels of energy efficiency investment, it will also provide useful information about the true value of demand side resources as an alternative to supply side resources. This approach would normally be considered the best option, provided that cost curves are available for supply side and demand side resources alike.


Recommendations for Successful Integrated Resource Planning

The goal of the State and Local Energy Efficiency Action Network (SEE Action) is to achieve all cost-effective energy efficiency by 2020. Integrated resource planning is one way to take a comprehensive look at cost-effectiveness. In an IRP, the central question is not "does this efficiency measure pay for itself?" but rather "is efficiency likely to be less costly than other alternatives for meeting customer demand, taking into account uncertainty and risk?"

Prerequisites for a Successful IRP

The process of developing an IRP can be a powerful force for encouraging investment in demand side resources. It is perhaps noteworthy that 17 of the top 20 states, in terms of per capita utility investments in energy efficiency,

effective energy efficiency, it is not known how replicable that result might be. Refer to:
http://eec.ucdavis.edu/ACEEE/2008/data/papers/10_355.pdf.



have IRP requirements.¹⁰ For an IRP process to successfully encourage all cost-effective energy efficiency, however, there are certain prerequisites that must be met.

Credible Load Forecasts

To begin with, projections of future load should be based on realistic assumptions about local population changes and local economic factors. Because of demographic and economic considerations, load growth will vary across utility service territories, from state to state within a region, and from region to region across the country. Locally relevant data are needed. The load forecast used in an IRP process must also take into consideration policies and programs that are already on the books. In states where energy efficiency policies and programs are well established and stable, future load growth might look very similar to recent past load growth. But in states that have newly adopted demand side policies and programs, estimates of the impacts of those policies and programs must be developed and incorporated into future load forecasts.

Credible Information about Costs and Availability of Resources

In most cases, planners will determine that load is expected to grow and will find that current supply side and demand side resources are not sufficient to meet future energy needs. Additional resources will need to be acquired. To determine the types and amounts of resources to acquire, planners need the best possible information about the availability and expected costs of new generation assets, transmission and distribution lines, and demand side measures. In the case of energy efficiency, it is critically important to have a potential study or other assessment in order to know how much demand reduction can realistically be achieved.¹¹

Fair and Equal Consideration of All Resources

An IRP will not be truly integrated and won't encourage energy efficiency unless demand side resources receive fair consideration. Most investor-owned utilities have the opportunity to earn a return on their investment when they build new supply side resources, but not when they purchase or fund demand side resources. Unless the IRP process itself is one that requires the utility to treat these resources equally, the utility might have an inherent preference for the more profitable supply side resources.¹²

IRP Best Practices

The goal of an IRP is to identify the portfolio of resources that performs best with respect to a stated objective, such as "minimize net present value system cost while meeting all system reliability requirements," under a wide variety of possible future scenarios.¹³ To maximize the chance of successfully attaining this goal, it is not enough to merely satisfy the minimum prerequisites listed above. All of the following ideas can be replicated across the country to improve IRP processes.

Load


The best IRP processes model a range of possible load forecasts, not just the one most likely forecast (i.e., the "reference case"). Probabilities can be assigned to each forecast for risk analysis purposes. This is the most straightforward way to acknowledge and address uncertainty about future energy prices, and the induced effect on demand, as well as uncertainty about demographic and economic variables. The process need not be complicated; for example, planners can develop a low load growth forecast and a high load growth forecast as

¹⁰ <http://www.cee1.org/ee-pe/docs/Table%206.pdf>.

¹¹ For more information on this topic, see the National Action Plan for Energy Efficiency Guide for Conducting Energy Efficiency Potential Studies, available at <http://www.epa.gov/cleanenergy/energy-programs/suca/resources.html>.

¹² The National Association of Regulatory Utility Commissioners has long recognized the importance of overcoming a utility's inherent disincentive to invest in energy efficiency, adopting a resolution in 1989 to "reform regulation so that successful implementation of a utility's least-cost plan is its most profitable course of action." For more information on this topic, see the National Action Plan for Energy Efficiency Aligning Utility Incentives with Investment in Energy Efficiency, available at <http://www.epa.gov/cleanenergy/energy-programs/suca/resources.html>.

¹³ Because the optimum portfolio may vary from one scenario to the next, planners seek to identify a robust portfolio that performs relatively well across all scenarios.



alternatives to their reference case, making use of low-end and high-end estimates of local load growth in industry or government reports.¹⁴

Generation Resources

Rather than using only a single reference value for the assumed cost and availability of each generation technology, the best IRP processes model a range of possible costs, considering uncertainties in the availability and costs of raw materials and skilled labor, construction schedules, and future regulations. A good IRP process will consider multiple scenarios entailing a range of possibilities.

Transmission and Distribution Resources

Some IRPs do not evaluate these resources on a comparable basis to generation or demand side resources. The best IRPs, however, not only consider new lines as a possible resource but also consider distribution system improvements as a way to reduce line losses and reduce the need for generation.

Energy Efficiency and Other Demand Side Resources

In many IRP processes, demand side resources are considered only to the extent that mandatory investments or standards are factored into future load forecasts. The very best IRPs either supplement this approach or take a completely different approach. Specifically, the best IRPs create levelized cost curves for demand side resources that are comparable to the levelized cost curves for supply side resources.¹⁵ In the case of energy efficiency, these curves should be derived from recent, local potential studies developed consistent with the Action Plan Guide for Conducting Energy Efficiency Potential Studies.¹⁶ Developing a locally specific potential study may be more costly than applying the results from a potential study for a broader geographic area, or a nearby area, but it can also produce data of much higher quality and value. By developing cost curves for demand side options, planners allow the model to choose an optimum level of investment.¹⁷ So if demand side resources can meet customer demand for less cost than supply side resources, as is frequently the case, this approach may result in more than the minimum investment levels required under other policies.

Model

All IRP efforts use simulation models to identify a least-cost (in terms of net present value) resource portfolio based on assumptions about the future values of variables, i.e., the reference case. In most cases, planners will then evaluate multiple alternative scenarios, with each scenario representing a different set of assumptions about some of the model inputs that have more uncertain future values. This consideration of multiple scenarios allows planners to identify a portfolio of resources that has low costs across most or all scenarios, instead of automatically choosing the one portfolio that looks best under the reference case. The very best IRP efforts, however, take this idea even further. The best efforts use simulation models that evaluate the cost *and risk* of multiple possible portfolios under dozens or even hundreds of future scenarios. Risk, in this context, might be measured by looking at *how often* each portfolio ends up being one of the most expensive of all the portfolios. With this kind of modeling, planners can choose a resource portfolio that is “robust” in the sense that its *average* cost across all scenarios is low, and in very few scenarios does it fare much worse than other possible portfolios.

¹⁴ Note that the multiple load forecasts described here are based solely on different economic and demographic assumptions for the geographic area covered by the IRP. Variations in load that might arise from assumptions about demand side investments will be discussed separately.

¹⁵ Recent experience with energy efficiency cost curves indicates that the costs of some measures can vary significantly depending on program design and delivery methods. For example, the cost of an integrated, whole-building approach to energy efficiency retrofits may differ from the aggregated costs of discreet building efficiency measures. Economies of scale may also affect cost curves. Planners and other stakeholders should seek to understand any assumptions about program design, delivery, or scale that are built into the cost curves.

¹⁶ http://www.epa.gov/cleanenergy/documents/suca/potential_guide.pdf.

¹⁷ Potential studies will normally distinguish between the technical or theoretical potential for energy savings, the economic or cost-effective potential, and the achievable potential considering real-world practicalities. Determining what level of savings is realistically achievable can be a contentious issue. If the cost curves are based on technical or economic potential, the model may identify an optimum level of investment that exceeds achievable potential. In this case, planners may feel that it is necessary to include a suboptimal level of energy efficiency in the portfolio, whereas some stakeholders may feel that such a decision undermines the results.



Environmental Regulations

Rather than assuming that the regulatory landscape never changes, or assuming that future regulations are utterly predictable, the best IRPs are developed after considering a range of possible future regulations. For example, the Environmental Protection Agency (EPA) is currently considering whether to regulate coal ash as a hazardous waste. If EPA does so, the cost of disposing coal ash may be significantly greater than otherwise. Another obvious example relates to the stringency of future federal or state greenhouse gas regulations. These regulations will make fossil fuel generation more expensive in at least some cases, but it is too early to know which sources will be affected and how costly it will be to comply. Although planners cannot know for sure what future regulations will be implemented, the best efforts assess the potential costs of a range of possibilities and consider those costs in their modeling.

Stakeholder Participation

The best IRP processes provide opportunities for consumer advocates and other stakeholders to review the modeling assumptions and the list of scenarios to be modeled and suggest changes or additions. These stakeholders frequently identify problems and opportunities that planners may have overlooked. Furthermore, stakeholders should have the chance to review modeling results before the IRP is finalized and (where applicable) approved by regulators. In general, the entire process should be conducted with a reasonable level of transparency, while of course respecting any confidential utility information that is included. Without transparency and stakeholder participation, public confidence in the IRP may be in jeopardy, and this could have negative ramifications when the plan is implemented.

Scale

With few exceptions, utilities operate within the context of a regional electricity grid where the cost and value of supply side and demand side resources cross service territories and state boundaries. The optimal way to meet customer demand for an entire regional electricity grid is likely to be different from what appears to be optimal when planning occurs only at the utility or state level. Because of this simple fact, regional resource planning represents another best practice, provided that it is done in a way that complements rather than supersedes more localized planning.



Best Practices	Resources for More Information
<p>Credible load forecasts: model a range of possible load forecasts, not just the reference case</p> <p>Generation resources: model a range of possible costs for each supply side technology, considering uncertainties</p> <p>Transmission and distribution resources: consider new transmission lines as a possible resource, but also consider distribution system improvements as a way to reduce line losses and reduce the need for generation</p> <p>Energy efficiency and other demand side resources: create levelized cost curves for demand side resources that are comparable to the levelized cost curves for supply side resources and allow the model to choose an optimum level of investment</p> <p>Modeling: use simulation models that evaluate the cost and risk of multiple possible resource portfolios under dozens or hundreds of future scenarios, where risk is measured by looking at how often each portfolio ends up being one of the most expensive of all the portfolios</p> <p>Environmental Regulations: assess the compliance costs associated with a range of possible future environmental regulations and consider those costs in their modeling</p> <p>Stakeholder participation: engage stakeholders early and in meaningful ways</p> <p>Scale: model at a regional scale or otherwise acknowledge that utilities operate within the context of a regional electricity grid</p>	<p>Webinar:</p> <ul style="list-style-type: none">• <i>“Integrating the Impact of Energy Efficiency Programs into Resource Planning”</i> <p>Publications:</p> <ul style="list-style-type: none">• <i>National Action Plan for Energy Efficiency Guide to Resource Planning with Energy Efficiency</i>• <i>National Action Plan for Energy Efficiency Vision for 2025: A Framework for Change</i>• <i>National Action Plan for Energy Efficiency Guide for Conducting Energy Efficiency Potential Studies</i>• <i>State and Local Energy Efficiency Action Network Setting Energy Savings Targets for Utilities</i>• <i>Energy Portfolio Management: Tools and Resources for State Public Utility Commissions</i>

The Impact of Applying IRP Best Practices

An IRP process that is based on the best practices described above is very likely to result in the selection of a portfolio that includes a substantial amount of energy efficiency, if not all cost-effective efficiency. There are two factors above all others that lead to that result. First, some amount of energy efficiency is virtually always achievable at a cost that is less expensive than new generation resources. When given a chance to compete on a fair basis with supply side resources, those energy efficiency measures will emerge as a preferred resource on cost alone. In fact, any IRP process that does not allow demand side resources to compete fairly is unlikely to identify a true “least-cost” portfolio. Second, the models that evaluate risk tend to find that demand side resources are much less risky than supply side options.

