APPENDIX A

REVIEW OF THE

2017 TEN-YEAR SITE PLANS

OF FLORIDA'S ELECTRIC UTILITIES

NOVEMBER 2017

Ten-Year Site Plan Comments

State Agencies

- Department of Economic Opportunity
- Department of Environmental Protection
- Fish and Wildlife Conservation Commission

Regional Planning Councils

- Treasure Coast Regional Planning Council

Water Management Districts

- Southwest Florida Water Management District

Environmental Groups

- Energy Storage Association
- Sierra Club

Rick Scott
GOVERNOR

FLORIDA DEPARTMENT of ECONOMIC OPPORTUNITY

Cissy Proctor
EXECUTIVE DIRECTOR

August 11, 2017

Mr. Orlando Wooten
Engineering Specialist
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

RE: Review of the 2017 Ten-Year Site Plans for Florida's Electric Utilities

Dear Mr. Wooten:

At your request, we have reviewed the 2017 Ten-Year Site Plans of the electric utilities. The Department of Economic Opportunity's review focused on potential and preferred sites for future power generation, and the compatibility of those sites with the applicable local comprehensive plan, including the adopted future land use map. Please see our enclosed comments.

Should you have any questions regarding these comments, please contact Scott Rogers, Planning Analyst, at (850) 717-8510, or by email at scott.rogers@deo.myflorida.com.

Sincerely,

James D. Stansbury, Chief
Bureau of Community Planning and Growth

JDS/sr

Enclosure: DEO Review Comments

Department of Economic Opportunity 2017 Ten-Year Site Plan Review Comments

The Department's review focused on potential and preferred sites for future power generation, and the compatibility of those sites with the applicable local comprehensive plan, including the adopted future land use map. Nine utilities (Duke Energy Florida, Florida Municipal Power Agency, Florida Power and Light Company, Gainesville Regional Utilities, Gulf Power Company, Orlando Utilities Commission, Seminole Electric Cooperative, City of Tallahassee, and Tampa Electric Company) have identified a total of 36 potential or preferred sites for future power generation in their Ten-Year Site Plan (TYSP). Potential sites are defined in Rule 25-22.070, Florida Administrative Code (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." Preferred sites are defined in Rule 25-22.070, F.A.C., as "sites within the state on which an electric utility intends to construct a power plant, a power plant alteration, or an addition resulting in an increase in generating capacity."

1. Duke Energy Florida

The Duke Energy Florida TYSP identifies three preferred sites (Osprey Energy Center site; Citrus County site; and Suwannee River Energy Center site) and one potential site (Levy County site) to increase power generating capacity.

A. Citrus County Site: The Citrus County site is located on 400 acres east of the existing Crystal River Energy Center. The site is designated as "Transportation, Communications and Utilities," which allows the electric generating facility. The 400 acre site has been certified by the State of Florida under the Power Plant Siting Act, and Duke Energy Florida has begun construction of the generating facility on the site.

B. Suwannee River Energy Center Site: The Suwannee River Energy Center site is located in Suwannee County, and the TYSP identifies the addition of a natural gas powered and/or solar generating facility on 68 acres within the Energy Center. The 68 acres is designated as "Agriculture" on the adopted Future Land Use Map of the Suwannee County Comprehensive Plan. Electric generating facilities may be allowed as a special exception in the Agriculture future land use category.

C. Osprey Energy Center Site: The Osprey Energy Center site is located on 18.5 acres in Auburndale and contains existing power generating facilities, which have been in operation since 2004. Duke Energy Florida purchased the site in January 2017 in order to utilize the existing power generating facilities. The City of Auburndale Comprehensive Plan Future Land Use Map designates the site as "Business Park Centers", which allows power generating facilities.

D. Levy County Site: The TYSP identifies an approximately 3,100 acre property located in Levy County as a potential site for a nuclear powered generation facility beyond the ten-year

planning horizon of the current TYSP. The Levy County site is located along the east side of U.S. Highway 19, approximately three miles north of the Withlacoochee River. The site is designated as "Public Use" on the adopted Future Land Use Map of the Levy County Comprehensive Plan. Power generating facilities are an allowed use within the Public Use future land use category at this potential site.

2. Florida Municipal Power Agency

The Florida Municipal Power Agency TYSP identifies three potential sites for the increase in power generating capacity: (1) Cane Island Power Park; (2) Treasure Coast Energy Center; and (3) Stock Island.

A. Cane Island Power Park Site: The Cane Island Power Park (CIPP) site is located on 1,027 acres in rural northwest Osceola County, approximately one mile northwest of Intercession City. The site contains existing power generation facilities. The Osceola County Comprehensive Plan Future Land Use Map designates the site as "Rural/Agriculture", which allows electric utility facilities.

B. Treasure Coast Energy Center Site: The Treasure Coast Energy Center (TCEC) site is located on 69 acres in the Midway Industrial Park in the City of Fort Pierce. The site contains existing power generation facilities. The City of Fort Pierce Comprehensive Plan Future Land Use Map designates the site as "Institutional", which allows an electric generating plant.

C. Stock Island Power Plant Site: The Stock Island Power Plant site is located on Stock Island near Key West, and the site contains existing power generation facilities. The Monroe County Comprehensive Plan Future Land Use Map designates the Stock Island Power Plant site as "Public Facilities", which allows electric generation plants.

3. Florida Power and Light Company

The Florida Power and Light Company (FPL) TYSP identifies eleven preferred sites for the increase in power generating capacity and various unspecified potential sites for the increase of power generating capacity.

A. Potential Sites:

The TYSP states that FPL is currently evaluating potential sites for new photovoltaic facilities in twelve counties (Alachua, Baker, Clay, Collier, Columbia, Hendry, Putnam, St. Lucie, Suwanee, Union, Volusia, and Miami-Dade Counties) and that FPL has not yet selected any specific locations for potential sites within these counties. The next TYSP should address any specific potential sites identified (selected) by FPL within these counties.

B. The TYSP identifies the following as preferred sites:

1. Horizon Solar Energy Center Site: The Horizon Solar Energy Center (HSEC) site is located on 1,310 acres in Putnam and Alachua Counties. The predominant existing use of the site is agriculture. The Alachua County Comprehensive Plan Future Land Use Map designates the site as "Rural Agriculture", which allows public utilities; and the Putnam County Comprehensive Plan designates the site as "Agriculture II", which allows passive energy generation projects (solar or wind).

2. Wildflower Solar Energy Center Site: The Wildflower Solar Energy Center site is located on 431 acres in DeSoto County. The predominant existing use of the site is agriculture. The DeSoto County Comprehensive Plan Future Land Use Map designates the site as "Electrical Generating Facility", which allows electrical power generation facilities.

3. Indian River Solar Energy Center: The Indian River Solar Energy Center site is located on 695 acres in Indian River County. The predominant existing use of the site is agriculture. The Indian River County Comprehensive Plan Future Land Use Map designates the site as "Agricultural-2", which allows public and private utilities.

4. Coral Farms Solar Energy Center Site: The Coral Farms Solar Energy Center site is located on 598 acres in Putnam County. The predominant existing use of the site is agriculture. The Putnam County Comprehensive Plan Future Land Use Map designates the site as "Agricultural-1" and "Agricultural-2", which allow passive energy generation projects (solar or wind).

5. Hammock Solar Energy Center Site: The Hammock Solar Energy Center site is located on 970 acres in Hendry County. The predominant existing use of the site is agriculture. The Hendry County Comprehensive Plan Future Land Use Map was amended April 25, 2017 (Ordinance Numbers 2017-07 and 2017-08) to designate the site as "Electrical Generating Facility", which allows solar photovoltaic facilities. The TYSP states that the future land use on the site is Agricultural; and, therefore, FPL should consider updating the future land use information to reflect the recent plan amendment.

6. Barefoot Bay Solar Energy Center Site: The Barefoot Bay Solar Energy Center site is located on 455 acres in Brevard County. The predominant existing use of the site is agriculture. The Brevard County Comprehensive Plan Future Land Use Map designates the site as "Public Facility", which allows electric utilities.

7. Blue Cypress Solar Energy Center Site: The Blue Cypress Solar Energy Center site is located on 605 acres in Indian River County. The predominant existing use of the site is agriculture. The Indian River County Comprehensive Plan Future Land Use Map designates the site as "Agricultural-2", which allows public and private utilities.

8. Loggerhead Solar Energy Center Site: The Loggerhead Solar Energy Center site is located on 570 acres in St. Lucie County. The predominant existing use of the site is agriculture. The St. Lucie County Comprehensive Plan Future Land Use Map designates the site as "Agricultural-5."

A solar power generating facility is allowable as a conditional land use within the Agricultural-5 future land use category.

9. Okeechobee Clean Energy Center Site: The Okeechobee Clean Energy Center site is located on 2,842 acres in Okeechobee County. The predominant existing use of the site is agriculture. The Okeechobee County Comprehensive Plan Future Land Use Map designates the site as "Agriculture", which allows power generation. Construction has commenced and commercial operation of a natural gas-fired power generation facility is projected to begin in June 2019.

10. Dania Beach Clean Energy Center Site: The Dania Beach Clean Energy Center site is located on the existing Lauderdale Plant property (392 acres) in Broward County within the City of Dania Beach and the City of Hollywood. The site contains existing power generating facilities, and FPL intends to modernize the Lauderdale Plant by replacing two existing power generating units with a new single unit and rename the facility "Dania Beach Clean Energy Center." The Broward County Comprehensive Plan is applicable to both the unincorporated area of the County and the land within the incorporated municipalities of the County. The Broward County Comprehensive Plan Future Land Use Map designates the site as "Electrical Generating Facility", which allows electrical power plants. The City of Hollywood Comprehensive Plan Future Land Use Map designates the portion of the site within the City as "Utilities" and "Industrial", and the "Utilities" category allows electrical power plants and the "Industrial" category allows utility uses. The City of Dania Beach Comprehensive Plan Future Land Use Map designates the portion of the site within the City as "Industrial" and "Utilities", and these categories do not allow electric power generation plants. FPL intends to apply to the City of Dania Beach for an amendment to the Comprehensive Plan to designate the site as "Electrical Generation Facilities", which would allow electrical power plants.

11. Turkey Point Plant Site: The Turkey Point Plant site is located on approximately 3,300 acres in the southern portion of Miami-Dade County. The site contains existing power generating facilities. The Miami-Dade County Comprehensive Plan Future Land Use Map designates the site as "Institutions, Utilities, and Communications" which allows power generation and "Environmental Protection Area."

4. Gainesville Regional Utilities

The Gainesville Regional Utilities TYSP identifies two potential sites for the increase in power generating capacity: (1) Deerhaven Generating Station site; and (2) South Energy Center site.

A. Deerhaven Generating Station Site: The Deerhaven Generating Station site is located on 3,474 acres within the City of Gainesville, and the site contains an existing power generation facility. The City of Gainesville Comprehensive Plan Future Land Use Map designates the site as "Public and Institutional Facilities", which allows utilities.

B. South Energy Center Site: The South Energy Center site is located on approximately five acres in the City of Gainesville and contains an existing power generation facility that supplies power, chilled water, and steam to the University of Florida Shands Cancer Hospital. The South Energy Center site is owned by University of Florida Health and leased to Gainesville Regional Utilities, and future power expansion would be primarily to serve the medical facilities. The City of Gainesville Comprehensive Plan Future Land Use Map designates the site as "Mixed-Use Low-Intensity", which allows the power generation facility as a planned development.

5. Gulf Power Company

The Gulf Power Company TYSP identifies six potential sites for the increase in power generating capacity: (1) Plant Scholz; (2) Plant Crist; (3) Plant Smith; (4) Caryville; (5) Shoal River; and (6) North Escambia.

A. Plant Scholz Site: The Plant Scholz site is located in Jackson County (approximately three miles southeast of the Town of Sneads) and contains existing power generating facilities. The Jackson County Comprehensive Plan Future Land Use Map designates the site as primarily Agricultural-1 and some Conservation (along the Apalachicola River). Electric power generating facilities are allowable as a conditional land use within the Agricultural-1 and Conservation future land use categories.

B. Plant Crist Site: The Plant Crist site is located in Escambia County (approximately ten miles north of the City of Pensacola) and contains existing power generating facilities. The site is designated Industrial and Agriculture on the Escambia County Comprehensive Plan Future Land Use Map. 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.

C. Plant Smith Site: The Plant Smith site is located in Bay County (approximately ten miles northwest of Panama City) and contains existing power generating facilities. The site is designated Industrial and Conservation on the adopted Future Land Use Map. Public utilities are allowed uses in both Industrial and Conservation.

D. Caryville Site: The Caryville site is located on 2,200 acres in Holmes County, Washington County, and the City of Caryville, and it is adjacent to the Choctawhatchee River. The site is designated on the adopted future land use maps as 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.

E. Shoal River Site: The site is located in Walton County (approximately three miles northwest of Mossy Head) along the Shoal River, near U.S. Highway 90. The Walton County Future Land Use Map designates the site as General Agriculture (approximately two-thirds of site) and Rural Residential (approximately one-third of site). Public utilities are allowed in areas designated General Agriculture or Rural Residential.

F. North Escambia Site: The North Escambia site is located on 2,728 acres in the northern part of Escambia County, approximately five miles southwest of Century, Florida. The existing use of the site is predominantly timber harvesting and agriculture. The Escambia County Comprehensive Plan Future Land Use Map designates the site as Agriculture, and electric power generating facilities may be allowed as a conditional use in Agriculture through the Land Development Code.

6. Orlando Utilities Commission

The Orlando Utilities Commission (OUC) TYSP states that OUC's existing Stanton Energy Center and Indian River Plant sites may accommodate future generating unit additions. It may be helpful to readers if the OUC TYSP (Section 10 Environmental and Land Use Information) included a map showing the location of these sites in relation to the surrounding roadway network.

A. Stanton Energy Center Site: The Stanton Energy Center site is located on 3,280 acres in unincorporated Orange County, approximately 12 miles southeast of the City of Orlando, and contains existing power generation facilities. The Orange County Comprehensive Plan Future Land Use Map designates the site as Institutional, which allows utilities and public facilities.

B. Indian River Plant Site: The Indian River Plant site is located on 160 acres in unincorporated Brevard County, south of the City of Titusville, and contains existing power generation facilities. The Brevard County Comprehensive Plan Future Land Use Map designates the site as Public Facility, which allows government managed utilities.

7. Seminole Electric Cooperative

The Seminole Electric Cooperative TYSP identifies one potential site (Gilchrist site) and two preferred sites (Midulla Generating Station site; and Seminole Generating Station site) for the increase in power generating capacity.

A. Gilchrist Site: The Gilchrist site is located on 520 acres in the central portion of Gilchrist County, approximately two miles northeast of the City of Bell. The site does not contain existing power generation facilities. Much of the site has been used for silviculture (pine plantation) and consists of large tracts of planted longleaf and slash pine community, and the site contains a limited amount of wetlands (10.1 acres). The site is designated Agriculture-2 on the adopted Future Land Use Map of the Gilchrist County Comprehensive Plan. Electric generating facilities are not identified as an allowable land use within the Agriculture-2 future land use category. Seminole Electric Cooperative should contact the Gilchrist County Community Development Department at (352) 463-3173 for information regarding consistency with the Gilchrist County Comprehensive Plan.

B. Midulla Generating Station Site: The Midulla Generating Station site is located on 1,300 acres in unincorporated Hardee County and Polk County, approximately nine miles northwest of the City of Wauchula. The site contains existing power generation facilities, and a 29-acre photovoltaic solar station is under construction on the Hardee County portion of the site. The site is designated as Industrial (with a small area of Conservation along the western boundary of the site) on the Future Land Use Map of the Hardee County Comprehensive Plan, and the location of the photovoltaic solar station is designated as Industrial on the Future Land Use Map of the Hardee County Comprehensive Plan. The portion of the site located in Polk County is designated as Phosphate Mining on the Future Land Use Map of the Polk County Comprehensive Plan, and electric power generation facilities are an allowable use within the Phosphate Mining future land use category.

C. Seminole Generating Station Site: The Seminole Generating Station site is located on 1,996 acres in unincorporated Putnam County, approximately five miles north of the City of Palatka. The site contains existing power generation facilities. The site is designated as Public Facilities on the adopted Future Land Use Map of the Putnam County Comprehensive Plan. Power generation facilities are an allowable use within the Public Facilities future land use category.

8. City of Tallahassee Utilities

The City of Tallahassee Utilities TYSP identifies two preferred sites (Hopkins Plant; and Substation 12) for the increase in power generating capacity. The Hopkins Plant is located in Leon County and contains existing power generation facilities. Substation 12 is located within the City of Tallahassee and contains existing substation facilities. The Tallahassee-Leon County Comprehensive Plan Future Land Use Map designates both sites as "Government Operational", which allows electric generating facilities.

9. Tampa Electric Company

The Tampa Electric Company TYSP identifies three potential sites for the addition of power generation capacity: (1) Polk Power Station; (2) H.L. Culbreath Bayside Power Station; and (3) Big Bend Power Station.

A. Polk Power Station Site: The Polk Power Station site is located in southwest Polk County and contains existing power generation facilities. The site is designated as "Phosphate Mining" on the adopted Future Land Use Map of the Polk County Comprehensive Plan, and electric power generation facilities are an allowable use within the Phosphate Mining future land use category.

B. H.L. Culbreath Bayside Power Station Site: The H.L. Culbreath Bayside Power Station site is located in unincorporated Hillsborough County and contains existing power generation facilities. The site is designated mostly as "Heavy Industrial" with a smaller area as "Light Industrial" on the adopted Future Land Use Map of the Hillsborough County Comprehensive

Plan. Electric generation plants are an allowed use in the Heavy Industrial future land use category.

C. Big Bend Power Station Site: The Big Bend Power Station site is located in unincorporated Hillsborough County and contains existing power generation facilities. The site is designated as "Heavy Industrial," "Light Industrial," and "Environmentally Sensitive Areas" on the adopted Future Land Use Map of the Hillsborough County Comprehensive Plan. Electric generation plants are an allowed use only in the Heavy Industrial future land use category. The "Environmentally Sensitive Areas" protect wetlands and significant wildlife habitat along the southern portion of the site.

Patti Zellner

From: Seiler, Ann <Ann.Seiler@dep.state.fl.us>
Sent: Thursday, April 27, 2017 3:14 PM
To: Orlando Wooten
Cc: Mulkey, Cindy
Subject: FW: Request for Comments on the 2017 Ten-Year Site Plans of Florida's Electric Utilities
Attachments: 2017 TYSP Comment Request -DEP.pdf

Good afternoon,

The Department of Environmental Protection's Siting Coordination Office has reviewed the 2017 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.

Ann Seiler
Florida Department of Environmental Protection
Siting Coordination Office
2600 Blair Stone Rd. MS 5500
Tallahassee, Florida 32399
ann.seiler@dep.state.fl.us
Office: 850.717.9113
Cell: 850.228.6237

From: Orlando Wooten [mailto:OWooten@psc.state.fl.us]
Sent: Thursday, April 20, 2017 1:00 PM
To: Mulkey, Cindy <Cindy.Mulkey@dep.state.fl.us>
Subject: Request for Comments on the 2017 Ten-Year Site Plans of Florida's Electric Utilities

Please see the attached file to see all relevant 2017 Ten Year Site Plans.

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 the appropriate state, regional, and local agencies. To this end, the Commission has made available on its website electronic copies of the 2017 Ten-Year Site Plans for all the Florida electric utilities at the following link: http://www.psc.state.fl.us/ElectricNaturalGas/TenYearSitePlans

Please forward all comments by July 20, 2017, including an electronic copy to my email address below. If you have any questions or require additional time to file comments please feel free to contact me by phone at (850) 413-6687 or by email (owooten@psc.state.fl.us) or Phillip Ellis by phone at (850) 413-6626 or by email (pellis@psc.state.fl.us). Thank you for your assistance.

Orlando Wooten
Engineering Specialist I
Division of Engineering
Phone: (850) 413-6686

June 14, 2017

Florida Fish and Wildlife Conservation Commission

Commissioners
Brian Yablonski
Chairman
Tallahassee

Aliese P. "Liesa" Priddy
Vice Chairman
Immokalee

Ronald M. Bergeron
Fort Lauderdale

Richard Hanas
Oviedo

Bo Rivard
Panama City

Michael W. Sole
Tequesta

Robert A. Spottswood
Key West

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

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MyFWC.com

Orlando Wooten
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, FL 32399-0850
OWooten@psc.state.fl.us

Re: Electric Utility 2017 Ten-Year Site Plans

Dear Mr. Wooten:

Florida Fish and Wildlife Conservation Commission (FWC) staff has reviewed the 2017 Ten-Year Site plans for the electric utilities operating in Florida submitted to the Florida Public Service Commission (PSC). We are submitting this letter to notify you that we have reviewed the following plans and have no comments or recommendations related to fish and wildlife resources:

- Duke Energy Florida
- Florida Municipal Power Agency
- Florida Power & Light
- Gainesville Regional Utilities
- Gulf Power
- Jacksonville Electric Authority
- Lakeland Electric
- Orlando Utilities Commission
- Seminole Electric Cooperative
- City of Tallahassee
- Tampa Electric Company

FWC staff appreciates the opportunity to review the Ten-Year Site Plans, as submitted by the PSC. If you need further assistance, please do not hesitate to contact Jane Chabre either by phone at (850) 410-5367 or by email at FWCConservationPlanningServices@MyFWC.com. If you have specific technical questions about our review of these plans, please do not hesitate to contact Jason Hight either by phone at (850) 413-6966 or by email at Jason.Hight@MyFWC.com.

Sincerely,

Jennifer D. Goff
Land Use Planning Program Administrator
Office of Conservation Planning Services

jdg/jh
ENV 2-11-2
2017 Ten Year Site Plans_32960_061417

cc: Melinda Fischer, JEA, fiscml@jea.com
Jamie Verschage, GRU, verschagejb@gru.com
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James Beasley, Tampa Electric, jbeasley@ausley.com
Robert McGee, Gulf Power, rimcgee@southernco.com

TREASURE COAST REGIONAL PLANNING COUNCIL

INDIAN RIVER – ST. LUCIE – MARTIN – PALM BEACH

June 19, 2017

Orlando Wooten, Engineering Specialist
Division of Engineering
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0850

Subject: 2017 Ten Year Power Plant Site Plans

Dear Mr. Wooten:

Treasure Coast Regional Planning Council has reviewed the ten year power plant site plan prepared by Florida Power and Light Company. Council approved the comments in the attached report at a board meeting on June 16, 2017. The report concludes that the region and all of South Florida continue to remain vulnerable to fuel price increases and supply interruptions, because of the continued heavy reliance on only two primary fuel types, natural gas and nuclear fuel.

Council is encouraged the FPL is continuing their 2016 expansion of solar capacity by proposing to build even more large scale solar projects in the next ten years (for a 625% increase). 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 yours,

Thomas J. Lanahan
Deputy Executive Director

Attachment

cc: Amy Brunjes, FPL

TREASURE COAST REGIONAL PLANNING COUNCIL

Report on the

Florida Power & Light Company Ten Year Power Plant Site Plan 2017-2026

June 16, 2017

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 total summer peak demand is expected to grow by 10.6 percent from 24,009 megawatts (MW) in 2017 to 26,552 MW in 2026. During the same period, FPL is expecting to reduce electrical use through demand side management programs, which include a number of conservation, energy efficiency, and load management initiatives. FPL's demand side management programs are expected to grow by 22.7 percent from 1,851 MW in 2017 to 2,271 MW in 2026 (see Exhibit 1 Schedule 7.1). After FPL's demand side management efforts are factored in, FPL will still require additional capacity from conventional and renewable power plants to meet future electrical demand. FPL is proposing to add a total of about 2,452 MW of summer capacity to its system from 2017 to 2026 (see Exhibit 2 Table ES-1). FPL plans to obtain additional electricity through: 1) upgrades to existing facilities; 2) modernization of existing FPL facilities; and 3) construction of new generating units. They also plan to take a considerable amount of older and coal-fired capacity out of service. Major changes in generating capacity are as follows:

- 2017 through 2023 – place in service a total of 2,086 MW of photovoltaic solar generation (PV) across the system;
- 2018 – retirement of 884 MW of combined cycle capacity at the Lauderdale site in Broward County;
- 2019 – expand the Okeechobee Next Generation Clean Energy Center in Okeechobee County by 1,750 MW of combined cycle capacity;
- 2019 – remove 636 MW of coal-fired capacity from the Saint Johns River Power Park in Jacksonville-Duval County;
- 2019 – discontinue 330 MW of coal-fired purchased power from the Indiantown Co-Generation facility in Martin County; and
- 2022 – place in service the 1,163 MW Dania Beach Clean Energy Center (Lauderdale modernization) in Broward County.

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

1. Horizon Solar Energy Center, Putnam and Alachua counties
2. Wildflower Solar Energy Center, DeSoto County
3. Indian River Solar Energy Center, Indian River County
4. Coral Farms Solar Energy Center, Putnam County
5. Hammock Solar Energy Center, Hendry County
6. Barefoot Bay Solar Energy Center, Brevard County
7. Blue Cypress Solar Energy Center, Indian River County
8. Loggerhead Solar Energy Center, St. Lucie County
9. Okeechobee Clean Energy Center, Okeechobee County
10. Dania Beach Clean Energy Center, Broward County
11. Turkey Point Plant, Miami-Dade County

Also, FPL has identified twelve 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. Alachua County
2. Baker County
3. Clay County
4. Collier County
5. Columbia County
6. Hendry County
7. Miami-Dade County
8. Putnam County
9. St. Lucie County
10. Suwannee County
11. Union County
12. Volusia County

The ten year site plan describes six factors that have impacted or could impact FPL's resource plan. These factors include:

1. Maintaining a balance between load and generating capacity in southeastern Florida, particularly in Miami-Dade and Broward counties.
2. Maintaining/enhancing fuel diversity in the FPL system.
3. Maintaining an appropriate balance of demand side management (DSM) and supply resources to achieve system reliability.
4. The impact of federal and state energy efficiency codes and standards on FPL's forecasted future demand and energy requirements and potential DSM gains.
5. The increasing cost competitiveness of utility-scale PV facilities due to the continued decline in the cost of PV modules and the recent extension of federal tax credits.
6. Projected changes in carbon dioxide regulations and related compliance costs.

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 three preferred sites and one potential site for future power generating facilities in the Treasure Coast Region (Exhibit 3). All four sites in the Region are being planned or evaluated for utility-scale PV facilities.

Each of the three preferred sites are planned for 74.5 MW PV solar plants. By their nature, these facilities have minimal offsite impacts but do occupy large areas of land (ranging from 570 to 695 acres).

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 4). The plan indicates fossil fuels will account for 73.5 percent (2.3 percent from coal and 71.2 percent from natural gas) of FPL's electric generation in 2017. The plan predicts fossil fuels will account for 71.4 percent (0.7 percent from coal and 70.7 percent from natural gas) of FPL's electric generation in 2026. During the same period, nuclear sources are predicted to change from 23.5 percent in 2017 to 22.5 percent in 2026. Solar sources are predicted to increase from 0.5 percent in 2017 to 4.2 percent in 2026.

Renewable Energy

The ten year site plan indicates FPL is increasing its efforts to implement cost-effective renewable energy. The factors driving these efforts are: 1) the price of PV modules has declined in recent years; 2) FPL has developed a methodology with which it can assign a firm capacity benefit for meeting FPL's summer peak load to PV; and 3) FPL has concluded from its implementation and analyses of utility-scale PV and PV demand side pilot programs that utility-scale PV applications are the most economical way to utilize solar energy. FPL's efforts to increase use of cost-effective renewable energy include the use of utility-scale PV facilities and distributed generation PV pilot programs, which are described below.

Utility-Scale PV Facilities. FPL is planning to add 298 MW of PV per year beginning in 2017 and running through 2023. In 2017, Solar Energy Centers will be constructed in the following counties: Putnam/Alachua (Horizon 74.5 MW), DeSoto (Wildflower 74.5 MW), Indian River (Indian River 74.5 MW), and Putnam (Coral Farms 74.5 MW). In 2018, Solar Energy Centers will be constructed in the following counties: Hendry (Hammock 74.5 MW), Brevard (Barefoot Bay 74.5 MW), Indian River (Blue Cypress 74.5 MW), and St. Lucie (Loggerhead 74.5 MW). Sites for the PV facilities to be added in 2019 through 2023 have not been determined yet. The new facilities will increase FPL's PV generation from 334 MW in 2016 to 2,420 MW in 2026 (an increase of 2,086 MW or 625% more). This equates to an additional 1,127 MW of firm summer capacity due to the inherent limitations of solar power (daylight hours, weather, etc.).

Distributed Generation PV Pilot Programs. FPL has three types of distributed generation (DG) PV programs. First is the *Community-Based Solar Partnership Pilot Program*, which is a voluntary solar pilot program to provide customers with an additional and flexible opportunity to

support development of solar power in Florida. This pilot program will provide all customers the opportunity to support the use of solar energy at a community scale and is designed for customers who do not wish, or are not able, to place solar equipment on their roof. Customers can participate in the program through voluntary contributions of $9/month. The voluntary contribution is required, because the cost per MW to construct this type of distributed generation scale facility is more than the cost of utility scale facilities. As of the end of February 2017, there were 19,853 participants enrolled. The tariff for the program was approved by the FPSC in January 2015 and the pilot program is scheduled to conclude at the end of 2017.

The second type of DG PV program is the *Commercial and Industrial Partnership Pilot Program*. This pilot program will be conducted in partnership with interested commercial and industrial customers over about a five year period. Limited investments will be made in PV facilities located at customer sites in selected geographic areas of FPL's service territory. The primary objective is to examine the effect of high penetration of DG PV on FPL's distribution system and to determine how best to address any problems that may be identified. FPL has installed approximately 3 MW of PV facilities on circuits that experience specific loading conditions to better study feeder loading impacts. Up to an additional 2 MW may be built in 2017 to further expand the understanding of integrating large PV facilities into the FPL system.

The third type of DG PV program is the *Battery Storage Pilot Program*. The purpose of this pilot program is to demonstrate and test a wide variety of battery storage grid applications. In addition, the pilot program is designed to help FPL learn how to integrate battery storage into the grid and optimize control. Under this pilot program, FPL has installed a 1.5 MW battery storage system in Miami-Dade County primarily for peak shaving and frequency response, a battery storage system of 1.5 MW in Monroe County for backup power and voltage support, and several smaller kilowatt-scale systems at other locations to study distributed storage reliability applications. FPL is also in the midst of designing a 50 MW expansion of the program, likely consisting of multiple sites in the 1 MW to 10 MW size range. This will be used to look at a variety of applications such as localized outage, momentary mitigation, and peak shaving. Several will be co-located with solar plants to explore the integration of intermittent resources into the grid.

Conclusion

Council is encouraged that FPL, after having tripled its solar capacity by building three more 74.5 MW solar energy centers by the end of 2016, is preparing to build even more large scale solar projects in the next 10 years. This will increase solar capacity by 2,086 MW (625% increase). At the same time, FPL is constructing and operating highly efficient natural gas plants that have decreased dependence on foreign oil and saved energy costs.

Council recommends that FPL continue to make progress toward adopting a more balanced portfolio of fuels that includes a significant component of renewable energy sources. This is important to reduce vulnerability to fuel price increases and supply interruptions. 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 supports FPL's existing and proposed solar projects and encourages FPL to develop additional projects based on renewable resources. FPL should consider developing other programs 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 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. Also, FPL should consider expanding solar rebate programs for customers who install PV and solar water heating systems on their homes and businesses. These rebates should be coordinated with other programs, such as the Solar and Energy Loan Fund (SELF) and Property-Assessed Clean Energy (PACE) programs, to provide participants in these programs the option of receiving a rebate. SELF is a low interest rate loan program that provides financing for clean energy solutions. PACE programs allow property owners to finance energy retrofits by placing an additional tax assessment on the property in which the investment is made.

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 power providers and 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

Schedule 7.1
Forecast of Capacity, Demand, and Scheduled
Maintenance At Time Of Summer Peak

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
August of Year	Firm Installed Capacity MW	Firm Capacity Import MW	Firm Capacity Export MW	Firm QF MW	Total Firm Capacity Available MW	Total Peak Demand MW	DSM MW	Firm Summer Peak Demand MW	Total Reserve Margin Before Maintenance MW	Total Reserve Margin Before Maintenance % of Peak	Scheduled Maintenance MW	Total Reserve Margin After Maintenance MW	Total Reserve Margin After Maintenance % of Peak	Generation Only Reserve Margin After Maintenance MW	Generation Only Reserve Margin After Maintenance % of Peak
2017	26,058	492	0	334	26,884	24,009	1,851	22,157	4,727	21.3	0	4,727	21.3	2,875	12.0
2018	26,357	492	0	334	27,182	24,297	1,906	22,391	4,791	21.4	0	4,791	21.4	2,885	11.9
2019	27,011	110	0	4	27,125	24,496	1,950	22,547	4,578	20.3	0	4,578	20.3	2,629	10.7
2020	27,320	110	0	4	27,433	24,605	1,994	22,612	4,822	21.3	0	4,822	21.3	2,828	11.5
2021	27,479	110	0	4	27,592	24,717	2,038	22,679	4,914	21.7	0	4,914	21.7	2,876	11.6
2022	28,889	110	0	4	29,002	24,967	2,083	22,883	6,119	26.7	0	6,119	26.7	4,035	16.2
2023	29,133	110	0	4	29,246	25,338	2,130	23,209	6,037	26.0	0	6,037	26.0	3,908	15.4
2024	29,290	110	0	4	29,404	25,756	2,177	23,579	5,825	24.7	0	5,825	24.7	3,648	14.2
2025	29,286	110	0	4	29,400	26,137	2,224	23,914	5,486	22.9	0	5,486	22.9	3,263	12.5
2026	29,283	110	0	4	29,396	26,552	2,271	24,281	5,115	21.1	0	5,115	21.1	2,844	10.7

Col. (2) represents capacity additions and changes projected to be in-service by June 1st. These MW are generally considered to be available to meet summer peak loads which are forecasted to occur during August of the year indicated.
Col. (6) = Col.(2) + Col.(3) - Col(4) + Col(5).
Col.(7) reflects the 2017 load forecast without incremental energy efficiency or cumulative load management.
Col.(8) represents cumulative load management capability, plus incremental energy efficiency and load management, from 9/2016-on intended for use with the 2017 load forecast.
Col.(10) = Col.(6) - Col.(9)
Col.(11) = Col.(10) / Col.(9)
Col.(12) indicates the capacity of units projected to be out-of-service for planned maintenance during the summer peak period.
Col.(13) = Col.(10) - Col.(12)
Col.(14) = Col.(13) / Col.(9)
Col.(15) = Col.(6) - Col.(7) - Col.(12)
Col.(16) = Col.(15) / Col.(7)

Exhibit 2

Table ES-1: Projected Capacity & Firm Purchase Power Changes

Year [1/]	Projected Capacity & Firm Purchase Power Changes	Summer MW (Appr.)	Date	Summer Reserve Margin [2/]
2017	Cedar Bay	(250)	January 2017	
	Ft. Myers - 2 CT Upgrade	40	May 2017	
	Lauderdale - 5 CT Upgrade	100	May 2017	
	Manatee 3	13	June 2017	
	Martin 4	9	March 2017	
	Martin 8	7	March 2017	
	Total of MW changes to Summer firm capacity:	**(81)**		**21.3%**
2018	Sanford 4	8	August 2017	
	Sanford 5	8	November 2017	
	Turkey Point 5	(40)	December 2017	
	Additional PV Sited [3/]	322	December 2017 and February 2018	
	Total of MW changes to Summer firm capacity:	**299**		**21.4%**
2019	Okeechobee Energy Center	1,748	June 2019	
	Turkey Point 3	20	October 2018	
	Martin 8	4	November 2018	
	Fort Myers 2	2	May 2019	
	St. Johns River Power Park 1 Partial Ownership [4/]	(127)	First Quarter 2019	
	St. Johns River Power Park 2 Partial Ownership [4/]	(127)	First Quarter 2019	
	St. Johns River Power Park PPA	(382)	First Quarter 2020	
	Indiantown 2 PPA	(330)	First Quarter 2019	
	Lauderdale 4	(442)	November 2018	
	Lauderdale 5	(442)	November 2018	
	Turkey Point 4	20	December 2018	
	Total of MW changes to Summer firm capacity:	**(57)**		**20.3%**
2020	Sanford 4	37	November 2019	
	Sanford 5	37	January 2020	
	Fort Myers 2	75	May 2020	
	Additional PV Unsited [3/]	161	Fourth Quarter 2019	
	Total of MW changes to Summer firm capacity:	**310**		**21.3%**
2021	Additional PV Unsited [3/]	161	Fourth Quarter 2020	
	Total of MW changes to Summer firm capacity:	**161**		**21.7%**
2022	Cape Canaveral Energy Center 3	88	June 2022	
	Lauderdale Modernization (Dania Beach Clean Energy Center)	1,163	June 2022	
	Additional PV Unsited [3/]	161	Fourth Quarter 2021	
	Total of MW changes to Summer firm capacity:	**1,412**		**26.7%**
2023	Riviera Beach Energy Center 5	86	June 2023	
	Additional PV Unsited [3/]	161	Fourth Quarter 2022	
	Total of MW changes to Summer firm capacity:	**247**		**26.0%**
2024	Additional PV Unsited [3/]	161	Fourth Quarter 2023	
	Total of MW changes to Summer firm capacity:	**161**		**24.7%**
2025		—	--	
	Total of MW changes to Summer firm capacity:	**0**		**22.9%**
2026		—	--	
	Total of MW changes to Summer firm capacity:	**0**		**21.1%**

[1/] Year shown reflects when the MW change begins to be accounted for in Summer reserve margin calculations.