Finally, it is important to note that an IRP process that fairly considers demand side resources will help planners and stakeholders see those resources in a new light. For many utilities, investments in energy efficiency get expensed and end up as a rider on retail rates. It is typical and understandable in these cases for some stakeholders to resist such investments on the argument that retail rates will increase in the near term. What the best IRP processes do, however, is demonstrate in a rigorous fashion that investments in energy efficiency can play a large role in the “least-cost” resource portfolio for the long term. In other words, when energy efficiency is treated as an add-on to the resource portfolio, via a rider added to the base rates, it appears to be unfavorable from a “least-rate” perspective. But when efficiency is treated as an integrated part of the resource portfolio via an IRP, it proves to be preferable from a more comprehensive “least-cost” perspective.

Federal and State Policies that Create a Supportive Framework for Best Practice IRPs

A number of states have adopted public policies – through statute, regulation, or PUC order – that require utilities or some other entity to engage in IRP or similar planning processes. In addition, federal laws and policies include similar requirements for some federally established regional power authorities.

One of the metrics used to measure progress in implementing the Action Plan *Vision for 2025* is to identify whether states have adopted policies that recognize energy efficiency as a high-priority resource. More specifically, progress is measured based on whether state policy requires energy efficiency to be integrated into an active IRP, portfolio management (PM), or other planning process; whether energy efficiency is procured as a resource for default service/standard offer customers in restructured markets; and whether energy efficiency is considered as an alternative to transmission based on a long-term transparent integrated resource planning or transmission system plan.¹⁸

As of the end of 2009, only six states had active policies in place that required fair consideration of energy efficiency not just in electric generation planning, but also in electric transmission and distribution planning and natural gas planning: California, Montana, Oregon, Utah, Washington, and Vermont.¹⁹ In terms of the comprehensive scope of the planning mandate, these states stand out as leaders in policy adoption. This does not necessarily mean that the IRP processes mandated in these states always conform to best practices. It may also be that the IRP processes in some other states are less comprehensive in scope but conform to best practices.

A good example of federal policy affecting regional power authorities is the *Pacific Northwest Electric Power Planning and Conservation Act of 1980*, which gives an even more powerful boost to demand side resources in planning processes. That law requires the Northwest Power and Conservation Council to develop IRPs that don't merely put demand side resources on an even footing with supply side resources but make energy efficiency the highest-priority resource for meeting electricity demand and assign it an assumed 10% cost advantage over supply side resources.

¹⁸ Refer to Appendix D at <http://www.epa.gov/cleanenergy/documents/suca/vision.pdf>.

¹⁹ Again refer to <http://www.raponline.org/Feature.asp?select=116>.

Alternatives to IRP in States with Competitive Retail Electricity Markets

In the United States, individual states are sometimes referred to as having “restructured” or “competitive” retail electricity markets if the state allows consumers to choose from whom to buy their power.²⁰ Prior to restructuring, which began in the 1990s, consumers across the country had no choice but to buy electricity from their local electric utility, whose rates reflected the cost of generating (or purchasing) power as well as transmission and distribution costs. This is still the norm in the majority of states. But now, in restructured states, companies compete to serve the power needs of consumers, and the role of the utility is limited to delivering power from the supplier of choice to the consumer.²¹

In competitive retail markets, distribution utilities have an obligation to serve customers regardless of which supplier the consumer chooses. The investments, expenditures, and rates of distribution utilities are still regulated by PUCs, but those of competitive suppliers are not. In addition, distribution utilities are also required in most restructured states to offer “default service” to customers who, for whatever reason, do not actually choose a supplier or cannot obtain service from a competitive supplier.²² The prices and terms of this default service are also regulated by the PUC.

Because of the more limited responsibilities of utilities in competitive retail markets, comprehensive IRP processes are generally not appropriate. Instead, distribution utilities in these markets can promote energy efficiency through at least three different alternative processes, described below.

One option is to consider energy efficiency as part of a default service PM process. In recent years, the term “portfolio management” has been used in the electric industry to describe approaches that can be used by distribution companies to plan for and procure default services by purchasing a mix of supply side and demand side resources, using contracts with varying terms. The concept of PM as applied to default services is based on the concept of portfolio management for financial investments; i.e., it is based on the theory that a balanced portfolio is likely to reduce the customer’s risk relative to placing all financial investments (or power purchases) into a very small, undiversified portfolio. In the context of power purchases, a balanced portfolio might mean, for example, (a) a mix of demand side and supply side resources; (b) a mix of short-term, medium-term, and long-term contracts; (c) a mix of fixed price contracts and indexed contracts; and (d) renewable contracts with fixed prices and fewer environmental risks. PM is based on the concept that many customers purchasing default service are not able or are not likely to switch to competitive retail suppliers, and, therefore, the distribution company has an obligation to provide those default customers with safe, reliable, low-cost power at stable prices. PM planning practices can resemble IRP practices in many ways, particularly in the way that demand side resources are compared on an equitable basis with supply side resources. Eight states with competitive retail markets currently require distribution utilities to procure energy efficiency as a resource for default service customers. In four of those states—Ohio, Delaware, Connecticut and Rhode Island—a PM or IRP approach is specifically required.²³ Under this option, only default service customers may receive energy efficiency services.


Another option is to employ IRP practices to transmission and distribution facilities only. Distribution companies need to ensure that they can provide low-cost, reliable transmission and distribution services to their customers, regardless of whether they provide any form of generation service. Some utilities may view this obligation entirely from a perspective of the need to build, maintain, and operate distribution lines and substations. But an increasing number of distribution utilities are adopting IRP or planning practices where demand side resources are seen as a

²⁰ Fifteen states plus the District of Columbia currently have competitive retail markets. Refer to http://www.eia.gov/cneaf/electricity/page/restructuring/restructure_elect.html. In half of these restructured markets, some form of IRP or an alternative process is mandatory, whereas more than two-thirds of the unstructured states require some form of planning.

²¹ In nearly all cases in the United States, customer service and billing is managed by the distribution utility. The utility purchases power from the competitive supplier and adds that cost to its own costs on the consumer’s bill.

²² Depending on the state, default service may be called “standard offer,” “provider of last resort,” or “basic generation service.”

²³ Based on Action Plan Policy Grid Updates compiled by Regulatory Assistance Project through 2009. Refer to <http://www.raponline.org/Feature.asp?select=116>.



potential alternative to transmission and distribution facilities. One example of this, from Con Edison in New York, is summarized in the section “Examples of Successful IRP or Alternative Planning Efforts” below.

A third option is for the distribution utility to be given full responsibility for implementing all energy efficiency resources that are cost-effective relative to generation, transmission, and distribution facilities. Although the distribution utility may have a limited role or no role at all in providing generation services (through default service), it is still considered appropriate for them to implement the energy efficiency associated with avoided generation costs as well as avoided transmission and distribution costs, because they are in the best position to implement those efficiency resources. Distribution companies can utilize a system benefits charge applied to all distribution customers, provide efficiency services to those same distribution customers, and act as a centralized, regulated agency with the public policy mandate to achieve all of the energy efficiency that is cost-effective for those customers. This approach has been used very successfully in California and Massachusetts, for example. It can be combined with the second option, and it enables all utility customers to participate in energy efficiency.

In the case of a distribution utility operating in a competitive retail market, some of the IRP best practices described above will not always be fully applicable. What matters, however, is that the utility takes an integrated approach where demand side resources have the opportunity to compete on a cost and risk basis with supply side and transmission and distribution assets.²⁴

Examples of Successful IRP or Alternative Planning Efforts

Three very different examples of successful IRP efforts are noted below. They are presented to illustrate some of the concepts and all of the best practices described in this white paper. The processes and the results of these efforts will only be briefly summarized, but interested readers are encouraged to delve deeply into the documents referenced in footnotes for more detail and illumination.

Northwest Power and Conservation Council

As previously noted, the federal *Pacific Northwest Electric Power Planning and Conservation Act of 1980* requires the Northwest Power and Conservation Council, a regional planning organization, to develop IRPs for the BPA that don't merely put demand side resources on an even footing with supply side resources but make energy efficiency the highest-priority resource for meeting electricity demand and assign it an assumed 10% cost advantage over supply side resources. These plans have a profound effect on the operations of BPA in Washington, Oregon, Idaho, and Montana.²⁵

The council adopted its Sixth Northwest Conservation and Electric Power Plan in February 2010 at the end of an IRP process that began in December 2007.²⁶ This plan provides an excellent example of all of the IRP best practices noted in this paper.


To begin with, the council acknowledged uncertainty about demographic and economic variables by developing three separate forecasts of future load—a baseline case as well as “high-” and “low-” growth cases. Planners also tested how sensitive their results were to a range of possible adoption levels for electric vehicles.

Detailed information was then developed about the levelized costs of generation, transmission, distribution, and energy storage resources, including consideration about cost uncertainties. Energy efficiency resource potential

²⁴ From the perspective of state policymakers, it can be uncomfortable to feel no control over the resource mix serving the state. This has led restructured states like Illinois, Maryland, and New Jersey to consider initiatives that would give the state some role in resource planning and acquisition.

²⁵ The council is funded by wholesale power revenues from the BPA, the federal agency that markets the electricity generated at federal dams on the Columbia River.

²⁶ <http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan.pdf>.



was estimated for the agricultural, residential, commercial, and industrial sectors, as well as for utility distribution systems and consumer electronics. Levelized cost curves were produced for each resource category.

The council's IRP included an evaluation of the costs and risks of thousands of possible resource portfolios against 750 different future scenarios, all over a 20-year planning horizon. This analysis included consideration, for example, of many different scenarios for the cost of complying with greenhouse gas regulations—ranging from no regulation (\$0 per ton of carbon dioxide emitted) to \$100 per ton emitted.

Finally, the planning effort was regional in scale, meetings were open to the public, documents were available on a Web site, and stakeholders were given the opportunity to review and comment on a draft plan before final decisions were made.

Through the IRP process, the council determined that 85% of its projected growth in demand over the next 20 years can be met through energy efficiency. On average, the council expects energy efficiency investments to cost just half as much as comparable supply side investments. The approved IRP includes 1,200 MW of energy efficiency savings in the first five years, and 5,900 MW over 20 years – the most aggressive targets in the nation.

The council has good reason to be confident that the Sixth Plan is not overly optimistic. Its evaluation of efficiency efforts from 1980 through 2008 found that nearly 4,000 MW of savings had been achieved, cutting demand growth in half and saving consumers \$1.8 billion on electric bills.

PacifiCorp

PacifiCorp is a large utility serving 1.7 million customers in six western states. Five of those states—Utah, Washington, Oregon, Idaho, and California—require utilities like PacifiCorp to file an IRP with the state PUC. Wyoming is an unusual case in that it requires utilities to file an IRP with the PUC only if the utility is required to file an IRP in another state, as is the case for PacifiCorp. So this company files its IRP in all six states.

In March 2011, PacifiCorp filed its 11th IRP with state regulators.²⁷ Although it is too soon to know how the latest plan will be received by regulators, the planning process offers a good illustration of some of the best practices noted in this paper.

PacifiCorp, like the Northwest Power and Conservation Council, developed a baseline load growth forecast, along with low-growth and high-growth forecasts. For supply side resources, the company developed separate cost data for the eastern and western parts of its territory.

In terms of demand side resources, the IRP is based on recent (2010) potential studies that developed levelized cost curves for the agricultural, residential, commercial, and industrial sectors. The cost information is specific to each state served by the company. The IRP process undertaken by PacifiCorp is also interesting because in most of its service territory it administers energy efficiency programs, whereas in Oregon those programs are administered by a third party. Consequently, PacifiCorp used a hybrid approach to evaluating energy efficiency potential, combining data from the Energy Trust of Oregon with a separate potential study it commissioned for the rest of its territory.

PacifiCorp defined 67 separate scenarios for portfolio development, covering a range of alternative transmission configurations, greenhouse gas regulation costs, natural gas prices, renewable energy requirements and costs, load forecasts, and demand side resource availability. Each portfolio was modeled using three natural gas price forecasts. PacifiCorp then ran 100 simulations before selecting a preferred portfolio, based on low average cost (across runs), low worst-case cost, and other considerations.

PacifiCorp provided numerous opportunities for stakeholder input into the IRP. Five meetings and three conference calls were open to the public. To encourage broad participation, meetings were held jointly in Salt Lake City and Portland, with telephone and videoconference access as well.

²⁷ The 2011 Plan and the approved plan from 2008 are available at <http://www.pacificorp.com/es/irp.html>.

Finally, it is worth noting that PacifiCorp's IRP had a regional perspective; it was not an aggregation of six different state-specific plans.

The results of PacifiCorp's 2011 IRP are eye-catching. Energy efficiency represents the largest resource added through 2030 across all portfolios, with cumulative capacity additions exceeding 2,500 MW in the preferred portfolio. The preferred portfolio also adds over 250 MW of demand response in the first five years.

Con Edison

Con Edison is an electric distribution utility in the New York City area that operates in a competitive retail market. In 2003, Con Edison saw that specific parts of its distribution network were approaching capacity limits while load continued to grow. Building new lines and substations promised to be an incredibly expensive engineering challenge. Instead, building on its experience delivering broad-based energy efficiency programs, Con Edison launched a targeted demand management program focused on the nearly overloaded portions of its network. Even though the utility was not subject to an IRP or similar planning mandate, managers decided that demand side resources should be compared on an equal basis to supply side resources. The decision was made that wherever energy efficiency proved to be more cost-effective than transmission and distribution system infrastructure investments, efficiency would be implemented as the one and only solution.

Con Edison's planners began by estimating potential future peak loads throughout the network. A plan was created to address any forecasted shortfalls at the transmission, subtransmission, and area substation levels through load relief projects, e.g., by installing transformer cooling or an entirely new substation. Planners estimated the cost of each such project and then issued a request for proposals for energy efficiency services targeted to address the same shortfalls. Where viable bids were received at a cost less than the cost of the infrastructure project, energy efficiency was procured through a contract. Otherwise, the infrastructure project was executed.

Over the five years that followed, Con Edison contracted with energy service companies that succeeded in procuring 89 MW of targeted savings at a benefit/cost ratio of 2.8. These efforts saved the utility over \$223 million in capital expenditures.²⁸ This example shows the value that utilities in competitive retail markets can derive from an IRP or similar planning process that values demand side resources, irrespective of any obligation to provide generation service. It is also a good example of best practices for looking at transmission, distribution, and demand side solutions in an integrated fashion.

Interaction of IRP and Alternative Planning Processes with Other Energy Efficiency Policies and Program Designs

The implementation of a best practice IRP process is compatible with mandatory energy savings targets, and it remains relevant in states where utilities do not administer energy efficiency programs.

IRP Processes in States with Mandatory Energy Efficiency Goals or Mandatory Demand Response Programs

In states that have mandatory demand side goals or programs, planners have options for how to develop an IRP that have already been mentioned. One good option is to include the effects of the mandates in load forecasts and then allow the model to consider supplemental demand side resources as an alternative to supply side resources. With this approach, it may be necessary to develop levelized cost curves that acknowledge potential differences between the mandated programs and the supplemental resources. An even better option is to include none of the demand side resources in the load forecasts but apply a single set of levelized cost curves to all the scenarios and

²⁸ <http://eec.ucdavis.edu/ACEEE/2010/data/papers/2059.pdf>.

let the model determine the optimum level of investment. This approach can provide helpful insights to planners and policymakers, such as insights on which measures are most valuable in terms of total system costs. For example, this approach may reveal situations where a resource that reduces demand during peak hours, or in an area of congested transmission, is more valuable in terms of total system cost than a less expensive measure that saves an equal amount of energy in a different time or place.²⁹

IRP Processes in States with Third Party-Administered Energy Efficiency Programs

Some mandated energy efficiency programs are not administered by utilities but instead by a state entity or a third party that manages funds collected from utility ratepayers and/or taxpayers. New York offers the best known example of a state-run program, while Oregon, Vermont, and Hawaii offer examples of states that contract with a nongovernmental third party. Depending on the state, utilities may be specifically authorized to fully or partially opt out of the centralized program and administer their own program, or they may be authorized to supplement the centralized program with their own efforts.³⁰

An IRP or PM process in these states need not be much different from those in states where utilities manage all of the energy efficiency programs. One difference is that planners will benefit from involving the program administrator in the development of model inputs, certainly with respect to cost curves and possibly with respect to load forecasts as well. For example, in Vermont the organization that currently administers efficiency programs (Vermont Energy Investment Corporation) also develops energy efficiency potential studies, which are a key input used by utilities in developing their mandatory IRPs. Another, more significant, difference may come if and when the IRP is implemented. If the IRP identifies an optimum portfolio that includes more energy efficiency than is mandated, a decision will need to be made as to whether the additional resources will be acquired by the utility independently or through the centralized program administrator.

Conclusion

IRP processes can stimulate investment in energy efficiency and other demand side resources by allowing those resources to compete on a fair and equal basis with supply side resources. The best IRP processes consider a range of possible values for the future cost and availability of all types of resources, as well as a range of possible future scenarios for demographic, economic, and regulatory changes.

IRP processes are most often found in states that have not introduced retail electric competition, where it is mandated by the legislature or PUC. In states with competitive retail markets, similar planning processes can be used to encourage distribution utilities to evaluate demand side and supply side resources on a comparable basis.

State policymakers can promote the Action Plan goal of all cost-effective energy efficiency by adopting IRP, PM, or other similar planning requirements where they do not currently exist or by improving existing planning processes to conform to best practices.

Additional Resources

The resources listed below may be useful to assist stakeholders with the integrated resource planning issues outlined in this paper.

²⁹ Compare the relative impacts of an efficient air conditioner and an efficient light bulb. In terms of meeting a mandatory goal for energy savings, each kWh saved from each measure looks the same. But a resource planning perspective can reveal that a kilowatt-hour saved by the air conditioner on a hot summer day, when electric demand and costs are highest, is worth more than a kilowatt-hour saved by the light bulb on a cool fall evening, when demand and costs are low.

³⁰ In New York, responsibility for administering mandated programs is shared by NYSERDA (New York State Energy Research and Development Authority) and utilities. Hybrid models of shared responsibility are found in a few other states, and no states currently have a 100% government-administered program.



Webinar

Messenger, M.; Eckman, T. (August 2010). "Integrating the Impact of Energy Efficiency Programs into Resource Planning." Hosted by the Regulatory Assistance Project.

http://go.webpresentnow.com/2753647/vmeetings/7193406/viewer.php?&user=Mike%20Messenger&brand_url=http://go.webpresentnow.com.

Publications

National Action Plan for Energy Efficiency (November 2007). *Guide to Resource Planning with Energy Efficiency*. Prepared by Snuller Price et al., Energy and Environmental Economics, Inc. www.epa.gov/cleanenergy/documents/suca/resource_planning.pdf.

Steinhurst, W.; White, D.; Roschelle, A.; Napoleon, A.; Hornby, R.; Biewald, B. (October 2006). "Energy Portfolio Management: Tools and Resources for State Public Utility Commissions." Cambridge, MA: Synapse Energy Economics. www.naruc.org/Publications/NARUC%20PM%20FULL%20DOC%20FINAL1.pdf.

SEE Action Driving Ratepayer-Funded Efficiency through Regulatory Policies Working Group. (September 2011). *Setting Energy Savings Targets for Utilities*. www1.eere.energy.gov/seeaction/pdfs/ratepayer_efficiency_targets.pdf.



The Driving Ratepayer-Funded Efficiency through Regulatory Policies Working Group of the State and Local Energy Efficiency Action Network is committed to taking action to increase investment in cost-effective energy efficiency. This document was developed under the guidance of and with input from the working group. The document does not necessarily represent an endorsement by the individuals or organizations of Driving Ratepayer-Funded Efficiency through Regulatory Policies Working Group members or the federal government. However, the working group members do urge consideration of these materials as they believe that the information contained within will promote the deployment of cost-effective energy efficiency.



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Re: Comments on 2013 Ten-Year Plan Submittals

Dear Mr. Ellis and Ms Matthews:

Thank you for accepting these comments on behalf of the Sierra Club and its nearly 27,000 Florida members and on behalf of Earthjustice. We appreciated the opportunity to participate in the Public Service Commission (PSC)'s Ten-Year Plan review process in 2012, and are happy to continue our participation this year.

In last year's comments,¹ we asked that the PSC consider the implications of the retirement of Duke (then Progress) Energy's Crystal River Units 1 & 2, and of Gulf Power's Lansing Smith Units 1 & 2. We advised the PSC that the units had significant environmental compliance obligations which rendered them noneconomic to run in the near-term, but that neither company had included full analysis of that possibility in its submittal.

We appreciate that the PSC addressed these retirement issues in its review of the 2012 plans. *See, e.g., PSC, Review of the 2012 Ten-Year Site Plans ("2012 Review")* at 3. We respectfully submit that that analysis should continue in further depth this year because both utilities have now confirmed our retirement predictions from last year. Duke has committed to retiring Crystal River 1 & 2 for economic reasons and Gulf, though it has not made a final decision, has deferred further environmental compliance work on Lansing Smith and has requested PSC approval for transmission upgrades which would allow for Lansing Smith 1 & 2 to shut down.

In its review, the PSC assumed that the capacity of these retiring units would be replaced by natural gas, which would increase natural gas's share in Florida's electric generation to 62.9% by 2022 (up from 56.7% without the retirements, and from 57.7% in 2011). *Id.* The PSC states that it views "the growing lack of fuel diversity" within Florida as a "major strategic concern." *Id.* at 39. Although we certainly welcome the retirements of these dangerous coal plants, we share this fuel diversity concern: Undue dependence on natural gas leaves the state overly vulnerable to fuel price volatility, even as potential LNG exports and other shifts in the gas market seem likely to increase gas prices in the medium term. For this reason, we strongly suggest that the PSC consider planning scenarios which employ other, less risky, resources to make up some or all of the share of generation now served by the retiring plants.

¹ Attached as Exhibits 1 & 2, for your reference.

In particular, we believe that demand-side management measures, including energy efficiency, other demand response programs, and demand-side renewable energy, can make up a significant portion of any resource gap left by the likely retirements. Increased supply side renewable energy can also increase the diversity of the state's resource mix. Because the PSC will be considering new goals for both Duke and Gulf under the Florida Energy Efficiency and Conservation Act (FEECA) this year, this is a particularly good time to develop the data needed for sensible planning.