[2/] Winter Reserve Margins are typically higher than Summer Reserve Margin. Winter Reserve Margin are shown on Schedule 7.2 in Chapter III.

[3/] MW values shown for the PV facilities represent the firm capacity assumptions for the PV facilities and FPL currently assumes 0.3% degradation annually for PV output

[4/] Subject to JEA Board and ultimately FPSC approval, SJRPP may cease operation as early as January 1, 2018.

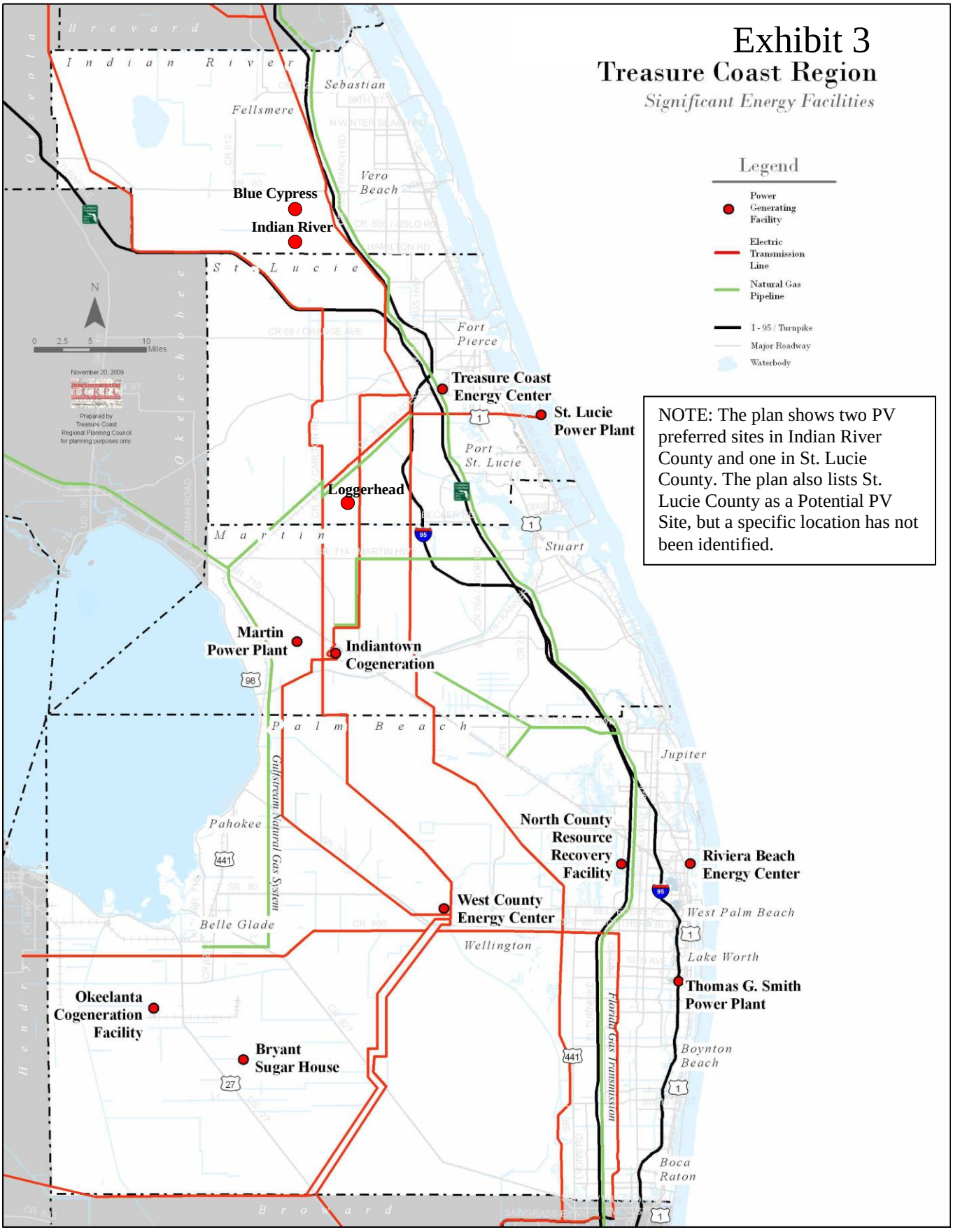
Exhibit 3
Treasure Coast Region
Significant Energy Facilities
Legend
Power Generating Facility
Electric Transmission Line
Natural Gas Pipeline
I - 95 / Turnpike
Major Roadway
Waterbody
NOTE: The plan shows two PV preferred sites in Indian River County and one in St. Lucie County. The plan also lists St. Lucie County as a Potential PV Site, but a specific location has not been identified.
Blue Cypress
Indian River
Treasure Coast Energy Center
St. Lucie Power Plant
Loggerhead
Martin Power Plant
Indiantown Cogeneration
North County Resource Recovery Facility
Riviera Beach Energy Center
West County Energy Center
Thomas G. Smith Power Plant
Okeelanta Cogeneration Facility
Bryant Sugar House
Gulfstream Natural Gas System
Florida Gas Transmission
Brevard
Indian River
Sebastian
Fellsmere
Vero Beach
St. Lucie
Fort Pierce
Port St. Lucie
Martin
Stuart
Palm Beach
Jupiter
Pahokee
Belle Glade
Wellington
West Palm Beach
Lake Worth
Boynton Beach
Boca Raton
Broward
Hendry
Okeechobee
Osceola
Prepared by Treasure Coast Regional Planning Council for planning purposes only.
November 20, 2009

Exhibit 4

Schedule 6.2
Energy Sources % by Fuel Type

Energy Source	Units	Actual [1] 2015	2016	Forecasted 2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
(1) Annual Energy Interchange [2]	%	3.9	1.4	0.6	0.8	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(2) Nuclear	%	22.0	23.1	23.5	23.1	23.6	23.3	23.2	23.6	23.1	22.8	23.1	22.5
(3) Coal	%	4.3	3.4	2.3	1.6	1.8	1.1	1.0	0.6	0.8	0.7	0.8	0.7
(4) Residual (FO6) -Total	%	0.3	0.4	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(5) Steam	%	0.3	0.4	0.1	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(6) Distillate (FO2) -Total	%	0.1	0.2	0.3	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(7) Steam	%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(8) CC	%	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(9) CT	%	0.0	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(10) Natural Gas -Total	%	69.9	70.8	71.2	71.3	70.9	71.6	71.2	70.6	70.4	70.3	70.0	70.7
(11) Steam	%	3.5	1.8	1.5	0.9	1.1	0.7	0.5	0.3	0.3	0.2	0.4	0.3
(12) CC	%	66.0	68.8	69.2	70.4	69.5	70.7	70.5	70.3	70.1	70.1	69.6	70.3
(13) CT	%	0.4	0.3	0.4	0.1	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0
(14) Solar [3]	%	0.1	0.2	0.5	1.6	1.8	2.3	2.9	3.4	4.0	4.3	4.3	4.2
(15) PV	%	0.1	0.1	0.5	1.6	1.8	2.3	2.9	3.4	4.0	4.3	4.3	4.2
(16) Solar Thermal	%	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
(17) Other [4]	%	-0.6	0.5	1.4	1.4	1.5	1.5	1.6	1.6	1.6	1.7	1.7	1.8
		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.
3/ Represents output from FPL's PV and solar thermal facilities.
4/ Represents a forecast of energy expected to be purchased from Qualifying Facilities, etc., Independent Power Producers, net of Economy and other Power Sales.

Southwest Florida Water Management District

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WaterMatters.org

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Tampa, Florida 33637-6759
(813) 985-7481 or
1-800-836-0797 (FL only)

July 14, 2017

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

Subject: 2017 Electric Utility Ten-Year Site Plans

Dear Mr. Wooten:

In response to your request, the Southwest Florida Water Management District (District) has completed its review of the 2017 Ten-Year Site Plans for Duke Energy Florida (DEF), Florida Power & Light Company (FPL) and Seminole Electric Cooperative (SEC). The District's review is being conducted pursuant to Section 186.801(2)(e), Florida Statutes, which requires the Public Service Commission to 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." Based on our review, two of the three utilities (DEF and SEC) are planning to construct new combustion turbine or combined cycle facilities at designated and/or undesignated sites.

The District offers the following technical assistance comments for consideration.

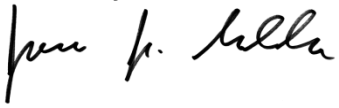
- The most water conserving practices must be used in all processes and components of the power plant's water use that are environmentally, technically and economically feasible for the activity, including reducing water losses, recycling, and reuse. If a lower quality water is available and is environmentally, technically and economically feasible for all or a portion of the proposed use, this lower quality water must be used.

- For new generating facilities proposed in the southern and much of the central portions of the District, there are additional water use constraints. 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 water levels in lakes and wetlands, and reduced stream flows, which have been caused by excessive ground water withdrawals. Regional recovery strategies are being implemented to address these adverse water resource impacts. Consequently, the District has heightened concerns regarding potential impacts due to additional water withdrawals in these areas.

Early coordination with the District's Water Use Permit (WUP) staff is encouraged prior to submittal of any Site Certification or WUP applications. For assistance or additional information concerning the District's WUP program, or to schedule a preapplication conference, please contact April Breton, WUP manager, at (813) 985-7481, extension 2049, or april.breton@watermatters.org.

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
c: April Breton, SWFWMD

1800 M Street NW Suite 400S | Washington DC 20036 | energystorage.org

October 3, 2017

Ms. Carlotta S. Stauffer
Office of Commission Clerk
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, Florida 32399-0850

RE: Comments on 2017 Ten-Year Site Plans of Electric Utilities, Docket No. 20170000-OT

Dear Ms. Stauffer:

The Energy Storage Association (ESA) appreciates the opportunity to provide comments on the 2017 Ten-Year Site Plans submitted by Florida's electric utilities.

Since its inception 27 years ago, ESA has promoted the development and commercialization of safe, competitive, and reliable energy storage delivery systems for use by electricity suppliers and their customers. ESA's nearly 200 members comprise a diverse group of electric sector stakeholders, including electric utilities, energy service companies, independent power producers, technology developers—of advanced batteries, flywheels, thermal energy storage, compressed air energy storage, supercapacitors, and other technologies—component suppliers, and system integrators.

In these comments, ESA urges the Florida Public Service Commission to reform the ten-year planning process in order to include greater consideration of energy storage. Doing so would ensure ratepayers are provided with the most cost-effective resources and a more flexible and resilient electric grid.

I. Energy storage was not sufficiently considered in the utilities' Ten-Year Site Plans

The Ten-Year Site Plans submitted by the utilities do not incorporate adequate consideration of energy storage into their system planning process. While ESA applauds the efforts made by Florida Power & Light Company and Lakeland Electric to include energy storage pilots in their Ten-Year Site Plans, these energy storage proposals do not appear to be a result of a broader analysis of the capabilities of energy storage.

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In their current form, the utility Ten-Year Site Plans propose nearly 3,900 megawatts (MW) of natural gas combustion turbine peaking plants in all. ESA notes that the proposals generally lack sufficient discussion of the selection methodology and process employed by the utilities in determining these investments. Considering that such investments would commit Florida ratepayers to long-term assets at a time when the state is reviewing its infrastructure resilience more broadly, it behooves the Commission to require a more robust showing by the utilities that these assets are the most cost-effective resource for Florida ratepayers and best address system need, as well as require that alternative resources are adequately explored.

Advanced energy storage is one such alternative that is now commercially contracted—and procured competitively with traditional resources—at project scales up to 100 MW, on par with natural gas-fired power plants. The case for energy storage is a proven one. In fact, some of the very utilities who have submitted Ten-Year Site Plans to the Florida Public Service Commission have proposed energy storage projects to deploy in other jurisdictions where they operate. In September 2017, Duke Energy Carolinas announced plans to deploy 75 MW of energy storage between 2019 and 2021 in its 2017 Integrated Resource Plan Update (Docket No. E-100). And, as noted earlier, Florida Power & Light Company's 50 MW energy storage pilot proposal to be deployed by 2020 suggests that the utility has already realized the business case for energy storage as a grid asset.

II. Commission must call on utilities to include modeling of sub-hourly intervals, up-to-date storage cost assumptions, and a method of valuing flexibility

Considering the potential for energy storage to serve as a cost-effective, flexible alternative, it is imperative that the Commission update the state's utility planning process to better incorporate energy storage.

Advanced energy storage technologies have unique characteristics that can serve many needs of the grid, if considered appropriately in planning processes. Unlikely standard generation resources, energy storage may both inject and withdraw electricity from the grid; it can respond nearly instantaneously to a control signal and can ramp nearly instantaneously up or down to a precise level of service; and it is "always on" and available for service, even when neither charging nor discharging. Such unique characteristics of storage require a different approach to resource modeling if a utility will realize the full value of storage to its system.

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As outlined in ESA's 2016 primer on including energy storage in utility IRPs,[1] the Commission should follow these three basic guidelines to ensure inclusion of storage in resource planning processes and enhance prudent planning:

1. Use sub-hourly intervals in modeling to quantify the value of both capacity and flexibility benefits provided by energy storage;
2. Use a "net cost" analysis of capacity investment options to more accurately compare energy storage with traditional capacity resources; and
3. Use up-to-date storage cost estimates and cost forecasts to better identify near- and long-term prudency of storage.

By incorporating these important modifications to system planning processes, utility modeling and evaluation of system needs for the Ten-Year Site Plans will be able to accurately capture both the benefits and costs of energy storage, and ensure that the technology is being reviewed alongside other resource options.

III. Energy storage is already being incorporated into utility planning processes in other states

There are a number of examples of utilities across the United States that have incorporated energy storage consideration into their planning process. For example, Tucson Electric Power's 2017 IRP found that energy storage was cost-effective capacity and included over 100 MW of storage in the selected resource portfolio.[2] Similarly, the Hawaiian Electric Companies updated their 2016 Power Supply Improvement Plan to capture the flexibility benefits of energy storage, resulting in selection of over 100 MW of additional cost-effective energy storage capacity.[3] Other recent IRP documents from utilities in Oregon,[4] Washington,[5] and Indiana[6] include considerations of energy storage in long-term resource planning. Finally, New Mexico's Public Utilities Commission recently approved unanimously the Commission's rule governing Integrated Resource Plans for electric utilities to include energy storage.[7]

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[1] Energy Storage Association, *Including Advanced Energy Storage in Integrated Resource Planning: Cost Inputs and Modeling Approaches,* November 2016, available at http://energystorage.org/system/files/attachments/irp_primer_002_0.pdf

[2] Tucson Electric Power, 2017 Integrated Resource Plan, 3 April 2017, available at https://www.tep.com/wp-content/uploads/2016/04/TEP-2017-Integrated-Resource-FINAL-LowResolution.pdf

[3] Hawaii Electric Companies' PSIPs Update Report: Book 1 of 4, 23 Dec 2016, available at https://www.hawaiianelectric.com/Documents/about_us/our_vision/dkt_2014_0183_20161223_companies_PSIP_update_report_1_of_4.pdf

[4] Portland General Electric, 2016 Integrated Resource Plan, 15 Nov 2016, available at https://www.portlandgeneral.com/-/media/public/our-company/energy-strategy/documents/2016- irp.pdf?la=en

[5] See Puget Sound Energy's Feb 3, 2017, presentation to its IRP Advisory Group at https://www.pse.com/aboutpse/EnergySupply/Documents/01_PSE_2017_IRPAG_Feb3_FINAL.pdf

[6] Indianapolis Power & Light Company, 2016 Integrated Resource Plan, available at https://www.iplpower.com/IRP/

[7] New Mexico Public Regulation Commission, "Final Order Amending Integrated Resource Planning Rules 17.7.3 NMAC to Include Energy Storage Resources," 2 August 2017.

Energy Storage Association

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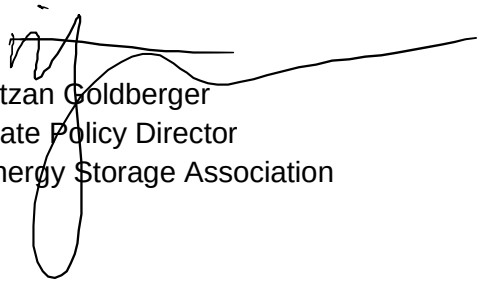
With utilities planning to invest significant ratepayer funds in new capacity over the next decade, the time is now to include storage in resource planning to ensure least cost solutions for ratepayers and prudent long-term investments for reliability.

Thank you for your consideration.

Respectfully,



Nitzan Goldberger
State Policy Director
Energy Storage Association

August 29, 2017

Via electronic filing and electronic mail

Chairman Brown, Comm'rs. Brisé, Graham, Polmann
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: Planning for least-cost electric service via 10-Year Site Plans

Dear Commissioners:

Sierra Club respectfully urges you to reject the 10-Year Site Plans filed by electric utilities this year ("2017 Plans") because, contrary to Florida law, they omit the information necessary to assure that Floridians will pay as little as possible for electric service. Florida law requires utilities to keep electric bills low and to expand clean energy use, as discussed in Sierra Club's past comments, enclosed and incorporated here by reference.[1] The 2017 Plans maintain, however, that Floridians should rely on dirty power plants that burn gas or coal imported from out of state, without any empirical support that those plants and imports would, somehow, cost less than clean energy.

In fact, new gas-burning generation dwarfs the clean energy investments contemplated in the 2017 Plans, even though, for instance, the chairman of Florida's largest electric utility, Florida Power & Light ("FPL"), has predicted the end of gas-burning peaker plants ("peakers") because they cannot compete with the plunging costs of solar and energy storage. Clean energy could very well save Floridians money, but the Commission cannot know how much, because the utilities routinely fail to present side-by-side comparisons of clean energy options and their planned fossil fuel plants. The 2017 Plans are thus "unsuitable" and should be rejected. Section 186.801, F.S.

With these comments, Sierra Club presents some of the latest market data showing

[1] *See* Exhibit K: Sierra Club 2016 10-Year Site Plan Comments; Exhibit L: Sierra Club 2015 10-Year Site Plan Comments; Exhibit M: Sierra Club 2013 10-Year Site Plan Comments.

that dirty power plants cannot keep up with the continuous cost and performance improvements of clean alternatives, such as solar, solar paired with storage, energy efficiency, and other demand-side resources.

Given this data and the utilities' omissions, Sierra Club respectfully urges the Commission to clarify at its upcoming 10-Year Site Plan workshop that utilities are required to provide cost comparisons of their plans, including to alternatives with higher levels of clean energy investments. To guide the development of meaningful comparisons going forward, the Commission should also specify that utilities are required to present cost data on a range of alternatives, pursuant to Florida law as well as resource planning and procurement best practices, by the April 1, 2018, deadline for new plans.

DISCUSSION

The utilities fail to reconcile their inherently high-cost, high-risk gas- and coal-laden proposals with abundant, money-saving clean energy alternatives. In light of the widely available data on those alternatives, the 2017 Plans are indefensible and the Commission should reject them.

I. More gas-burning generation is not justified.

The 2017 Plans anticipate over 8,800 MW of new gas-burning generation by 2026.[2] Nearly all of the utilities' proposed generation additions consist of gas-burning units, further rendering Florida "increasingly dependent on natural gas as a fuel supply."[3] For example, FPL's generation mix already consists of over 71% gas,[4] and Duke Energy Florida ("DEF") plans to follow suit, increasing from 57.5% to 74.5%[5] gas generation over the next decade.

The costs of gas for Floridians are well-documented: Overreliance on gas exposes Florida ratepayers to significant economic risk, as gas markets are prone to wild swings.[6] Efforts to reduce price volatility have imposed enormous costs on customers,[7] and

[2] Exhibit C: Planned Gas Burning Generation Additions.

[3] DEF Response to Commission Staff's First Data Request, question no. 25, at 22; *see also* Union of Concerned Scientists, *Rating the States on Their Risk of Natural Gas Overreliance* (Oct. 2015), goo.gl/95bAu4.

[4] FPL 2017 10-Year Site Plan at 96-97, Schedules 6.1, 6.2.

[5] DEF 10-Year Site Plan at 2-27, 2-28, Schedules 6.1, 6.2.

[6] *See* U.S. Energy Info. Admin., *Henry Hub Natural Gas Spot Price*, (July 6, 2017), goo.gl/19Besa (illustrating gas price spikes in 2001, 2003, 2005, and 2008).

[7] *See* Briefing by Public Counsel, filed July 15, 2016, in Docket No. 160096-EI, Joint petition for approval of modifications to risk management plans by DEF, FPL, Gulf and Tampa Electric Company, goo.gl/byXsL4; Sierra Club, Comment Letter on Staff and IOU Proposed Natural Gas Hedging Strategies (Mar. 6, 2017), goo.gl/gd65rZ.

Floridians have lost nearly $7 billion on hedging programs since 2002.[8]

Adding gas-burning generation also risks leaving ratepayers with stranded assets. Building new gas peakers require major capital expenditures. Yet FPL, the state's largest utility, has acknowledged that by 2020, these units will be economically obsolete, raising stranded asset risks.[9]

While no evidence is presented in the 2017 Plans that gas-burning generation additions are least cost, there *is* evidence of conflicts of interest surrounding these planned expenditures. In fact, gas generation and infrastructure, such as interstate pipelines, pave the way for windfalls for investor-owned utilities ("IOUs") and their affiliates, thus advancing private interests at the expense of the captive customer base.[10] In recent years, mergers between IOUs and pipeline companies have proliferated,[11] raising the threat of Floridians improperly subsidizing pipeline companies.

In short, the utilities' planned gas generation is unjustified[12] and this alone renders the 2017 Plans as a whole unsuitable.

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[8] Susan Salisbury, *Hedging Costs Florida Consumers $7 Billion—Why Start Again?*, PALM BEACH POST (Apr. 4, 2017), goo.gl/ki2ezW; *see also* Jerome R. Stockfish, *Utilities Put Hedging on Hold*, TAMPA BAY TIMES (Nov. 3, 2016), goo.gl/Kmp8eT; Direct Testimony of Elizabeth A. Stanton On Behalf of Sierra Club, filed Aug. 10, 2017, in Docket No. 20170057-EI.

[9] Eric Wesoff*, NextEra on Storage: 'Post 2020, There May Never Be Another Peaker Built in the US'*, GREENTECH MEDIA (Sept. 30, 2015), goo.gl/rQDK0H.

[10] *See, e.g.*, Jonathan Peress, Testimony Before the Senate Energy and Natural Resources Committee (June 14, 2016), at 5, goo.gl/rPoudE (highlighting "a disturbing trend of utilities pursuing a capacity expansion strategy by imposing transportation contract costs on state-regulated retail utility ratepayers so that affiliates of those same utilities can earn shareholder returns as pipeline developers.").

[11] *See, e.g.*, 2016 Sierra Club 10-Year Site Plan Comments, Exhibit C: Mergers between pipeline companies and IOUs/their affiliates.

[12] The utilities' responses to Commission Staff's First Data Request—asking the utilities to "identify the next best alternative" for each planned generating unit—fail to remedy these critical deficiencies. In responding, the utilities list only gas plant alternatives, if any, and share no information, alternatives, or criteria that would make these answers constructive. *See* Exhibit F. For example, DEF suggests, without looking to non-gas alternatives, that a combined cycle ("CC") unit is the best alternative to three new combustion turbine ("CT") units, yet shows that the CC unit would be *more* cost effective in the long run and offers no alternative to a fourth gas unit; FPL only compares new gas-burning generation at its Lauderdale plant to maintaining old units, without sharing cost data; Gulf Power lists (mostly redacted) a CC plant as an alternative to new CT units, without comparison to non-gas resources, discussion of revenue requirements, or comparison to planned additions; Orlando Utilities Commission ("OUC") lists gas units as "placeholders" and simply "assume[s] … that OUC will add combined cycle capacity to meet the projected capacity requirements;" Seminole lists three new CT and two new CC units subject to "future economic studies;" the City of Tallahassee only shared a comparison of gas additions to existing plants; TECO compared a new CC unit to its planned generation without other alternatives or explanation.

II. Continued reliance on old coal-burning generation is not justified.

Florida's utilities continue to rely on over 11 GW of aging, dirty coal-burning generation. This generation includes several units well past their book lives (e.g., Crist Units 4 and 5, which are 58- and 56-years-old, respectively)—and the 2017 Plans are devoid of evidence that any of the units are economic today, much less over the next ten years.

Throughout the U.S., coal plants are continuing to shutter due to losing economics. Since 2010, more than 257 coal plants have announced retirement.[13] The reasons cited for these retirements include exorbitant variable costs and costs for producing and cleaning up hazardous air, waste, and water pollution. In short, coal is one of the most expensive[14] and polluting[15] methods of generation, and continuing to rely on old coal is risky for ratepayers.

Despite industry trends to divest from coal generation, the 2017 Plans include no meaningful discussion of how the utilities will manage the costs and risks associated with operating the over 7 GW of coal units without retirement dates.[16] Of the roughly 4 GW of old coal generation slated for retirement, 78% of this capacity will continue to operate past 2026.[17] But the utilities present no evidence that continued operation of remaining coal plants makes economic sense.

As we've previously highlighted,[18] Lakeland Electric is the single Florida utility that has commissioned a study of options for its remaining coal unit, comparing retrofit and retirement scenarios.[19] Unsurprisingly, Lakeland concluded that renewables and energy efficiency could meet load growth more cost-effectively than any of the scenarios where the coal unit would continue to operate.[20]

The Plans must demonstrate that the utilities have must considered the risks and relative costs of retirement of existing coal-burning generation versus continuing operation and maintenance. Without such a demonstration, the utilities' plans to continue to operate their aging coal units indefinitely are unjustified.

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[13] Sierra Club, goo.gl/izv3ix.

[14] *See* Exhibit K at 17-19.

[15] *See, e.g.*, Tim McDonnell, *Environmentalists Hate Fracking. Are They Right?*, MOTHER JONES (May 11, 2016), goo.gl/dGtFju.

[16] Exhibit D: Existing Coal Burning Generation & Retirement Dates.

[17] *Id.*

[18] Exhibit K at 18-19.

[19] nFront Consulting LLC, "Strategic Resource Plan, Lakeland Electric" (Mar. 2015).

[20] *Id.* at 3-13, 3-24.

III. Renewables, storage, and demand-side resources are a bargain.

Proposed investments in gas-burning generation in the 2017 Plans dwarf those for clean energy resources. Combined, the utilities propose a whopping 8,800 MW of new gas generation by 2027, versus less than 2,863 MW of solar, 427 MW in new solar PPAs, and one 94 MW wind PPA.[21] Half of the utilities are now beginning to explore battery storage projects, albeit still at a small scale and in preliminary stages.[22]

These are trivial amounts of clean energy compared to both gas-burning additions and to the vast, untapped potential for these resources in Florida. The utilities describe commercial interest and regular outreach from renewable energy developers, particularly for solar photovoltaics ("PV"): "[a]s the cost of solar PV technology continues to drop, there has been more interest from developers utilizing this technology."[23] Previous requests for proposals ("RFPs") by Florida municipal utilities confirm that there is no shortage of opportunities for cost-effective solar PV in Florida.[24] For example, a 2015 RFP for solar PPAs in Florida, produced bids as low as $59 per MWh.[25] Evidence also shows that RFPs in *every* other state in the Southeast have returned plentiful, cost-effective solar PV bids.[26]

Critically, the 2017 Plans lack essential side-by-side comparisons of adding more renewables (particularly solar), storage, and demand-side resources versus new, planned gas-burning generation. Abundant renewables, energy storage, and demand-side resources are available to meet peak demand and save costs across the grid's generation, transmission, and distribution functions. Moreover, investing in these resources helps to divorce electricity production from the unpredictable gas market.[27] And the market for these resources in

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[21] Exhibit A: Planned Solar & Wind Generation Additions; Exhibit C: Planned Gas Burning Generation Additions.

[22] Exhibit B: Existing & Planned Battery Storage Projects.

[23] Exhibit E: Developer Interest in New Renewable Energy Projects; DEF, Response to Commission Staff's First Data Request, question no. 36.

[24] 2016 Sierra Club Comments, Exhibit B: Florida RFPs for Solar.

[25] JEA, 2015 Solar RFP—Phase 2 Summary, 1 (June 2015), goo.gl/iSZiRD (reporting bid prices submitted in response to JEA's 2015 Solar RFP).

[26] Exhibit G: Examples of Recent Southeast RFPs & PPAs for Renewables; *see also* Mark Bolinger & Joachim Seel, UTILITY-SCALE SOLAR 2015: EMPIRICAL ANALYSIS OF PROJECT COST, PERFORMANCE, AND PRICING TRENDS IN THE UNITED STATES, Lawrence Berkeley Nat'l Lab. (Aug. 2016), goo.gl/VXne9M.

[27] *See, e.g.*, Thomas Jenkin, et al., THE USE OF SOLAR AND WIND AS A PHYSICAL HEDGE AGAINST PRICE VARIABILITY WITHIN A GENERATION PORTFOLIO, Nat'l Renewable Energy Lab. (Aug. 2013), at 34, goo.gl/TAUYAG, (renewable energy "generation significantly reduces the exposure of electricity costs to natural gas price uncertainty."); CEC, RENEWABLE ENERGY AS A HEDGE AGAINST FUEL PRICE FLUCTUATION: HOW TO CAPTURE THE BENEFITS (Sept. 2008), goo.gl/UQyxLq.

Florida is better than ever—

- Solar is cheap, plentiful, and flexible: Solar generation technologies, especially solar PV, can help meet peak demand and achieve deep cost savings as a hedge against gas price volatility.[28] Florida has abundant solar resources, has been ranked the third best state in the country for solar generation potential,[29] and has the least expensive market to invest in solar PV,[30] with pricing as low as $0.7 per kWh.[31] As the utilities already recognize, solar costs have "plunged"[32] in recent years. Nationwide, the unsubsidized levelized cost of solar has dropped to as low as $46 per MWh, versus $165 per MWh for gas peaking plants.[33] In Florida, the levelized cost of solar is estimated at $49 per MWh and expected to continue to decline.[34] Indeed, FPL has admitted that solar can now work "cost-effectively at large-scale"[35] and "save customers money."[36]

- Florida utilities have access to low-cost wind generation: For example, Gulf Power's 178 MW and 94 MW wind purchases from Oklahoma are priced below avoided cost.[37]

- Energy storage can save money and help meet peak demand: Energy storage technologies allow utilities to reduce or avoid expensive peak generation by redeploying surplus energy from lower cost, off-peak hours. Investments in storage can save states hundreds of millions, if not billions, of dollars in generation, transmission, and

[28] UTILITY-SCALE SOLAR 2015: EMPIRICAL ANALYSIS OF PROJECT COST, PERFORMANCE, AND PRICING TRENDS IN THE UNITED STATES, *supra* n. 26.

[29] AEE, ADVANCED ENERGY IN FLORIDA (Jun. 11, 2015), goo.gl/SjjkfK.

[30] U.S. Dep't of Energy, PHOTOVOLTAIC SYSTEM PRICING TRENDS: HISTORICAL, RECENT, AND NEAR-TERM PROJECTIONS (Sept. 2014), at 11, goo.gl/W1dJ8z.

[31] *See* Herman K. Trabish, *Tipping point' for FL solar? Orlando utility buys at under fossil generation prices*, Utility DIVE, (Aug. 2015), goo.gl/NiXNLh.

[32] Wesoff, *supra* n. 9.

[33] Exhibit H: Lazard's Levelized Cost of Energy Analysis at 2.

[34] Bloomberg New Energy Finance, H2 2016 AMER. LEVELIZED COST OF ELECTRICITY UPDATE (Oct. 2016) (providing estimates of LCOE for solar by state).

[35] Transcript of Prudence Hearing, Vol. 2, 302, *Sierra Club v. Brown*, No. SC17-82 (Fla. 2017).

[36] Transcript of Prudence Hearing, Vol. 12, 1514, *Sierra Club v. Brown*, No. SC17-82 (Fla. 2017).

[37] *See, e.g.,* Sierra Club and Southern Alliance for Clean Energy letter of May 1, 2015 (discussing benefits of wind power purchases for Florida's ratepayers); Order No. PSC-16-0507-PAA-EI, goo.gl/WeZzmX.

distribution costs.[38] Storage is projected to become even more cost-competitive in coming years, with costs continuing to drop dramatically: Median prices for battery storage are projected between $774 and $1,083 per kW by 2020, roughly half of 2016 costs.[39] PPAs for combined solar and storage are already beating gas plants, dropping below 4.5¢ per kWh.[40]

- Demand-side management is cost-effective and increases grid reliability: Energy efficiency is the lowest-cost energy resource available[41] and is essential to providing least-cost, low-risk electric service and meeting seasonal peak demand.[42] Utilities report saving billions of dollars from targeted efficiency programs, especially those that defer or avoid large transmission and distribution expenditures.[43] Demand-side resources, such as peak-shaving demand response programs, reduce total system demand and help protect ratepayers against price volatility.[44] For example, FPL's "On Call" demand response program saved $429,000 in 2016[45] and could reduce summer peak demand 226 MW by 2022.[46]

- Investing in clean energy creates jobs for Floridians: Florida's clean energy industry

[38] STATE OF CHARGE: MASSACHUSETTS ENERGY STORAGE INITIATIVE STUDY (2016), at xvi-xvii, goo.gl/D3zviD; *see also* The Brattle Group, THE VALUE OF DISTRIBUTED ELECTRICITY STORAGE IN TEXAS PROPOSED POLICY FOR ENABLING GRID-INTEGRATED STORAGE INVESTMENTS (2014), at 14, goo.gl/fv2mYF.

[39] Energy Storage Ass'n., INCLUDING ADVANCED ENERGY STORAGE IN INTEGRATED RESOURCE PLANNING: COST INPUTS AND MODELING APPROACHES (Nov. 2016), at 5, goo.gl/Ao2HhS.

[40] Gavin Bade & Pete Maloney, *Tucson Electric signs solar + storage PPA for 'less than 4.5¢/kWh'*, UTILITYDIVE (May 23, 2017), goo.gl/SKrGGB.

[41] *See, e.g.,* Exhibit I: The Best Value for America's Energy Dollar—A National Review of the Cost of Utility Energy Efficiency Programs; SEE ACTION GUIDE FOR STATES: ENERGY EFFICIENCY AS A LEAST-COST STRATEGY TO REDUCE GREENHOUSE GASES AND AIR POLLUTION, AND MEET ENERGY NEEDS IN THE POWER SECTOR (2016), goo.gl/ZtQ7pc.

[42] Regulatory Assistance Project, RECOGNIZING THE FULL VALUE OF ENERGY EFFICIENCY (2013), at 41, goo.gl/APjr2s; Electric Power Research Institute, U.S. ENERGY EFFICIENCY POTENTIAL THROUGH 2035 (April 2014), goo.gl/LMfXrw.

[43] *See, e.g.*, NEEP Northeast Energy Efficiency Partnerships, ENERGY EFFICIENCY AS A T&D RESOURCE: LESSONS FROM RECENT U.S. EFFORTS TO USE GEOGRAPHICALLY (2015), at 12, goo.gl/AXRf3m.

[44] *See e.g.,* Steven Nadel, D*emand Response Programs Can Reduce Utilities' Peak Demand an Average of 10%, Complementing Savings from Energy Efficiency Programs*, AM. COUNCIL FOR AN ENERGY-EFFICIENT ECON. (Feb. 9, 2017), goo.gl/qXBnMQ.

[45] FPL, 2016 DSM Annual Report (Mar. 1, 2017), at 3, 9, goo.gl/sAB8TT.

[46] *Id.* Extrapolated based on ratio of 2016 summer peak demand reductions at generator from current program participants.

employs four times more workers than the fossil fuel sector.[47] A recent study showed that energy efficiency programs alone "could create 10,000 new jobs in Florida's energy efficiency sector."[48] Other states have experienced similar benefits: North Carolina's renewable energy policy "contributed to the creation of over 4,000 jobs and $2 billion in direct investment across the state."[49]

IV. The utilities must submit missing alternatives and analyses in future 10-Year Site Plans in a transparent and timely manner.

The 2017 Plans are plainly inadequate: For the plans to be "suitable," the utilities must submit sufficient information to allow the Commission to consider potential money-saving alternatives to the planned gas and coal generation. Presently the Commission cannot do so because such information is missing from the Plans and from the data responses provided to Commission Staff.

Accordingly, we urge the Commission to use the upcoming 10-Year Site Plan workshop as an opportunity to invite utilities and stakeholders to discuss plans for completing this analysis in a transparent and timely manner. To allow for meaningful stakeholder input, the Commission should make sure this information is included when the utilities submit their initial plans—i.e., April—so that stakeholders have time to evaluate, comment on, and influence the plans.[50]

CONCLUSION

The utilities fail to present the Commission with options allowing for least-cost comparison. These omissions violate the explicit regulatory requirement that the Commission "shall review"—" [p]ossible alternatives to the proposed plan[s]"[51] and preclude a determination that the utilities are meeting their obligation to provide least-cost service to Florida ratepayers.

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[47] Clean energy jobs include those associated with energy efficiency, wind, solar, storage, and smart grid technologies. Fossil fuel jobs include coal, oil, and gas jobs in both the electric sector and fuel extraction. *See* U.S. Dep't of Energy, 2017 U.S. ENERGY AND JOBS REPORT STATE CHARTS (Jan. 2017), at 56–61, goo.gl/1AzILd.

[48] Clean Jobs Florida, *Sizing Up Florida's Clean Energy Jobs Base and its Potential* (2014), at 5, goo.gl/Gqpmju.