I. Coal Retirements

Both Duke and Gulf have confirmed that retirement is likely in the cards for their economically vulnerable plants, though Duke has gone further and confirmed that Crystal River 1 & 2 will certainly retire. Duke appears to be planning to address these retirements largely through adding new generating capacity. Gulf intends to rely on power imports in the near term.

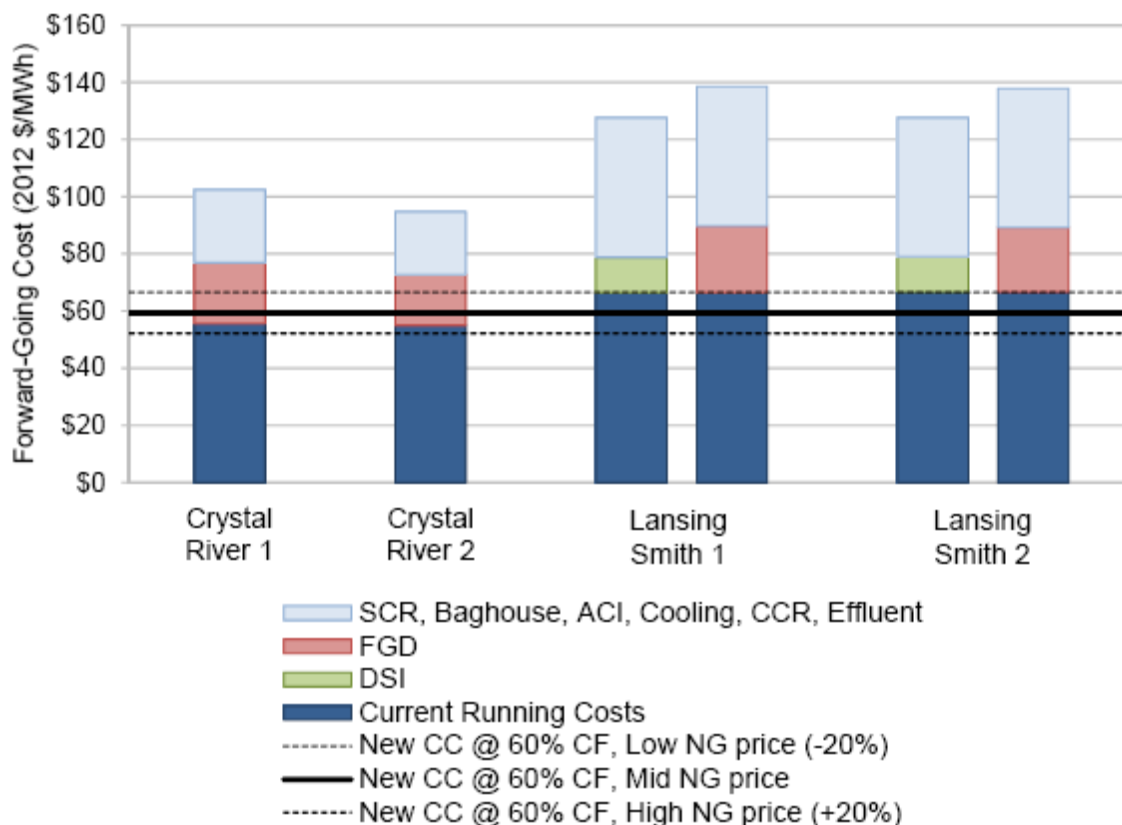
Duke/Progress

Duke has confirmed “expected retirement of Crystal River 1 & 2 in 2016.” Duke TYSP at 3-2. As Duke explains in testimony filed in the Environmental Cost Recovery Docket, the lifecycle projected system cost for retiring units 1 & 2 is far lower than the cost of retrofitting the units to comply with environmental compliance obligations: The difference between the retirement and retrofit scenarios is \$ 1.32 billion in Duke's base case analysis; retrofit is unfavorable only in the extremely unlikely case of very high gas prices and no CO₂ regulation. Direct Testimony of Benjamin M. H. Borsch on Behalf of Progress Energy Florida (Apr. 1, 2013) at 4, Docket No. 130007-EI; *see also* Progress Energy Florida, *Review of Integrated Clean Air Compliance Plan* (Apr. 1, 2013) (“*Duke Compliance Plan*”) at 25-26.

To be sure, Duke has held out the option of making short-term fuel mix adjustments which might allow the units to continue operating, perhaps as long as 2020. *Duke Compliance Plan* at 21. Continued operation would plainly be economically imprudent. As we demonstrated in our comments and workshop presentation on last year's plan, and as the figure below shows, the Crystal River units already verge on noneconomic when compared even against the substantial expense of constructing a new combined cycle natural gas plant to replace their capacity, much less against more sensible options, including demand side programs.²

² This figure is drawn from our 2012 workshop presentation and is based on work by Synapse Energy Economics, using public cost estimates from the Energy Information Administration's cost reporting forms and the EPA's Integrated Planning Model, developed by Sargent & Lundy.

Forward Going Costs of Existing Coal Units and Probable Environmental Controls



Because Crystal River 1 & 2 are uneconomic by almost any measure (as Duke acknowledges), the pertinent question is how best to replace any portion of their 965 MW in nameplate capacity which will be required going forward. (In practice, this lost capacity is smaller: both units have been relatively little used in recent years.) Lost capacity from the 860 MW Crystal River 3, the retired nuclear unit at the site, will also play a substantial role in system planning, of course.

Over the period from 2013 to 2022, Duke expects its firm summer peak demand to grow by 1287 MW, TYSP at 3-7, and increase of just shy of 15% over the next decade, or about 1.5% per year. At present, Duke reports that it intends to make up necessary capacity to match this growth through “planned power purchases from 2016 through 2020 and planned installation of combined cycle facilities in 2018 and 2020 at undesignated sites.” *Id.* at 3-2. According to Duke, these energy imports are likely to grow an additional 1470 MW above its current ~ 1900 MW of imported capacity, *id.* at Schedule 7.1. The addition of a 1307 MW (winter capacity) combined cycle facility in 2018, and a second 1307 MW facility in 2020 then replaces these imports. *See id.* at 3-7, 3-10 – 3-11. This additional capacity is 764 MW greater than the capacity which Duke is losing, leading to a 21% reserve margin by 2022.

As we discuss below, Duke’s strategy of increasing its built generating capacity substantially in response to projected growth, and relying on natural gas generation to do so, is not the prudent one for either the company or for Florida.

Gulf Power

As the figure above indicates, Lansing Smith 1 & 2 are even less economically attractive to operate than the uncontrolled Crystal River coal units. Gulf has not yet committed to retirement publicly, but its filings in this docket and in the Environmental Cost Recovery docket make clear that it is preserving that option.

Specifically, Gulf has requested the PSC approve a \$77 million transmission upgrade project, which it explains is necessary to ensure that Lansing Smith is not a must run unit. Gulf Power, *Third Supplemental Petition of Gulf Power Company Regarding its Environmental Compliance Program*, Docket No. 13007-EI (Mar. 29, 2013) at 8. According to Gulf, these upgrades will allow Plant Smith to run at lower levels or to close, and would be “required if these units retire or are controlled as a result of [the mercury and air toxics rule.]” *Id.* at 8. Gulf, thus, maintains that it intends to “reserve the decision to install ... controls or to retire the two units for a future time when more is known with regard to costs of compliance requirements associated with additional environmental regulations.” *Id.*

Because Gulf Power – unlike Duke – has not shared cost information with the public comparing the cost of controlling versus retiring the plant, *see* Gulf Power, *Environmental Compliance Program Update*, Docket No. 13007-EI (Mar, 29, 2013) at 22-27, it is clear that it anticipates considerable additional compliance obligations at Plant Smith, including additional air, water, and waste rules. *Id.* at 22. Although Gulf has not provided economic analysis of a retirement option, it is clear that operating costs from the mercury rule alone would “greatly increase the variable operating cost of Smith Units 1 and 2,” *id.* at 23, enough so that spending \$77 million on transmission to reduce the operating need for the plant is more economic than continuing to run it, *id.* at 26.

We certainly agree that it is better to run Plant Smith less. The truth, however, is that Plant Smith is not economic to run *at all* under current conditions. It is certainly not economic to run going forward as environmental compliance costs increase. The appropriate course for Gulf Power is to retire the facility, rather than simply building transmission which will allow it to operate the costly plant somewhat less. Its transmission project, apparently, will enable that retirement, which remains an option. We urge the PSC to continue to analyze retirement possibilities.

In this regard, Gulf’s Ten Year Site Plan submission does not clearly discuss all the implications of Plant Smith. It acknowledges, again, that “potential incremental capital expenditures for compliance may be substantial,” Gulf TYSP at 3, but does not yet appear to provide a straightforward retirement analysis. Gulf anticipates 575 MW in summer peak demand growth by 2022 (about 20% growth over that period, or, according to Gulf, a 1.9% annual increase over the next decade). *See* Gulf TYSP at Schedule 3.1.

Gulf’s plan indicates that capacity additions are not necessary to manage this projected growth. Gulf reports that a power purchase agreement (PPA) which it has signed with Shell Energy for use of 885 MW of capacity from an existing gas combined cycle plant will meet its needs through 2023, after which it will construct additional in-system capacity. *Id.* at 2-3. For this reason, the PSC’s projection last year that Lansing Smith’s retirement will lead to gas generation increases in Florida appears to be incorrect in the near term. As with Crystal River’s retirement, however, we believe that demand-side

options and other non-gas resources should be emphasized to meet any capacity needs that eventually arise.

II. Implications for the Ten-Year Plan and FEECA Goal-Setting Processes

Because the PSC will shortly move fully into the FEECA goal-setting process for the next five years, this is a particularly appropriate time to consider alternate futures for the Duke and Gulf power networks, with an emphasis on resources which the Legislature designed FEECA to encourage. The cost of adding new fossil capacity will almost always be higher than the cost of demand-side measures. The savings possible through an efficiency-focused strategy, coupled with efficiency's potential to help Florida avoid the undue dependence on natural gas which the PSC is seeking to avoid, argue strongly for a careful analysis of these questions in this year's Ten-Year Site Plan Review.

The Legislature has determined that it is "critical to utilize the most efficient and cost-effective demand-side renewable energy systems and conservation systems in order to protect the health, prosperity, and general welfare of the state and its citizens." Section 366.81, F.S. A study commissioned by the Legislature this past year confirmed these findings, concluding that "FEECA appears to provide a positive net benefit to ratepayers." Galligan *et al.*, *Evaluation of Florida's Energy Efficiency and Conservation Act* (Dec. 7, 2012) ("FEECA Study") at 9.

Despite these benefits, the PSC has, in the past, opted to suspend further program expansion for Duke and FPL, on cost grounds. *See, e.g., Re: Progress Energy Florida, Inc.*, Docket No. 1000160-EG, 2001 WL 3659327 (Aug. 6, 2011). The PSC should revisit this position during this year's goal-setting process in view of the positive findings of the legislative study, and the pressing need to address the retirements of vulnerable coal units in ways that best protect the ratepayers from further risk from fossil fuel price shifts and regulatory uncertainty. Ratepayers will face costs associated with new capacity and loss of fuel supply diversity which are far greater than those imposed by demand-side programs --- programs which the legislative study have determined have net *benefits*.

In particular, the PSC should view with skepticism Duke's proposal to construct 2614 MW of natural gas generation in just the next few years in order to cope with a 1.5% annual average growth rate in its predicted demand. Initially, Duke has a history of significant positive errors in its forecasts. As the PSC explained in its 2012 Ten Year Site Plan Review, Duke overestimated net energy for load forecasts by 11.36% on average between 2007 and 2011, and by 6.17% between 2006 and 2010. *2012 Review at 19*. Certainly the recession contributed to some of this overage, but the size of the error should give the PSC pause.

More importantly, however, the 1.6% demand growth rate which Duke forecasts, even if accurate, is within the range of load growth rates which demand-side management can address. According to the legislative FEECA study, many states require annual reductions far greater. *See FEECA Study at 177-180*. States requiring savings of at least 1% a year, according to that study, include Arizona, Indiana, Maine, Maryland, Michigan, Minnesota, New York, Ohio, and Texas, with many other states not far behind (still other states, including California, are listed as having very large reduction goals, but a percentage reduction is not specified). *See id.* Such reduction rates would entirely offset Duke's projected load growth, obviating the need for much, if not all, of its projected capacity needs in light of the Crystal River retirements.

Duke plainly has the potential to greatly expand its programs. It reports that only 25% (405,000 customers out of 1.6 million) take part in its demand response program, for instance. Duke TYSP at 1-1. This low participation is likely one reason that Duke is well below its FEECA goals for summer MW and annual GWh reductions – missing the annual target by more than 60%. *See* PSC, *Annual Report on Activities Pursuant to [FEECA]* (Feb. 2013) at 19. Duke has told the PSC that it was unable to reach its performance levels because “of the Commission decision to not approve a new DSM plan” for the company. *Id.* at 20. Thus, if the PSC engages with Duke to approve an improved plan, Duke may well be able to increase efficiency programs sufficiently to greatly decrease its capacity needs.

This analysis also applies to Gulf. Although Gulf does not plan new capacity for the next decade, it, too, has potential for further improvements, failing to meet even its modest existing FEECA goal by 12%. *Id.* at 19. If Gulf were performing at the level of nationally leading utilities – saving more than 1.5% of its demand per year – it could likely avoid those projected capacity additions.

Such enhanced performance could help Florida, as a whole, to meet the Legislature’s directive in FEECA. At present, Florida ranks in the bottom half of the states with regard to energy efficiency. *See* American Council for an Energy-Efficient Economy, *State Scorecard 2012* (ranking Florida #29).³ The coal retirements before the PSC provide a strong incentive to do better.

We understand that the PSC will be conducting substantial analysis on this front during its FEECA goal-setting process, *see* Section 366.82, F.S., which requires careful consideration of the “full technical potential” of demand-side programs. We suggest that the PSC conduct that analysis in tandem with its Ten-Year Site Plan review, valuing demand-side programs as a resource which can be used to address capacity and energy issues arising from the coal retirements announced or likely in the site plan docket. Thus, in its 2013 Ten-Year Site Plan Review, the PSC could profitably evaluate the several different scenarios post-retirement, including scenarios in which capacity is replaced with more aggressive demand side measures. Other scenarios should also, of course, explore the potential of other energy sources, including enhanced in-state renewables, including solar, and out-of-state PPAs for renewable (and hence zero fuel cost) energy. In the FEECA process, meanwhile, the PSC can consider the costs and benefits of such measures, especially as compared with costly and risky new gas capacity. The two processes can and should reinforce each other as the PSC works to find ways to minimize risks and costs to ratepayers.

III. Conclusion

Last year, we cautioned that a significant amount of coal-fired capacity in Florida was set for retirement. That process has continued. To manage any ratepayer risk from these retirements and the possible over-dependence on natural gas which they may promote, the PSC should emphasize demand-side management options as alternatives to gas-fired capacity. We look forward to working with the Commission to ensure that Florida ratepayers secure healthier air and a more reliable and efficient electricity system.

Sincerely,

³ Available at: <http://aceee.org/energy-efficiency-sector/state-policy/aceee-state-scorecard-ranking>.

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Power Purchase Agreement Checklist for State and Local Governments

This fact sheet provides information and guidance on the solar photovoltaic (PV) power purchase agreement (PPA), which is a financing mechanism that state and local government entities can use to acquire clean, renewable energy. We address the financial, logistical, and legal questions relevant to implementing a PPA, but we do not examine the technical details—those can be discussed later with the developer/contractor. This fact sheet is written to support decision makers in U.S. state and local governments who are aware of solar PPAs and may have a cursory knowledge of their structure but they still require further information before committing to a particular project.

Overview of PPA Financing

The PPA financing model is a “third-party” ownership model, which requires a separate, taxable entity (“system owner”) to procure, install, and operate the solar PV system on a consumer’s premises (i.e., the government agency). The government agency enters into a long-term contract (typically referred to as the PPA) to purchase 100% of the electricity generated by the system from the system owner. Figure 1 illustrates the financial and power flows among the consumer, system owner, and the utility. Renewable energy

certificates (RECs), interconnection, and net metering are discussed later. Basic terms for three example PPAs are included at the end of this fact sheet.

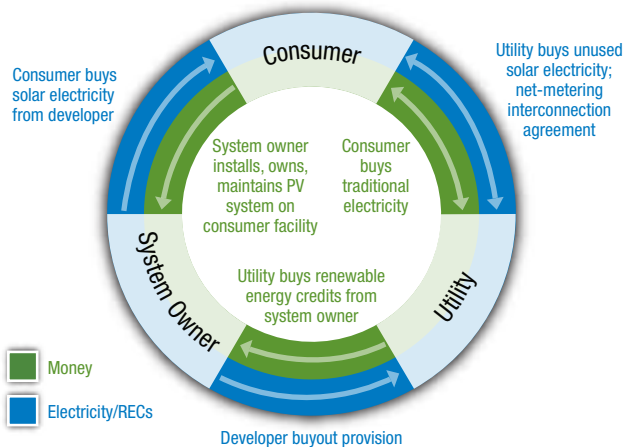
The system owner is often a third-party investor (“tax investor”) who provides investment capital to the project in return for tax benefits. The tax investor is usually a limited liability corporation (LLC) backed by one or more financial institutions. In addition to receiving revenues from electricity sales, they can also benefit from federal tax incentives. These tax incentives can account for approximately 50% of the project’s financial return (Bolinger 2009, Raus 2008). Without the PPA structure, the government agency could not benefit from these federal incentives due to its tax-exempt status.¹

The developer and the system owner often are distinct and separate legal entities. In this case, the developer structures the deal and is simply paid for its services. However, the developer will make the ownership structure transparent to the government agency and will be the only contact throughout the process. For this reason, this fact sheet will refer to “system owner” and developer as one in the same.

While there are other mechanisms to finance solar PV systems, this publication focuses solely on PPA financing because of its important advantages:²

1. No/low up-front cost.
2. Ability for tax-exempt entity to enjoy lower electricity prices thanks to savings passed on from federal tax incentives.
3. A predictable cost of electricity over 15–25 years.
4. No need to deal with complex system design and permitting process.
5. No operating and maintenance responsibilities.

Figure 1
Contracts and Cash Flow in Third-Party Ownership/PPA Model



Source: NREL

¹ Clean renewable energy bonds (CREBs) are also available to municipalities and other public entities as an alternative means of benefiting from federal tax benefits.

² For a full discussion of alternative financing mechanisms, see Cory et al. 2009.

High-Level Project Plan for Solar PV with PPA Financing

Implementing power purchase agreements involves many facets of an organization: decision maker, energy manager, facilities manager, contracting officer, attorney, budget official, real estate manager, environmental and safety experts, and potentially others (Shah 2009). While it is understood that some employees may hold several of these roles, it is important that all skill sets are engaged early in the process. Execution of a PPA requires the following project coordination efforts, although some may be concurrent:³

Step 1. Identify Potential Locations

Identify approximate area available for PV installation including any potential shading. The areas may be either on rooftops or on the ground. A general guideline for solar installations is 5–10 watts (W) per square foot of usable rooftop or other space.⁴ In the planning stages, it is useful to create a CD that contains site plans and to use Google Earth software to capture photos of the proposed sites (Pechman 2008). In addition, it is helpful to identify current electricity costs. Estimating System Size (this page) discusses the online tools used to evaluate system performance for U.S. buildings.

Step 2. Issue a Request for Proposal (RFP) to Competitively Select a Developer

If the aggregated sites are 500 kW or more in electricity demand, then the request for proposal (RFP) process will likely be the best way to proceed. If the aggregate demand is significantly less, then it may not receive sufficient response rates from developers or it may receive responses with expensive electricity pricing. For smaller sites, government entities should either 1) seek to aggregate multiple sites into a single RFP or 2) contact developers directly to receive bids without a formal RFP process (if legally permissible within the jurisdiction).

Links to sample RFP documents (and other useful documents) can be found at the end of this fact sheet. The materials generated in Step 1 should be included in the RFP along with any language or requirements for the contract. In addition, the logistical information that bidders may require to create their proposals (described later) should be included. It is also worthwhile to create a process for site visits.

Renewable industry associations can help identify Web sites that accept RFPs. Each bidder will respond with an initial proposal including a term sheet specifying estimated output, pricing terms, ownership of environmental attributes (i.e., RECs) and any perceived engineering issues.

Step 3. Contract Development

After a winning bid is selected, the contracts must be negotiated—this is a time-sensitive process. In addition to the PPA between the government agency and the system owner, there will be a lease or easement specifying terms for access to the property (both for construction and maintenance). REC sales may be included in the PPA or as an annex to it (see Page 6 for details on RECs). Insurance and potential municipal law issues that may be pertinent to contract development are on Page 8.

Step 4. Permitting and Rebate Processing

The system owner (developer) will usually be responsible for filing permits and rebates in a timely manner. However, the government agency should note filing deadlines for state-level incentives because there may be limited windows or auction processes. The Database of State Incentives for Renewables and Efficiency (<http://www.dsireusa.org/>) is a useful resource to help understand the process for your state.

Step 5. Project Design, Procurement, Construction, and Commissioning

The developer will complete a detailed design based on the term sheet and more precise measurements; it will then procure, install, and commission the solar PV equipment. The commissioning step certifies interconnection with the utility and permits system startup. Once again, this needs to be done within the timing determined by the state incentives. Failure to meet the deadlines may result in forfeiture of benefits, which will likely change the electricity price to the government agency in the contract. The PPA should firmly establish realistic developer responsibilities along with a process for determining monetary damages for failure to perform.

Financial and Contractual Considerations

The developer's proposal should include detailed projections of all financial considerations. This section helps the government agency become a more informed purchaser by explaining key components that are needed for a complete proposal.

Estimating System Size

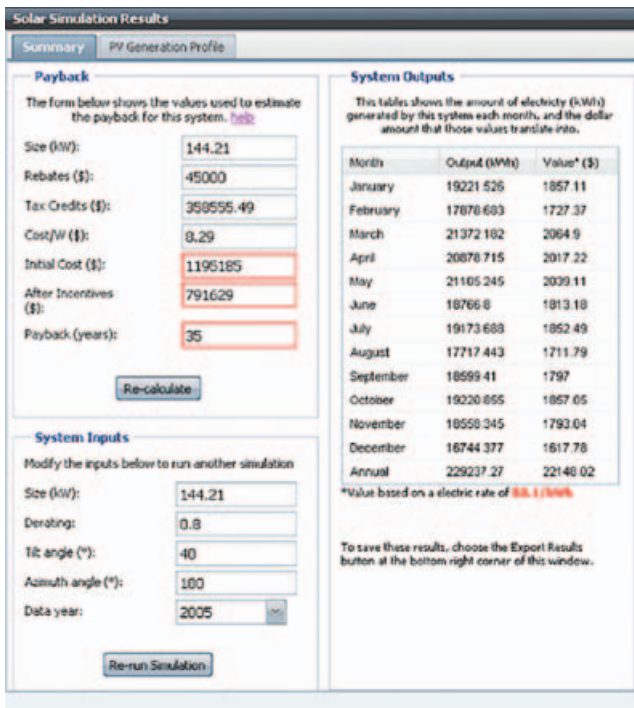
One of the first steps for determining the financial feasibility of a PPA is to estimate the available roof and ground space, and to approximate the size of the PV system or systems. NREL provides a free online tool called In My Backyard (IMBY) to make this assessment—the program can be found at <http://www.nrel.gov/eis/imby/>

³ Adapted from a report by GreenTech Media (Guice 2008) and from conversations with Bob Westby, NREL technology manager for the Federal Energy Management Program (FEMP).