[49] Community And Economic Development Program at UNC School of Government, *Solar Powers Economic Development in NC* (Mar. 3, 2016), goo.gl/o1hRLz.

[50] *See, e.g.*, Exhibit J: Best Practices in Electric Utility Integrated Resource Planning at 2 ("For an IRP process to be deemed successful, it should include both a meaningful stakeholder process and oversight from an engaged public utilities commission").

[51] Section 186.801(2), F.S.

Without detailed information on assumptions and alternatives, the Commission cannot fulfill its oversight duties. Every year that passes without plans for least-cost electric service further jeopardizes the competitiveness of Florida's economy and the well-being of its residents, including the millions of low- or fixed-income Floridians facing disproportionate energy burdens. Further, the absence of proper consideration and valuation of clean energy alternatives risks locking ratepayers into paying for expensive, risky, and polluting energy sources.

Thank you for your consideration.

Sincerely,

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List of Exhibits:

- Exhibit A: Planned Solar & Wind Generation Additions
- Exhibit B: Existing & Planned Battery Storage Projects
- Exhibit C: Planned Gas Burning Generation Additions
- Exhibit D: Existing Coal Burning Generation & Retirement Dates
- Exhibit E: Developer Interest in New Renewable Energy Projects
- Exhibit F: Next Best Alternatives to Planned Additions
- Exhibit G: Examples of Recent Southeast RFPs & PPAs for Renewables
- Exhibit H: Lazard's Levelized Cost of Energy Analysis
- Exhibit I: The Best Value for America's Energy Dollar—A National Review of the Cost of Utility Energy Efficiency Programs
- Exhibit J: Best Practices in Electric Utility Integrated Resource Planning
- Exhibit K: Sierra Club 2016 10-Year Site Plan Comments
- Exhibit L: Sierra Club 2015 10-Year Site Plan Comments
- Exhibit M: Sierra Club 2013 10-Year Site Plan Comments

Exhibit A

Exhibit A: Planned Solar & Wind Generation Additions

The table below reflects utility responses to Commission Staff's First Supplemental Data Request regarding planned solar and wind generation additions. The text of the relevant requests (nos. 25, 27, and 28) are reproduced below the table.

	DEF	FMPA	FPL	GRU	GULF	JEA	LAK	OUC	SEC	TAL	TECO
Planned Solar	754 MW (2017-2026)[1]	None	596 MW (2017-2018);[2] 596 MW (2019-2020);[3] 894 MW (2021-2023)[4]	None	1 MW (in-service date TBD)	None	None	0.28 MW (March 2017)	2.2 MW (April 2017)	None	19.36 MW (Feb. 2017)
Planned Wind	None	None	None	None	None	None	None	None	None	None	None
Ongoing Solar PPAs	None	None	None	18.6 MW (2032)	None	12 MW (2040)	0.25 MW (2030); 2.3 MW (2037); 3.0 MW (2027); 6.0 MW (2040); 0.553 MW (2029); 3.15 MW (2041)	5.1 MW (2031); 0.335 (2038); 0.268 MW (2038)	None	None	None
Ongoing Wind PPAs	None	None	None	None	178 MW (2035)	10 MW (2019)	None	None	None	None	None
Planned Solar PPAs	5 non-firm agreements of 50 MW each	None	None	None	120 MW (2017-2043)[5]	7 MW (2017-2042); 20 MW (2017-2037)[6]	None	8.89 MW (2017-2037)	None	0.85 MW (TBD-2020); 20 MW (2017-2037)	None
Planned Wind PPAs	None	None	None	None	94 MW (2017- 2035)	None	None	None	None	None	None

Sources: 2017 TYSP Plans from each utility. MW data describes "Installed Capacity."

[1] Total addition of 754 MW over 10 years through 12 different sites of varying capacities.

[2] 4 sites (74.5 MW each) are projected to enter into service in Dec. 2017; 4 sites (74.5 MW each) are projected to enter into service in March 2018; 1-2 more research sites are in early stage development, projected to enter into service in Jan. 2018.

[3] 2 sites (298 MW each), which will total 298 MW, "are in early planning stages with specific designs and locations not yet firm."

[4] 3 sites (298 MW each), which will total 894 MW, "are in early planning stages with specific designs and locations not yet firm."

[5] 3 different contracts of varying MW.

[6] 6 different contracts of varying MW.

Question #25: Please refer to the list of planned utility-owned renewable resources for the period 2017 through 2026 above. Discuss the current status of each project.

Question #27: Please identify and describe each purchased power agreement with a renewable generator that delivered energy during 2016. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

Question #28: Please identify and describe each purchased power agreement with a renewable generator that is anticipated to begin delivering renewable energy to the Company during the period 2017 and 2026. Provide the name of the seller, the name of the generation facility associated with the contract, the unit type of the facility, the fuel type, the facility's installed capacity (AC-rating for PV systems), the amount of contracted firm capacity (if any), and the start and end dates of the purchased power agreement.

Exhibit B

Exhibit B: Existing & Planned Battery Storage Projects

Mentions of battery storage projects in the 2017 10-Year Site Plans and in Responses to Commission Staff's Supplemental Data Requests are compiled below.

DEF

"As with all forecasts included here, the forecast relies heavily on the forward looking price for this technology, the value rendered by this technology, and considerations to other emerging and conventional cost effective alternatives, including the use of emerging battery storage technology."[1]

FMPA

No mention.

FPL

3 MW Battery Storage Pilot Program:

"The purpose of the Battery Storage Pilot Program is to demonstrate and test a wide variety of battery storage grid applications including peak shaving, frequency response, and backup power for FPL's system. In addition, the pilot program is designed to help FPL learn how to integrate battery storage into the grid and optimize control of these flexible resources. Under the pilot program, FPL has installed a 1.5 MW battery storage system in Miami-Dade County primarily for peak shaving and frequency response, a battery storage system of 1.5 MW in Monroe County for backup power and voltage support, and several smaller kilowatt-scale systems at other locations to study distributed storage reliability applications."[2]

50 MW Battery Storage Pilot Program:

"As part of the settlement agreement in FPL's 2016 base rate case, FPL has been authorized to pursue an additional 50 MW in grid-tied battery energy storage demonstration projects by 2020. FPL is in the midst of planning the details of this 50 MW pilot program. It is anticipated that FPL will target individual project sizes ranging from 1 to 10 MW each with various durations, which will enable FPL to test a wide range of applications. The majority of projects are intended to be distribution-interconnected and will test a mix of reliability applications (i.e., localized outage and momentary mitigation) together with generation related applications (i.e., peak shaving). Several battery projects will be co-located and paired with solar plants to explore ways to improve the integration of intermittent resources into

[1] DEF 2017 10-Year Site Plan, 3-23.
[2] FPL Response to Staff's First Supplemental Data Request, question no. 35.

FPL's grid. Specific project sites are in the process of being identified and future Ten-Year Site Plans will provide additional information as plans are finalized."[3]

Project	Location	Capacity (MW / MWh)	Cost ($MM)	Technology	Applications	Duty Cycle
CES – Palm Beach	12517 174th CT N, Jupiter FL 33475	0.025 / 0.05	$0.27	Li-Ion	Customer backup Peak Shaving	As-needed 4 hours
CES – Broward	3251 SW 142ND AVE. Davie FL 33330	0.025 / 0.05	$0.25	Li-Ion	Customer backup Peak Shaving	As-needed 4 hours
CES – Miami Dade	12061 West Okeechobee Road, Hialeah Gardens, FL 33018	0.025 / 0.05	$0.26	Li-Ion	Customer backup Peak Shaving	As-needed 4 hours
Florida Bay	11 Flamingo Lodge Hwy, Homestead, FL 33034	1.5 / 1.5	$3.25	Li-Ion	Backup Power Peak Shaving Voltage Regulation Frequency Response	As-needed 10 hours As-needed As-needed
Southwest	3925 SW 70th Ave, Miami, FL	1.5 / 4.0	$6.4	Recycled Li-Ion auto batteries	Peak Shaving Frequency Response	8 hours As-needed
Mobile	7300 Crandon Blvd, Key Biscayne, FL 33149 / 2400 NW 55th Ct, Fort Lauderdale, FL 33309	0.75 / 0.013	$1	Lead Acid	Momentary Mitigation Test Mobility	As-needed

[4]

Project	Location	Capacity (MW / MWh)	Cost ($MM)	Technology	Applications	Duty Cycle
Babcock Ranch	Co-located with Babcock Ranch Solar	10 / 40	$20	Li-Ion	AC-Coupled Design Firming Solar Generation Peak Shaving Regulation	TBD
Citrus	Co-located with Citrus Solar	4 / 16	$9	Li-Ion	DC-Coupled Design Firming Solar Generation Peak Shaving Regulation	TBD

[5]

GRU

"GRU has no existing or planned energy storage projects at this time."[6]

GULF

"Gulf Power's Training and Storm Center in Pensacola presently houses a two-year Southern Company energy storage battery research and development demonstration project in collaboration with the Electric Power Research Institute's Integrated Grid Initiative.

[3] *Id.*
[4] FPL Response to Staff's Second Data Request, question no. 1.
[5] *Id.*, question no. 3.
[6] GRU Response to Staff's Second Data Request, question no. 3.

The 250-kilowatt/1 megawatt-hour Tesla Powerpack lithium-ion battery energy storage system project will enable a better understanding of the siting, installation and operational requirements of commercial and industrial scale energy storage systems, as well as the value storage applications can offer customers and the energy provider through peak shaving, demand management, ancillary services, energy arbitrage and backup power. Key objectives of the project include:

- Demonstrate and validate performance of a commercial / industrial energy storage system
- Improve integration of distribution level energy storage technology
- Refine industry standards and best practice

Development, engineering and design was completed in 2016, and the construction and commissioning of the demonstration project was completed in July 2017."[7]

JEA

"JEA currently has no utility scale energy storage projects in our service territory. There are plans to incorporate a proposed 5 MWh Li-Ion battery storage unit with one of the solar PV facilities in our service territory, under a Purchase Power Agreement with the owner/operator. JEA will not own the storage unit. The primary purpose of the storage unit will be to smooth and firm the solar generation. At this time, all other project details are unknown."[8]

LAK

Energy Storage Solution Pilot:

"The City of Lakeland is constantly looking to provide its customer base with the highest value by offering creative solutions to improve reliability and efficiency. The COL is planning to deploy a pilot battery energy storage solution in 2017. The energy storage solution is intended to provide energy storage capability to shave customer's peak demand which can potentially lead to monetary savings."[9]

"Lakeland Electric is planning to utilize the alternative energy by participating in a pilot battery storage project. The objective to test the impact energy storage that might have on its local distribution system. Lakeland Electric is also exploring the benefits associated with 'peak shaving', shifting how and when you use electricity to lower the overall highest point or 'peak' demand required to power all of Lakeland Electric's territory.

[7] Gulf Power Company Response to Staff's Second Data Request, question no. 10.
[8] JEA Response to Staff's Second Data Request, question no. 6.
[9] Lakeland Electric, 2017 10-Year Site Plan, 4-13.

The project utilizes the Sunverge energy platform that consists of two 6 kW Schneider Electric inverters and two 19.4 kWh Kokam lithium-ion batteries that will provide 10kW for 3.3 hours at 5kW continuous output. Lakeland Electric chose the City of Lakeland's Beerman Family Tennis Center located at 1000 E Edgewood Drive. The goal is to gain a better understanding of the potential of this technology including curbing peak demand and financial savings. Battery storage units such as this, work well when integrated with photo voltaic systems which will charge the units during off peak period and allow them to discharge to the customer during mid and on peak times. In our pilot program, we will charge the units from the distribution grid during off-peak hours and discharge daily during on-peak hours. Our unit will also serve as a back-up power supply if there is an outage on the distribution grid.

The useful life for this product is estimated to be 15-20 years depending on the frequency and level on charging/discharging. The total estimated cost for acquiring and installing the system is $62,000."[10]

OUC

"OUC is planning to install a 500 kWh battery energy storage system (BESS) for its planned microgrid in 2018. The battery chemistry is anticipated to be lithium-ion and have an estimated life of 10 years. The intended use for the BESS will be peak-shaving. Other operational parameters and cost are not known at this time."[11]

SEC

"Seminole does not currently have nor is planning for any energy storage projects."[12]

TAL

"The City of Tallahassee, Electric Utility has no existing or planned energy storage projects at this time."[13]

TECO

"Tampa Electric is currently exploring the feasibility and potential for both supply side and demand side energy storage projects.

Supply Side: Tampa Electric monitors and investigates the value that could be gained from battery storage systems. Leveraging these systems could provide system benefits for customers like: operational reserve, energy arbitrage, frequency regulation, voltage support,

[10] Lakeland Response to Staff's Second Data Request, question no. 5.
[11] OUC Response to Staff's Second Data Request, question no. 2.
[12] SEC Response to Staff's Second Data Request, question no. 5.
[13] City of Tallahassee Response to Staff's Second Data Request, question no. 1.

black start, resource adequacy, transmission congestion relief, transmission deferral and distribution deferral. In addition, the company is in discussions with major battery storage suppliers/integrators investigating pairing battery storage with utility scale photovoltaic ('PV') arrays. These pairings would be for future utility scale PV projects and are studying the feasibility and potential. Because these are in the early stage of study, the size, location and number of battery storage pairings is undetermined at this time.

Demand Side: Tampa Electric is currently in the process of conducting a Research and Development ("R&D") project to evaluate the feasibility of potentially offering a battery storage Demand Side Management ("DSM") program for commercial/industrial customers. The battery storage R&D project will be evaluated through research and field study with at least one battery being installed at a commercial/industrial customer's facility. To assist in the performance of this R&D project, Tampa Electric has partnered with the University of South Florida's College of Engineering. Tampa Electric has specified the size of battery for this R&D project to be between 10 kW and 150 kW with the project from inception to completion lasting approximately three years which would afford this program to become a DSM program within the company's future 2020-2029 DSM Plan if the results are positive. This R&D project is projected to cost approximately $250,000 with the following objectives:

- Evaluate the potential for battery storage for the use of load shifting on demand savings.
- Evaluate the efficiency of load shifting from a battery storage system and the associated control and monitoring system.
- Evaluate the impact on the total energy consumption of the battery and facility when used in a load shifting capacity (versus reliability).
- Evaluate and compare batteries based on performance and cycling tolerance when used in Florida's climate.
- Examine the associated costs from cradle to disposition of battery.
- Evaluate the load profile impact on power vs. capacity tradeoffs."[14]

[14] TECO Response to Staff's Second Data Request, question no. 14.

Exhibit C

Exhibit C: Planned Gas Burning Generation Additions

Per the 10-Year Site Plans filed on April 1, 2017, Florida utilities plan to add electric generating units that primarily burn gas, as shown in the table below.[1]

Utility Owner/Operator	Unit	Unit Type	Capability (MW)[2]	Projected service date
FPL	Okeechobee Energy Center	CC	1,748	2019 (Q2)
	Dania Beach (a.k.a., Lauderdale Modernization)	CC	1,163	2022 (Q2)
	Gas Plant Upgrades: Ft. Meyers, Lauderdale, Manatee, Martin, Sanford, Turkey Point	CT/CC	211	2017-2019
DEF	Osprey	CC	313	2023 (Q2)
	Location Unknown	CT	228	2024 (Q2)
	Location Unknown	CT	228	2025 (Q2)
	Location Unknown	CT	228	2026 (Q2)
GULF	Location Unknown	CT	654	2023 (Q2)
	Location Unknown	CT	654	2023 (Q2)
	Location Unknown	CT	654	2023 (Q2)
TECO	Location Unknown	CT	204	2021 (Q2)
	Location Unknown	CT	204	2024 (Q2)
JEA	N/A		N/A	N/A
LAK	N/A		N/A	N/A
OUC	Location Unknown	CC	360	2022 (Q2)
FMPA	N/A		N/A	N/A
TAL	Sub 12 DG No. 1	IC	18	2018 (Q3)
	Sub 12 DG No. 2	IC	18	2018 (Q3)
	Hopkins IC No. 1	IC	74	2018(Q4)
	Hopkins IC No. 2	IC	74	2018(Q4)
	Hopkins IC No. 3	IC	74	2018(Q4)
	Hopkins IC No. 4	IC	74	2018 (Q4)
	Hopkins IC No. 5	IC	18	2024 (Q2)
GRU	N/A		N/A	N/A
SEC	Seminole No. 1	CC	593	2021 (Q2)
	Location Unknown	CC	593	2022 (Q4)
	Location Unknown	CT	215	2024 (Q4)
	Location Unknown	CT	215	2027 (Q4)
	Location Unknown	CT	215	2027 (Q4)

[1] The data in the table above reflects information submitted to the Commission in Schedules 8 and 9 of the 2017 Plans.
[2] Capability reflects summer MW capability as reported by the utilities.

Exhibit D

Exhibit D: Existing Coal Burning Generation & Retirement Dates

Per the plans filed on April 1, 2017, Florida utilities own or operate coal-burning electric generating units and project retirement dates for those units as shown in the table below.[1]

Utility Owner/Operator	Unit	Capacity (MW)[2]	Projected retirement date
FPL-JEA	St. Johns No. 1 (a)	136	2019 (Q1)
	St. Johns No. 2 (a)	136	2019 (Q1)
DEF	Crystal River No. 1	441	2018 (Q2)
	Crystal River No. 2	524	2018 (Q2)
	Crystal River No. 4	739	N/A
	Crystal River No. 5	739	N/A
GULF	Crist No. 4	94	2024 (Q4)
	Crist No. 5	94	2026 (Q4)
	Crist No. 6	370	2035 (Q4)
	Crist No. 7	578	2038 (Q4)
	Daniel No. 1 (b)	274	2042 (Q4)
	Daniel No. 2 (b)	274	2046 (Q4)
	Scherer No. 3 (c)	223	2052 (Q4)
TECO	Big Bend No. 1	446	N/A
	Big Bend No. 2	446	N/A
	Big Bend No. 3	446	N/A
	Big Bend No. 4	486	N/A
	Polk No. 1	326	N/A
JEA	St. Johns No. 1 (d)	680	2018 (Q1)
	St. Johns No. 2 (d)	680	2018 (Q1)
	Scherer No. 4 (e)	990	N/A
LAK-OUC	C.D. McIntosh, Jr. No. 3 (f)	219	N/A
OUC-FMPA	Stanton No. 1 (g)	465	N/A
	Stanton No. 2 (h)	465	N/A
GRU	Deerhaven No. FS02	228 (i)	2031
SEC	Seminole No. 1	736	N/A
	Seminole No. 2	736	N/A

(a) FPL owns 20% of St. Johns No. 1 & 2.
(b) Gulf Power owns 50% of Daniel No. 1 & 2 (located in Mississippi).
(c) Gulf Power owns 25% of Scherer No. 3 (located in Georgia).
(d) JEA owns 80% of St. Johns No. 1 & 2.
(e) JEA owns 23.64% of Scherer No. 4
(f) LE owns 60% and OUC owns 40% of C.D. McIntosh, Jr. No. 3.
(g) OUC owns 68.6% of Stanton No. 1
(h) OUC owns 71.6% of Stanton No. 2.
(i) Net summer capability.

[1] The data in the table above reflects information submitted to the Commission in Schedule 1 of the 2017 Plans.
[2] Capability reflects "Gen. Max. Nameplate" as reported by the utilities.

Exhibit E

Exhibit E: Developer Interest in New Renewable Energy Projects

The below quotes describe each utility's interactions with renewable energy contractors. The text is from responses to question no. 36 of the Commission Staff's First Supplemental Data Request.

Question #36: Please discuss whether the Company has been approached by renewable energy generators during 2016 regarding constructing new renewable energy resources. If so, please provide a description of the number and type of renewable generation represented.

DEF
"DEF has officially recorded over 24 requests from potential renewable energy providers through DEF's Request for Renewables program and DEF has undertaken many more phone conversations. As the cost of solar PV technology continues to drop, there has been more interest from developers utilizing this technology. This interest can be seen in the dramatic increase in interconnection requests that DEF has received from solar PV projects. DEF currently has over 2,100 MW in the DEF interconnection queues in Florida. DEF continues to educate renewable energy generators on the potential QF structure and pricing of a renewable power purchase agreement. Most of the inquiries during 2016 were for solar photovoltaic projects, but there were also some inquiries regarding biomass, landfill gas and marine energy projects."

FMPA
"FMPA is routinely approached by renewable energy generators and we view discussions with these entities as a way to stay on top of market developments. During 2016, we met face to face or had conference calls with ten developers. Most of the developers were focused on promoting solar photovoltaic technology projects with one case focusing on solar with battery backup. Two developers also approached FMPA with wind energy generation opportunities."

FPL
"FPL frequently receives inquiries from developers of potential renewable facilities throughout its service territory. Most of these developers are less sophisticated and are interested in obtaining information as to the process necessary to develop a renewable facility selling to FPL, and are provided information on our various tariffs applicable to renewables, current avoided costs, and the interconnection process. Very rarely does the process go further.

Two proposed projects, however, have proceeded at least as far as a system impact study for interconnection. Both projects are solar photovoltaic. One project is for 20 MW in Putnam County, the other for 60 MW in Baker County. Both have indicated an on-line date in late 2018. Neither project has started discussion with FPL regarding a formal power purchase agreement; although as solar generators they would have the right to sell to FPL under our COG-1 tariff."

GRU
"GRU was not approached by renewable energy generators in 2016."

GULF
"Gulf routinely fields inquiries from outside entities regarding the potential development of renewable projects in the area served by Gulf. To date, there have been no conclusive results from any of these discussions."

JEA
"Through the Solar PV Policy RFP process discussed in question 35; JEA received more than 30 proposals for Solar PV power from 14 companies. Those renewable energy generators in which JEA signed purchased power agreements are shown in question 28."

LAK
"Renewable developers occasionally contact the utility in attempts to enter into renewable energy contracts, usually in the form of a long term PPA for electricity generated by solar or a biofuel. There is no tracking system in place to measure the frequency or quantity of these callers."

OUC
"OUC was not approached by renewable energy generators with unsolicited proposals to construct renewable energy resources in 2016."

SEC
"Seminole issued a RFP in March 2016 for 600 MW of capacity and energy starting in June 1, 2021 up to 1000 MW of capacity and energy by 2022. As a result of this process, Seminole received numerous offers from companies with solar photovoltaic technology to build and place facilities in service by June 2021 (or earlier). Seminole also received RFP responses from biomass (wood waste and landfill gas) and wind facilities. Seminole is still reviewing the solar photovoltaic responses and expects to make a renewable recommendation to its Board of Trustees in 3Q 2017."

TAL

"For calendar year 2016, TAL was approached by four different renewable energy generators. Of the four, three were offering solar PV from 10-20 MW capacity, and one was offering up to 100 MW of wind energy from the panhandle of Oklahoma via the Plains and Eastern Transmission Line."

TECO

"Numerous renewable energy developers contacted Tampa Electric Company in 2016 regarding utility-scale renewable construction. The discussions focused on solar primarily and, less frequently, wind energy. Some of the developers were large, experienced companies, while other businesses were much smaller in scale. Although TEC does not have the exact number of company contacts in 2016, the number of company contacts was about ten (10)."

Exhibit F

Exhibit F: Next Best Alternatives to Planned Additions

The below quotes describe each utility's investigation of next best alternatives for planned generating units. The selected text is from responses to request no. 42 of the Commission Staff's First Supplemental Data Request.

Question #42: For each of the planned generating units contained in the Company's Ten-Year Site Plan, please identify the next best alternative that was rejected for each unit. Provide information similar to Schedule 9 regarding each of the next best alternative unit(s). As part of this response, please also provide the additional revenue requirement that would have been associated with the next best alternative compared to the planned unit.

DEF

"DEF's next best alternative to the 2017 TYSP alternative units included replacing 685 MW of Combustion Turbine capacity (or 3 Combustion Turbine Units) with an in-service date of 6/2024, 6/2025 and 5/2026 with a 1,151 MW Combined Cycle Unit with an in-service date of 6/2024. The following requested information, per Q42, includes similar information to Schedule 9 that is followed by the additional revenue requirements of the next best alternative containing the 1,152 MW Combine [*sic*] Cycle.

DUKE ENERGY FLORIDA
SCHEDULE 9
STATUS REPORT AND SPECIFICATIONS OF PROPOSED GENERATING FACILITIES AS OF JANUARY 1, 2017

(1)Plant Name and Unit Number:	**Undesignated Combined Cycle**
(2)Capacity	
a. Summer:	1151
b. Winter:	1241
(3)Technology Type:	COMBINED CYCLE
(4)Anticipated Construction Timing	
a. Field construction start date:	1/2021
b. Commercial in-service date:	6/2024
(5)Fuel	
a. Primary fuel:	NATURAL GAS
b. Alternate fuel:	DISTILLATE FUEL OIL
(6)Air Pollution Control Strategy:	SCR and CO Catalyst
(7)Cooling Method:	Cooling Tower

(8)Total Site Area:	UNKNOWN	ACRES
(9)Construcion [*sic*] Status:	PLANNED	
(10)Certificaion [*sic*] Status:	PLANNED	
(11)Status wih [*sic*] Federal Agencies:	PLANNED	
(12)Projected Unit Performance Data		
a. Planned Outage Factor (POF):		690%
b. Forced Outage Factor (FOF):		4.60%
c. Equivalent Availability Factor (EAF):		8882%
d. Resulting Capacity Factor (%):		63.3%
e. Average Net Operaing [*sic*] Heat Rate (ANOHR):		6,527BTU/kWh
(13)Projected Unit Financial Data		
a. Book Life (Years):		35
b. Total Installed Cost (In-service year $/kW):		1160
c. Direct Construction Cost ($/kW): ($2017)		940
d. AFUDC Amount ($/kW):		66
e. Escalation ($/kW):		155
f. Fixed O&M ($/kW-yr): ($2017)		523
g. Variable O&M ($/MWh): ($2017)		2.11
h. K Factor:	NO CALCULATION	

NOTES
Total Installed Cost includes gas expansion, transmission interconnecion[*sic*] and integration
$/kW values are based on Summer capacity
Fixed O&M cost does not include firm gas transportation costs

	2017 TYSP Revenue Requirements		Suboptimal - Optimal
CPVRR $K	$35,074,440	$35,280,092	$205,653
Nominal $K	Optimal Plan 2024 CT, 2025 CT, 2026 CT	Suboptimal Plan 2024 CC	Difference
2017	3,993,907	3,993,907	-
2018	4,159,665	4,159,665	-
2019	4,284,308	4,284,308	-
2020	4,489,576	4,489,576	-
2021	4,650,582	4,650,582	-
2022	4,890,000	4,890,000	-
2023	5,026,391	5,111,193	84,803
2024	4,990,529	5,134,198	143,669
2025	5,327,540	5,438,519	110,979
2026	5,489,647	5,476,929	(12,718)

,,

FMPA
"FMPA currently has no planned generating units identified in the Ten-Year Site Plan."

FPL
"FPL interprets the question to exclude planned generating units that have received FPSC approval for determination of need or cost recovery and which would have been reviewed on the basis, among other factors, of alternatives considered.

The units/additions presented in the 2017 Ten-Year Site Plan that have not yet received FPSC approval for determination of need or cost recovery include:

- PV annual additions of approximately 298 MW in each of the years 2017 through 2023; and,
- The Lauderdale modernization planned for mid- 2022.

In regard to the 2017 through 2023 PV additions, these additions are based not on meeting a projected specific resource need, but rather on analyses that projected these PV facilities would be economic for FPL's customers compared to not adding the PV. FPL provided the projected economics of the 2017 and 2018 PV additions versus no PV in the Solar Base Rate Adjustment filing with the FPSC in the 1st Quarter of 2017.

Similarly the planned Lauderdale modernization is not based on meeting a projected specific resource need, but on analyses that projected the retirement of the existing Lauderdale Units 4 & 5, followed by the addition of a new combined cycle unit at the site, would be economic for FPL's customers compared to not retiring the existing units and not replacing them with a new combined cycle. FPL's customers are currently projected to benefit by approximately $400 million CPVRR by this retirement and replacement."

GRU
"The planned reciprocating unit is installed in a combined heat and power application. GRU looked at other reciprocating units as well as small gas turbines for this application, but the planned unit had the best overall fit for GRU's customer's needs. As the costs associated with this unit will be recovered from one particular costs, the additional revenue requirement is not applicable to GRU's other electric customers."

GULF
"Gulf's current estimate of the cumulative present value revenue requirements for the best alternative generating unit addition, a combined cycle facility, is $933 million.

PLANT TYPE:	2-on-1 Combined Cycle, Gas-Only
NET CAPACITY (MW)	788
BOOK LIFE (Years):	40
IN-SERVICE YEAR:	2023"

JEA

"JEA has no generating unit additions planned in this TYSP."

LAK

"None."

OUC

"OUC has not made any commitments to development of the new generating unit identified in the 2017 10-Year Site Plan. The unit addition shown in the 2017 10-Year Site Plan is a placeholder in order to maintain projected reserve margin requirements. As such, no next best alternative was rejected."

SEC

"For long-term planning, Seminole currently meets all additional needs with generic unit placeholders. These placeholders are modeled with information obtained from Thermoflow's GT-Pro, GT-Master and Peace software packages. The inclusion of these units does not represent a commitment for construction by Seminole. A formal RFP process began in March of 2016 and detailed assessments of offers to satisfy the 2021 need are in process with a completion target of 12/31/2017."

TAL

"TAL did not evaluate each of the unit additions in the 2017 TYSP Schedule 9 forms individually but instead evaluated different combinations of these units as alternative expansion plans. The evaluation was not intended to consider a wide array of potential generation technologies and combustion fuels but instead to evaluate replacing retiring older, gas-fired generating units with new gas-fired reciprocating internal combustion engine (RICE) generating units to provide a more diverse capacity mix, improved efficiency, greater commitment/dispatch flexibility and lower emissions profiles. Under this evaluation approach the "next best alternative" for each of the planned units would best be described as follows:

- Schedule 9A - For the 2018 addition of two (2) 9 MW Wartsila 20V34SG unit additions planned for construction at Substation 12 TAL did not identify any generation alternatives that were considered viable or acceptable due to siting constraints. A transmission alternative was considered but, due to the density of businesses, residences and roadways in the area, this alternative was dismissed as not cost feasible.

- Schedule 9B - For the 2018 addition of four (4) 18 MW Wartsila 18V50SG units at TAL's existing Hopkins Plant site the next best alternative of the units evaluated would have been the Wartsila 20V34SG. Given that the Wartsila 20V34SG has a capacity of 9 MW versus and the Wartsila 18V50SG units has a capacity of 18 MW, a total of eight (8) 9 MW Wartsila 20V34SG unit additions would have to instead been planned for addition at Hopkins. The per unit information for the alternative addition of the Wartsila 20V34SG is identical to that provided on Schedule 9A.

- Schedule 9C - The proposed 2024 addition of one (1) 18 MW Wartsila 18V50SG unit at Hopkins is considered a 'placeholder' pending future analysis. It is acknowledged that the number, timing, site, type and size of the 2024 resource addition may vary as the nature of the need becomes better defined. Alternatively, this proposed addition could be a generator(s) of a different type/size at the same or different locations or a peak season purchase.

The generation expansion plan alternative with the next lowest evaluated CPWRR for 2018-2045 was very similar to the base plan reflected in TAL's 2017 TYSP. The only difference in the next best alternative generation expansion plan was that the 2024 addition in the base plan was advanced to 2018. This alternative's CPWRR for 2018-2045 was estimated as $1.886 billion, or a CPWRR difference of about $5 million."

TECO

"The next best alternative to TEC's current planned generating units would have been a simple cycle combustion turbine in 2021. The estimated cumulative present revenue requirements for this unit would have been $567,385,000 more than TEC's current plan.

Incremental RR from 2017 TYSP Base Case	
Capital Revenue Requirements	360,255
Variable O&M	190,273
Fixed O&M	16,857
CPWRR (2016 $000)	567,385

Next best alternative: GE Simple Cycle LMS 100
Net Capability:
A. Summer: 101 MW
B. Winter: 91.2 MW
Technology Type: Simple Cycle
Estimated construction timing: 24+ from start date
Fuel: NG
Planned Outage Factor: 3.0%
Forced Outage Rate: 2.0%
Equivalent Availability Factor: 52.3%
Average Net Operating Heat Rate: 9,010 Btu/kWh
Book Life: 30
Total Installed Cost (In-Service Year $/kW): 1,404.0
Direct Construction Cost ($/kW): 1,163.4
AFUDC Amount ($/kW): 84.78
Escalation ($/kW): 155.85
Fixed O&M ($/kW-yr.): 18.90
Variable O&M ($/MWh): 0.89
K-Factor: 1.4823"

Exhibit G

Exhibit G: Examples of Recent Southeast RFPs & PPAs for Renewables

State	Utility	Project	Energy Source	Cost	Capacity	Date
Alabama	Alabama Power	Alabama Power plans to procure up to 500 MW of renewable energy from 80 MW or smaller facilities[1] and received over 200 bids.[2]	Solar, hydro, biomass		500 MW	Mar. 2019
		Anniston Army Depot[3]	Solar	$23 Million	7 MW	Apr. 2017
		Fort Rucker[4]	Solar	$25 Million	10 MW	Apr. 2017
		Redstone Arsenal[5]	Solar		10 MW	Late 2017
		LaFayette[6]	Solar	$140 million	72 MW	Dec. 2017
Arkansas	Entergy Arkansas	2016 EAI RFP for Long-Term Renewable Generation Resources[7]	Solar PV, wind, hydro, biomass		100 MW	2018
		The 2014 EAI RFP[8] received 28 proposals and resulted in a 20-year PPA for the Stuttgart Solar Project[9]	Solar, wind		81 MW	2018
Georgia	Georgia Power	2013 Advanced Solar Initiative[10]	Solar	<8.5 cents/kWh	50 MW	2016
		2014 Advanced Solar Initiative and IRP[11]	Solar	<6.5 cents/kWh	515 MW	2016

		Advanced Solar Initiative Distribution Generation Program[12]	Solar		190 MW	Late 2017
		Renewable Energy Development Initiative (REDI)[13]	Solar, wind, biomass, biogas		1,050 MW utility-scale, 100 MW DG	Georgia Power will conduct two 525 MW utility-scale RFPs in 2017 and 2019
Kentucky	KyMEA	2017 Renewable Capacity and Energy Procurement, 10- to 20-year PPA[14]	Solar PV, wind		50 MW	2019 – 2022
Louisiana	Entergy Louisiana	2016 Request for Proposals for Long-Term Renewable Generation Resources[15]	Solar PV, solar thermal, wind, biomass, hydro		200 MW	20-year PPA starting by 2020
Mississippi	South Mississippi Electric Power Association	2015 RFP for a 20-year PPA and up to 250 MW of capacity from wind resources[16]	Wind		250 MW	
North Carolina	Duke Energy Carolinas	Duke Energy 2017 Wind RFP[17]			500 MW	2022
		DEC 2016 Renewables RFP[18]	Solar, wind, biomass, landfill gas		750,000 MWh	Dec. 2018

	City of Raleigh	RFP sought proposals to own, install, operate, and maintain solar systems on 53 acres of city-owned land[19]	Solar	Land is being leased for $87,500/ year	13 MW	2018
	Avangrids Renewables	Amazon Wind Farm US East [20]	Wind	$400 million	208 MW	2016
	NC Green Power	Dec. 2015 RFP,[21] seeking contracts for a one- to two-year term	Solar PV, wind, small hydro (<10 MW), biomass		70,000 MWh	
		Oct. 2014 RFP,[22] seeking contracts for a one- to two-year term	Solar PV, wind, small hydro (<10 MW), biomass		40,000 MWh	
South Carolina	Duke Energy	Duke Energy 2015 Solar RFP[23]	Solar		53 MW utility-scale, 5 MW Shared Solar Program	2016
	South Carolina Electric & Gas Company	SCE&G 2015 Solar RFP[24]	Solar		30 MW	Late 2016
		SCE&G 2014 Solar RFP[25]	Solar		3-4 MW	2015
Tennessee	Tennessee Valley Authority	TVA Request for Pricing for Solar Power Agreements[26]	Solar		80 MW	2018

	EPB	Solar Share Pilot Project[27]	Solar		1.35 MW	2017
Virginia	Appalachian Power Company	2015 Solar RFP[28]	Solar		10 MW	Dec. 2017
Multiple States	Appalachian Power Company	2017 RFP for Virginia or West Virginia[29]	Solar		25 MW	Dec. 2019
		Bluff Point Wind Energy Center,[30] for Virginia, West Virginia, and Tennessee	Wind	$200 million	120 MW	2018
	SWEPCO	2016 Wind RFP[31] for Arkansas, Louisiana, and Texas	Wind		Up to 100 MW	Dec. 2018

[1] goo.gl/uf5Ffm.
[2] goo.gl/icxhHV.
[3] goo.gl/CPGLZK; goo.gl/EbwCRv.
[4] goo.gl/CPGLZK; goo.gl/Buf4h9.
[5] goo.gl/CPGLZK; goo.gl/xba7ZP.
[6] goo.gl/BfX1vi; goo.gl/IMi0G2.
[7] goo.gl/kRTM8z.
[8] goo.gl/1EjszM.
[9] goo.gl/o6T2iA.
[10] goo.gl/ZBrDfc.
[11] *Id.*
[12] *Id.*
[13] *Id.*
[14] goo.gl/DEvfkq.
[15] goo.gl/1jTkyt.
[16] goo.gl/ds51gU.
[17] goo.gl/xNLLcg.
[18] goo.gl/STfN6C.
[19] goo.gl/qLi1no.
[20] goo.gl/xzFmsW; goo.gl/1xgYym.
[21] goo.gl/QevrwT.
[22] goo.gl/MrxUU2.
[23] goo.gl/19pkRA.
[24] goo.gl/fiwnWP.
[25] goo.gl/LEmyJD.