⁴ This range represents both lower efficiency thin-film and higher efficiency crystalline solar installations. The location of the array (rooftop or ground) can also affect the power density. Source: <http://www.solarbuzz.com/Consumer/FastFacts.htm>

The IMBY tool, which uses a Google Maps interface, allows users to zoom-in on a particular building or location and trace the approximate perimeter of the potential solar array. From this information, IMBY simulates financial and technical aspects of the system; the results provide a first-level estimate and might not capture the exact situation (system performance, system cost, or utility bills) at a particular location (an example is shown in Figure 2). IMBY estimates the system size and annual electricity production as well as the monetary value of the electricity generated by the photovoltaic system. Users can adjust primary technical and financial inputs to simulate more specific conditions. The amount of electricity generated by the solar system can be compared to the facility's monthly utility electric bills to estimate potential offset capacity of the PV system.⁵

Figure 2
IMBY Example



Source: NREL

PPA Pricing

A key advantage of power purchase agreements is the predictable cost of electricity over the life of a 15- to 25-year contract. This avoids unpredictable price fluctuations from utility rates, which are typically dependent on fossil fuel prices in most of the United States. The approval of climate change legislation also may cause utility electricity rates to

⁵ It is important to be cognizant of any planned or potential changes to the facility that could affect the electrical demand (and, therefore, electricity offset) such as the additions to the facility.

increase significantly; thus, the projected savings may be further accentuated. In a PPA, the electricity rates are predetermined, explicitly spelled out in the contract, and legally binding with no dependency on fossil fuel or climate change legislation.

The most common PPA pricing scenarios are **fixed price** and **fixed escalator**. In a **fixed-price** scheme, electricity produced by the PV system is sold to the government agency at a fixed rate over the life of the contract (see Figure 3 for an example of this scenario). Note that it is possible for the PPA price to be higher than the utility rate at the beginning. However, over time, the utility rate is expected to overtake the PPA price such that the PPA generates positive savings over the life of the contract. This structure is most favorable when there is concern that the utility rates will increase significantly.

In a **fixed-escalator** scheme, electricity produced by the system is sold to the government agency at a price that increases at a predetermined rate, usually 2–5% (see Figure 4 for an example of this scenario). Some system owners will offer a rate structure that escalates for a time period (e.g., 10 years) and then remains fixed for the remainder of the contract.

Figure 3
Fixed-Price PPA

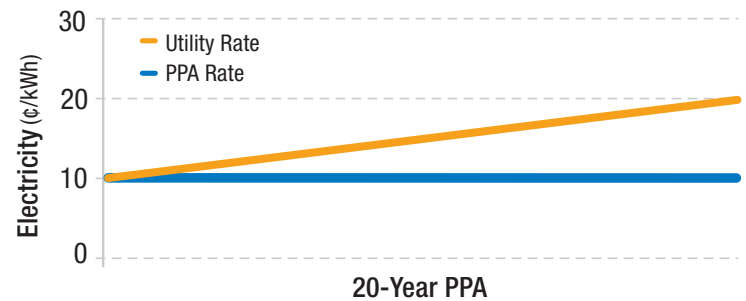
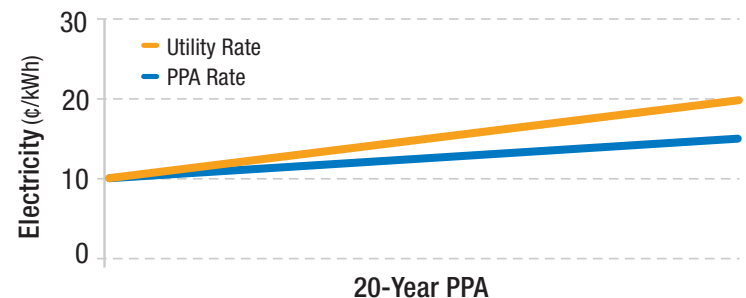
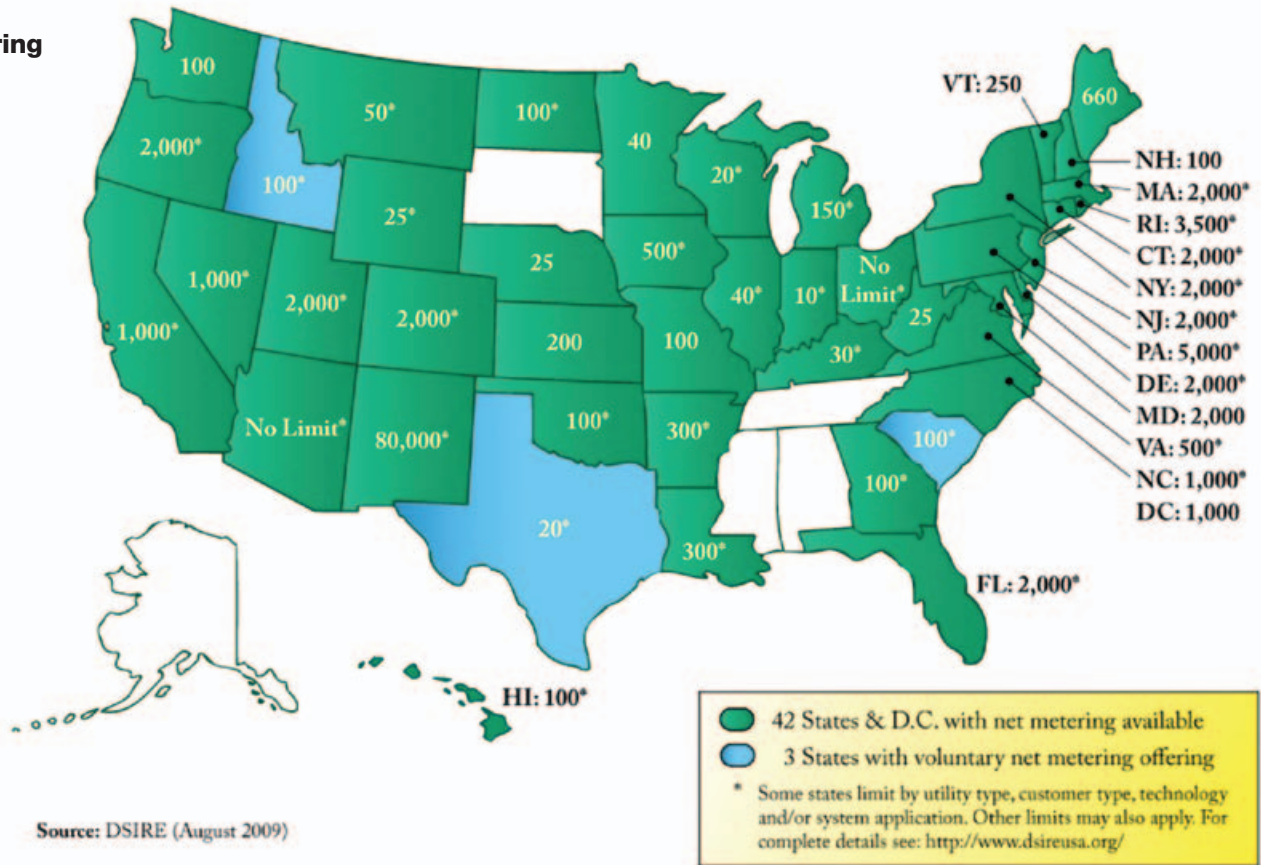


Figure 4
PPA Price Escalator



**Figure 5
Net Metering**



A less common PPA pricing model involves the PPA price based on the utility rate with a predetermined discount. While this ensures that the PPA price is always lower than utility rates, it is complicated to structure and it undermines the price-predictability advantage of a PPA.

A recently emerging PPA structure has consumers either 1) prepay for a portion of the power to be generated by the PV system or 2) make certain investments at the site to lower the installed cost of the system. Either method can reduce the cost of electricity agreed to in the PPA itself. This structure takes advantage of a governmental entity’s ability to issue tax-exempt debt or to tap other sources of funding to buy-down the cost of the project. Prepayments can improve economics for both parties and provide greater price stability over the life of the contract. Boulder County exercised this option by making investments to lower the project costs (see the table on Page 10, which provides examples of PPA pricing and structures from state and local government projects in California and Colorado).

Interconnection and Net Metering

Interconnection to the existing electrical grid and net metering are important policies to consider.⁶ Interconnection standards vary according to state-mandated rules (and sometimes by utility), which regulate the process by which renewable energy systems are connected to the electrical grid. Federal policy mandates that utilities accept interconnection from solar power stations, but each utility’s process varies. The system owner and utility develop an interconnection agreement, which spells out the conditions, equipment, and processes. Such conditions may include standby charges, which are fees that utilities impose on solar system owners to account for the cost of maintaining resources in case the solar system is not generating. Additionally, the project host and developer should consider utility tariff charges applicable to electricity purchased in backup mode—contact your local utility to fully comprehend the process of interconnection in the early stages of RFP development. The Interstate Renewable Energy Council has a report on state-specific interconnection standards, which is available at <http://www.irecusa.org/index.php?id=86>.

⁶ The 2008 Edition of *Freeing the Grid*, issued by the Network for New Energy Choices, provides a listing of the best and worst practices in state net-metering policies and interconnection standards. Much of the report discusses the technical aspects, which your developer should be able to address. http://www.newenergychoices.org/uploads/FreeingTheGrid2008_report.pdf

Net metering is a policy that allows a solar-system owner to receive credit on his/her electricity bill for surplus solar electricity sent back to the utility. The electricity meter “spins backward,” accurately tracking the excess electricity. Net-metering regulations vary by state but typically include specifications for the amount of excess electricity that the utility can count, the rate at which the utility can produce the credit, and the duration of the agreement (Rahus Institute 2008). States that do not have net-metering guidelines may require the system owner to install a second meter.

States differ on their net-metering pricing scheme, but they fall into three basic categories: (1) retail rate (the rate consumers pay), (2) the wholesale rate (market rate), or (3) the utilities’ avoided-generation rate. Time of use (TOU) net metering is a system of indexing net-metering credits to the value of the power sold on the market during that time period. This is advantageous to solar power because it is strongest during electricity peak demand times (Rahus Institute 2008). Figure 5 shows the states with net-metering policies in place.

Sizing PV systems for specific locations/applications depends highly on energy demand schedules as well as net-metering laws. When sizing a PV system, it is important to avoid the potential for overproduction. If there are unanticipated changes in demand, or if electricity production is not coincident with electricity consumption at the site, the PV system may generate more electricity than the utility can credit the customer for—some net-metering laws cap this amount. The risk is overproducing and sending electricity to the grid without compensation. A facility can produce a disproportionate amount of energy during peak periods and may not make up for this discrepancy during off-peak periods (Pechman 2008).

Federal Tax Incentives for the System Owner

An important aspect of the PPA structure is that a system owner can take advantage of federal tax incentives that a tax-exempt entity cannot. The two most significant tax benefits are the investment tax credit (ITC) and accelerated depreciation. The ITC offers tax-paying entities a 30% tax credit on the total cost of their solar system.⁷ Accelerated depreciation is an accounting practice used to allocate the cost of wear and tear on a piece of equipment over time – in this case, more quickly than the expected system life. The Internal Revenue Service (IRS) allows a five-year modified accelerated cost recovery system (MACRS) for commercial PV systems. Although a solar array may produce power during the entirety of a 20-year PPA, the system owner can take advantage of the entire tax benefit within the first five years. Both of these incentives

⁷ Under the American Recovery and Reinvestment Act (Recovery Act), tax-paying entities can elect to recover the ITC using a Department of Treasury grant, once project construction is complete. This is expected to improve the financial benefits of the incentive.

alleviate a great deal of financial risk for system owners, encourage project development, and help make renewable energy an affordable alternative to fossil fuel energy sources.

The Value of Renewable Energy Certificates

Twenty-nine states and the District of Columbia have implemented renewable portfolio standard (RPS) policies. An RPS requires utilities to provide their customers with a minimum percentage of renewable generation by statutory target dates. Failure to meet these requirements usually results in compliance penalties. Figure 6 shows these RPS policies by state.

Utilities typically prove RPS compliance using renewable energy certificates (RECs), which represent 1 megawatt-hour (MWh) of electricity produced from a renewable source. In many states, RECs can be traded separately from the electricity. In these cases, the RECs represent the environmental attributes of renewable energy. In addition, some states offer carve-outs for solar renewable energy certificates (SRECs) or distributed generation (DG) (see Figure 6). These states create separate markets for these RECs (usually at higher prices) or offer multiple credits for each megawatt-hour. For example, a 3x multiplier allows the utility to count each REC from solar electricity as 3 MWh for compliance purposes.⁸

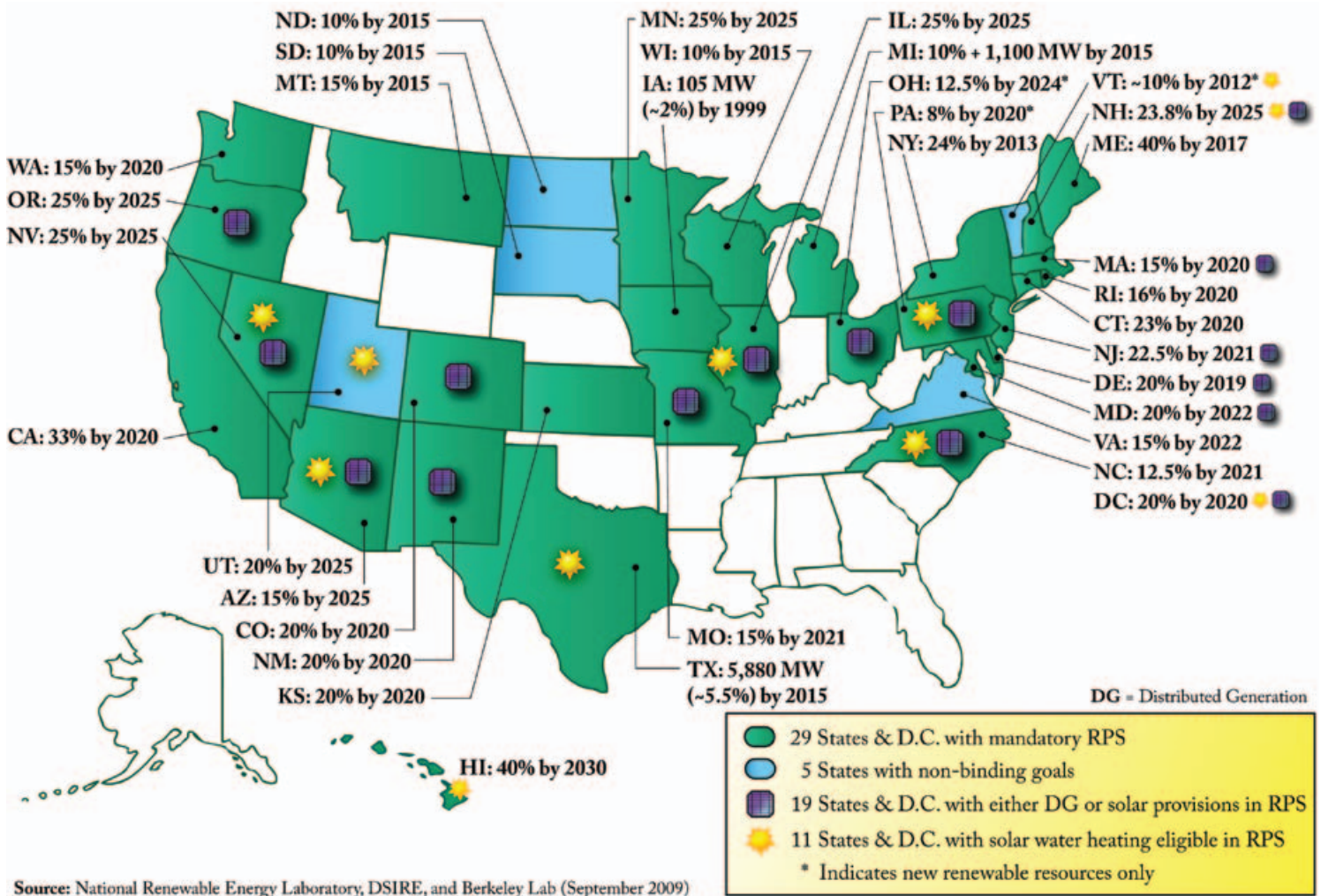
States with RPS policies are known as “compliance markets.” In these markets, utilities can include purchased RECs in demonstration of compliance with state energy mandates. This can provide an important source of cash flow to PV system owners. In addition, states with carve-outs for solar or DG can realize even higher prices for SRECs.

“Voluntary markets” also exist in which residential, commercial, and industrial consumers can buy SRECs from system owners to claim their energy is produced from renewable technologies. The advantage is that consumers do not have to develop renewable projects but still can claim the environmental benefits (Cory 2008).

In general, PPAs are structured so that the RECs remain with the system owner. However, the host can negotiate to buy the RECs along with the electricity. This will drive up the price per kilowatt-hour in the PPA to compensate the system owner for the RECs. If the host does not buy the RECs, it is important to manage the claims made regarding the PV system. The government agency can say it is hosting a renewable energy project but it cannot say that it is powered by renewable energy. One option is an SREC swap. In this case, the host would decide against buying the solar RECs from the PPA provider and instead buy cheaper replacement RECs (wind or biomass, for example) in the voluntary market (Coughlin 2009). REC prices in the voluntary markets are substantially

⁸ Under the Waxman-Markey bill (as of July 2009), Congress is considering a federal solar multiplier of 3x for all distributed generation projects.

Figure 6
States with Renewable Portfolio Standards (indicating solar/DG set-asides)



lower than in the compliance market. This REC swap would allow the host to claim green power benefits (but not solar power because the replacement RECs were not SRECs).

State and Utility Cash Incentives

Other important state-level programs are those that provide cash incentives for system installation. These programs (often called “buy-down” or “rebate” programs) come in two varieties. The capacity-based incentive (CBI) provides a dollar amount per installed watt of PV. Incentives can also be structured as performance-based incentives (PBI). They do not provide up-front payments, but rather provide ongoing payments for each kilowatt-hour of electricity produced over a time period (e.g., five years). Consumers will normally prefer CBIs because of the up-front cash. However, some states

prefer PBIs because they encourage better performance. The downside of these more recent programs is that the government agency must finance a large part of system costs (if not under a solar PPA) and incur performance risk (Bolinger 2009).

Approximately 20 states and 100 utilities offer financial incentives for solar photovoltaic projects. Depending on the state and local programs, these incentives can cover 20-50% of a project’s cost (DSIRE 2009). Specifics for individual state programs can be found on the Database of State Incentives for Renewables and Efficiency (<http://www.dsireusa.org/>). Additional government incentives include state tax credits, sales tax exemptions, and property tax exemptions, which can be important under the solar PPA model.

System Purchase Options

If the host prefers, the solar PPA can include provisions for a consumer to buy the PV system. This can occur at any point during the life of the contract but almost always after the sixth year because of tax recapture issues related to the ITC. The buyout clause is phrased as the greater of fair market value (FMV) or some “termination” value (that is higher than the FMV). This termination value often includes the present value of the electricity that would have been generated under the remaining life of the PPA. Buyout options are more readily available in third-party PPAs in which the investors are motivated by the tax incentives rather than long-term electricity revenues. A different set of investors may have a longer-term investment horizon and may be less likely to favor early system-purchase options.

When issuing RFPs and evaluating bids, it is important to understand the project goals of the potential developers and decide which most closely align with those of your organization. From the government agency’s point of view, there are both benefits and responsibilities that come with owning the system. The obvious benefit is that the electricity generated by the PV system can now be consumed by the host at no cost (financing charges notwithstanding); the costs and responsibilities revolve around the need to operate and maintain the PV system. Owner’s costs include physical maintenance (including inverter replacement, which can be costly) and monitoring, as well as financial aspects such as insurance.

Although PPAs are inherently structured as a contract by which a government agency can buy electricity, system ownership may be a viable option at some point. If the buyout option is not available or not exercised by the end of the contract life, the government agency can purchase the system at “fair market value,” extend the PPA, or request the system owner remove the system (Rahus 2008). Government hosts may want to consider requiring (in the RFP and the PPA) that the system owner pay for the cost of equipment removal at contract maturity.

Logistical Considerations

Appropriate roof or land areas must be identified, and there are also important logistical requirements to consider. The issues discussed in this section should be included in the RFP because they will allow the developer to provide a firmer bid with less assumptions and contingencies.

Rooftop Mounted Arrays

After the RFP, the winning bidder will conduct a structural analysis to determine whether the roof can sustain the load. By documenting the condition in the RFP, you may avoid potential adjustments. It is important to assess the following information:

- **Roof structure and type** (flat, angled, metal, wood, etc.) – determines the attachment methods that may be used.
- **Orientation of the roof** – especially important if it is a sloped roof. Southern facing roofs are ideal but not necessarily mandatory.
- **Roof manufacturer’s warranty** – usually lasts a minimum of 10 years but can extend over 20 years. Before installing solar panels, it is important to ensure that the solar installation will not void the warranty. Systems that do not penetrate the roof surface or membrane are usually acceptable, but it is important to obtain this allowance in writing prior to moving forward with the solar project.
- **Planned roof replacement** – if it is to be scheduled within a few years, it a good idea to combine projects, which will cut costs and minimize facility disturbance.
- **Potential leak concern** – if this exists, you may opt for a formal roof survey to assess and document the condition of the roof prior to the solar installation.
- **Obstructions on the roof** – items such as roof vents and HVAC equipment can hinder the project.
- **Shade from adjacent trees or buildings** – can reduce solar potential.

Ground-Mounted Systems

Ground-mounted photovoltaic systems are advantageous in some situations because they can be cheaper and easier to install and can be scaled-up more easily. This reduces the cost per kilowatt-hour and translates into cheaper energy costs for the consumer. Additionally, ground systems offer flexibility in the type of technology that can be used. For example, the project may have tracking technologies, which can result in higher energy output and better project economics. One of the key logistical issues for ground-mounted systems is the wind speed the system is designed to withstand, which depends primarily on the location of the project site (e.g., hurricane risks); the soil type and strength characteristics are also important. To obtain more accurate bids, consumers often will have a third-party conduct soil sample tests prior to issuing an RFP. Wind and soil conditions can greatly influence the design and cost of a project. Perimeter fencing and site monitoring should be specified in the RFP to ensure security, safety, and compliance with local codes.