[26] goo.gl/RXJPzv.

[27] goo.gl/kthBka; goo.gl/R1R597.
[28] goo.gl/vGg2EW.
[29] goo.gl/3a97fn.
[30] goo.gl/9G2oPz; goo.gl/MiK8Y3.
[31] goo.gl/gcwdNv.

Exhibit H

LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 10.0

LAZARD

Introduction

Lazard's Levelized Cost of Energy Analysis ("LCOE") addresses the following topics:

- **Comparative "levelized cost of energy" analysis for various technologies on a $/MWh basis, including sensitivities, as relevant, for U.S. federal tax subsidies, fuel costs, geography and cost of capital, among other factors**
- **Comparison of the implied cost of carbon abatement for various generation technologies**
- **Illustration of how the cost of various generation technologies compares against illustrative generation rates in a subset of the largest metropolitan areas of the U.S.**
- **Illustration of utility-scale and rooftop solar versus peaking generation technologies globally**
- **Illustration of how the costs of utility-scale and rooftop solar and wind vary across the U.S., based on illustrative regional resources**
- **Illustration of the declines in the levelized cost of energy for various generation technologies over the past several years**
- **Comparison of assumed capital costs on a $/kW basis for various generation technologies**
- **Illustration of the impact of cost of capital on the levelized cost of energy for selected generation technologies**
- **Decomposition of the levelized cost of energy for various generation technologies by capital cost, fixed operations and maintenance expense, variable operations and maintenance expense, and fuel cost, as relevant**
- **Considerations regarding the usage characteristics and applicability of various generation technologies, taking into account factors such as location requirements/constraints, dispatch capability, land and water requirements and other contingencies**
- **Summary assumptions for the various generation technologies examined**
- **Summary of Lazard's approach to comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies**

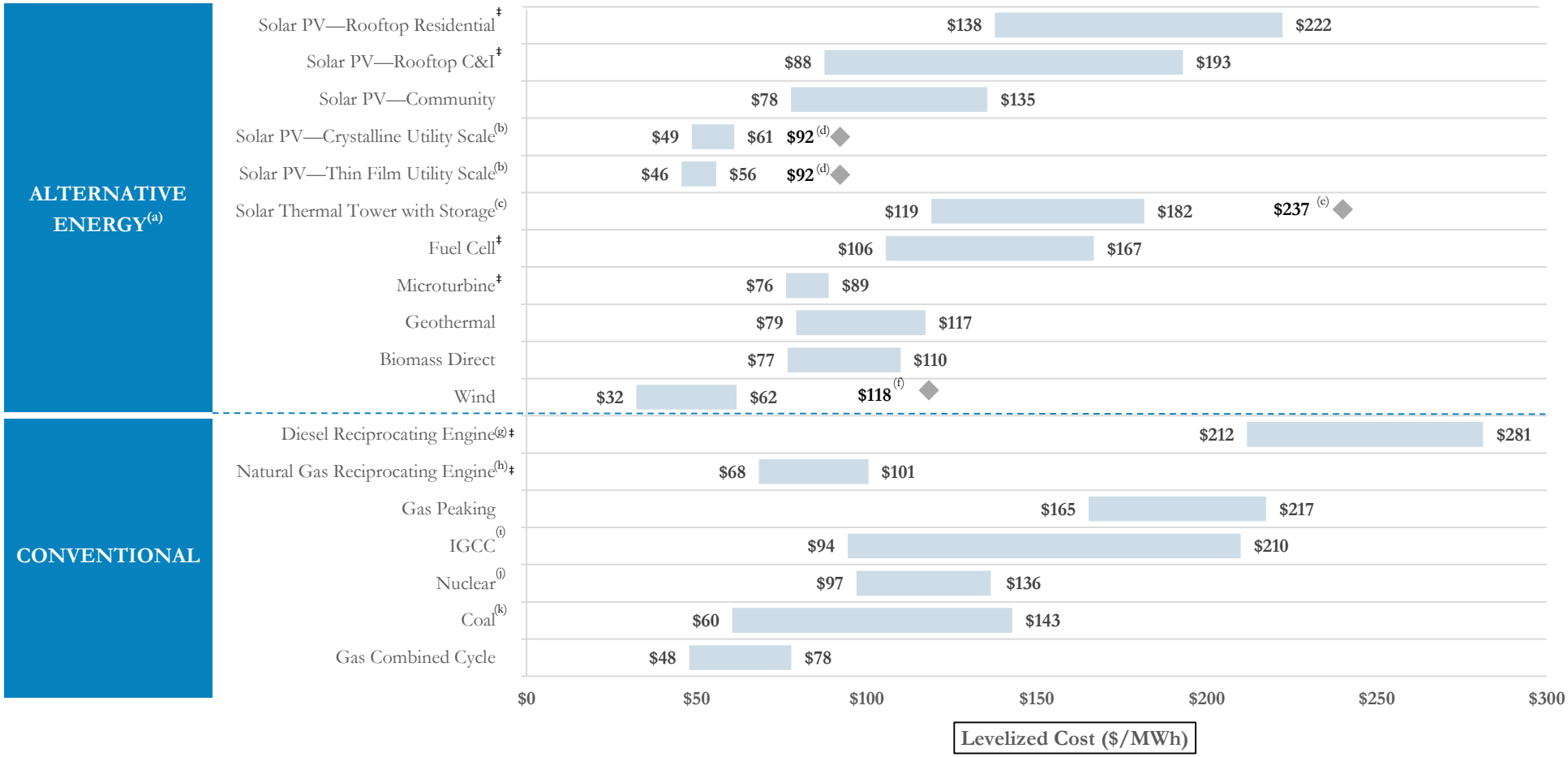
Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission or congestion costs or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets, emissions control systems). The analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, environmental impacts, etc.)

While prior versions of this study have presented the LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 10.0 present the LCOE on an unsubsidized basis, except as noted on the page titled "Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies"

 Note: This study has been prepared by Lazard for general informational purposes only, and it is not intended to be, and should not be construed as, financial or other advice.

Unsubsidized Levelized Cost of Energy Comparison

Certain Alternative Energy generation technologies are cost-competitive with conventional generation technologies under some scenarios; such observation does not take into account potential social and environmental externalities (e.g., social costs of distributed generation, environmental consequences of certain conventional generation technologies, etc.), reliability or intermittency-related considerations (e.g., transmission and back-up generation costs associated with certain Alternative Energy technologies)



Source: *Lazard estimates.*

Note: Here and throughout this presentation, unless otherwise indicated, analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost for conventional and Alternative Energy generation technologies. Reflects global, illustrative costs of capital, which may be significantly higher than OECD country costs of capital. See page 15 for additional details on cost of capital. Analysis does not reflect potential impact of recent draft rule to regulate carbon emissions under Section 111(d). See pages 18–20 for fuel costs for each technology. See following page for footnotes.

‡ Denotes distributed generation technology.

Unsubsidized Levelized Cost of Energy Comparison (cont'd)

(a) Analysis excludes integration (e.g., grid and conventional generation investment to overcome system intermittency) costs for intermittent technologies.

(b) Low end represents single-axis tracking system. High end represents fixed-tilt design. Assumes 30 MW system in a high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients within technologies, balance-of-system costs or other potential factors which may differ across select solar technologies or more specific geographies.

(c) Low end represents concentrating solar tower with 18-hour storage capability. High end represents concentrating solar tower with 10-hour storage capability.

(d) Illustrative "PV Plus Storage" unit. PV and battery system (and related mono-directional inverter, power control electronics, etc.) sized to compare with solar thermal with 10 hour storage on capacity factor basis (52%). Assumes storage nameplate "usable energy" capacity of ~400 MWh_{dc}, storage power rating of 110 MW_{ac} and ~200 MW_{ac} PV system. Implied output degradation of ~0.40%/year (assumes PV degradation of 0.5%/year and battery energy degradation of 1.5%/year, which includes calendar and cycling degradation). Battery round trip DC efficiency of 90% (including auxiliary losses). Storage opex of ~$10/kWh-year and PV O&M expense of ~$9.2/kW DC-year, with 20% discount applied to total opex as a result of synergies (e.g., fewer truck rolls, single team, etc.). Total capital costs of ~$3,900/kW include PV plus battery energy storage system and selected other development costs. Assumes 20 year useful life, although in practice the unit may perform longer. Illustrative system located in U.S. Southwest.

(e) Diamond represents an illustrative solar thermal facility without storage capability.

(f) Represents estimated implied midpoint of levelized cost of energy for offshore wind, assuming a capital cost range of $2.75 – $4.50 per watt.

(g) Represents distributed diesel generator with reciprocating engine. Low end represents 95% capacity factor (i.e., baseload generation in poor grid quality geographies or remote locations). High end represents 10% capacity factor (i.e., to overcome periodic blackouts). Assumes replacement capital cost of 65% of initial total capital cost every 25,000 operating hours.

(h) Represents distributed natural gas generator with reciprocating engine. Low end represents 95% capacity factor (i.e., baseload generation in poor grid quality geographies or remote locations). High end represents 30% capacity factor (i.e., to overcome periodic blackouts). Assumes replacement capital cost of 65% of initial total capital cost every 60,000 operating hours.

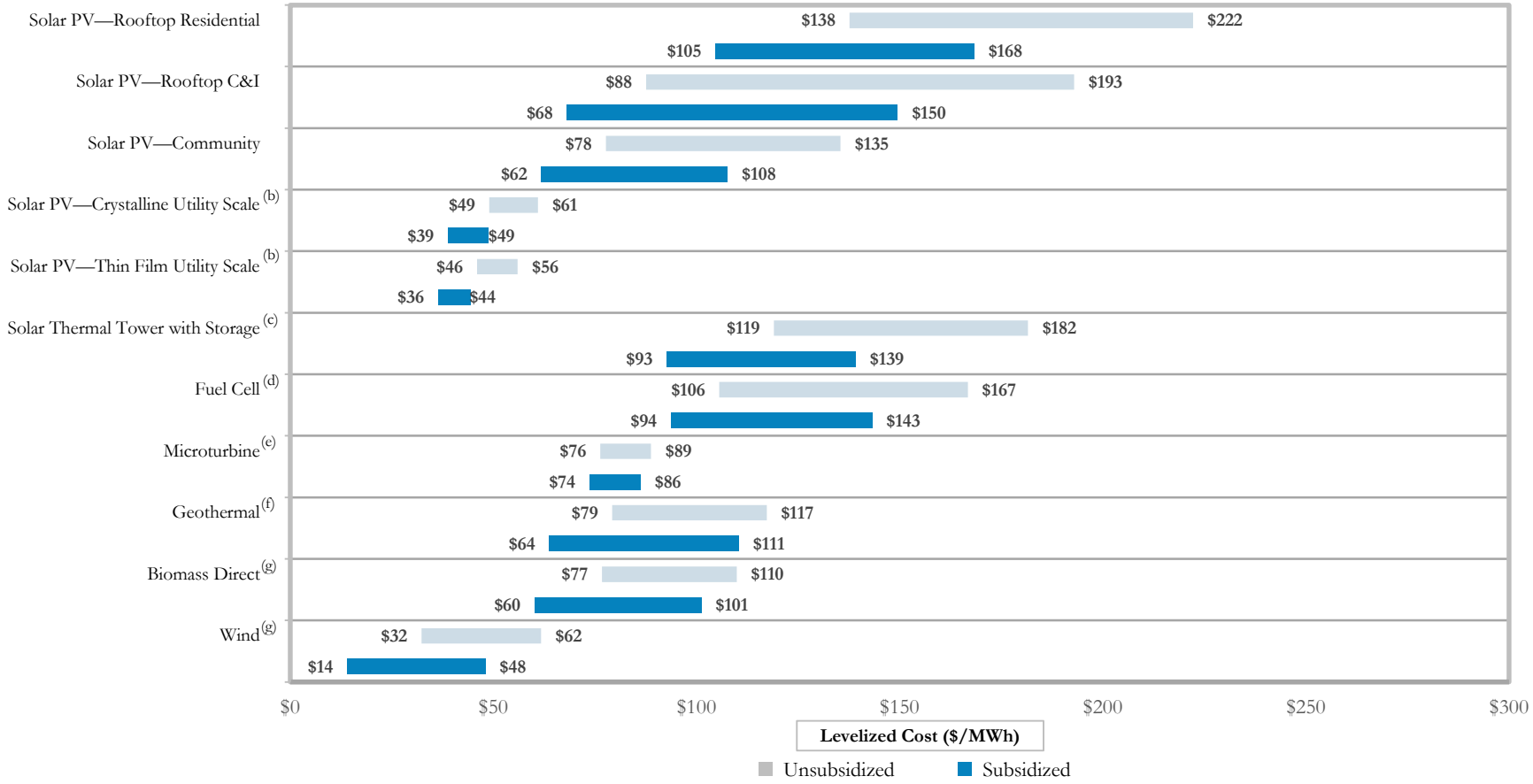
(i) Does not include cost of transportation and storage.

(j) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(k) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Levelized Cost of Energy—Sensitivity to U.S. Federal Tax Subsidies[(a)]

Given the extension of the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") in December 2015 and resulting subsidy visibility, U.S. federal tax subsidies remain an important component of the economics of Alternative Energy generation technologies (and government incentives are, generally, currently important in all regions)



Source: *Lazard estimates.*

(a) Unless otherwise noted, the subsidized analysis assumes projects placed into service in time to qualify for full PTC/ITC. Assumes 30% debt at 8.0% interest rate, 50% tax equity at 10.0% cost and 20% common equity at 12.0% cost, unless otherwise noted.

(b) Low end represents a single-axis tracking system. High end represents a fixed-tilt design. Assumes 30 MW installation in high insolation jurisdiction (e.g., Southwest U.S.).

(c) Low end represents concentrating solar tower with 18-hour storage. High end represents concentrating solar tower with 10-hour storage capability.

(d) The ITC for fuel cell technologies is capped at $1,500/0.5 kW of capacity.

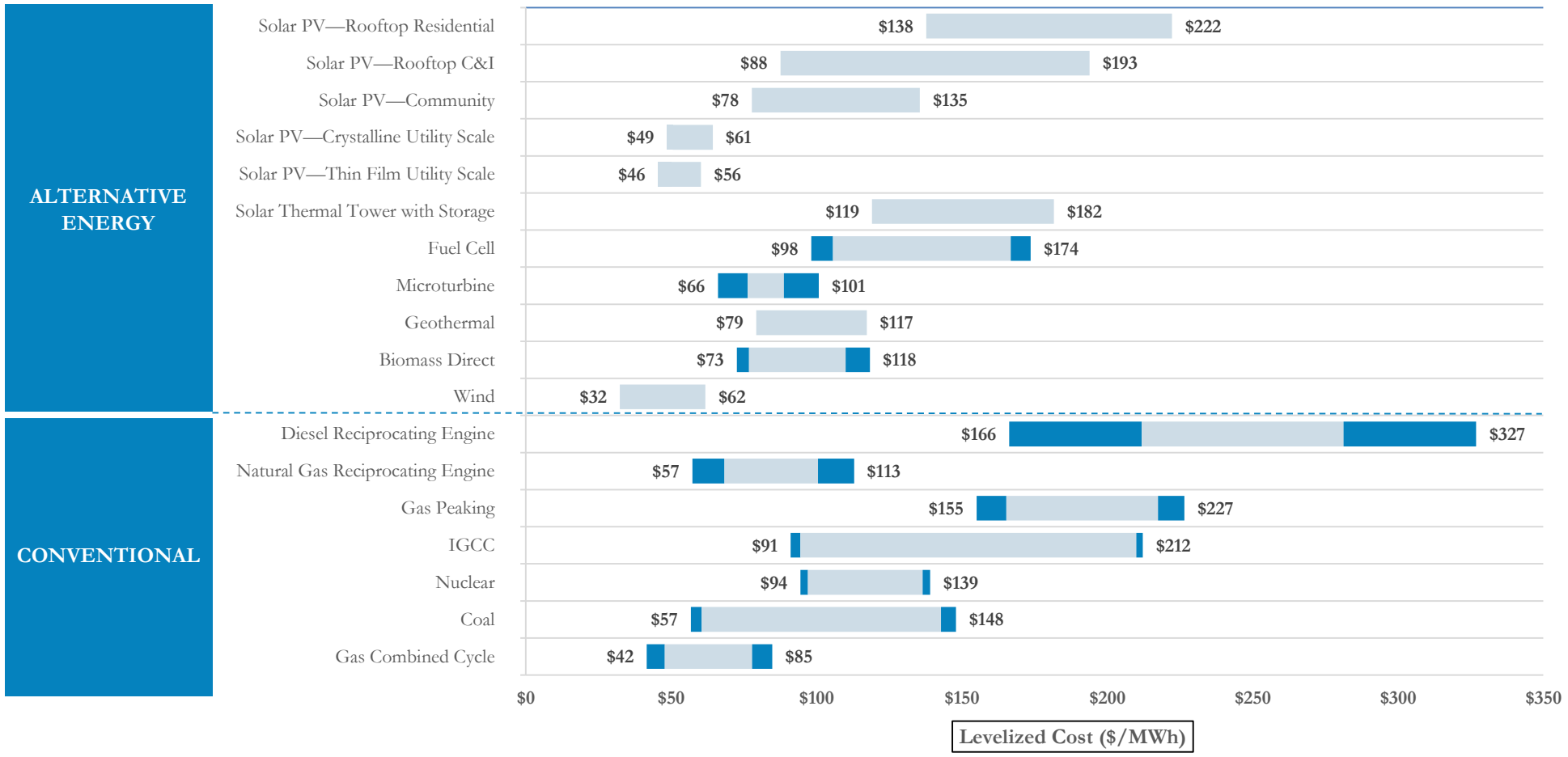
(e) Reflects 10% ITC only. Reflects no PTC. Capital structure adjusted for lower ITC; assumes 50% debt at 8.0% interest rate, 30% tax equity at 10.0% cost and 20% common equity at 12.0% cost.

(f) Reflects no ITC. Reflects $23/MWh PTC, escalated at ~1.5% annually for a term of 10 years.

(g) Reflects no ITC. Reflects $23/MWh PTC, escalated at ~1.5% annually for a term of 10 years. Due to high capacity factor and, relatedly, high PTC investor appetite, assumes 15% debt at 8.0% interest rate, 70% tax equity at 10.0% cost and 15% common equity at 12.0% cost.

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the levelized cost of energy for conventional generation technologies, but direct comparisons against "competing" Alternative Energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)



Source: Lazard estimates.

Note: Darkened areas in horizontal bars represent low end and high end levelized cost of energy corresponding with ±25% fuel price fluctuations.

Cost of Carbon Abatement Comparison

As policymakers consider the best and most cost-effective ways to limit carbon emissions (including in the U.S., in respect of the Clean Power Plan and related regulations), they should consider the implicit costs of carbon abatement of various Alternative Energy generation technologies; an analysis of such implicit costs suggests that policies designed to promote wind and utility-scale solar development could be a particularly cost-effective way of limiting carbon emissions; rooftop solar and solar thermal remain expensive, by comparison

- **Such observation does not take into account potential social and environmental externalities or reliability or grid-related considerations**

		CONVENTIONAL GENERATION			ALTERNATIVE ENERGY RESOURCES			
	Units	**Coal[b]**	**Gas Combined Cycle**	**Nuclear**	**Wind**	**Solar PV Rooftop Residential**	**Solar PV Utility Scale[c]**	**Solar Thermal with Storage[d]**
Capital Investment/KW of Capacity[a]	$/kW	$3,000	$1,006	$5,385	$1,250	$2,000	$1,450	$10,296
Total Capital Investment	**$mm**	**$1,800**	**$704**	**$3,339**	**$1,263**	**$6,380**	**$2,697**	**$6,795**
Facility Output	MW	600	700	620	1010	3190	1860	660
Capacity Factor	%	93%	80%	90%	55%	18%	30%	85%
Effective Facility Output	**MW**	**558**	**558**	**558**	**558**	**558**	**558**	**558**
MWh/Year Produced[e]	GWh/yr	4,888	4,888	4,888	4,888	4,888	4,888	4,888
Levelized Cost of Energy	$/MWh	$60	$48	$97	$32	$138	$49	$119
Total Cost of Energy Produced	**$mm/yr**	**$296** (2)	**$234**	**$474**	**$158**	**$673**	**$237** (1)	**$582**
CO_2 Equivalent Emissions	Tons/MWh	0.92	0.51	—	—	—	—	—
Carbon Emitted	mm Tons/yr	4.51	2.50	—	—	—	—	—
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		—	2.01	4.51	4.51	4.51	4.51 (3)	4.51
vs. Gas		—	—	2.50	2.50	2.50	2.50	2.50
Difference in Total Energy Cost	$mm/yr							
vs. Coal		—	($62)	$179	($138)	$377	($58) (4)	$286
vs. Gas		—	—	$241	($76)	$439	$4	$348
Implied Abatement Cost/(Saving)	$/Ton							
vs. Coal		—	($31)	$40	($31)	$84	($13) (5)	$63
vs. Gas		—	—	$96	($30)	$176	$1	$139

Source: Lazard estimates.

Note: Unsubsidized figures. Assumes 2016 dollars, 20 – 40 year economic life, 40% tax rate and five – 40 year tax life. Assumes 2.25% annual escalation for O&M costs and fuel prices. Inputs for each of the various technologies are those associated with the low end levelized cost of energy. LCOE figures calculated on a 20-year basis.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.

(c) Represents crystalline utility-scale solar with single-axis tracking.

(d) Low end represents concentrating solar tower with 18-hour storage capability.

(e) All facilities illustratively sized to produce 4,888 GWh/yr.

Illustrative Implied Carbon Abatement Cost Calculation:

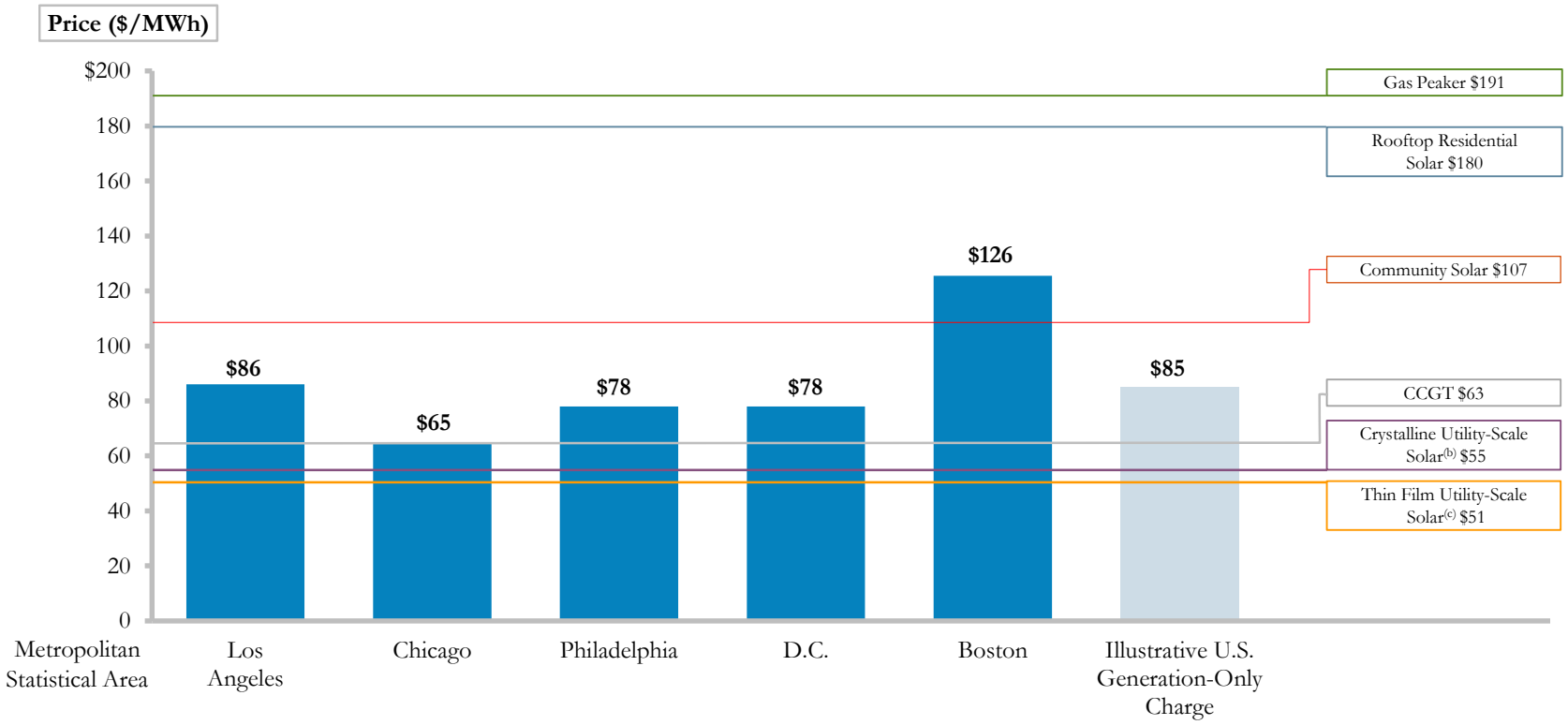
(4) Difference in Total Energy Cost vs. Coal = (1) – (2)
= $237 mm/yr (solar) – $296 mm/yr (coal) = ($58) mm/yr

(5) Implied Abatement Cost vs. Coal = (4) ÷ (3)
= ($58) mm/yr ÷ 4.51 mm Tons/yr = ($13)/Ton

Generation Rates for Selected Large U.S. Metropolitan Areas[(a)]

Setting aside the legislatively-mandated demand for solar and other Alternative Energy resources, utility-scale solar is becoming a more economically viable peaking energy product in many key, high population areas of the U.S. and, as pricing declines, could become economically competitive across a broader array of geographies

- **Such observation does not take into account potential social and environmental externalities or reliability-related considerations**



Source: *EEI, Lazard estimates.*

Note: Actual delivered generation prices may be higher, reflecting historical composition of resource portfolio. All technologies represent an average of the high and low levelized cost of energy values unless otherwise noted. Represents average retail rate for generation-only utility charges per EEI for 12 months ended December 31, 2015.

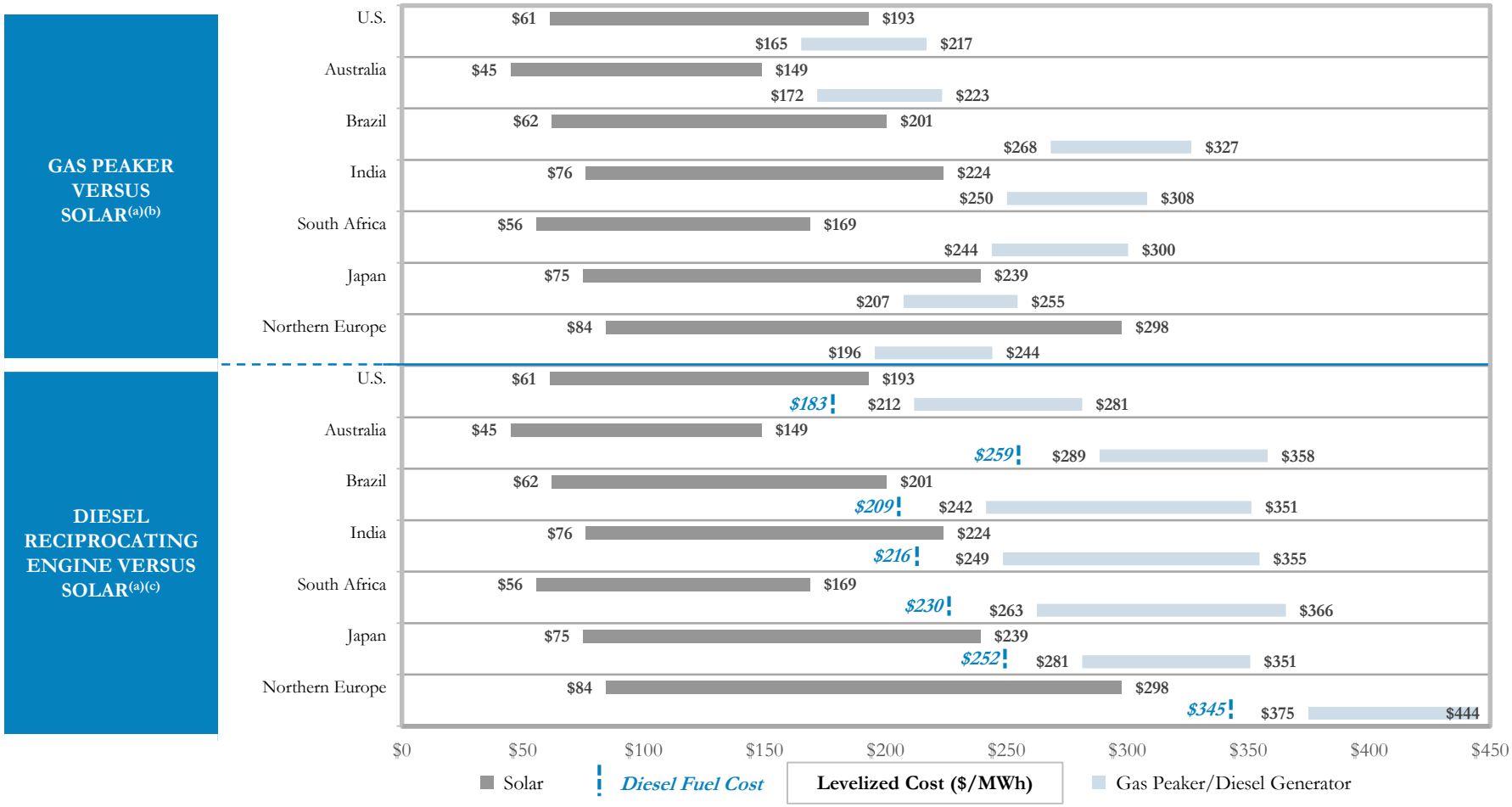
(a) Includes only those cities among top ten in population (per U.S. census) for which generation-only average $/kWh figures are available.

(b) Represents crystalline utility-scale solar with single-axis tracking design. Excludes Investment Tax Credit.

(c) Represents thin film utility-scale solar with single-axis tracking design. Excludes Investment Tax Credit.

Solar versus Peaking Capacity—Global Markets

Solar PV can be an attractive resource relative to gas and diesel-fired peaking in many parts of the world due to high fuel costs; without storage, however, solar lacks the dispatch characteristics of conventional peaking technologies



Source: *World Bank, IHS Waterborne LNG and Lazard estimates.*

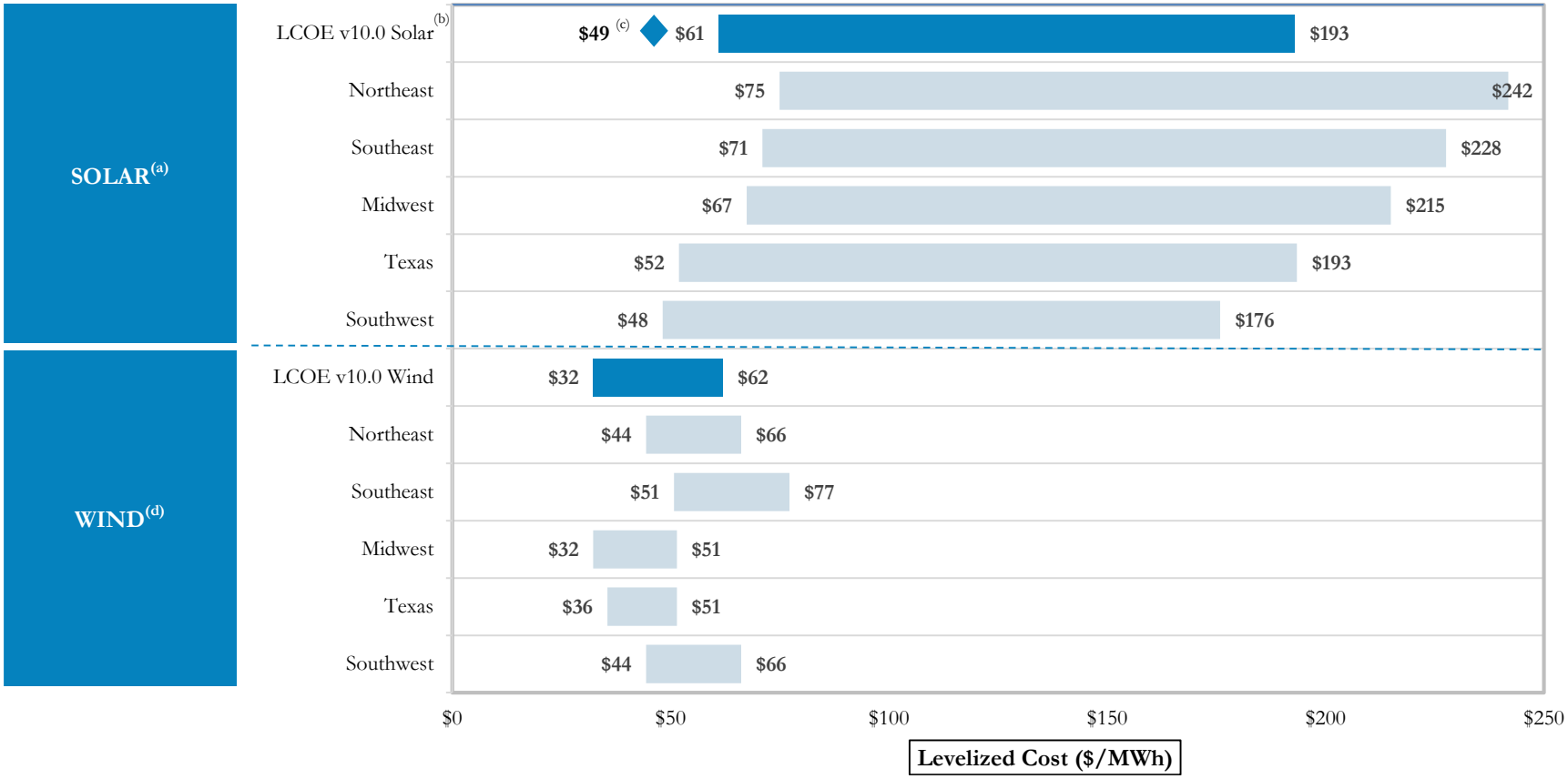
(a) Low end assumes crystalline utility-scale solar with a fixed-tilt design. High end assumes rooftop C&I solar. Solar projects assume illustrative capacity factors of 26% – 30% for Australia, 26% – 30% for Brazil, 22% – 23% for India, 27% – 29% for South Africa, 16% – 18% for Japan and 13% – 16% for Northern Europe. Equity IRRs of 12% are assumed for Australia, Japan and Northern Europe and 18% for Brazil, India and South Africa; assumes cost of debt of 8% for Australia, Japan and Northern Europe, 14.5% for Brazil, 13% for India and 11.5% for South Africa.

(b) Assumes natural gas prices of $4.00 for Australia, $8.00 for Brazil, $7.00 for India, $7.00 for South Africa, $7.00 for Japan and $6.00 for Northern Europe (all in U.S.$ per MMBtu). Assumes a capacity factor of 10%.

(c) Diesel assumes high end capacity factor of 10% representing intermittent utilization and low end capacity factor of 95% representing baseload utilization, O&M cost of $30 per kW/year, heat rate of 10,000 Btu/kWh and total capital costs of $500 to $800 per kW of capacity. Assumes diesel prices of $3.60 for Australia, $2.90 for Brazil, $3.00 for India, $3.20 for South Africa, $3.50 for Japan and $4.80 for Northern Europe (all in U.S.$ per gallon).

Wind and Solar Resource—U.S. Regional Sensitivity (Unsubsidized)

The availability of wind and solar resource has a meaningful impact on the levelized cost of energy for various regions of the U.S. This regional analysis varies capacity factors as a proxy for resource availability, while holding other variables constant. There are a variety of other factors (e.g., transmission, back-up generation/system reliability costs, labor rates, permitting and other costs) that would also impact regional costs



Source: *Lazard estimates.*

Note: Assumes solar capacity factors of 16% – 18% for the Northeast, 17% – 19% for the Southeast, 18% – 20% for the Midwest, 20% – 26% for Texas and 22% – 28% for the Southwest. Assumes wind capacity factors of 35% – 40% for the Northeast, 30% – 35% for the Southeast, 45% – 55% for the Midwest, 45% – 50% for Texas and 35% – 40% for the Southwest.

(a) Low end assumes a crystalline utility-scale solar fixed-tilt design, as tracking technologies may not be available in all geographies. High end assumes a rooftop C&I solar system.

(b) Low end assumes a crystalline utility-scale solar fixed-tilt design with a capacity factor of 21%.