General Logistical Considerations

Electrical upgrades or changes may affect the system design and potential interconnection to the electrical grid. Any planned changes should be documented within the RFP.

For proper maintenance, accessibility to the inverter and solar array will be important to the system owners throughout the life of the project.

Fire departments will have building accessibility requirements, particularly for roof-mounted systems. Some jurisdictions formally specify these standards and will confirm that the system meets the requirements during the permitting phase and final approval process. In states that do not have such requirements, it is important for the government agency and the system owner to gain fire department approval early in the process.

Contractually, operation and ongoing maintenance of the solar system is typically the responsibility of the system owner unless otherwise specified.

Insurance⁹

While many governmental entities may be able to self-insure, it is important to investigate the minimum insurance required by your utility's interconnection rules. The requirements may necessitate additional coverage through private insurance.

Unfortunately, insurance underwriters charge fairly high premiums for PV installations. These premiums can represent approximately 25% of the annual operating budget and may be as large as 0.25% to 0.50% of the project installed costs. According to discussions with developers, the cost of insurance can increase energy pricing by 5–10%. The high premiums are due to two underlying reasons: 1) Insurance underwriters still view PV as a risky technology due to its lack of long operating history, and 2) the relatively low number of projects do not allow underwriters to average risk across a large number of installations (i.e., “the law of large numbers”). Until recently, Lloyds of London was the only underwriter for PV in the United States; however, Munich Re, AIG, Zurich Insurance Group, ACE Ltd., and Chubb are also actively pursuing renewable energy policies. Reportedly, a fifth underwriter is developing a PV product, but no public announcements have been made (Kollins et al., forthcoming).

In general, insurance is the responsibility of the system owner (developer). At a minimum, the system owner should be expected to carry both general liability and property insurance. Additional considerations may be given to separate policies for location-specific risks (e.g., hurricane coverage in Florida), property-equivalent policies (which cover engineering), and environmental risk (inclusive of pre-existing conditions). If covered by the system owner, the cost of insurance will be factored into the PPA cost of electricity and not passed through separately. Thus, a fairly recent realization is that it may be cheaper for the government agency to insure the system directly, although they don't actually own the system. Then, the system owner is named as an additional insured party on the policy and agrees to reimburse the government agency for the premiums. Insurance companies have agreed to this in previous PPAs (Boylston 2008). Because this can reduce overall project costs, this arrangement deserves further investigation with a provider.

One final note concerns indemnification for bad-acts and pre-existing structural or environmental risks. Whether contractual or not, the government agency may want to acquire its own insurance to protect itself from the potential of future liabilities.

Potential Deal Constraints Embedded in Municipal Laws¹⁰

Municipal laws were written before PV installations were even a remote consideration. While each jurisdiction operates under its own unique statutes, this section lists some common constraints that may be encountered. Listed below are the categories that may require investigation. More detail on the following specific issues is provided at the end of this fact sheet:

1. **Debt limitations** in city codes, state statutes, and constitutions
2. Restrictions on **contracting power** in city codes and state statutes
3. **Budgeting, public purpose, and credit-lending** issues
4. **Public utility rules**
5. Authority to **grant site interests and buy electricity**

⁹ Much of this section is adopted from a forthcoming NREL paper: “Insuring Solar Photovoltaics: Challenges and Possible Solutions”; Speer, B.; Mendelsohn, M.; and Cory, K.

¹⁰ Much of this section is adapted from the transcript of a June 12, 2008, NREL conference call led by Patrick Boylston of Stoel Rives LLP.

Conclusions

Financing solar PV through a power purchase agreement allows state and local governments to benefit from clean renewable energy while minimizing up-front expenditures and outsourcing O&M responsibilities. Also important, a PPA provides a predictable electricity cost over the length of the contract.

This fact sheet is a concise guide that will help states and municipalities with the solar PPA process. The following five steps are recommended to formally launch a project (and are described in this brief):

Step 1: Identify Potential Locations

Step 2: Issue a Request for Proposal (RFP) to Competitively Select a Developer

Step 3: Contract Development

Step 4: Permitting and Rebate Processing

Step 5: Project Design, Procurement, Construction, and Commissioning

The U.S. Department of Energy (DOE) can help facilitate the process by providing quick, short-term access to expertise on renewable energy and energy efficiency programs. This is coordinated through the Technical Assistance Project (TAP) for state and local officials.¹¹ More information on the program can be found at <http://apps1.eere.energy.gov/wip/tap.cfm>.

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¹¹ TAP currently has a focus on assisting programs that are related to Recovery Act funds.

Sample Terms of Executed Power Purchase Agreements (PPAs)

Government Level	State	County	City
Name	Caltrans District 10 Solar Project	Boulder County Solar Project	Denver Airport Solar Project
Location	Stockton, California	Boulder County	Denver, Colorado
Customer	California Department of Transportation	Boulder County	Denver International Airport
Utility	Pacific Gas & Electric	Xcel Energy	Xcel Energy
Size (DC)	248 kW	615 kW	2,000 kW
Annual Production	347,407 kWh	869,100 kWh	3,000,000 kWh
Type	123 kW rooftop, 125 kW carport	570 kW rooftop, 45 kW ground	Ground-mount, single-axis tracking
Location	Maintenance Warehouse Maintenance Shop Parking Lot Canopy	Recycling Center Courthouse Clerk and Recorder Addiction Recovery Center Justice Center Walden Ponds (ground-mount) Sundquist	Ground of the Denver International Airport
Area	22,200 sq ft	8 county buildings	7.5 acres
Developer	Sun Edison, LLC	Bella Energy	World Water & Solar Technologies
Owner	Sun Edison, LLC	Rockwell Financial	MMA Renewable Ventures
PPA Terms	20 years, 5.5% discount from utility rates	20 years, fixed-price 6.5 ¢/kWh for first 7 years, renegotiate price and buyout option at beginning of year 8	25 years, fixed-price 6 ¢/kWh for first 5 years, buyout option at beginning of year 6 or price increases to 10.5 ¢/kWh
Status	Completed September 2007	Completed January 2009	Completed August 2008
Contact	Patrick McCoy (916) 375-5988 patrick.mccoy@dgs.ca.gov	Ann Livingston (303) 441-3517 alivingston@bouldercounty.org	Woods Allee (303) 342-2632 woods.allee@flydenver.com

Source: NREL

Potential Deal Constraints Embedded in Municipal Laws

This table lists potential constraints posed by municipal laws. Not all issues will pertain to your jurisdiction; however, this table can serve as a short checklist for use in your investigation. The request for proposal (RFP) issue column is meant to qualify each issue as to whether it needs to be highlighted in the RFP.

Category	RFP Issue?	Issue	Implication	General Findings and Next Steps
1. Debt Limitations in City Codes, State Statutes, and Constitutions	No	Is PPA debt or contingent liability?	Debt would require public vote for approval. Contingent liability is allowed under purchasing authority without a vote.	Most states see as purchasing only what is consumed. Thus, a vote not is required. PPA agreements usually called “energy services agreement” to avoid any appearance of debt. Must be wary of “take or pay provisions” in PPA requiring payments regardless of use. Also, be careful to size so as to not over-produce based on net-metering rules
	No	Is system purchase option debt?	A vote will be required to approve debt for system purchase.	It is important that the PPA deems the purchase as optional at fair market value so that a vote is not needed until the option is exercised.
2. Restrictions on Contracting Power in City Codes and State Statutes	Yes	Contract Tenor statutes (e.g., limited to 10 yrs or 15 yrs)	May limit choice of developers based on investment goals.	Research of local rules and precedents may be required.
	Yes	Ability to buy/sell RECs	When codes and statutes were created, RECs were not envisioned. May determine where beneficial REC ownership is assigned in PPA.	Each jurisdiction will be different. Research of local rules and precedents is required. Is there enough general authority under electricity purchases (or other) to justify REC trading?
	Yes	Public bidding laws	May preclude RFP process unless there is an applicable exemption to public bidding laws.	Research of local rules and precedents may be required. Developer will ask for representation and warranty that the contract is exempt from public bidding rules.
3. Public Purpose and Lending of Credit Issues	Yes	Pre-paying for electricity	Is this a grant to a for-profit LLC that owns the PV system?	In most states, authority exists (such as in the opinion of attorneys general) that it is permissible if the entities are fulfilling a government purpose. Research may be required if pre-payment is envisioned.
4. Public Utility Rules	Yes	How many entities will be buying electricity (i.e., city, county, and/or other government entities occupy site)?	Most state laws and/or rules clarify that if you are selling electricity to a certain number of consumers, then you are a utility and subject to Public Utility Commission (PUC) regulation. ¹² This can be prohibitively expensive for the developer.	Developers will generally want to contract only with a single entity that owns the meter. The costs can then be divided among various entities. If the entities are all behind the meter, then they would not be subject to PUC regulations.
5. Authority to Grant Site Interests and Purchase Electricity	No	Lease or easement?	A lease can have problems with disposal and interest in public property, which may require a public-bidding or offering process.	Framing the document as an “easement” instead of a “lease” has worked well. Works much like a lease except without ability to transfer it—except in accordance with agreement (usually restricted).

Source: Boylston 2008

¹²The threshold is set differently by each state. Most are in the two-five range.

Sources for Sample Documents

Samples of requests for proposals can be found using simple Web searches—the links below will get you started in your search.

NV Energy (Nevada Power Company) is a good source for documents which have been previously tested in the marketplace:

<http://www.nvenergy.com/company/doingbusiness/rfps/>

Oregon University System

http://www.ous.edu/bapp/contractfiles/20090522_1545_PhotoVoltaic%20Power%20Purchase%20Agreement/RFP%202009-06%20Solar%20PPA.doc

City of Santa Ana

<http://www.ci.santa-ana.ca.us/pwa/documents/RFP-SolarProjectandGuideline.pdf>

The U.S. Navy recently released an RFP that is very thorough in its specifications:

<http://www.allenmatkins.com/emails/Renewable/Img/NAVY.pdf>

Example RFPs from several California municipalities:

<http://www.lgc.org/spire/rfps.html>

A current federal government RFP:

<https://www.desc.dla.mil/DCM/DCMSolic.asp?SolicID=1533>

Other Useful Documents:

The documents below are more detailed, in-depth solar financing guides.

The Customer's Guide to Solar Power Purchase

Agreements, by the Rarus Institute
<http://www.californiasolarcenter.org/sppa.html>

Solar Photovoltaic Financing: Deployment on Public Property by State and Local Governments, by Karlynn Cory, Jason Coughlin, and Charles Coggeshall. This NREL report (May 2008) examines ways that state and local governments can optimize the financial structure of deploying solar PV for public uses. It can be accessed at <http://www.nrel.gov/docs/fy08osti/43115.pdf>

Solar Photovoltaic Financing: Residential Sector Deployment, by Jason Coughlin and Karlynn Cory. This NREL technical report (March 2009) can be accessed at <http://www.nrel.gov/docs/fy09osti/44853.pdf>.

Solar Photovoltaic Financing: Deployment by Federal Government Agencies, by Karlynn Cory, Charles Coggeshall, Jason Coughlin, and Claire Kreycik. This NREL technical report (August 2009) can be accessed at <http://www.nrel.gov/docs/fy09osti/46397.pdf>

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