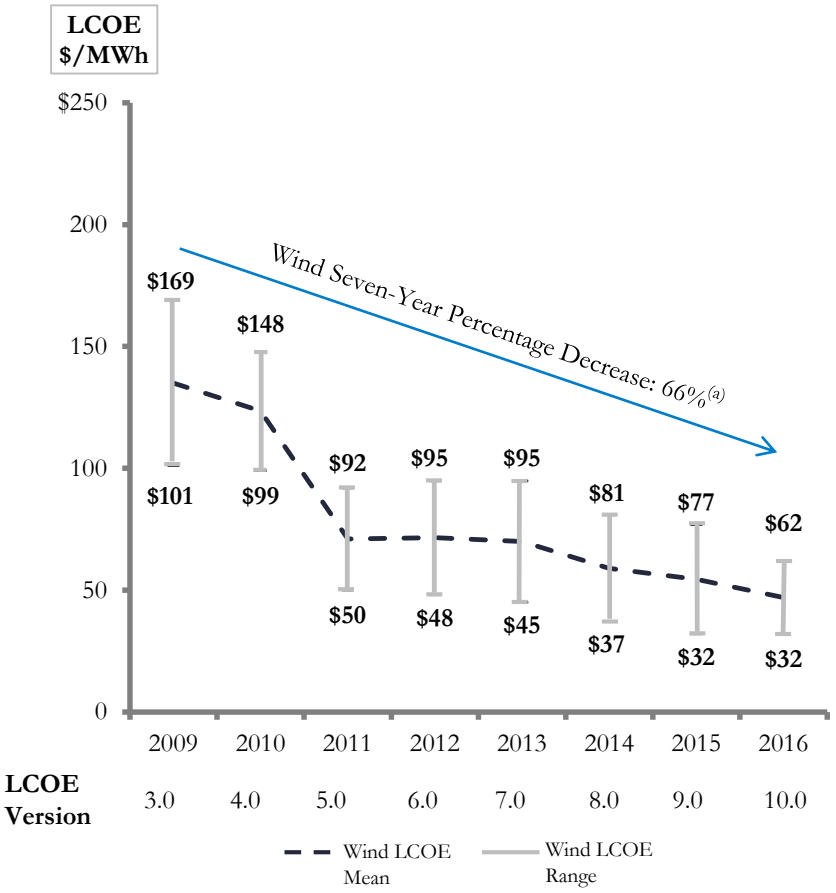
(c) Diamond represents a crystalline utility-scale solar single-axis tracking system with a capacity factor of 30%.

(d) Assumes an onshore wind generation plant with capital costs of $1.25 – $1.70 per watt.

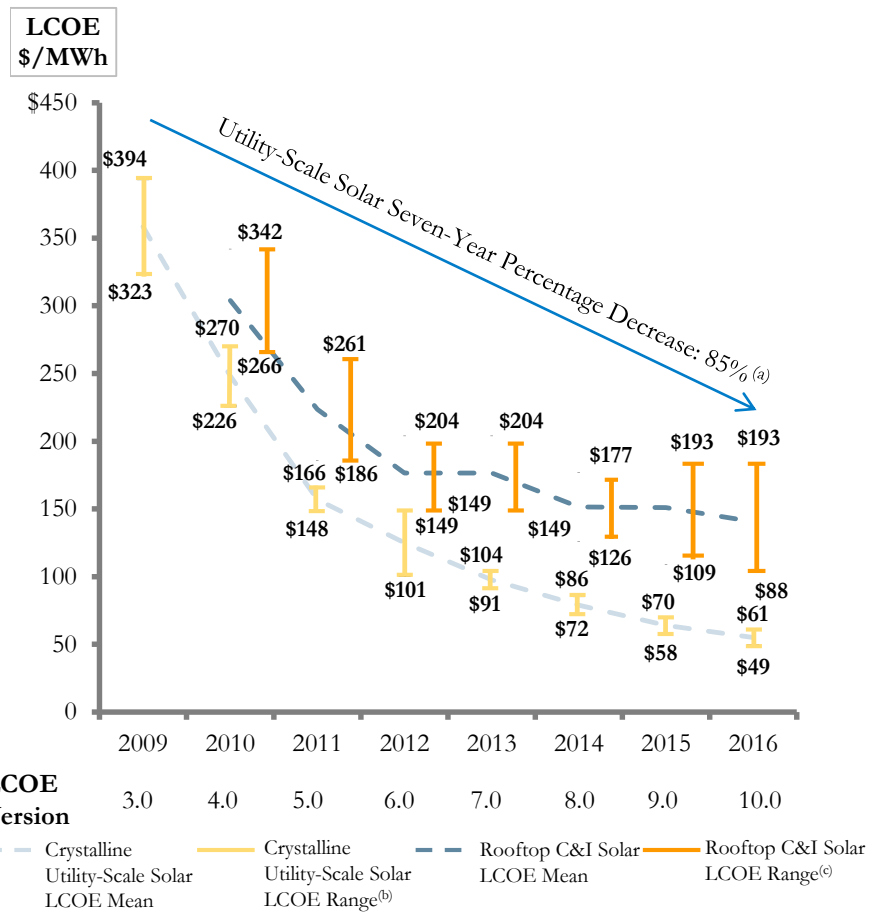
Unsubsidized Levelized Cost of Energy—Wind/Solar PV (Historical)

Over the last seven years, wind and solar PV have become increasingly cost-competitive with conventional generation technologies, on an unsubsidized basis, in light of material declines in the pricing of system components (e.g., panels, inverters, racking, turbines, etc.), and dramatic improvements in efficiency, among other factors

WIND LCOE



SOLAR PV LCOE



Source: *Lazard estimates.*

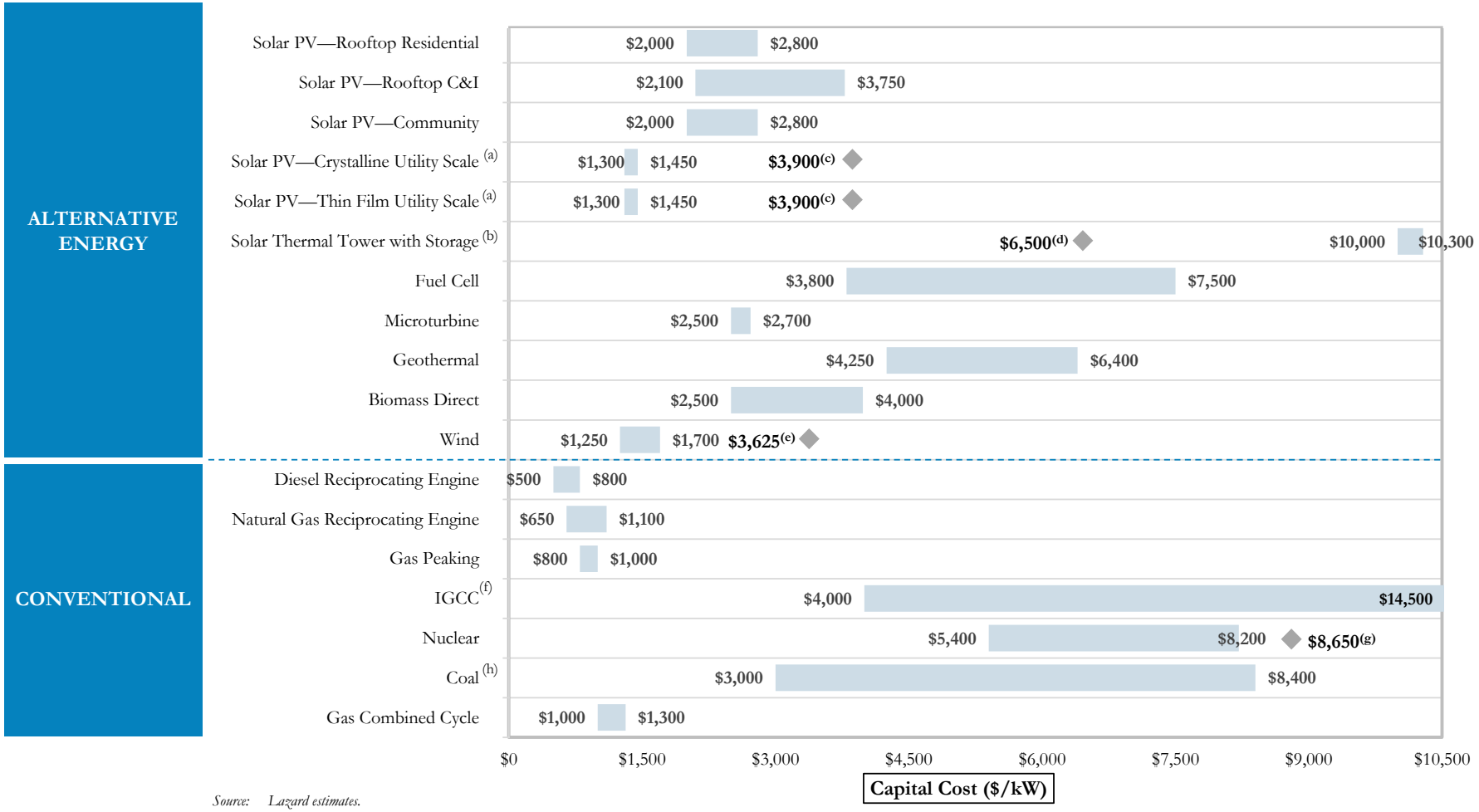
(a) Represents average percentage decrease of high end and low end of LCOE range.

(b) Low end represents crystalline utility-scale solar with single-axis tracking in high insolation jurisdictions (e.g., Southwest U.S.), while high end represents crystalline utility-scale solar with fixed-tilt design.

(c) Lazard's LCOE initiated reporting of rooftop C&I solar in 2010.

Capital Cost Comparison

While capital costs for a number of Alternative Energy generation technologies (e.g., solar PV, solar thermal) are currently in excess of some conventional generation technologies (e.g., gas), declining costs for many Alternative Energy generation technologies, coupled with uncertain long-term fuel costs for conventional generation technologies, are working to close formerly wide gaps in electricity costs. This assessment, however, does not take into account issues such as dispatch characteristics, capacity factors, fuel and other costs needed to compare generation technologies

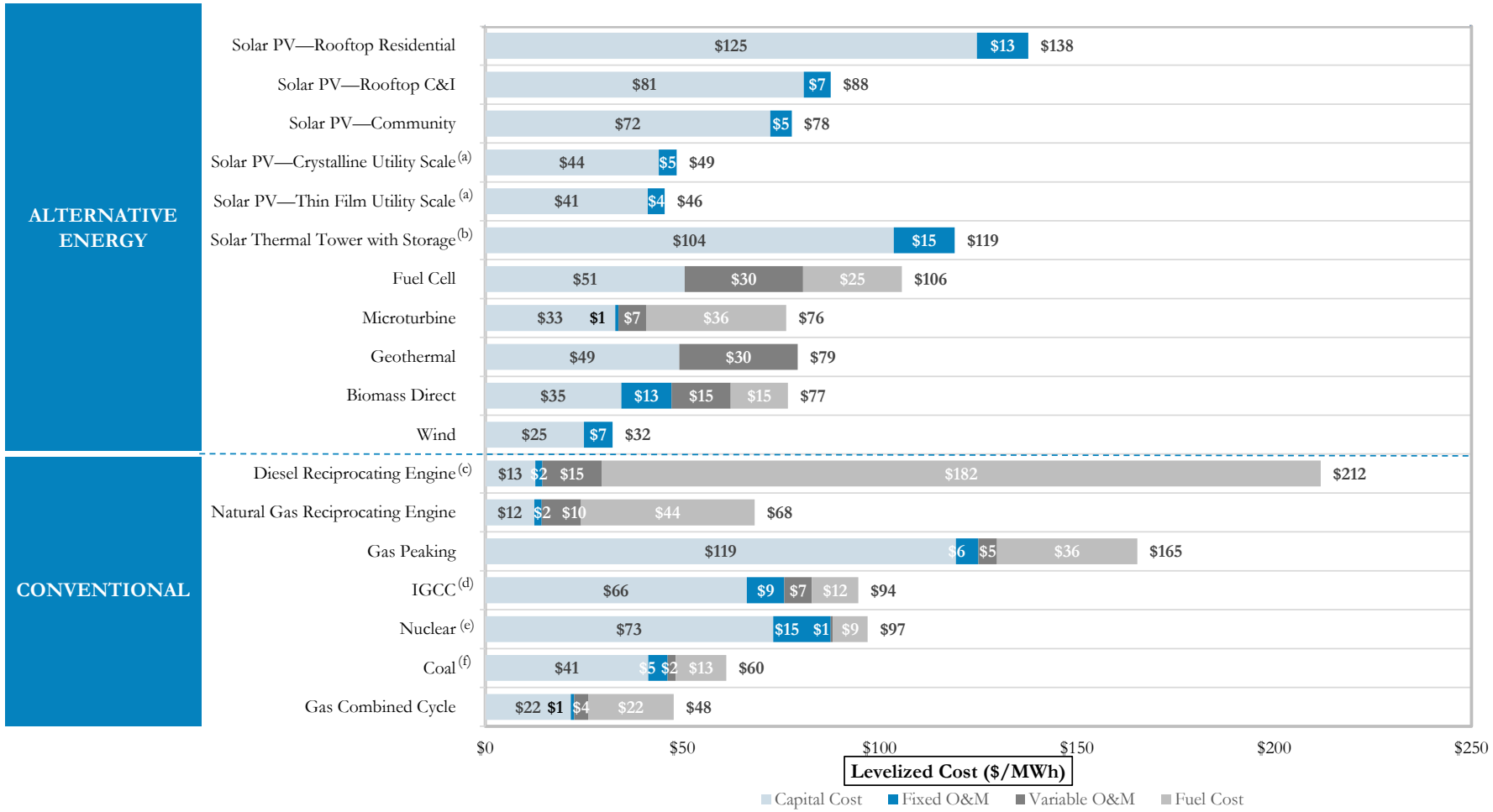


Source: *Lazard estimates.*

(a) High end capital cost represents the capital cost associated with the low end LCOE of utility-scale solar. Low end capital cost represents the capital cost associated with the high end LCOE of utility-scale solar.
(b) Low end represents concentrating solar tower with 10-hour storage capability. High end represents concentrating solar tower with 18-hour storage capability.
(c) Diamond represents PV plus storage.
(d) Diamond represents solar thermal tower capital costs without storage.
(e) Represents estimated midpoint of capital costs for offshore wind, assuming a capital cost range of $2.75 – $4.50 per watt.
(f) High end represents Kemper and it incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.
(g) Represents estimate of current U.S. new nuclear construction.
(h) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.

Levelized Cost of Energy Components—Low End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as has been the case with solar PV and wind technologies)

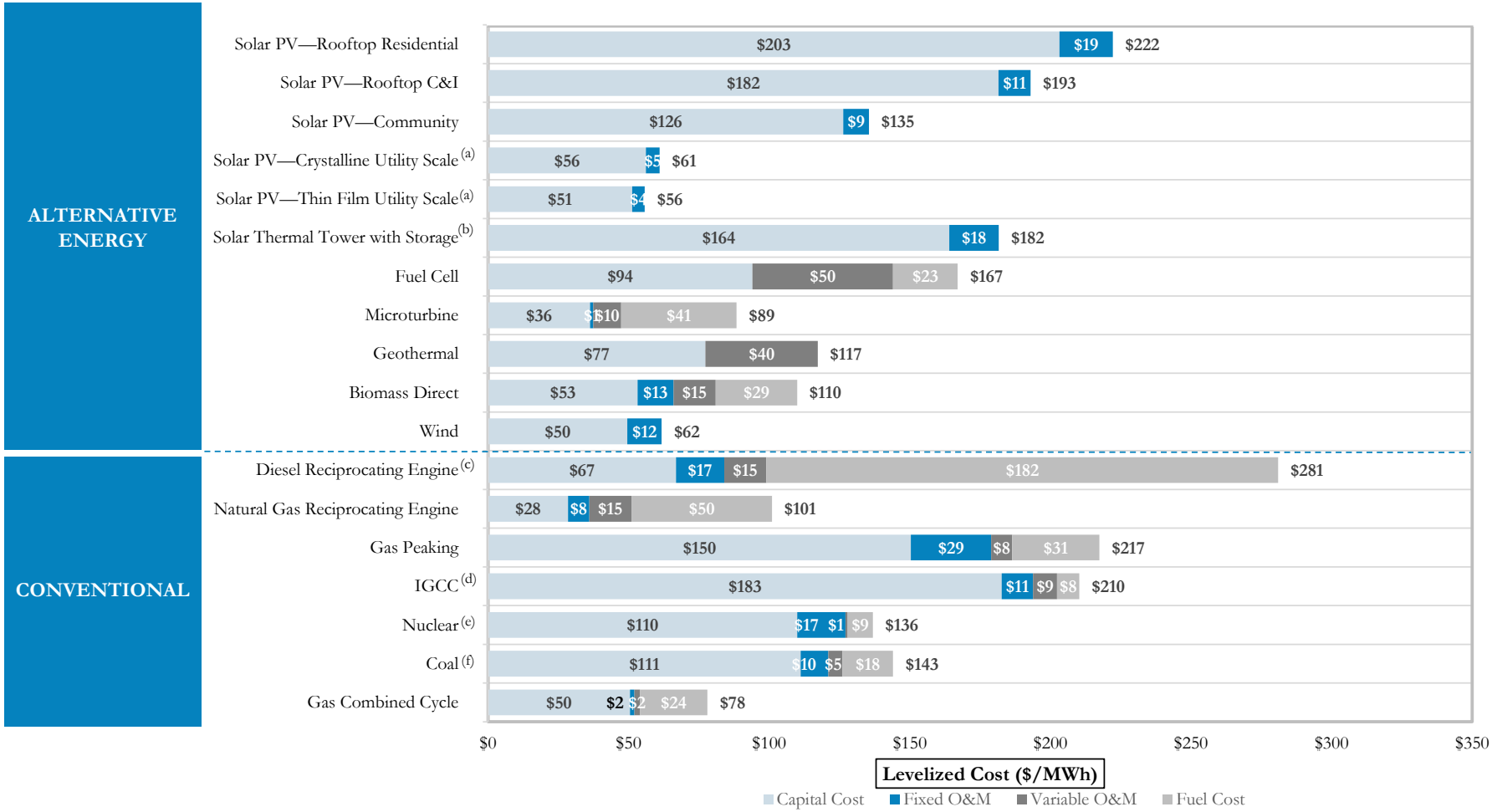


Source: *Lazard estimates.*

(a) Represents the low end of a utility-scale solar single-axis tracking system.
(b) Represents concentrating solar tower with 18-hour storage capability.
(c) Represents continuous operation.
(d) Does not incorporate carbon capture and compression.
(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.
(f) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.

Levelized Cost of Energy Components—High End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of currently more expensive Alternative Energy technologies is the ability of technological development and increased production volumes to materially lower the capital costs of certain Alternative Energy technologies, and their levelized cost of energy, over time (e.g., as has been the case with solar PV and wind technologies)



Source: *Lazard estimates.*

(a) Represents the high end of utility-scale solar fixed-tilt design.

(b) Represents concentrating solar tower with 10-hour storage capability.

(c) Represents intermittent operation.

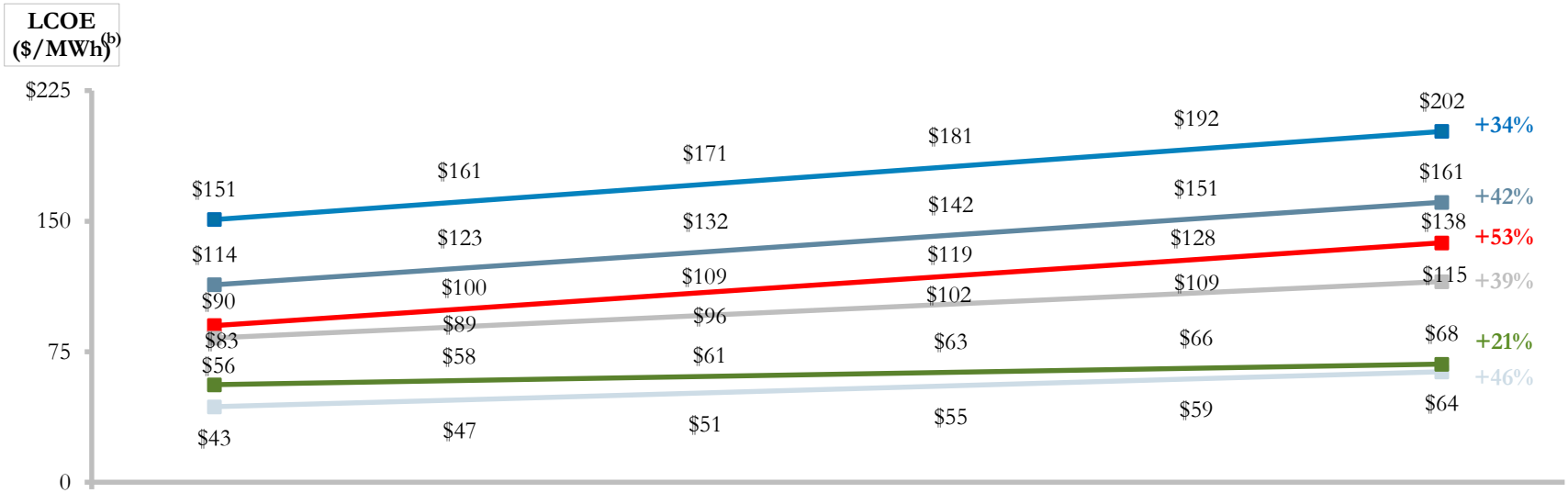
(d) Incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(f) Based on of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Levelized Cost of Energy—Sensitivity to Cost of Capital

A key issue facing Alternative Energy generation technologies is the impact of the availability and cost of capital[(a)] on LCOEs (as a result of capital markets dislocation, technological maturity, etc.); availability and cost of capital have a particularly significant impact on Alternative Energy generation technologies, whose costs reflect essentially the return on, and of, the capital investment required to build them



After-Tax IRR/WACC	5.4%	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Solar PV—Rooftop Residential
Solar PV—Rooftop C&I
Solar PV—Utility Scale
Nuclear (c)
Coal (d)
Gas—Combined Cycle

Reflects cost of capital assumption utilized in Lazard's Levelized Cost of Energy analysis

Reflects potentially more prevalent North American cost of capital—see next page for additional details

Source: Lazard estimates.

(a) Cost of capital as used herein indicates the cost of capital for the asset/plant vs. the cost of capital of a particular investor/owner.

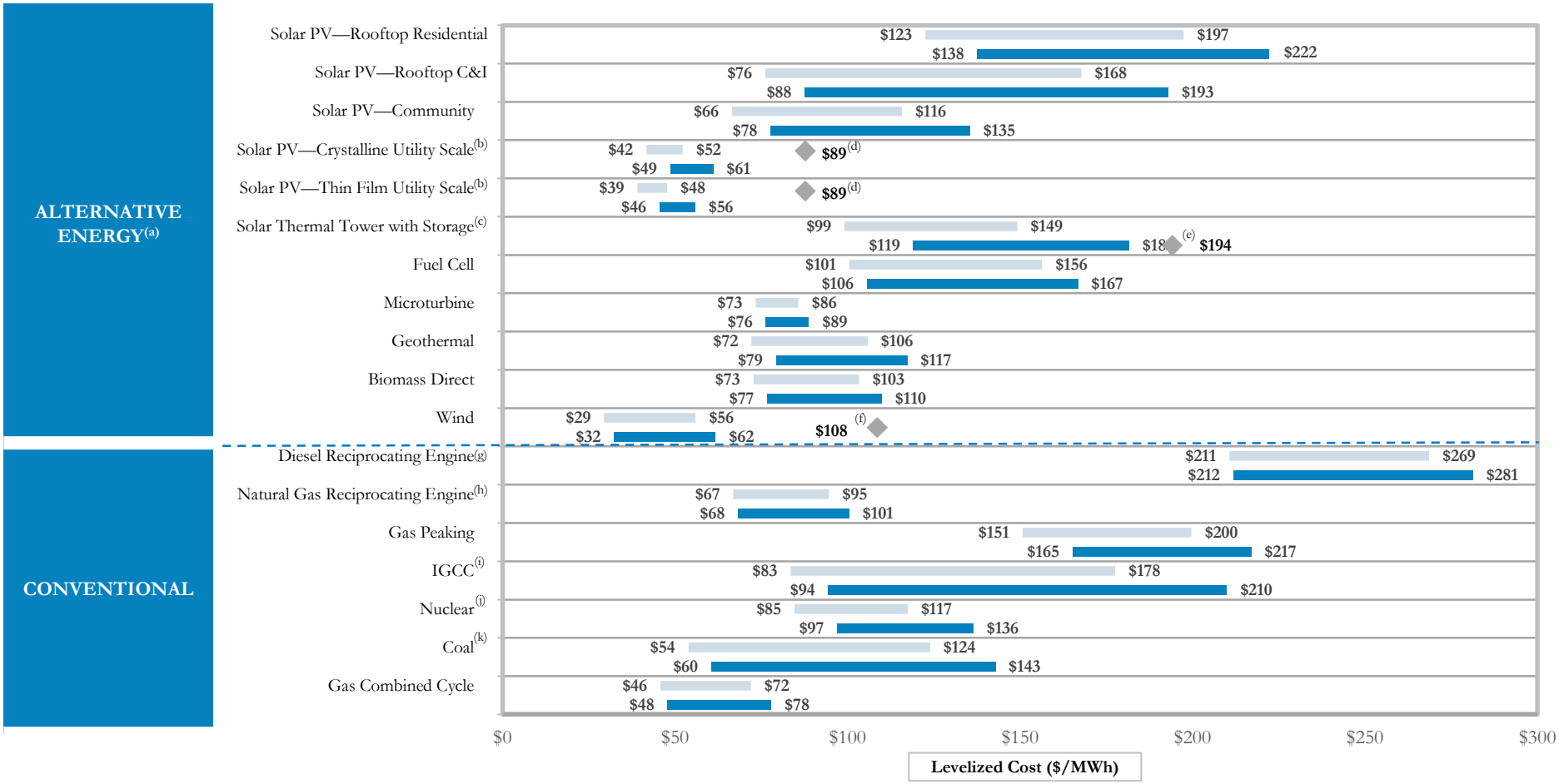
(b) Reflects average of high and low LCOE for given cost of capital assumption.

(c) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(d) Based on average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Does not incorporate carbon capture and compression.

Unsubsidized Levelized Cost of Energy—Cost of Capital Comparison

While Lazard's analysis primarily reflects an illustrative global cost of capital (i.e., 8% cost of debt and 12% cost of equity), such assumptions may be somewhat elevated vs. OECD/U.S. figures currently prevailing in the market for utility-scale renewables assets/investment—in general, Lazard aims to update its major levelized assumptions (e.g., cost of capital, capital structure, etc.) only in extraordinary circumstances, so that results track year-over-year cost declines and technological improvements vs. capital markets



Source: *Lazard estimates.*

Note: Reflects equivalent cost and operational assumptions as pages 2 – 3. Analysis assumes 60% debt at 6% interest rate and 40% equity at 10% cost for conventional and Alternative Energy generation technologies. Assumes an average coal price of $1.47 per MMBtu based on Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. Assumes a range of $0.65 – $1.33 per MMBtu based on Illinois Based Rail for IGCC. Assumes a natural gas price of $3.45 per MMBtu for Fuel Cell, Microturbine, Gas Peaking and Gas Combined Cycle. Analysis does not reflect potential impact of recent draft rule to regulate carbon emissions under Section 111(d).

‡ Denotes distributed generation technology.

Energy Resources: Matrix of Applications

While the levelized cost of energy for Alternative Energy generation technologies is in some cases competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

- **This analysis does not take into account potential social and environmental externalities or reliability-related considerations**

					LOCATION			DISPATCH			
		LEVELIZED COST OF ENERGY	CARBON NEUTRAL/ REC POTENTIAL	STATE OF TECHNOLOGY	DISTRIBUTED	CENTRALIZED	GEOGRAPHY	INTERMITTENT	PEAKING	LOAD-FOLLOWING	BASE-LOAD
ALTERNATIVE ENERGY	SOLAR PV	$46 – 222[a]	✓	Commercial	✓	✓	Universal[b]	✓	✓		
	SOLAR THERMAL	$119 – 182	✓	Commercial		✓	Varies	✓	✓	✓	
	FUEL CELL	$106 – 167	?	Emerging/ Commercial	✓		Universal				✓
	MICROTURBINE	$76 – 89	?	Emerging/ Commercial	✓		Universal				✓
	GEOTHERMAL	$79 – 117	✓	Mature		✓	Varies				✓
	BIOMASS DIRECT	$77 – 110	✓	Mature		✓	Universal			✓	✓
	ONSHORE WIND	$32 – 62	✓	Mature		✓	Varies	✓			
CONVENTIONAL	DIESEL RECIPROCATING ENGINE	$212 –281	×	Mature	✓		Universal	✓	✓	✓	✓
	NATURAL GAS RECIPROCATING ENGINE	$68 – 101	×	Mature	✓		Universal	✓	✓	✓	✓
	GAS PEAKING	$165 – 217	×	Mature	✓	✓	Universal		✓	✓	
	IGCC	$94 – 210	×[c]	Emerging[d]		✓	Co-located or rural				✓
	NUCLEAR	$97 – 136	✓	Mature/ Emerging		✓	Co-located or rural				✓
	COAL	$60 – 143	×[c]	Mature[d]		✓	Co-located or rural				✓
	GAS COMBINED CYCLE	$48 – 78	×	Mature	✓	✓	Universal			✓	✓

Source: *Lazard estimates.*

(a) Represents the full range of solar PV technologies; low end represents thin film utility-scale solar single-axis tracking, high end represents the high end of rooftop residential solar.

(b) Qualification for RPS requirements varies by location.

(c) Could be considered carbon neutral technology, assuming carbon capture and compression.

(d) Carbon capture and compression technologies are in emerging stage.

Levelized Cost of Energy—Methodology

Lazard's Levelized Cost of Energy analysis consists of creating a power plant model representing an illustrative project for each relevant technology and solving for the $/MWh figure that results in a levered IRR equal to the assumed cost of equity (see pages 18 – 20 for detailed assumptions by technology)

WIND — HIGH CASE SAMPLE CALCULATIONS

Year[a]	*0*	*1*	*2*	*3*	*4*	*5*
Capacity (MW) – (A)		100	100	100	100	100
Capacity Factor (%) – (B)		38%	38%	38%	38%	38%
Total Generation ('000 MWh) – (A) x (B) = (C)*		329	329	329	329	329
Levelized Energy Cost ($/MWh) – (D)		***$61.75***	***$61.75***	***$61.75***	***$61.75***	***$61.75***
Total Revenues – (C) x (D) = (E)*		**$20.3**	**$20.3**	**$20.3**	**$20.3**	**$20.3**
Total Fuel Cost – (F)		$0.0	$0.0	$0.0	$0.0	$0.0
Total O&M – (G)*		4.0	4.1	4.2	4.3	4.4
Total Operating Costs – (F) + (G) = (H)		$4.0	$4.1	$4.2	$4.3	$4.4
EBITDA – (E) - (H) = (I)		**$16.3**	**$16.2**	**$16.1**	**$16.0**	**$15.9**
Debt Outstanding - Beginning of Period – (J)		$102.0	$100.0	$97.8	$95.4	$92.9
Debt - Interest Expense – (K)		(8.2)	(8.0)	(7.8)	(7.6)	(7.4)
Debt - Principal Payment – (L)		(2.0)	(2.2)	(2.4)	(2.5)	(2.8)
Levelized Debt Service – (K) + (L) = (M)		($10.2)	($10.2)	($10.2)	($10.2)	($10.2)
EBITDA – (I)		$16.3	$16.2	$16.1	$16.0	$15.9
Depreciation (MACRS) – (N)		(34.0)	(54.4)	(32.6)	(19.6)	(19.6)
Interest Expense – (K)		(8.2)	(8.0)	(7.8)	(7.6)	(7.4)
Taxable Income – (I) + (N) + (K) = (O)		**($25.9)**	**($46.2)**	**($24.4)**	**($11.2)**	**($11.1)**
Tax Benefit (Liability) – (O) x (tax rate) = (P)[b]		**$10.4**	**$18.5**	**$9.7**	**$4.5**	**$4.4**
After-Tax Net Equity Cash Flow – (I) + (M) + (P) = (Q)	**($68.0)**	**$16.5**	**$24.5**	**$15.7**	**$10.3**	**$10.2**
IRR For Equity Investors	**12.0%**					

Key Assumptions[c]	
Capacity (MW)	100
Capacity Factor	38%
Fuel Cost ($/MMBtu)[d]	$0.00
Heat Rate (Btu/kWh)	0
Fixed O&M ($/kW-year)	$40.0
Variable O&M ($/MWh)	$0.0
O&M Escalation Rate	2.25%
Capital Structure	
Debt	60.0%
Cost of Debt	8.0%
Equity	40.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	40%
Economic Life (years)[e]	20
MACRS Depreciation (Year Schedule)	5
Capex	
EPC Costs ($/kW)	$1,100
Additional Owner's Costs ($/kW)	$600
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$1,700
Total Capex ($mm)	$170

Source: *Lazard estimates.*
Note: Wind—High LCOE case presented for illustrative purposes only.
* Denotes unit conversion.
(a) Assumes half-year convention for discounting purposes.
(b) Assumes full monetization of tax benefits of losses immediately.
(c) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(d) Fuel costs converted from relevant source to $/MMBtu for conversion purposes.
(e) Economic life sets debt amortization schedule. For comparison purposes, all technologies calculate LCOE on 20-year IRR basis.

Technology-dependent
Levelized

Levelized Cost of Energy—Key Assumptions

		Solar PV					
	Units	Rooftop—Residential	Rooftop—C&I	Community	Utility Scale—Crystalline[c]	Utility Scale—Thin Film[c]	Solar Thermal Tower with Storage[d]
Net Facility Output	MW	0.005 – 0.002	1	1.5	30	30	110
EPC Cost	$/kW	$2,000 – $2,800	$2,100 – $3,750	$2,000 – $2,800	$1,450 – $1,300	$1,450 – $1,300	$9,000 – $8,750
Capital Cost During Construction	$/kW	—	—	—	—	—	$1,300 – $1,250
Other Owner's Costs	$/kW	included	included	included	included	included	included
Total Capital Cost[a]	$/kW	$2,000 – $2,800	$2,100 – $3,750	$2,000 – $2,800	$1,450 – $1,300	$1,450 – $1,300	$10,300 – $10,000
Fixed O&M	$/kW-yr	$20.00 – $25.00	$15.00 – $20.00	$12.00 – $16.00	$12.00 – $9.00	$12.00 – $9.00	$115.00 – $80.00
Variable O&M	$/MWh	—	—	—	—	—	—
Heat Rate	Btu/kWh	—	—	—	—	—	—
Capacity Factor	%	18% – 15%	25% – 20%	25% – 20%	30% – 21%	32% – 23%	85% – 52%
Fuel Price	$/MMBtu	0	0	0	0	0	0
Construction Time	Months	3	3	6	9	9	36
Facility Life	Years	20	25	30	30	30	35
CO_2 Emissions	lb/MMBtu	—	—	—	—	—	—
Levelized Cost of Energy[b]	$/MWh	$138 – $222	$88 – $193	$78 – $135	$49 – $61	$46 – $56	$119 – $182

Source: *Lazard estimates.*

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 10.0 present LCOE on an unsubsidized basis.

(c) Left column represents the assumptions used to calculate the low end LCOE for single-axis tracking. Right column represents the assumptions used to calculate the high end LCOE for fixed-tilt design. Assumes 30 MW system in high insolation jurisdiction (e.g., Southwest U.S.). Does not account for differences in heat coefficients, balance-of-system costs or other potential factors which may differ across solar technologies.

(d) Left column represents concentrating solar tower with 18-hour storage capability. Right column represents concentrating solar tower with 10-hour storage capability.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Fuel Cell	Microturbine	Geothermal	Biomass Direct	Wind—On Shore	Wind—Off Shore
Net Facility Output	MW	2.4	1 0.25	20	35	100	210 385
EPC Cost	$/kW	$3,000 – $7,500	$2,500 – $2,700	$3,700 – $5,600	$2,200 – $3,500	$950 – $1,100	$2,750 – $4,500
Capital Cost During Construction	$/kW	—	—	$550 – $800	$300 – $500	—	—
Other Owner's Costs	$/kW	$800 – $0	included	included	included	$300 – $600	included
Total Capital Cost[(a)]	$/kW	$3,800 – $7,500	$2,500 – $2,700	$4,250 – $6,400	$2,500 – $4,000	$1,250 – $1,700	$2,750 – $4,500
Fixed O&M	$/kW-yr	—	$6.85 – $9.12	—	$95.00	$35.00 – $40.00	$80.00 – $110.00
Variable O&M	$/MWh	$30.00 – $50.00	$7.00 – $10.00	$30.00 – $40.00	$15.00	—	—
Heat Rate	Btu/kWh	7,260 – 6,600	10,300 – 12,000	—	14,500	—	—
Capacity Factor	%	95%	95%	90% – 85%	85%	55% – 38%	48% – 40%
Fuel Price	$/MMBtu	3.45	$3.45	—	$1.00 – $2.00	—	—
Construction Time	Months	3	3	36	36	12	12
Facility Life	Years	20	20	25	25	20	20
CO_2 Emissions	lb/MMBtu	0 – 117	—	—	—	—	—
Levelized Cost of Energy[(b)]	$/MWh	$106 – $167	$76 – $89	$79 – $117	$77 – $110	$32 – $62	$82 – $155

Source: Lazard estimates.

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 10.0 present LCOE on an unsubsidized basis.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Diesel Reciprocating Engine[c]	Natural Gas Reciprocating Engine	Gas Peaking	IGCC[d]	Nuclear[e]	Coal[f]	Gas Combined Cycle
Net Facility Output	MW	0.25	0.25	216 – 103	580	1,100	600	550
EPC Cost	$/kW	$500 – $800	$650 – $1,100	$580 – $700	$3,300 – $11,600	$3,800 – $5,300	$2,000 – $6,100	$750 – $1,000
Capital Cost During Construction	$/kW	—	—	—	$700 – $2,900	$1,000 – $1,400	$500 – $1,600	$100 – $100
Other Owner's Costs	$/kW	included	included	$220 – $300	$0 – $0	$600 – $1,500	$500 – $700	$200 – $200
Total Capital Cost[a]	$/kW	$500 – $800	$650 – $1,100	$800 – $1,000	$4,000 – $14,500	$5,400 – $8,200	$3,000 – $8,400	$1,000 – $1,300
Fixed O&M	$/kW-yr	$15.00	$15.00 – $20.00	$5.00 – $25.00	$62.25 – $73.00	$135.00	$40.00 – $80.00	$6.20 – $5.50
Variable O&M	$/MWh	$15.00	$10.00 – $15.00	$4.70 – $7.50	$7.00 – $8.50	$0.50 – $0.75	$2.00 – $5.00	$3.50 – $2.00
Heat Rate	Btu/kWh	10,000	8,000 – 9,000	10,300 – 9,000	8,800 – 11,700	10,450	8,750 – 12,000	6,300 – 6,900
Capacity Factor	%	95% – 10%	95% – 30%	10%	75%	90%	93%	80% – 40%
Fuel Price	$/MMBtu	$18.23	$5.50	$3.45	$1.33 – $0.65	$0.85	$1.47	$3.45
Construction Time	Months	3	3	25	57 – 63	69	60 – 66	36
Facility Life	Years	20	20	20	40	40	40	20
CO_2 Emissions	lb/MMBtu	0 – 117	117	117	169	—	211	117
Levelized Cost of Energy[b]	$/MWh	$212 – $281	$68 – $101	$165 – $217	$94 – $210	$97 – $136	$60 – $143	$48 – $78

Source: *Lazard estimates.*

(a) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

(b) While prior versions of this study have presented LCOE inclusive of the U.S. Federal Investment Tax Credit and Production Tax Credit, Versions 6.0 – 10.0 present LCOE on an unsubsidized basis.

(c) Low end represents continuous operation. High end represents intermittent operation. Assumes diesel price of ~$2.50 per gallon.

(d) High end incorporates 90% carbon capture and compression. Does not include cost of storage and transportation.

(e) Does not reflect decommissioning costs or potential economic impact of federal loan guarantees or other subsidies.

(f) Reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of storage and transportation.

Summary Considerations

Lazard has conducted this study comparing the levelized cost of energy for various conventional and Alternative Energy generation technologies in order to understand which Alternative Energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions, as well as to understand which technologies are best suited for various applications based on locational requirements, dispatch characteristics and other factors. We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including RPS requirements, carbon regulations, continually improving economics as underlying technologies improve and production volumes increase, and government subsidies in certain regions.

In this study, Lazard's approach was to determine the levelized cost of energy, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, etc.) were identical for all technologies, in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and other important metrics on the levelized cost of energy. These inputs were originally developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant. This study (as well as previous versions) has benefited from additional input from a wide variety of industry participants.

Lazard has not manipulated capital costs or capital structure for various technologies, as the goal of the study was to compare the current state of various generation technologies, rather than the benefits of financial engineering. The results contained in this study would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or capital costs (e.g., a willingness to accept lower returns than those assumed herein).

Key sensitivities examined included fuel costs and tax subsidies. Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission or congestion costs; integration costs; and costs of complying with various environmental regulations (e.g., carbon emissions offsets, emissions control systems). The analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, environmental impacts, etc.).

Exhibit I

The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs

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Report Number U1402

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Executive Summary

After a decades-long history, U.S. energy efficiency programs have expanded rapidly in recent years. As program administrators face rising energy efficiency targets that require more comprehensive portfolios, they have an increasing concern about the impact on program costs. This creates the need for high-quality, comprehensive, and consistent data metrics on energy efficiency program costs and cost effectiveness. To this end, the American Council for an Energy-Efficient Economy (ACEEE) has undertaken an assessment of utility-sector energy efficiency program costs and cost effectiveness in 2009-2012.

The results of our analysis clearly demonstrate that energy efficiency programs are holding steady as the least-cost energy resource option that provides the best value for America's energy dollar. Data from a large number of diverse jurisdictions across the nation show that energy efficiency has remained the lowest-cost resource even as the amount of energy efficiency being captured has increased significantly. At an average cost of 2.8 cents per kilowatt hour (kWh), electricity efficiency programs are one half to one third the cost of alternative new electricity resource options such as building new power plants. Natural gas energy efficiency programs also remain a least-cost option at an average cost of 35 cents per therm as compared to the national average natural gas commodity price of 49 cents per therm in 2013. In addition, both electricity and natural gas efficiency costs have remained consistent over the past decade. This consistency shows the reliability of efficiency as a long-term resource.

METHODOLOGY

The goal of the current ACEEE analysis is to collect and aggregate recent data on energy efficiency program costs and cost effectiveness from jurisdictions across the United States. Our focus is on the costs to utilities or other program administrators to run efficiency programs, but we also include some data on the broader costs and benefits to participants and to society. We do not aim to compare one state's efficiency portfolio results to others, but instead to present overall results.

We collected data for 20 states for electricity programs and 10 states for natural gas efficiency programs from 2009 to 2012, pulling from utilities' and other program administrators' program results. We collected the necessary data (annual program costs, net energy savings, and measure lifetime) to calculate the levelized utility cost of saved energy (CSE). By levelized we mean that upfront costs are amortized over the lifetime of a measure at an assumed real discount rate. The levelized CSE is the best measure for comparing energy efficiency to other energy resource options.

Our definition of utility energy efficiency costs includes

- Direct program costs incurred by administrators, including incentives to participants and all non-incentive costs such as the direct installation of measures, program design and administration, marketing, education, and evaluation
- Shareholder incentives or performance fees, which reflect the rate of return utilities earn in some states to meet or exceed certain thresholds of energy savings levels

We also collected some data on participant costs; however these data are much more sparsely reported and therefore the data set includes only seven states.

Our task of data collection and comparison was complicated by numerous challenges, including inconsistent reporting formats, nomenclature, and frequency; variation in energy savings evaluation approaches and in the accounting of demand response programs; and structural differences in program portfolios. We tried to make the data as consistent as possible in the face of these challenges. We consistently calculated the CSE based on a 5% real discount rate, we used net energy savings values and measure lifetimes as reported by the program administrator, and we used energy savings reported at the meter rather than at generation. We converted all data to real 2011 dollars.

RESULTS

As shown in figure S1, the CSE for electricity energy efficiency programs ranged from $0.013 to $0.056 per kWh across the 20 states from 2009 to 2012.

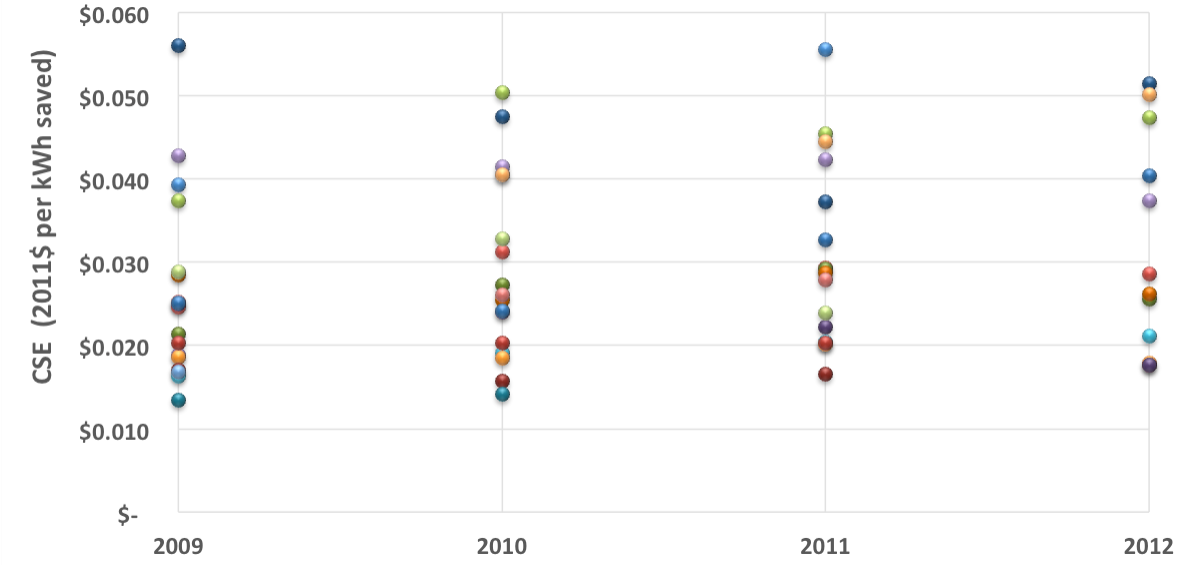

Figure S1. Electricity energy efficiency program CSE by year. Each dot represents average costs for each state in a given year. 2011$ per levelized net kWh at meter. Assumes 5% real discount rate.

We calculated four-year averages (2009-2012) for each of the 20 jurisdictions (and 10 jurisdictions for gas programs), and display the average, median, minimum, and maximum for the dataset in table S1. The simple average utility CSE was $0.028 per kWh for electricity programs and $0.35 per therm for gas programs.

Table S1. Summary of results for four-year averages (2009-2012) for all states in dataset

	Electricity programs ($ per kWh)	Natural gas programs ($ per therm)
Average	$0.028	$0.35
Median	$0.026	$0.37
Minimum	$0.016	$0.10
Maximum	$0.048	$0.59

2011$ per levelized net kWh or therm at meter. 5% real discount rate. Each state's four-year average is a distinct data point. The complete data set for individual years (Figure S1) has lower minimum and higher maximum values.

We also reviewed energy savings and CSE by customer class. Among the 17 states that readily reported electricity savings by customer class, the average portfolio included 45% savings from residential customers and 55% from business (commercial and industrial) customers. We calculated electricity CSE values by customer class for nine states (complete data was not readily available for the other jurisdictions), and identified an average CSE of $0.037/kWh for residential portfolios and $0.027/kWh for business portfolios.

While this study focused on the utility costs to deliver energy efficiency programs, we also examined some results of the total resource cost (TRC) test, which involves a system-wide perspective.[1] TRC test results from nine states show benefit-cost ratios ranging from 1.24 to 4.0 for electricity portfolios. In other words, in these jurisdictions, each dollar invested by utilities and participants in energy efficiency measures yields $1.24 to $4.00 in benefits.

Many analysts have hypothesized that program CSE will increase over time as administrators increase energy savings levels. An initial correlation analysis in this study finds only a very weak correlation between CSE values and energy savings levels. This analysis casts doubt on the claim that higher savings levels are associated with higher costs.

While comparisons of efficiency program costs to current levelized costs for new electricity resource options or natural gas commodity prices provide useful context, they do not tell the complete cost-effectiveness story for energy efficiency. For example, in addition to the avoided energy- and capacity-related costs to all customers, energy efficiency programs also result in utility benefits such as avoided transmission and distribution (T&D) costs, peak demand benefits, price mitigation effects in wholesale markets, and reduced pollution. Program participants can also benefit from lower water and fuel usage and improved comfort. In addition, energy efficiency programs result in reinvestment of local dollars in local jobs and industries. Also, these indicators of current avoided energy costs do not reflect future expected avoided energy costs and future price volatility. Including higher levels of low-cost energy efficiency in long-term planning can hedge against volatile and/or rising costs of supply resources.

In summary, the results of this analysis clearly demonstrate that energy efficiency programs are the least-cost resource option available to utilities. As shown in figure S2, electricity

[1] A complete and balanced TRC test should include benefits both to participants and to the system.

efficiency programs, at a range of about 2 to 5 cents per kWh and an average of 2.8 cents per kWh, are about one half to one third the levelized cost of alternative new electricity resource options.

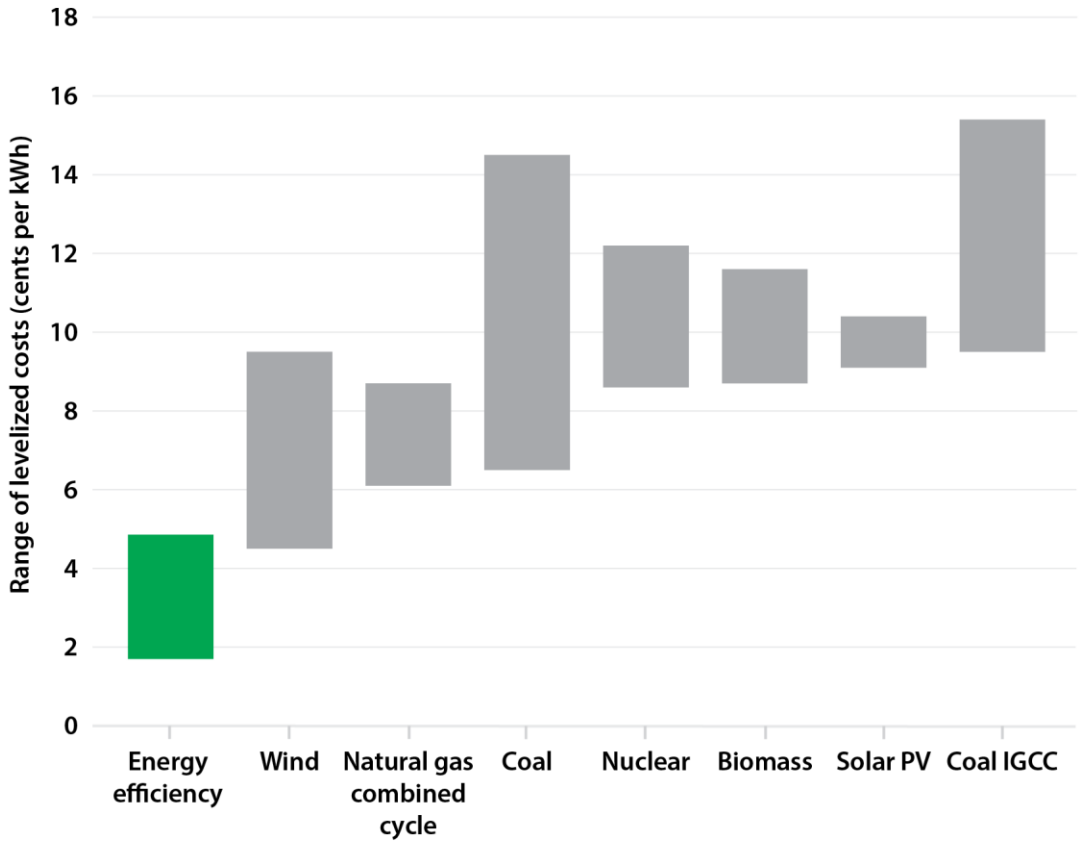

Figure S2. Levelized costs of electricity resource options. *Source:* Energy efficiency data represent the results of this analysis for utility program costs (range of four-year averages for 2009-2012); supply costs are from Lazard 2013.

RECOMMENDATIONS AND FURTHER RESEARCH

Given the inconsistency in efficiency program report formatting, nomenclature, and frequency, we recommend that utilities, regulators, and program administrators in each state discuss these issues, perhaps also at a regional and national level, and work toward adopting best reporting practices. We offer several specific recommendations to improve consistency and transparency in reporting.

In this review we discuss numerous metrics that may have a direct impact on the cost of efficiency, e.g., the share of savings by customer class, or the types of programs offered. Further research is needed on the relative impact of these different variables on CSE values and on the broader set of benefits to customers. Trends in CSE over time may be another fruitful area of study. Correlation analyses of CSE trends over time across jurisdictions are difficult and may produce incomplete results because of differences among program portfolio structures and reporting consistency. Further research should delve into this question, perhaps examining individual jurisdictions or regions.

Introduction

The energy future of the United States has entered an era of increasing change and uncertainty. While oil and gas production have increased in recent years, ongoing challenges include the environmental impacts of power generation, difficulty in siting new energy facilities and infrastructure as well as their high capital cost, and the continuing risk of fuel price volatility. In the face of these challenges and the need for economic development strategies, an increasing number of states have turned to energy efficiency as a significant component of their long-term energy resource planning.

Energy efficiency has long been demonstrated to be a low-cost and low-risk strategy. The American Council for an Energy-Efficient Economy (ACEEE) has conducted two reviews of utility-sector energy efficiency programs to document their cost effectiveness (Kushler, York and Witte, 2004; Friedrich, Eldridge, and York 2009). Both studies found that energy efficiency programs are the least-cost resource option compared to supply-side energy options.

ACEEE's 2004 and 2009 efficiency program cost reviews found the following:

- Examining data from seven states, the 2004 review identified a range of levelized cost of saved energy (CSE) from $0.023 to $0.044 per kilowatt hour (kWh), with a median value of $0.03 per kWh (Kushler, York, and Witte, 2004).
- The 2009 review of 14 states identified CSEs ranging from $0.016 to $0.033 per kWh, with an average cost of $0.025 per kWh. Six natural gas efficiency program portfolios covered in the report had an average CSE of $0.37 per therm (Friedrich, Eldridge, and York 2009).

Utility-sector energy efficiency programs have a decades-long history in the U.S., but have expanded significantly in recent years, which means the availability of new data sets and the increasing visibility of efficiency.[1] As states face rising energy savings targets, some stakeholders are concerned that energy efficiency programs' cost of saved energy will increase as they ramp up to hit their targets. These recent trends and concerns suggest the need for an updated and expanded review of energy efficiency program costs.

From 2006 to 2011, national annual electricity efficiency program spending tripled from $1.6 billion to about $4.8 billion (Downs et al. 2013). Although budgets for natural gas efficiency

[1] This report focuses exclusively on utility-sector energy efficiency programs that aim to reduce overall customer energy usage. We do not include demand response programs, which aim to reduce or shift energy usage only during times of peak demand. By "utility-sector energy efficiency programs," we mean programs funded through utility rates (whether embedded in rates or as a separate tariff rider or surcharge) or through associated public benefits charges and administered by utilities, government agencies, or third-party organizations.

programs have been much smaller, they have gained popularity in recent years and increased from $0.3 billion in 2006 to $1.1 billion in 2011.

This rapid growth stems largely from the increasing adoption of energy efficiency resource standards (EERS) and other regulatory mechanisms that reduce barriers to efficiency and encourage utilities to pursue it cost effectively.[2] States have also increasingly recognized energy efficiency as a low-cost economic development tool that attracts new businesses, creates jobs, and stimulates the economy. Twenty-six states now have EERS policies, and many others have other short-term energy efficiency planning processes.

These recent trends open up a wider set of utilities and states that collect data on efficiency program costs. Similarly, as efficiency programs gain traction as a true resource that planners can use in long-term forecasting, the need increases in step for high-quality and uniform data metrics on energy efficiency program costs and benefits.

Numerous utilities and statewide program administrators are now facing rising energy efficiency targets as part of their EERS policies, and they must hit these targets within firm cost-effectiveness requirements. Some stakeholders are concerned that the cost of efficiency programs is rising and that it is becoming more difficult to realize savings as federal appliance and equipment standards raise the baseline. It is true that program costs increase in the short term as programs target the uptake of higher-cost technologies, e.g., as they move from CFLs to LEDs. But, continuing with this example, costs are quickly declining for LEDs, which can counterbalance the initial higher program costs. Similarly, utilities are developing new, highly cost-effective program strategies such as large customer reverse auctions and strategic energy management. They are also identifying market gaps such as multifamily buildings. Still, much uncertainty and many misconceptions remain about the costs and cost trends of efficiency programs.

The goal of this analysis is to collect and aggregate recent data on energy efficiency program costs and cost-effectiveness metrics from jurisdictions across the U.S. as a comprehensive source of information for stakeholders. Our primary focus is on the costs incurred by utilities or other program administrators to run efficiency programs, but we also include some data on the broader costs and benefits to participants and society. We collected data by reviewing utilities' and other program administrators' program results to calculate CSE values. We do not aim to compare states' efficiency portfolio results, but instead to present overall results. We also would like to advance the discussion on how to improve protocols and consistency in the reporting of efficiency programs.

[2] EERS policies establish specific, long-term (3+ years) energy efficiency targets that utilities or non-utility program administrators must meet through customer energy efficiency programs. See http://www.aceee.org/topics/eers for more information.

Measuring Cost Effectiveness: Practices and Challenges

Since the 1980s, energy efficiency programs have gained traction as a true resource option that utilities and states can scale up and rely on within their resource plans. As a demand-side resource, however, efficiency is fundamentally different from supply options such as power plants and wind turbines. This difference calls for a unique set of methodologies to quantify efficiency as a resource by measuring its energy savings and cost effectiveness.

Since the 1970s and 80s, regulators have adopted particular practices to evaluate the costs and energy savings from efficiency programs. States have adopted these practices with varying degrees of consistency, and this creates a challenge for reviewing efficiency program costs across states. Some regions of the country have begun to coordinate methodologies and reporting guidelines through efforts such as the Regional Technical Forum in the Pacific Northwest and the Northeast Energy Efficiency Partnership (NEEP) Regional Evaluation, Measurement, and Verification Forum.[3] However most states continue to use a diverse set of methodologies and reporting structures.

This section presents our approach to reviewing the costs, savings, and cost effectiveness of efficiency programs, addressing the following questions:

1) What is typically included in the definition of energy efficiency program costs?
2) How are energy savings evaluated, measured, and verified (EM&V)?
3) How are costs expressed relative to energy savings? For example, what is the relationship between levelized costs, first-year costs, and measure lifetimes?
4) How are energy efficiency cost-effectiveness tests currently applied?

We discuss practices and challenges for each topic in this background section, as well as the approach we took to these issues in our review. The subsequent section on methodology goes into further detail on our approach to some of these topics.

ENERGY EFFICIENCY COSTS

Program Costs

What types of values should be attributed to the cost of delivering energy efficiency as a utility resource? We include two broad categories of energy efficiency resource costs: (1) direct program costs and (2) shareholder incentives (also called performance incentives or performance fees) earned by utilities or third-party program administrators for reaching or exceeding certain energy savings thresholds.[4] From a utility or program administrator perspective, the sum of efficiency program costs and performance incentives comprises the total cost of energy efficiency resources.

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[3] For more information, see http://rtf.nwcouncil.org/ and http://neep.org/emv-forum/.

[4] For more information on performance incentives, see http://aceee.org/sector/state-policy/toolkit/utility-programs/performance-incentives.

The following types of costs are commonly incurred by energy efficiency program administrators as the direct costs to administer programs:

a. direct rebates or incentives to customers
b. engineering or technical support
c. program administration, planning, and delivery
d. evaluation, measurement, and verification (EM&V)
e. marketing and education[5]

The second general category is performance incentives, which are either utility shareholder incentives or performance management fees for non-utility program administrators. Both are typically established as a way to encourage greater levels of efficiency, and typically they are earned only if certain thresholds of energy savings are met or exceeded. While utilities earn the incentives for good performance and may not perceive them as a direct cost of efficiency programs, ratepayers foot the bill for performance incentives, so they need to be accounted for in calculating the overall cost of delivering energy efficiency resources. Not all jurisdictions, however, adopt performance incentives: currently 28 states have them in place for at least one major utility (Downs et al. 2013). We have chosen to include performance incentives as a cost component of delivering energy efficiency resources because they are a direct way to encourage energy efficiency performance, and they are equivalent to a rate of return that utilities would earn on a supply-side investment.[6]

Participant Costs

In addition to the program costs incurred by administrators, program participants may spend additional money to purchase or install energy efficiency upgrades. Depending on the type of cost-effectiveness test used (as discussed later in this section), participant costs may or may not be included as a component in cost-effectiveness screening. The total resource cost (TRC) test, for example, includes participant costs, while the utility or program administrator cost test (UCT/PACT) assumes the perspective of the utility planner and so does not take participant costs into account.

The best way to directly compare efficiency costs to supply-side options is to take the perspective of the UCT/PACT and focus on the cost of energy efficiency programs as a resource option to utility planners. Since this is how we focused our analysis, we did not conduct an extensive review of participant costs. Although we did collect some limited data, most annual program administrator reports do not include participant cost estimates and benefits. Participant costs are used as an input to the TRC calculations, however, and therefore embedded in the results of any TRC test. See the Methodology and Results sections for further details on participant cost estimates and TRC test results.

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[5] For all of these cost types, the nomenclature and reporting vary across jurisdictions.

[6] Including this factor in comparisons with the cost of supply-side resources is only appropriate if those supply cost estimates include all associated utility "incentives" (e.g., rate of return).

Decoupling and Lost Fixed Cost Recovery

Symmetrical decoupling is a way to remove the throughput incentive to utilities, which otherwise links utility profits to increased energy sales. While the decoupling mechanism is a critical component of a regulatory approach that puts efficiency on a level playing field with supply resources, it should not be considered a cost of delivering energy efficiency programs. Rather, it is used to improve regulatory certainty in ratemaking. Decoupling was widely adopted in the gas utility industry, for example, during the era of declining energy sales.

Mechanisms to directly compensate utilities for lost fixed cost are a different approach than decoupling.[7] These mechanisms allow utilities to recover fixed-cost revenues that are "lost" due to energy savings from efficiency, but they do not adjust rates downward if revenues are greater than authorized.

Neither decoupling nor lost fixed cost adjustments are costs of delivering efficiency services, because they do not increase total revenue requirements. Rather, they are rate tools designed to reallocate fixed costs in different ways, i.e., to recover the same fixed costs that would have been recovered anyway. For these reasons, neither mechanism is included in our analysis of efficiency costs.

It is noteworthy that these policy mechanisms are being used as a way to improve the business case for energy efficiency. Currently 13 states have full revenue decoupling for at least one major electric utility in the state, and 19 states have lost fixed cost mechanisms for at least one utility (Downs et al. 2013). Recent literature has explored the impact of decoupling on rates and found that most rate adjustments (64%) are within plus or minus 2% of the retail energy rate, which amounts to about $2.30 for the average electric residential consumer (Morgan 2012).

EVALUATION, MEASUREMENT, AND VERIFICATION (EM&V) OF ENERGY SAVINGS

Dating back to the 1970s and 1980s, EM&V of energy efficiency results aims to assess the performance and implementation of programs, document and measure their effects, help program planners improve performance, and ensure that programs are cost effective. The State and Local Energy Efficiency Action Network (SEE Action) defines EM&V as the

> collection of approaches for determining and documenting energy and non-energy benefits resulting from end-use energy efficiency activities and programs. Effective EM&V can confirm energy savings, verify cost-effectiveness, and guide future energy efficiency investment decisions.[8]

Various international, national, and regional groups have been working to improve consistency and standardization in the EM&V process. For example, the International

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[7] These are often called lost revenue adjustment mechanisms (LRAM) or lost contribution to fixed costs (LCFC).

[8] See http://www1.eere.energy.gov/seeaction/evaluation.html.

Performance Measurement and Verification Protocol (IPMVP), published by the Energy Valuation Organization, defines standard terms and provides a framework for verifying project-specific energy efficiency savings. In the United States, the Department of Energy's SEE Action network, the NEEP EM&V Forum, and the Regional Technical Forum (RTF) of the Northwest Power and Conservation Council all have initiatives to develop common standards and approaches to verify and evaluate efficiency savings.

While efforts to improve consistency in energy savings EM&V have expanded, in practice states still use a diverse set of methods to document savings. Not only do they use a variety of cost-effectiveness tests, as discussed below, but they also have various approaches to the energy savings calculations themselves. For example, whereas most states use deemed savings (i.e., predetermined engineering estimates of savings per measure, or savings estimates verified in past EM&V studies), some states use different methodologies to calculate savings after measures are installed.[9] Similarly, states have different approaches to achieving consistency in evaluation. Many adopt their own technical resource manual (TRM) as a way to specify engineering calculations for estimating savings. Others in regions such as the Northeast or Northwest may share resources, and still others do not have standard methodologies.

Net Versus Gross Savings

Another key methodological difference among states in evaluating energy savings is whether they estimate net or gross energy savings impacts from efficiency programs (or both). The definition of these terms, methodology used, and application for use also vary. Gross energy savings impacts are "changes in energy consumption that result directly from program-related actions taken by participants in an energy efficiency program, regardless of why they participated" (NREL 2013). Net energy savings are "changes in energy use attributable to a particular energy efficiency program. These changes may implicitly or explicitly include the effects of factors such as freeridership, participant and non-participant spillover, and induced market effects" (NREL 2013).[10] In practice, net savings calculations typically account for freeridership, but only sometimes account for spillover and induced market effects.

A recent national review by ACEEE examines and documents state practices, precedents, and issues regarding net and gross savings (Kushler, Nowak, and Witte 2014). The study finds that the majority (54%) of the 43 states that responded to the survey estimate net energy savings using specific values for programs, another 5 states apply a uniform net-to-gross (NTG) ratio, another 4 states estimate both net and gross, and the final 11 states estimate gross savings only. The study's review of states and national experts makes it clear that both net and gross savings can serve useful purposes. For example, estimates of net savings help program improvement as they provide information toward minimizing

[9] ACEEE's 2012 survey of EM&V practices found that 36 of the 42 states that responded used deemed savings values to calculate energy savings (Kushler, Nowak, and Witte 2012).

[10] Freeriders are participants who would have adopted efficiency measures in the absence of the program.

freeriders, while gross savings are more straightforward and less expensive to estimate. Overall, there is a need and often regulatory pressure to understand the net impacts attributable to programs, especially as a way to calculate things like cost effectiveness and lost revenue adjustments in order to protect ratepayer interests.

For our CSE calculations, we chose to use net energy savings figures, which most jurisdictions reported. We recognize that methodologies for calculating net savings can vary by state and jurisdiction, making it difficult to directly compare results. However, because the focus of this review is on energy efficiency as a resource for utility planners, and since stakeholders by and large are most interested in the net impacts of efficiency programs on energy usage, we decided to focus on cost effectiveness based on net savings.

Electricity Savings at Site or Generation Level

Another variation in reporting of energy savings (for electricity only) is that some entities report "at-site" savings, i.e., at the customer meter, whereas others report "at-generation" savings, which add in estimated transmission and distribution (T&D) line losses that are avoided. The at-generation approach is an attempt to directly compare the energy savings to the electric generation that would otherwise be needed to offset the efficiency gains. It is useful in integrated resource planning (IRP) because it puts efficiency on a level playing field with supply-side resources.

At-generation savings are most appropriate for comparing efficiency costs to electric supply resources, and perhaps the appropriate framework for this analysis. However at-site savings are more useful for comparing efficiency gains to overall electricity sales, and they are the most common and longstanding approach to measuring and evaluating energy savings. Moreover most state EERS are established as a percentage of retail sales. For these reasons, this analysis presents energy savings data at site or meter. In the Results section, we also examine the implications of using generation-level energy efficiency savings.

While this range of diversity in methodology among states makes it challenging to compare cost values, our review tries to make the differences across states transparent. See the Methodology section for more details.

LEVELIZED COSTS VERSUS FIRST-YEAR COSTS

Program managers and regulators typically use two general approaches to express the costs of energy efficiency portfolios relative to energy savings: (1) levelized CSE and (2) first-year "acquisition" costs. Since both approaches provide meaningful information to planners, we review them both. However, ACEEE finds that levelized costs are the best way to compare efficiency program costs to supply options, and therefore we place more emphasis on this metric. By levelized, we mean that upfront investments are annualized over the life of the investment assuming a real discount rate.

Energy planners commonly use levelized costs as a way to express the costs of long-term energy supply investments. For electricity generation technologies, for example, the levelized cost represents the per-kWh cost expressed in real dollars of building and

operating a power plant over an assumed financial life, duty cycle, and capacity factor.[11] Similarly, levelized cost is an appropriate metric for energy efficiency resources, which continue to save energy over several years of their effective useful lifetime. A full description of the cost-of-saved energy approach is included in the Methodology section.

A second approach to expressing efficiency program costs relative to their savings is to use first-year costs, which are representative of the annual costs to administer an efficiency portfolio divided by the energy savings in the first year only. These are sometimes called energy efficiency acquisition costs, and they can be useful for program budgeting purposes. Program administrators and regulators tend to focus on first-year costs when they are faced with one-year savings targets. These costs, however, do not take into account the full value of efficiency investments because they capture only the first-year savings, whereas the measures continue saving energy throughout their useful lifetime.[12] (We present data on typical measure lifetime in the Results section.) In other words, higher first-year costs do not necessarily mean higher levelized CSE values. First-year costs thus misrepresent the full benefits of efficiency. Furthermore, supply-side investments are not typically assessed based on the full upfront costs.

COST-EFFECTIVENESS TESTS

Regulators typically predicate energy efficiency programs on the fact that they are cost-effective compared to their avoided costs.[13] This adds a layer of rigor to the requirements for energy efficiency program review, necessitating detailed analysis to evaluate how efficiency costs and benefits accrue to various parties with different perspectives.

Utilities and other program administrators use some combination of various cost-effectiveness tests. These tests have evolved from the first California Standard Practice Manual in 1983, which has been periodically revised since then, most recently in 2011. Representing various perspectives, the five standard cost-effectiveness tests are

[11] See http://www.eia.gov/forecasts/aeo/er/electricity_generation.cfm

[12] For example, two measures can have identical levelized costs, while the first-year cost for a measure with a shorter lifetime (e.g., CFLs) appears lower than that of a measure with a much longer lifetime (e.g., insulation).

[13] The term "avoided costs" originated with federal laws designed to encourage independent power production. They refer to the costs that utilities would incur to produce one more unit of electricity (kWh) and/or capacity (kW) or one more unit of natural gas (therm). For energy efficiency cost-effectiveness evaluation, avoided costs refer to the energy-related and capacity-related costs that would have been incurred by utilities if the energy efficiency measures had not been adopted. Thus they are used as a reference point against which efficiency programs are compared. The methodology for calculating avoided costs can vary significantly across jurisdictions.

- Utility/Program Administrator Cost Test (UCT/PACT)
- Total Resource Cost (TRC) test
- Societal Cost Test (SCT)
- Participant Cost Test (PCT)
- Ratepayer Impact Measure (RIM) test

Numerous resources are available on the topic of cost-effectiveness tests (e.g., National Action Plan for Energy Efficiency 2008; Woolf et al. 2012; Kushler, Nowak, and Witte 2012).[14] A recent national review by ACEEE found that most states use a combination of the tests, with the TRC being the most widely used as the primary test and the RIM rarely being used (Kushler, Nowak, and Witte 2012). For information on each state's approach to cost-effectiveness tests, see the ACEEE State Energy Efficiency Policy Database.[15]

From a utility resource planning perspective, the UCT is the preferred approach for evaluating energy efficiency as a resource for utility planners, and thus is the focus of this report. A handful of states use the UCT as their primary test: Connecticut, Michigan, New Mexico, Texas, and Utah. The TRC, although most widely used as the primary test, can be challenging to implement properly because it takes a system-based approach that requires all costs and benefits to be fully accounted. While costs to utilities and customers are relatively straightforward to count, the benefits are less straightforward, particularly for customers, and as a result they are often underreported (Kushler and Neme 2010).

Given the diversity of cost-effectiveness tests used across the states as well as methodological differences such as discount rates, the results of these tests can be difficult to compare across jurisdictions. While the focus of this review is on the cost of saved energy, we also collected the benefit/cost (B/C) ratio results of the TRC when they were available.

ENERGY EFFICIENCY VALUATION IN INTEGRATED RESOURCE PLANNING

Energy efficiency program costs are typically evaluated differently than other energy resources: they are evaluated against the avoided costs of supply options. In other words, regulators want to know how the cost of procuring additional energy efficiency compares to the prevailing cost of the next marginal unit of supply that would otherwise be incurred. Efficiency resources that cost less than avoided costs are deemed cost effective.

As efficiency gains traction as a resource option, efficiency programs should be incorporated into integrated resource plans (IRP) and other planning tools that truly optimize efficiency as analogous to a supply-resource option. Although many states began to do this in the 1980s and many continue today, efficiency is typically treated through scenarios of the demand curve rather than as an explicit resource option. Improved analysis of energy efficiency program costs and impacts in terms of procured energy (kWh) and demand (kW)

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[14] Resources are available from the Regulatory Assistance Project (RAP), the SEE Action Network (and its predecessor the National Action Plan for Energy Efficiency), and ACEEE.

[15] http://www.aceee.org/sector/state-policy

savings will be crucial to the incorporation of efficiency into multi-objective resource planning tools. For more information, see the resources offered by the Regulatory Assistance Project (RAP) on best practices for the incorporation of energy efficiency into IRP processes (e.g., RAP 2013).

Methodology

This section describes the data collection process for this study, the challenges and caveats attendant on processing the data, and the various calculations used to estimate the CSE and first-year acquisition costs.

DATA COLLECTION AND PROCESSING

For this review, we collected data on energy efficiency program costs and energy savings from secondary sources including annual reports, EM&V reports, and in some cases individual requests to contacts at public utility commissions (PUCs), utilities, and state agencies. ACEEE's 2009 review collected data from 14 states. Now, with more states developing comprehensive energy efficiency portfolios and reporting their results, we were able to collect data for 20 states for electricity programs, as shown in table 1, and 10 states for natural gas efficiency programs, as shown in table 2. We chose the states for two reasons: (1) they were included in the last study and thus were good candidates to include again, and/or (2) they had readily available cost data in consistent reporting formats. Other states or utilities may have had data on energy efficiency program cost effectiveness, but if they did not have consistent and transparent metrics reported in a common location, they were not good candidates for this study. ACEEE hopes to continue conducting reviews of this sort and to expand the data set in the next update.

Table 1. States and program administrators covered in the review: electricity programs

	State	Program administrator covered		State	Program administrator covered
1	Arizona	Arizona Public Service Company (APS)	11	New Mexico	Public Service of New Mexico
2	California	IOUs	12	New York	NYSERDA
3	Colorado	Xcel Energy	13	Nevada	NV Energy
4	Connecticut	CEEF (all IOUs)	14	Oregon	Energy Trust of Oregon
5	Hawaii	Hawaii Energy	15	Pennsylvania	IOUs
6	Illinois	Ameren and Com-Ed	16	Rhode Island	National Grid
7	Iowa	IOUs	17	Texas	IOUs
8	Massachusetts	IOUs	18	Utah	Rocky Mountain Power
9	Michigan	All utilities	19	Vermont	Efficiency Vermont

	State	Program administrator covered		State	Program administrator covered
10	Minnesota	Xcel Energy	20	Wisconsin	Focus on Energy

IOUs are investor-owned utilities.

Table 2. States and program administrators covered in the review: natural gas programs

	State	Program administrator covered
1	California	IOUs
2	Colorado	Xcel Energy
3	Connecticut	CEEF
4	Iowa	IOUs
5	Massachusetts	IOUs
6	Michigan	All utilities
7	Minnesota	Xcel Energy
8	Oregon	Energy Trust of Oregon
9	Rhode Island	National Grid
10	Wisconsin	Focus on Energy

IOUs are investor-owned utilities.

We collected 10 data points for 2009 to 2012 annual program years as available. Some states did not yet have 2012 data available, and others only had one or two years available. Not all data points were available for all states. Note that in many cases we had to manipulate the data to permit consistent comparison among programs, e.g., by subtracting out demand response or renewable energy program costs. We provide some details here for each of the data points collected and processed, and we further discuss key challenges and caveats in the next section.

1. *Annual total program costs by program year.* We included energy efficiency program portfolio costs only, not renewable energy or demand response.

2. *Annual program costs by customer class (residential and business).* Most states categorize classes by residential and business, whereas only a couple of jurisdictions disaggregate business customers into commercial and industrial. Low-income programs are often categorized separately; however we chose to include these programs in the residential category for convenience in reporting.

3. *Shareholder or performance incentives awarded annually as applicable.* We collected data for those states with performance incentives that had been approved for the applicable program

year. In a couple of cases (e.g., Wisconsin), performance incentives are awarded on a cumulative-year basis, and so they were not yet approved and were not included in our estimates.

4. *Annual costs by type (customer incentives, non-incentive program costs, and shareholder/performance incentives).* Several of the jurisdictions in our review reported customer incentives as a distinct category, and some reported numerous other categories of spending such as administrative, research and development, education, and marketing. In these cases, we combined all non-incentive costs into one category. Other states may have reported program costs as distinct from administrative or EM&V; however it was unclear whether the definition of program costs included both customer incentives and other program-related costs.

5. *Annual participant cost estimates.* Only a handful of states explicitly and readily report participant contributions to energy efficiency measures, or at least report full incremental measure costs. It is possible to derive participant cost contributions by subtracting incentives from full incremental measure costs.

6. *Gross and net energy (kWh and therms) savings reported, both total and by customer class.* We collected both gross and net electricity and natural gas savings from efficiency programs, and by customer class if available. For electricity savings, we noted whether savings were reported at site or at generation. We also collected some data on electricity demand (kW) impacts, but not comprehensively enough to report here.

7. *Applicable electricity sales within jurisdiction.* We collected electricity sales for the jurisdictions included in the state for 2010, which is the most readily accessible data point from the Energy Information Administration (EIA) for all jurisdictions. We collected electricity sales data in order to normalize savings as a percentage of sales and to compare this metric to CSE values.

8. *Measure lifetimes by customer class.* As available, we collected measure lifetimes by customer class and in aggregate for the entire portfolio as an input to CSE calculations.

9. *Cost-effectiveness test ratios.* We collected these for TRC tests and UCT/PACT, as available.

10. *Weighted average cost of capital assumed in cost-effectiveness calculations.* In some cases, program administrators reported their own utility CSE values. We collected the weighted average cost of capital (WACC) that was assumed for these calculations, along with aggregate measure lifetimes, in order to derive first-year cost assumptions. Also, we were interested in this metric in general to compare to our own assumptions, and so we also collected WACC and social discount rate assumptions for other states as available.

CHALLENGES AND CAVEATS

As previously discussed, there are a number of challenges involved in the collection and comparative review of national energy efficiency cost-effectiveness data. In light of these, the goal of this report is not to compare one state's efficiency portfolio results to others, but

to present overall information and trends in energy efficiency program costs and cost effectiveness—and also to improve the transparency of key data issues. This section explores several of the challenges and discusses our approach to improving consistency within the dataset.

Variation In Reporting Formats, Frequency, And Timing

Most utilities and program administrators prepare annual reports on the impacts of efficiency programs, and some prepare reports more frequently, e.g., semiannually or quarterly. The frequency and formats are usually based on regulator requirements; however this varies by state. In some limited cases, annual reports present only cumulative data for multiple years and not distinct annual results.

The location and consistent availability of reports vary significantly by state. Some utilities and program administrators post reports on their own websites, others file them on commission websites or within commission dockets, some states have a separate website hosted by an advisory group, or there may be combination of these approaches. Program administrators who do not produce reports that are readily available in a common location were less likely to be included in this study.

Most program administrators are required by their regulators to calculate cost and energy impacts separately for electricity and natural gas programs (and they may also present combined results). A few states combine electricity and natural gas programs in their reporting. In some cases, on request, program administrators suggested a methodology for disaggregating program costs; in other cases we were unable to disaggregate the data and so these jurisdictions were not good candidates for this type of review. Similarly, renewable energy programs or demand response programs were sometimes combined in the overall reporting of cost-effectiveness metrics. In these cases we backed out these program costs and savings impacts to isolate the energy efficiency programs.

Variation In Reporting of Net or Gross Energy Savings, and At-Site or At-Generation Electricity Savings

As discussed earlier, we chose to calculate and report CSE values based on net energy savings. The great majority of jurisdictions in this review reported net energy savings values. A couple of states or program administrators explicitly assume that net and gross savings are equivalent, i.e., that there is a 100% NTG ratio. Only a couple of states in our data set (Minnesota and Nevada) do not estimate net savings; in those cases we adjusted gross savings figures by an NTG ratio of 0.9 to estimate net savings and make them more comparable to net savings figures reported by other states.[16] An NTG ratio of 0.9 falls within the range of factors used by several states in calculating net energy efficiency savings.

As discussed earlier, some states report electricity savings at the customer or site level while others report savings at the generation level. At-site savings appear to be the most common and longstanding approach to measuring and evaluating energy savings; moreover most

[16] This methodology is consistent with ACEEE's *State Energy Efficiency Scorecard* (Downs et al. 2013).

state EERS are established as a percentage of retail sales. For these reasons, this review presents at-site energy savings data. In some cases we converted at-generation savings to at-site savings assuming the same line loss factor used by the reporting entity.

Demand Response

Many program administrators combine their reporting of energy efficiency (EE) and demand response (DR) programs in their overall demand-side management reports and evaluations.[17] While EE aims to reduce overall energy usage (kWh), DR aims to curtail demand (kW) only during peak hours or to shift usage from peak hours to off-peak hours. As demand-side resources, EE and DR have documented synergies; for example, EE can contribute on-peak demand reductions, and DR can produce some kWh savings. However they remain fundamentally different resources. This review focuses exclusively on EE costs and energy (kWh) savings. In some cases we had to subtract out DR costs from reported spending to focus on EE costs and benefits.

Structural Differences in Program Portfolios

In addition to variations in reporting and evaluation methods, numerous differences in the structure of efficiency programs can affect efficiency costs. The type of programs offered, the relative share of program savings from different customer classes, and the range of eligible efficiency measures can all affect program cost effectiveness. These factors can also impact the balance of incentive versus non-incentive program costs. While this study does not tease out costs by program type, we do classify costs by customer class and try to identify trends. For trends in costs at the program level, readers should review an analysis by the Lawrence Berkeley National Laboratory (LBNL 2014).

Differences In Program Cost Type Definitions

As discussed earlier, energy efficiency program administrators commonly incur the following types of costs as the direct costs to administer programs, with the nomenclature and reporting often inconsistent across jurisdictions:

a. direct rebates or incentives to customers
b. engineering or technical support
c. program administration, planning, and delivery
d. EM&V
e. marketing and education

In particular, the definition of cost categories such as "administrative" varies by state, and sometimes categories are not disaggregated. Nor is this an exhaustive list of current or future cost types. Emerging programs such as behavioral and loan programs may require new cost-type definitions.

In addition, whether a program administrator earns a shareholder or performance incentive can increase the cost of energy efficiency resources. Also, we note that some states have an

[17] Demand response is also referred to as load management; however "demand response" is the more modern term.

incentive mechanism in place but they award it on a cumulative basis. If the award had not yet been finalized for program years 2009-2012, we did not include it in this analysis. Future work on CSE values could develop a methodology for estimating average annual values in such instances.

CALCULATIONS AND ASSUMPTIONS

After the data collection process, we first converted all cost data by program year to 2011$ using GDP deflators from the Bureau of Economic Analysis (BEA).

Utility CSE

In the 2009 review, ACEEE presented the CSE as reported by the state in many cases, while calculating the CSE for some states. Reported values have the limitation that input assumptions may not be clear, which create inconsistencies in the data set. For this update, to attempt a more consistent review and methodology, we instead calculate the CSE for each state, as shown below.

To calculate the CSE, we multiply annual energy efficiency program costs (C) by a capital recovery factor and then divide by the annual energy savings (D). The calculation for the capital recovery factor, which is used as a way to levelize or spread the costs over a specified period of time and assumed interest rate, is shown below. For consistency, we use the same real discount rate (A) for all jurisdictions. We use each state's estimated measure lifetime (B), program costs (C), and net energy savings (D). We discuss each of these elements in further detail below.

The CSE calculation is:

CSE in $/kWh = (C) x (capital recovery factor)/(D)

where:
A = Real discount rate (5%)
B = Estimated measure life in years
C = Total annual program cost in 2011$
D = Incremental net annual energy (kWh or therms) saved by energy efficiency programs
Capital recovery factor = [A*(1+A)^(B)]/[(1+A)^(B)-1]

DISCOUNT RATE The discount rate for energy efficiency cost-benefit analysis depends on the cost-effectiveness test used. For the utility cost test and TRC, jurisdictions typically use the utility's WACC. The SCT takes a societal perspective and should use a lower social discount rate to appropriately value long-term societal perspective. We collected some utility data on WACC rates, and found that they ranged from 7% to 8% over the 2009-2012 period. It was not always clear whether these values were nominal or real; however we presumed them to be nominal rates because they were used for annual reporting and in some cases they were

confirmed as nominal.[18] We also collected some data on assumed social discount rates used for cost-effectiveness screening and found they ranged widely from about 1.2% to 6.0% (real).

The current practice of assuming the WACC for energy efficiency cost-effectiveness screening, however, has been criticized as undervaluing the reduced risk of energy efficiency program expenditures versus supply-side investments (Woolf et al. 2012). To reflect the lower financial risk of efficiency investments, some jurisdictions have adopted alternative discount rates for energy efficiency valuation in the UCT and TRC tests, such as a societal discount rate or a risk-adjusted discount rate. In Massachusetts, for example, regulators have acknowledged that energy efficiency resources are a low-risk investment and that a low-risk discount rate is most appropriate for the TRC test (Woolf et al. 2013). In the Northwest, the preferred approach is to use a risk-free discount rate for both supply resource and energy efficiency, and then to explicitly model resource risk (i.e., fuel price, environmental regulation, capital cost, and so forth) in the analysis of resource options (Northwest Power and Conservation Council 2010). This approach improves transparency by requiring that the type and magnitude of risk estimates for each resource are displayed.

For this analysis, we assume a real discount rate of 5% (value A in our CSE calculation) for the overall presentation of the results.[19] This is meant to be fairly consistent with the weighted average utility cost of capital in real terms, and is consistent with the approach in the 2009 ACEEE review of energy efficiency costs. We also report the aggregate CSE values (for all states) in the Results section using a 3% real discount rate and 7% real discount rate to show the impact of this assumption on the results.

MEASURE LIFETIME The estimated measure lifetime in years (B) is based on data from the program administrator, if available. For some states (Colorado, Illinois, Michigan, Nevada, Pennsylvania, and Texas), we were unable to track down average measure lifetime estimates for the entire portfolio. In some cases these states did report program- or measure-specific measure lifetimes; however, due to time constraints, we were unable to go through all program data to develop an average portfolio-wide estimate ourselves. Instead, for these states we assumed an overall 11-year measure lifetime, which was the average of states that did provide data. Similarly, to estimate CSE values by customer class, if state-specific data were not available, we assumed an 8-year measure lifetime for the residential class and 12.5 years for the business class, which were the average values for states that did provide data.

COSTS AND SAVINGS Total program costs (C) and incremental net annual energy savings (D) are based on data collected from the program administrators, as previously discussed and defined. Note that we used net savings (D) as available. Some states assume that net savings

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[18] Real discount rates do not include inflation, whereas nominal discount rates do. Assuming 1% inflation, these nominal WACC rates of 7-8% would range from 6% to 7% in real dollar terms. Assuming 2% inflation, they range from 5% to 6%.

[19] In deciding whether to use a nominal or real discount rate, the key is consistency. This analysis examines energy efficiency program costs in real (2011$) terms, and therefore we apply a real discount rate.

equal gross savings (i.e., a 100% NTG ratio); a couple of states do not estimate net savings, in which case we estimated net savings using an NTG ratio of 0.9.

First-Year Acquisition Costs

We also calculate the first-year acquisition costs ($ per kWh-net or $ per therm-net), as shown below:

First-year cost in $/kWh net or $ per therm net = C / D

where:
C = Total annual program cost in 2011$
D = Incremental net annual energy (kWh or therms) saved by energy efficiency programs

Energy Savings Relative to Sales

For the electricity data set, we collected data on actual electricity sales in each applicable jurisdiction for one year (2010). We then were able to calculate energy savings as a percentage of applicable energy sales in the given jurisdiction. This allowed for a direct comparison of energy savings thresholds to energy costs.

Results

This section presents the results of the review. Data sources for each state can be found in Appendix A.

ELECTRICITY

The review includes electricity energy efficiency program data for the 20 states listed in table 1 above.

Cost of Saved Energy

Our results are focused on the CSE values as presented in figure 1 and table 3 below. We emphasize again that the goal is not to compare results among states, but to present an overall picture of the range and typical values across many different jurisdictions, each of which has its own factors that bear on the costs of efficiency programs. For example, note that the costs in figure 1 range from $0.013/kWh to $0.056/kWh, a spread of about $0.042/kWh.

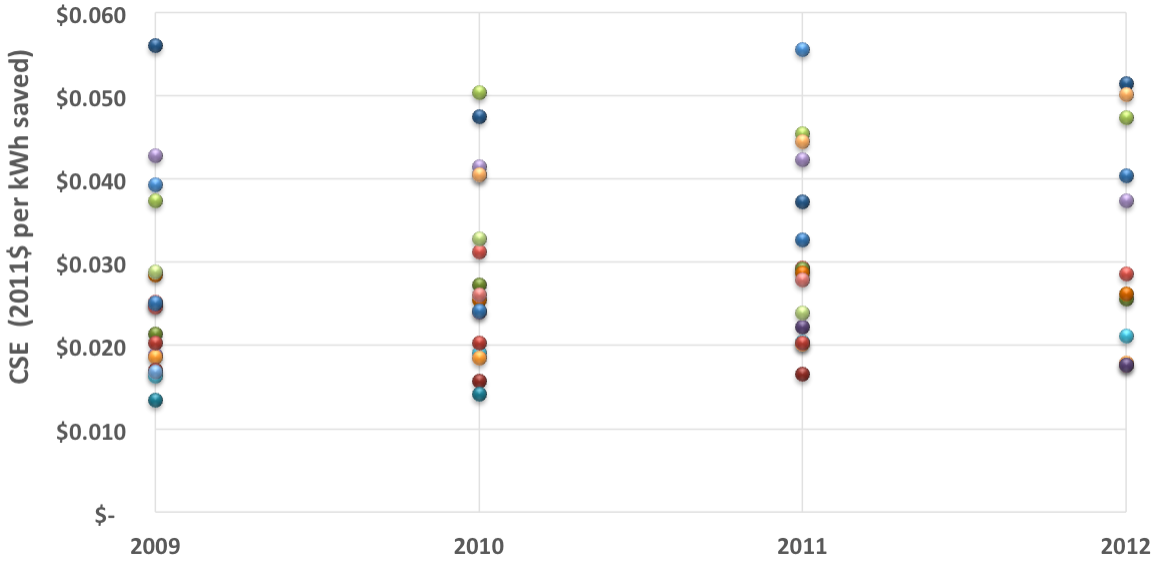

Figure 1. Electricity energy efficiency program CSE by year. Each dot represents average costs for each state in a given year. 2011$ per levelized net kWh at meter. Assumes 5% real discount rate.

Table 3 presents the average for each state for each year, and the state's four-year average from 2009 to 2012. We were unable to calculate data for every state for each year due to missing data points, which means that the overall average for each year represents a varying number of jurisdictions.

Table 3. CSE in $ per levelized net kWh at meter

State	2009	2010	2011	2012	4-year average (2009-2012)
Arizona	$0.016	$0.019	$0.020	$0.021	$0.019
California	$0.039	$0.041	$0.056	n/a	$0.045
Colorado	$0.023	$0.029	$0.027	$0.027	$0.027
Connecticut	$0.037	$0.050	$0.045	$0.047	$0.045
Hawaii	$0.025	$0.024	$0.033	$0.040	$0.031
Illinois	n/a	n/a	$0.019	n/a	$0.019
Iowa	$0.019	$0.018	$0.020	$0.018	$0.019
Massachusetts	$0.056	$0.048	$0.037	$0.051	$0.048
Michigan	$0.017	$0.016	$0.017	$0.018	$0.017
Minnesota	$0.021	$0.027	$0.029	$0.026	$0.026
New Mexico	$0.025	$0.024	$0.022	$0.018	$0.022
Nevada	$0.013	$0.014	$0.016	$0.020	$0.016

State	2009	2010	2011	2012	4-year average (2009-2012)
New York	$0.020	$0.020	$0.020	n/a	$0.020
Oregon	$0.028	$0.025	$0.029	$0.026	$0.027
Pennsylvania	n/a	n/a	$0.017	n/a	$0.017
Rhode Island	n/a	$0.040	$0.044	$0.050	$0.045
Texas	$0.025	$0.026	$0.028	n/a	$0.026
Utah	$0.029	$0.033	$0.024	$0.029	$0.029
Vermont	$0.043	$0.041	$0.042	$0.037	$0.041
Wisconsin	n/a	n/a	$0.022	$0.015	$0.019
Average	**$0.027**	**$0.029**	**$0.028**	**$0.030**	**$0.028**
Median	**$0.025**	**$0.026**	**$0.026**	**$0.026**	**$0.026**
Minimum	**$0.013**	**$0.014**	**$0.016**	**$0.015**	**$0.016**
Maximum	**$0.056**	**$0.050**	**$0.056**	**$0.051**	**$0.048**

2011$. 5% real discount rate. N/A means that we were unable to track down sufficient data for the calculation. Average for each year represents a varying number of states, so they are not directly comparable.

For the four-year average values in the column furthest to the right, we find an overall national average of $0.028/kWh, and a range of $0.016 to $0.048/kWh. As pointed out in the Discussion section, these typical efficiency program costs compare very favorably to the typical costs of new electricity generation.

The values in table 3 vary among states due to numerous factors such as structural differences in program types and share of savings by customer class. For example, portfolios with a larger share of savings from residential programs or low-income programs tend to have higher overall CSE values. (We present some data by customer class for several states later in this section.) On the other hand, program portfolios that rely heavily on low-cost lighting programs, or that have lower shares of savings from low-income programs, tend to have lower CSE values. An analysis by LBNL provides further insight into specific CSE values and ranges for different types of programs (LBNL 2014).

In addition, the eligibility and attribution of non-electricity savings from programs differ by jurisdiction, which can affect the cost of saved electricity. For example in Massachusetts, electric ratepayer funds are used to support investments in oil and propane energy savings. Because the values in table 3 are developed using total electric spending (without adjusting for spending on oil and propane savings) and total electric savings, the cost per unit of electricity savings appears higher than it would if spending were adjusted for non-electricity savings.

The CSE values in figure 1 and table 3 represent costs per net electricity savings, and they assume a 5% real discount rate. This rate is meant to be roughly consistent with the typical nominal utility WACC of about 7%. We also wanted to calculate and compare the values under different real discount rate assumptions. Table 4 presents values for 3%, 5%, and 7% real discount rates.

Table 4. CSE values under various real discount rate assumptions

	3% real discount rate	5% real discount rate	7% real discount rate
Average	$0.025	$0.028	$0.031
Median	$0.023	$0.026	$0.029
Minimum	$0.014	$0.015	$0.018
Maximum	$0.043	$0.048	$0.054

These values represent aggregate 4-year averages (2009-2012) for all states.

Table 4 shows that a difference of 2% in the discount rate assumption can impact the CSE values by about 10-12%, which is minimal compared to the wide margin between energy efficiency portfolios and alternative energy options. For specific programs on the margins, however, the assumed rate can have an impact on whether programs are deemed cost effective.

From a utility resource planning perspective, it is important that analysts use appropriate discount rates for energy efficiency and supply side resources, considering their relative risks and other characteristics, in any levelized cost analyses. As discussed earlier, planners should also consider explicitly modeling resource risk in their analysis of resource options.

All these results reflect energy savings reported at the meter, which is how most states report energy efficiency savings. However, as discussed earlier, the more appropriate metric for comparing costs to supply-side resources may be savings at the generator level, which account for T&D line losses that are avoided by efficiency. EIA estimates a national average line loss factor of 7%.[20] If we convert the savings values at the meter level to the generator level, the average CSE value of $0.028/kWh would decrease by 7% to $0.026/kWh. No matter which method is chosen, the most important thing is that the assumptions be transparent and that avoided T&D line losses be factored into the cost-effectiveness analysis in some way.

First-Year Acquisition Costs

In addition to the CSE values, in figure 2 and table 5 we present the first-year program costs (non-amortized), which are often called acquisition costs. As noted earlier, first-year costs

[20] See http://www.eia.gov/tools/faqs/faq.cfm?id=105&t=3

can be useful for program budgeting purposes, but we caution that this metric is not reflective of the full resource value of efficiency.

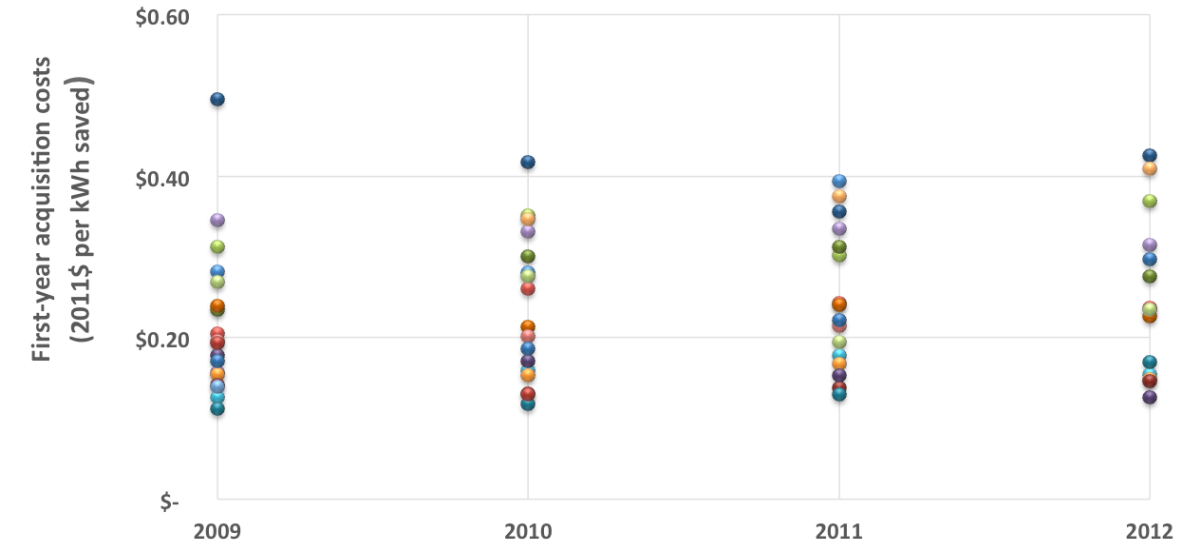

Figure 2. Electricity energy efficiency program first-year acquisition costs by year

Table 5. First-year acquisition costs

State	2009	2010	2011	2012	4-year average (2009-2012)
Arizona	$0.13	$0.16	$0.18	$0.15	$0.15
California	$0.28	$0.28	$0.39	n/a	$0.32
Colorado	$0.20	$0.26	$0.24	$0.24	$0.24
Connecticut	$0.31	$0.35	$0.30	$0.37	$0.33
Hawaii	$0.17	$0.19	$0.22	$0.30	$0.22
Illinois	n/a	n/a	$0.16	n/a	$0.16
Iowa	$0.15	$0.15	$0.17	$0.15	$0.16
Massachusetts	$0.49	$0.42	$0.36	$0.43	$0.42
Michigan	$0.14	$0.13	$0.14	$0.15	$0.14
Minnesota	$0.23	$0.30	$0.31	$0.28	$0.28
New Mexico	$0.18	$0.17	$0.15	$0.13	$0.16
Nevada	$0.11	$0.12	$0.13	$0.17	$0.13
New York	$0.21	$0.21	$0.21	n/a	$0.21
Oregon	$0.24	$0.21	$0.24	$0.23	$0.23
Pennsylvania	n/a	n/a	$0.14	n/a	$0.14
Rhode Island	n/a	$0.35	$0.37	$0.41	$0.38

State	2009	2010	2011	2012	4-year average (2009-2012)
Texas	$0.20	$0.20	$0.22	n/a	$0.20
Utah	$0.27	$0.28	$0.20	$0.23	$0.24
Vermont	$0.35	$0.33	$0.34	$0.31	$0.33
Wisconsin	n/a	n/a	$0.19	$0.13	$0.16
Average	$0.23	$0.24	$0.23	$0.24	$0.23
Median	$0.21	$0.21	$0.21	$0.23	$0.21
Minimum	$0.11	$0.12	$0.13	$0.13	$0.13
Maximum	$0.49	$0.42	$0.39	$0.43	$0.42

2011$ per first-year net kWh at meter. N/A means that we were unable to track down sufficient data for the calculation. Average for each year represents a varying number of states, so they are not directly comparable. Values vary among states due to numerous factors such as structural differences in program types and share of savings by customer class.

Participant Costs

Program administrators use estimates of participants' costs for energy efficiency measures as inputs to the TRC test and the SCT.[21] Program administrators typically estimate participant costs either through deemed measure costs or for custom-based programs through actual reporting by customers.

Unfortunately most program administrators do not explicitly include participant cost estimates or participant benefits in their annual reporting. However they are implicit in their TRC outcomes. It might be possible to use TRC values as compared to UCT values to derive estimates of participant costs, but this approach has obvious caveats: cost-benefit tests do not make transparent all the annual values or discount rate assumptions, and they use a net present value basis. Further work should more fully explore participant cost and associated participant benefit estimates.

Several program administrators did report estimates of annual participant contributions, or made it possible to derive participant costs as the difference between incremental measure costs and incentives paid to participants. Although limited, we report these estimates along with program costs for the states listed in table 6 below, but we caution that there are significant caveats.

[21] Participant costs are the additional costs incurred by program participants net of any incentives paid to them by program administrators.

Table 6 shows that the ratio of participant costs to program costs varies significantly by state. The ratio depends largely on the nature of the programs, e.g., the level of participant rebates versus non-financial incentives including technical assistance and marketing.

Table 6. Combined program and participant cost estimates

State	Program cost estimate	Ratio of participant costs to program costs	Participant cost estimate	Combined program and participant cost estimate
Hawaii	$0.033	149%	$0.049	$0.076
Illinois	$0.016	115%	$0.018	$0.041
Iowa	$0.019	159%	$0.030	$0.049
New York	$0.020	262%	$0.053	$0.073
Pennsylvania	$0.018	159%	$0.029	$0.043
Rhode Island	$0.045	25%	$0.011	$0.056
Wisconsin	$0.019	118%	$0.022	$0.041
Average for this dataset	**$0.024**	**141%**	**$0.030**	**$0.054**

2011$ per kWh levelized

For these seven states, the ratio of participant costs to program costs ranges from 25% to 262%, and the simple average is 141%. In other words, for every $1 invested by the program administrator, participants are estimated to spend on average an additional $1.41 on efficiency upgrades.

The sum of program costs and participant costs on average for these states is $0.054 per kWh levelized. However, given the limited dataset, this figure is highly uncertain and does not represent a national average. It is also important to recognize that this metric is not an appropriate comparison to the utility cost of supply-side resources, because it captures participant costs which are not incurred by utilities.[22]

The 2009 ACEEE review similarly collected participant costs for about six program portfolios and found that on average participants contributed $0.83 for every $1 invested by program administrators. Again, these values varied significantly across jurisdictions. The states included in the 2009 review were different from the ones in this review (only three states were included in both reviews), which explains the large difference between the 2009 results and those presented in table 6. Overall, much caution is warranted in making comparisons among jurisdictions about participant costs.

[22] The inclusion of participant costs in a cost-effectiveness test also requires incorporating participant non-energy benefits for a systematically balanced calculation. For example, see http://www.nhpci.org/publications/NHPC_EE-Screening-Coalition-Position-Paper-final_20131118.pdf.

Benefit-Cost Ratios

Next we present the benefit-cost (B/C) ratios as reported by program administrators. While the CSE values represent only the cost side of the cost-effectiveness equation, the B/C ratios represent a more complete picture of how program costs compare to program benefits. It is important to note that the benefits side of the equation can also vary significantly from state to state. Benefits include avoided energy, capacity, and T&D costs for the UCT, as well as participant and other system-wide non-energy benefits for the TRC test. Moreover, as noted earlier, implementation of the TRC test is incomplete in many states, i.e., the range of benefits calculated can vary significantly.

As in our review of CSE values, our goal is not to directly compare B/C ratios, but to present overall trends. Although most states conduct the TRC test when evaluating energy efficiency cost effectiveness, the results are not always presented clearly in reports. Therefore the TRC results presented in table 7 reflect only 9 of the 20 states. The results show that energy efficiency benefits in these states exceed costs by a factor of 1.24 to 4.0. In other words, each dollar invested by program administrators and customers in energy efficiency measures yields $1.24 to $4.00 in benefits to all customers.

Table 7. Benefit-cost ratios for TRC tests

State	2009	2010	2011	2012
California	1.83	1.61	1.24	n/a
Colorado	3.66	2.87	2.47	2.09
Hawaii	n/a	1.40	1.60	2.60
Illinois	2.15	2.84	2.24	n/a
Iowa	2.54	2.06	2.10	2.34
Massachusetts	3.28	3.11	4.00	3.50
New Mexico	1.57	2.20	1.78	2.63
Utah	1.99	1.68	1.95	2.00
Wisconsin	n/a	n/a	2.84	3.26
Minimum	**1.57**	**1.40**	**1.24**	**2.00**
Maximum	**3.66**	**3.11**	**4.00**	**3.50**

Savings by Customer Class

Figure 3 displays the results of electricity savings in several jurisdictions by customer class for 2009-2012. (17 states readily reported savings by customer class.[23]) Jurisdictions with the highest share of savings from residential customers are on the left, and those with the highest share of savings from business customers are on the right.

[23] Some of the other jurisdictions reported savings at the program level, but did not aggregate by customer class.

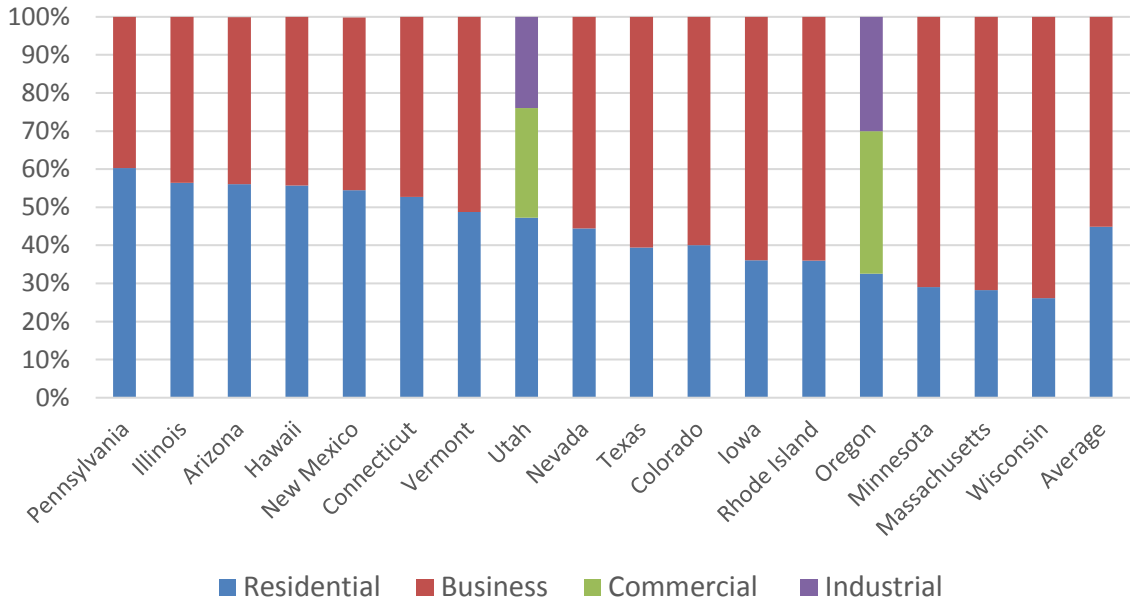

Figure 3. Electricity savings by customer class. Program administrators often report low-income programs as a separate category; we include these with residential savings. Most jurisdictions report savings in aggregate for residential customers and for business customers. Only Utah and Oregon readily reported commercial and industrial customer categories separately.

As shown in the column furthest to the right, the average savings by customer class amount to 45% from residential customers and 55% from business customers. However this ratio varies significantly by state; for example, the share of savings from residential programs ranges from 60% to 26%. There are several likely reasons for this variation. For example, the relative size of energy savings potential by customer class itself can differ from state to state, or regulators may require that a specific share of savings come from specific customer classes.

In general it appears that jurisdictions that are newer to broad-scale energy efficiency portfolios (e.g., Pennsylvania, Illinois, Arizona, and New Mexico) have a higher share of savings from residential customers, while states with more mature portfolios (e.g., Minnesota, Massachusetts, Oregon, and Rhode Island) have a higher share of savings from business customers. New program development tends to start with a large portion of funding to mass residential lighting and appliance programs, and a smaller portion to business programs, before launching into more comprehensive programs for business customers.

There is no optimal mix of savings by customer class because it may vary significantly by jurisdiction. Also, stakeholders must consider a number of factors in addition to cost effectiveness (e.g., equity) to ensure that all customer segments benefit from efficiency programs. In sum, these data show that the portion of savings by customer class can vary significantly by state, and this is a likely factor in the overall average CSE values. See the section on Costs by Customer Class for further discussion.

Measure Lifetime Estimates

Energy efficiency upgrades continue saving energy over the lifetime of the measure installed. The estimate of measure lifetime is an important factor in calculating the cost of energy efficiency resources. As with many metrics, states vary in their explicit reporting of this figure. Table 8 presents the average electricity measure lifetimes by customer class (if available) for several jurisdictions, either as they were explicitly reported or as we derived them by dividing lifetime energy savings estimates by annual energy savings estimates. For these jurisdictions, the average measure lifetime for residential programs is 8 years, for business programs, about 13 years, and for the overall portfolio, about 11 years.

Table 8. Average electricity measure lifetimes by state and customer class

State	Residential	Commercial/business	Industrial	All sectors
Arizona	7.3	13.4	n/a	9.8
California	n/a	n/a	n/a	9.1
Connecticut	6.5	12.8	n/a	9.6
Hawaii	6.7	12.3	n/a	9.2
Massachusetts	8	13	n/a	11.6
Minnesota	n/a	n/a	n/a	13.8
New Mexico	8	10	n/a	8.9
Oregon	10.6	13.5	9.5	11.2
Rhode Island	9.1	12.3	n/a	11.1
Utah	n/a	n/a	n/a	11.3
Vermont	7.7	13.1	n/a	11
Wisconsin	9	12.4	n/a	11.4
Average	**8.1**	**12.5**	**9.5**	**10.6**

Values for each state typically represent the average over the 2009-2012 program period, although data were not available for all years in each state.

Costs by Customer Class

We can discern some trends from the CSE results of electricity efficiency resources by customer class. First-year costs are comparable for both residential and business (commercial and industrial) programs at about $0.22/kWh. However, because business energy efficiency measures tend to have longer measure lifetimes (an average of 12.5 years in this electricity data set) than residential measures (8.1 years), the levelized CSE is on average lower for business program portfolios than for residential portfolios. We calculated electricity CSE values by customer class for 9 states as shown in figure 4 and table 9, and

identified an average CSE of $0.037/kWh for residential portfolios and $0.027/kWh for business portfolios.[24]

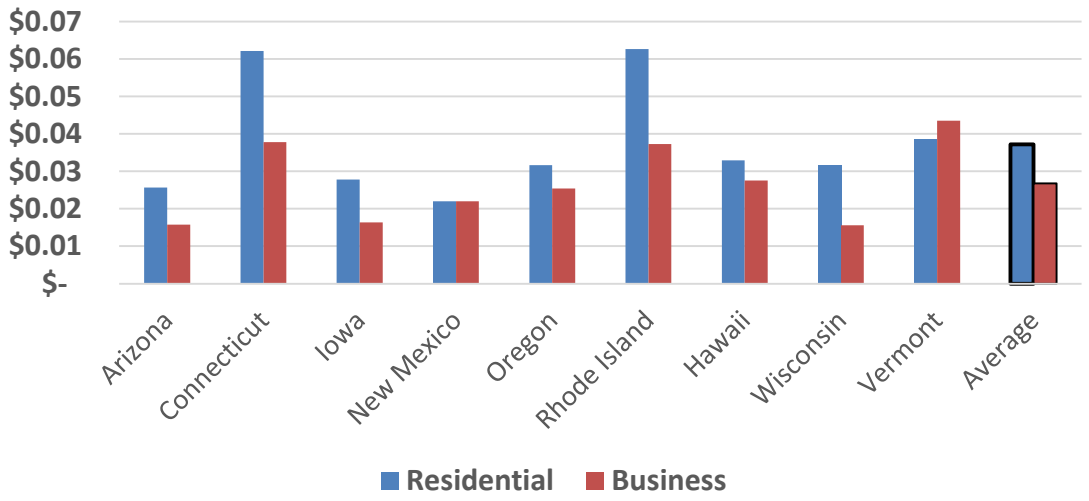

Figure 4. Electricity CSE by state and customer class, and average

Table 9. Electricity CSE by state and customer class

State	Residential	Business	All Sectors
Arizona	$0.026	$0.016	$0.019
Connecticut	$0.062	$0.038	$0.045
Iowa	$0.028	$0.016	$0.019
New Mexico	$0.022	$0.022	$0.022
Oregon	$0.032	$0.025	$0.027
Rhode Island	$0.063	$0.037	$0.045
Hawaii	$0.033	$0.028	$0.031
Wisconsin	$0.032	$0.016	$0.019
Vermont	$0.039	$0.044	$0.041
Average	**$0.037**	**$0.027**	**$0.030**

$ per kWh levelized

We selected states that had readily available data for all three components of this calculation: savings, costs, and measure lifetime by customer class. While the average difference between customer class portfolio costs is about $0.01/kWh higher for residential programs, figure 4 demonstrates that it can vary significantly by state. A couple of states

[24] Note that the overall average CSE for this limited set of states is $0.030/kWh, which is slightly higher than the complete data set average value of $0.028/kWh.

have cost differences of about $0.02/kWh higher for residential programs, while other states exhibit very negligible differences, and a few states have business programs that cost more than residential portfolios. Note also that the residential portfolio includes low-income programs, which tend to have higher CSE values and therefore (depending on the size of the programs) will have an impact on the overall residential CSE values.

We did not review individual program CSE values; however it is worth noting that there is significant variation in CSE value by program type. A report by LBNL provides information at the program level (LBNL 2014). These results again demonstrate the significant variation among jurisdictions in CSE trends by customer class. The estimates of measure lifetime values in particular are a large factor in determining CSE values.

Costs by Type

Figure 5 breaks down efficiency program costs by type, including customer incentives, performance incentives, and non-incentive program costs such as marketing, EM&V, and administrative costs.

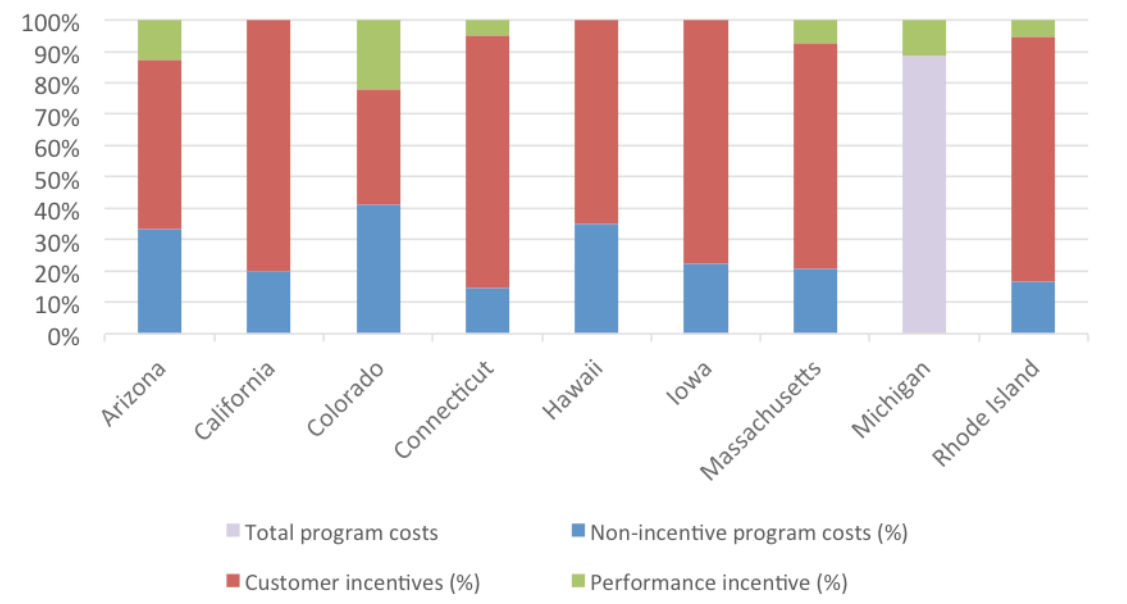

Figure 5. Electricity energy efficiency program costs by type. Some states did not explicitly define costs as customer incentives; for example, California uses the term "direct implementation costs" and Connecticut, "direct program costs." However we took these to mean customer incentives.

Since definitions of cost types vary from state to state, there is significant uncertainty in directly comparing states. In particular, the types of costs included in the non-incentive program category can vary significantly. For the 8 states shown in figure 5, for instance, non-incentive program costs range from about 15% to 40%. One example that might help explain this range is mass marketing-based programs. As programs ramp up marketing and outreach as a way to increase participation and spur market transformation, this type of spending would fall into non-incentive costs. However it might have the same if not higher

energy savings impact as spending on direct incentives. Spending categories may need to shift as next-generation efficiency programs develop.

CSE Relative to Electricity Savings Thresholds

The hypothesis that programs with higher savings also have higher CSE values has been suggested but not readily demonstrated. This idea is especially relevant because as program administrators face increasing energy savings targets, they fear that program costs will rise as they go after higher savings. To test this hypothesis, we compare CSE values for each jurisdiction with relative electricity savings thresholds, i.e., savings as a percentage of applicable retail electricity sales. Figure 6 shows the scatter plot of these results, where each dot represents an individual jurisdiction for an individual year. Note that we were not able to present these data for all states.

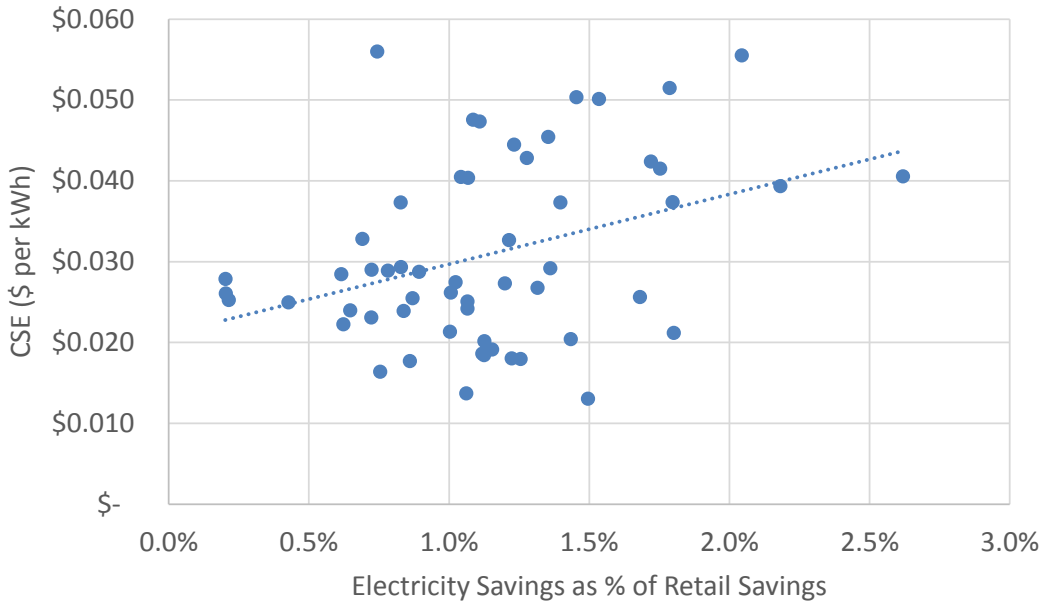

Figure 6. CSE values relative to electricity savings as a percentage of sales

We calculated the Pearson correlation coefficient (r) for this data set in Excel. This correlation coefficient is a measure of how well two data arrays are linearly related or dependent. Correlation tests do not indicate a causal relationship between two variables; rather, they measures the strength of a linear association. The correlation coefficient may range from +1.0 to -1.0, where 1 is a total positive correlation, 0 is no correlation, and -1 is a total negative correlation. An r value of greater than 0.7 is generally regarded as strong, whereas an r value of less than 0.3 is generally regarded as weak. Values in between are considered moderate. However these general guidelines should not be regarded as strict rules; the strength ascribed to a particular value depends on the context and purpose of the calculation. Studies that use scientific data, for example, may require much higher values than social science data to indicate strength in correlation.

The r value for the data set in figure 6 is 0.27, which indicates a positive, but low or weak correlation between CSE and electricity savings as a percentage of sales. These findings cast doubt on the hypothesis that programs with higher electricity savings levels are associated with higher CSE values. In fact, other analysis suggests that CSE values may decrease as savings levels increase, due to factors such as economies of scale (Takahashi and Nichols 2008). Our findings indicate that many robust program portfolios can exceed and are exceeding 1% or 1.5% savings as a percentage of sales while maintaining a cost-effective portfolio.

While these general findings are notable, there are many differences in the data points. For example, individual jurisdictions may have different program types or share of savings by customer class. Future work should examine trends over time for individual jurisdictions and within regions.

NATURAL GAS

The review includes natural gas energy efficiency program data for 10 states as shown in table 2 above.

Cost of Saved Energy

Figure 7 shows CSE results by jurisdiction and year.

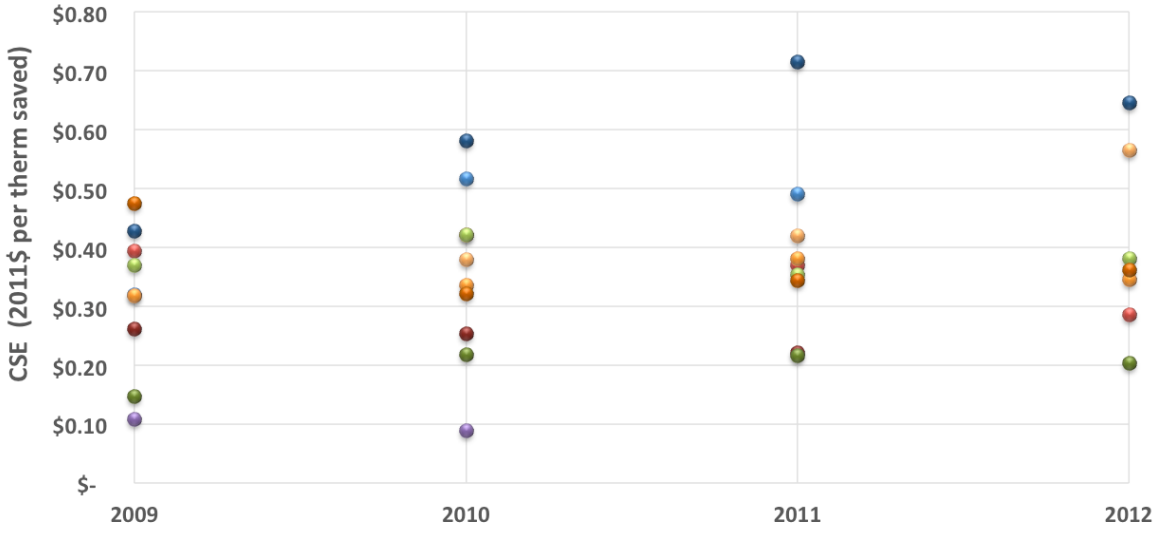

Figure 7. Natural gas CSE results by year. Each dot represents average costs for each state in a given year. 2011$ per levelized net therm at site. Assumes a 5% real discount rate.

Table 10 shows CSE values by state for each year, as well as the average, median, minimum, and maximum values for each year across the 10 jurisdictions, and for the average of 2009-2012. The CSE ranges from $0.15 per therm to $0.71 per therm across the time period, with a four-year average of $0.35 per therm.

Table 10. Natural gas efficiency CSE results by state

State	2009	2010	2011	2012	4-year average (2009-2012)
Colorado	$0.39	$0.42	$0.37	$0.29	$0.37
Connecticut	$0.37	$0.42	$0.35	$0.38	$0.38
California	$0.32	$0.52	$0.49	n/a	$0.44
Iowa	$0.32	$0.34	$0.38	$0.34	$0.34
Massachusetts	$0.43	$0.58	$0.71	$0.64	$0.59
Michigan	$0.26	$0.25	$0.22	n/a	$0.25
Minnesota	$0.15	$0.22	$0.22	$0.20	$0.20
Oregon	$0.47	$0.32	$0.34	$0.36	$0.37
Rhode Island	n/a	$0.38	$0.42	$0.56	$0.45
Wisconsin	n/a	n/a	$0.11	$0.09	$0.10
Average	**$0.34**	**$0.38**	**$0.36**	**$0.36**	**$0.35**
Median	**$0.34**	**$0.38**	**$0.36**	**$0.35**	**$0.37**
Minimum	**$0.15**	**$0.22**	**$0.11**	**$0.09**	**$0.10**
Maximum	**$0.47**	**$0.58**	**$0.71**	**$0.64**	**$0.59**

2011$ per therm at site. 5% real discount rate. N/A means that we were unable to track down sufficient data for the calculation. Average for each year represents a varying number of states, so they are not directly comparable. Values vary among states due to numerous factors such as structural differences in program types and share of savings by customer class.

First-Year Acquisition Costs

Figure 8 shows the results of the first-year costs by jurisdiction and year.

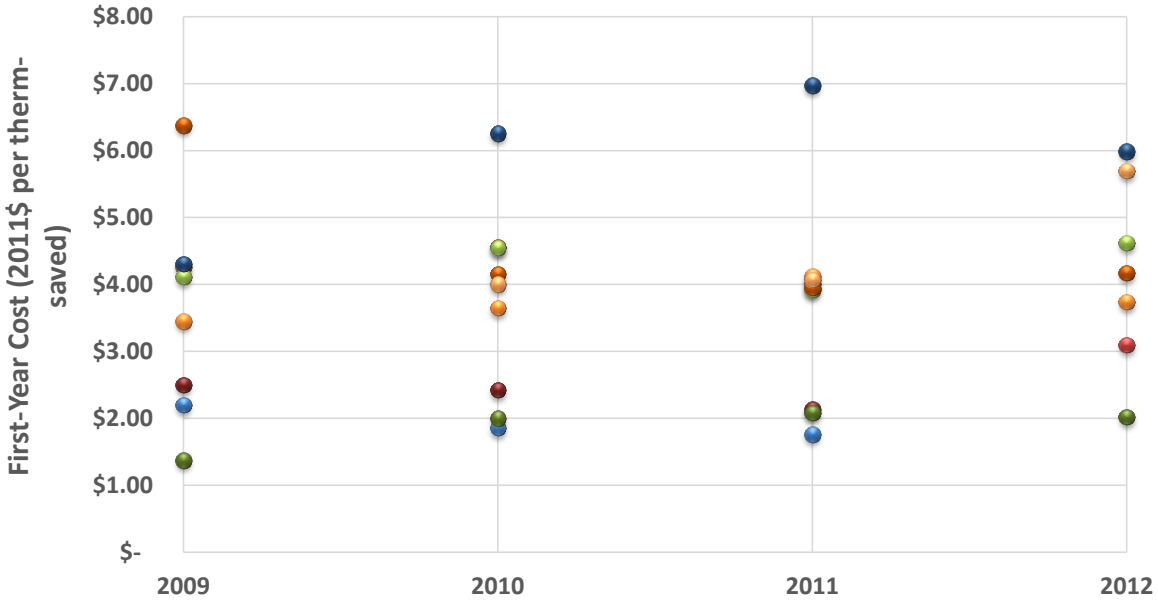

Figure 8. Natural gas first-year acquisition costs by year. Each dot represents average costs for each state in a given year.

Table 11 shows the average, median, minimum, and maximum values for each year across the 9 jurisdictions, and for the average of 2009-2012. The first-year acquisition cost ranges from $1.37 per therm to $6.97 per therm across the time period, with an overall average of $3.73 per therm.

Table 11. Natural gas efficiency first-year cost results

	2009	2010	2011	2012	4-year average (2009-2012)
Colorado	$4.26	$4.56	$4.00	$3.1	$3.98
Connecticut	$4.11	$4.55	$3.92	$4.6	$4.30
California	$2.20	$1.86	$1.76	n/a	$1.94
Iowa	$3.45	$3.64	$4.12	$3.74	$3.74
Massachusetts	$4.30	$6.25	$6.97	$5.99	$5.88
Michigan	$2.84	$2.75	$2.40	n/a	$2.66
Minnesota	$1.37	$1.99	$2.08	$2.01	$1.86
Oregon	$6.37	$4.16	$3.95	$4.17	$4.66
Rhode Island	n/a	$4.00	$4.07	$5.69	$4.59
Wisconsin	n/a	n/a	$1.13	$0.95	$1.04
Average	**$3.61**	**$3.75**	**$3.70**	**$4.19**	**$3.73**

	2009	2010	2011	2012	4-year average (2009-2012)
Median	**$3.78**	**$4.00**	**$3.95**	**$4.17**	**$3.98**
Minimum	**$1.37**	**$1.86**	**$1.76**	**$2.01**	**$1.86**
Maximum	**$6.37**	**$6.25**	**$6.97**	**$5.99**	**$5.88**

$ per therm. N/A means that we were unable to track down sufficient data for the calculation. Average for each year represents a varying number of states, so they are not directly comparable. Values vary among states due to numerous factors such as structural differences in program types and share of savings by customer class.

Measure Lifetimes

We also collected gas efficiency measure lifetimes overall and by customer class, as presented in table 12.

Table 12. Average natural gas measure lifetimes by state and customer class

State	Residential	Commercial/business	Industrial	All sectors
California	n/a	n/a	n/a	17.6
Connecticut	18.0	13.9	n/a	17.1
Massachusetts	13.2	12.9	n/a	13.1
Minnesota	n/a	n/a	n/a	13.2
Oregon	23.1	18.2	14.0	19.8
Rhode Island	19.1	12.1	n/a	14.4
Vermont	18.1	17.6	n/a	18.0
Wisconsin	24.2	13.3	n/a	15.4
Average	**19.3**	**14.7**	**14.0**	**16.1**

Average values for each state typically represent the average over the 2009-2012 program period, although data were not available for all years in each state. For example Massachusetts data represent 2012 only, and Wisconsin data represent 2011-2012 average.

The average measure lifetime is about 16 years overall. Unlike electricity measures, which tend to have longer lifetimes for business than for residential measures, natural gas efficiency measure lifetimes tend to be longer for residential measures. This is likely due to the prevalence of equipment replacement and residential building shell measures for residential programs.

Due to the limited available data, we did not calculate CSE values by customer class for natural gas efficiency programs.

Discussion and Recommendations

The results of this review provide a large data set that we can draw on for a discussion of energy efficiency program costs. First we discuss program costs in terms of cost effectiveness and as compared to supply-side options. Second, we discuss issues related to the consistency and transparency of energy efficiency reporting, and we make recommendations for improvements. Third, we discuss areas for further research that can build upon the findings of this review.

ENERGY EFFICIENCY COSTS COMPARED TO SUPPLY-SIDE OPTIONS

This review finds that energy efficiency programs are clearly the least-cost resource option compared to new energy supply resources. Here we discuss the results of our efficiency program cost review compared to typical costs for supply-side resource. A couple of important caveats are worth noting. First, we do not try to conduct a new cost-benefit analysis here; rather, we aim to provide a high-level discussion. Energy efficiency offers multiple benefits to utilities and program administrators—as well as to society and to participants—which we do not analyze for this study. Second, this discussion compares efficiency program costs to indicators of current avoided energy- and capacity-related costs. A complete cost-benefit analysis compares the costs of efficiency programs to *forecast* avoided energy costs, because efficiency measures continue to provide energy savings over their useful lifetimes. Examining forecasted avoided energy costs would show additional benefits if avoided energy costs are expected to increase in future years.

Electricity

Figure 9 shows the CSE results from this analysis alongside data from Lazard, an energy industry analysis firm, for national averages of new electricity generation options (Lazard 2013). On a levelized cost basis, new electricity energy efficiency programs cost about one-half to one-third as much as new electricity generation resources.

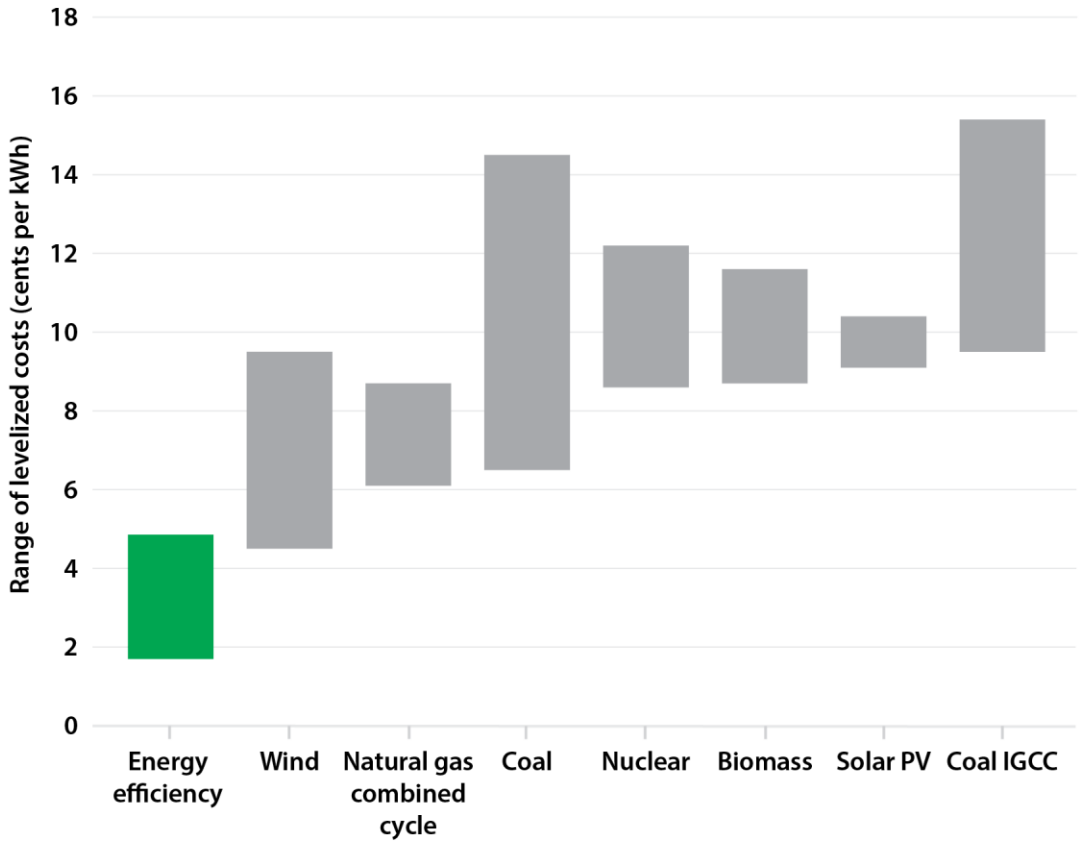

Figure 9. Levelized costs of electricity resource options. *Source:* Energy efficiency data represent the results of this analysis for utility program costs (range of four-year averages for 2009-2012); supply costs are from Lazard 2013.

The costs for all resources in figure 9 are presented as a range, which is indicative of the variability and uncertainty implicit in any energy resource option for new electricity generation. The results of our energy efficiency program cost review may at first seem to display an overly wide variation across states; however, when seen next to supply-side options, this variation is not unlike what we find in other resource options.

Comparing efficiency program costs to other new electricity resource options on a levelized cost basis provides useful context. However it does not tell the complete cost-effectiveness story for energy efficiency. When done properly, efficiency cost-benefit analysis should be more comprehensive. The utility cost test, for example, compares efficiency costs to the utility's avoided energy-related costs and capacity-related costs (as well as avoided T&D and other benefits to utilities). States use different methodologies for calculating avoided costs. Due to differences in methodology, economics, and market structures, avoided costs can vary significantly by jurisdiction, and may represent various mixes of the resources shown in figure 9. A complete utility cost-test analysis should consider additional benefits to utilities such as avoided T&D, wholesale price mitigation impacts, avoided environmental compliance costs, and other non-energy benefits.

In addition, levelized annual costs as shown in figure 9 do not reflect the added value of energy efficiency resources at certain periods of time during the year. For example, avoided energy costs can vary significantly between seasons and between peak and non-peak hours. Energy efficiency measures that reduce demand during peak periods can result in higher benefits.

The TRC and societal cost-effectiveness tests also include the broader benefits that efficiency provides to participants and to society, which are significant and present an even more complete view of the benefits of efficiency. (However as discussed earlier, in practice the TRC test is often incomplete when it does not include full participant benefits.) Our review of the TRC ratios reported by several states finds that the benefits of efficiency exceed costs by a factor of about 1.2 to 4.0. These results further demonstrate that the benefits of efficiency far exceed the costs.

Natural Gas

Average natural gas commodity prices have fallen significantly in recent years, which has put pressure on gas program administrators to keep costs below avoided costs. Our analysis finds that natural gas energy efficiency programs remain a low-cost and cost-effective resource at an average portfolio cost of $0.35/therm across 10 states. This average value is lower than the average citygate price of natural gas of $0.49/therm nationally in 2013 (EIA 2014).[25] However the avoided gas commodity cost does not tell the complete story of gas energy efficiency benefits. In addition to the commodity cost of gas, avoided costs to utilities can also include avoided distribution and transmission costs, peak demand benefits, hedging against fuel price volatility, and environmental benefits. Adding these benefits of efficiency savings further tilts the scale in favor of efficiency as a cost-effective resource.

In addition, natural gas avoided costs vary significantly across the country due to methodology and market structure differences, and they are subject to the uncertainty around future gas prices. For example, we collected a sample of recent (2012 and 2013) avoided natural gas costs, both current values and forecasts, for a handful of jurisdictions across the country. We identified a range of $0.37/therm to $1.019/therm for current and forecasted avoided gas costs. In comparison, we identified a range of natural gas efficiency portfolios of about $0.10 to $0.70/therm, very favorable values compared to avoided costs. And looking at the average gas efficiency program CSE of $0.35/therm, we can see that energy efficiency remains cost effective compared to average gas prices.

Efficiency Cost Trends

Energy efficiency program costs appear to be holding steady as the least-cost resource. The average utility CSE value in this review ($0.028/kWh) is only slightly higher than the average CSE 2009 review value ($0.025/kWh), and slightly lower than the 2004 value ($0.030/kWh). Similarly, the average natural gas efficiency program cost in the current data set ($0.35/therm) is comparable to the 2009 review value of $0.37/therm. Figure 10 displays

[25] Per EIA, the citygate price is the "point or measuring station at which a distributing gas utility receives gas from a natural gas pipeline company or transmission system."

the annual results from the 2009 review and from this analysis for average, minimum, and maximum CSE values. Annual results from the 2004 review were not available.

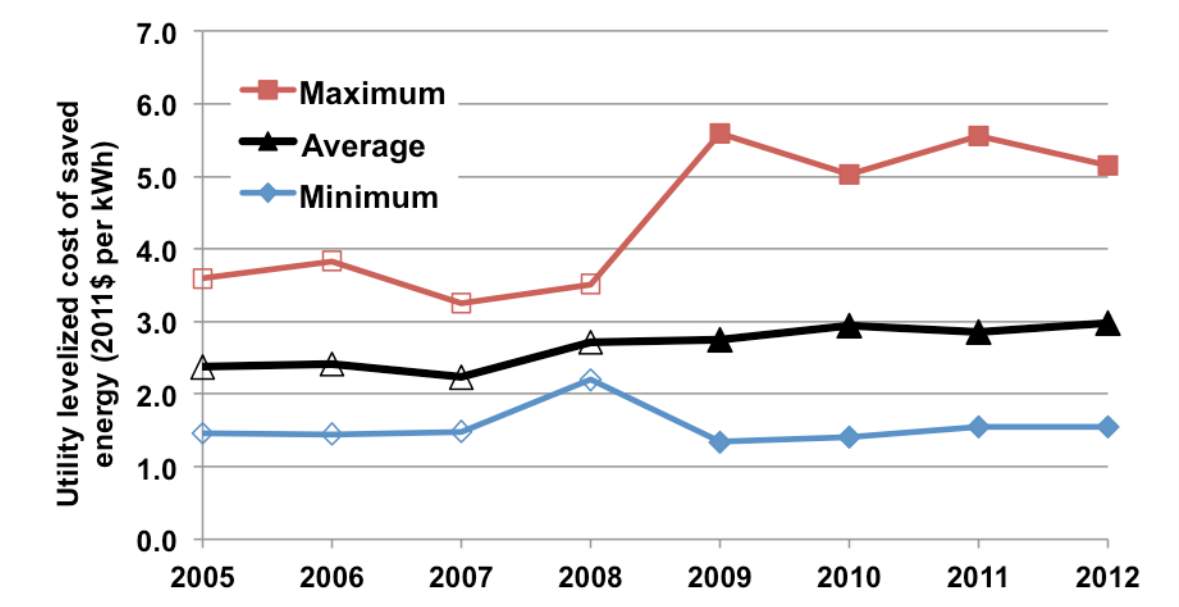

Figure 10. Utility cost of saved energy 2005-2012. *Source:* Data for 2005-2008 are from Friedrich et al. 2009 (designated by unfilled markers). Data for 2009-2012 are from this analysis.

Some caution is warranted in drawing direct comparisons between the results of the two studies, since they used different data sets (i.e., the number and specific jurisdictions included) and slightly different methodologies. For example, the 2009 study did not review whether the CSE captured net or gross energy savings, and it did not include utility shareholder incentives, both of which we addressed in the current analysis. In addition, the current review calculates all CSE values, whereas the 2009 study relied on a combination of reported and calculated values. As discussed in the next section, there is a need for further analysis on CSE trends.

What is clear, however, is that the available data refute the claims that the low-hanging fruit has been picked and that the future availability and cost effectiveness of energy efficiency are in doubt. Data from a large number of diverse jurisdictions across the nation show that energy efficiency has consistently remained the lowest-cost resource for the past decade, even as the amount of captured energy efficiency has increased significantly.

CONSISTENCY AND TRANSPARENCY IN ENERGY EFFICIENCY REPORTING

Throughout this report we have discussed the challenges in energy efficiency reporting around the country. All states should take steps toward improving consistency and transparency in reporting. To this end, we recommend that utilities, regulators and program administrators in a given state (and perhaps also at a regional and national level) discuss these issues and work toward adopting best reporting practices. Guidelines are already available for program administrators interested in improving the transparency and consistency of their reporting metrics. For stakeholders interested in detailed guidelines and

templates for reporting, we suggest the NEEP *Common Statewide Energy Efficiency Reporting Guidelines* and *Regional Energy Efficiency Database (REED)* (NEEP 2010, 2013), and *Energy Efficiency Program Typology and Data Metrics: Enabling Multi-State Analyses through the Use of Common Terminology* (LBNL 2013).

Rather than offering detailed guidelines, the following section makes recommendations around several common issues that program administrators should address to improve consistency and transparency.

Regularize Location and Frequency of Reporting

First and foremost, annual program reports and evaluations should be easily accessible on a common website. They should also follow a consistent annual schedule if possible, or provide public notification of schedule and availability. The website may be an individual program administrator's site, a common docket established by the commission, or an independent advisory group website. Regulators or advisory groups should require at least some minimum threshold of reporting and provide sample templates that build on best practices such as those laid out by NEEP. In cases where there are multiple utilities or program administrators reporting, it makes sense and is in the interest of all stakeholders to have one dedicated entity to aggregate key metrics across all territories.

Improve Transparency of Energy Efficiency Metrics and Assumptions

To improve overall transparency, we recommend that program administrators and regulators adopt or improve on measures such as the following:

- Report energy efficiency program portfolio spending and impacts separately from demand response and renewable energy impacts.
- Separate electricity and natural gas program spending and savings. For combined programs, develop methodologies for attributing spending and savings to gas or electric.
- Report estimated participant costs by customer class.
- Indicate whether electricity savings are reported at site or at generation. If at generation, make clear the assumption of T&D line losses so they can be converted to site.
- Identify whether energy savings are net or gross, and what assumptions are used.
- Provide a succinct but transparent description of the methodologies used to estimate gross and/or net savings, with links to more detailed information.
- If the emphasis is on cumulative (i.e., multiyear) energy savings and cost-effectiveness impacts, provide incremental annual impacts to indicate trends over time and facilitate comparisons with other jurisdictions.

Expand Reporting and Disaggregation of Key Metrics

More often than not, energy efficiency reporting leaves out critical metrics or assumptions that are necessary to calculate the cost of saved energy, or at least does not report aggregate values across customer classes. We recommend reporting measures such as the following:

- Report both net and gross energy savings values.
- Report measure lifetime estimates.
- Disaggregate all data by customer class (e.g., residential, commercial, and industrial). Most jurisdictions currently disaggregate business customers into commercial and industrial; however we recommend that programs disaggregate data in a way that furthers program development (e.g., commercial versus industrial customers, or small versus large business customers).
- Disaggregate cost data at least by the following: customer incentives, non-incentive program costs, and performance/shareholder incentives.

FURTHER RESEARCH

This review presents a large quantitative dataset combined with qualitative findings on energy efficiency cost-effectiveness metrics and reporting practices. However we offer only a very limited initial statistical analysis of trends. Further analysis is needed to discern trends in CSE values over time and the relative impact of various metrics on CSE values. As for trends over time, many analysts have hypothesized that the cost of saved energy for programs will increase as program administrators raise energy savings levels. Yet an initial correlation analysis in this study (for electricity programs only) finds only a weak correlation between CSE values and electricity savings levels and therefore casts doubt on the broad notion that high savings are associated with high CSE values.[26] However correlation analyses of CSE trends over time across jurisdictions are difficult and may provide incomplete results because of fundamental differences among program portfolio structures and reporting consistency. Further research should delve into this question, perhaps examining individual jurisdictions or regions.

The relative impact of different variables on CSE values is also an important area for further statistical and qualitative research. In this review we present numerous metrics that may have a direct impact on the cost of efficiency, e.g., the share of savings by customer class, or the types of programs offered. Also of interest is the impact of avoided costs on CSE within a jurisdiction, which we hypothesize should be a significant indicator of CSE values. (We did not conduct this analysis because we did not collect avoided costs data.) If program administrators must pass cost-effectiveness screening up to the point that efficiency programs cost more than the marginal unit of energy supply (i.e., avoided costs), that would allow for a higher ceiling on program costs in jurisdictions with higher avoided costs. Similarly, labor and capital costs may have a direct influence on the cost of energy efficiency programs.

Conclusion

This analysis finds that energy efficiency is clearly holding steady as the least-cost energy option that provides the best value for America's energy dollar. At an average cost of 2.8 cents per kWh, electricity efficiency programs are one half to one third the cost of the

[26] Note that this is different from the notion that total program dollar costs will increase to meet higher savings levels. Total program costs may increase, but the levelized CSE for the efficiency resources can hold steady.

alternative of building new power plants. Natural gas energy efficiency programs also remain a least-cost option at an average cost of 35 cents per therm, which is less than the average natural gas commodity price of 49 cents per therm in 2013. These data represent a large number of diverse jurisdictions across the nation.

The data show that energy efficiency has remained consistent as the lowest-cost resource over the past decade even as the amount of energy efficiency being captured has increased significantly. Energy efficiency also provides additional benefits beyond avoided energy costs, including reductions in water and fuel usage, avoided T&D costs, price mitigation effects in wholesale markets, and non-energy benefits to society such as reduced pollution and job creation. As utility and state planners face increasing uncertainty and rising supply costs in their long-term planning (including fuel-price volatility and the need to address the environmental impacts of power generation), they should look to energy efficiency as a reliable and consistent "first fuel" in their loading order of energy options.

The need increases for high-quality and consistent data across the country as efficiency gains even wider adoption and traction as the least-cost energy resource option. In this analysis we found that jurisdictions collect and report a wealth of data and information on efficiency programs. However we also found that the collection and comparison of energy efficiency cost data across the nation face numerous challenges, including variation in reporting formats, nomenclature, and frequency. All states should take steps toward improving consistency and transparency in reporting. Finally, further work should explore the relative impact of different variables on CSE values, as well as trends over time for individual jurisdictions.

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Appendix A. Data Sources by State and Program Administrator

State and administrator	Data sources
Arizona: Arizona Public Service Company (APS)	DSM semiannual reports with annual data for 2009, 2010, 2011, and 2012. Published in March each year.
California: Southern California Gas; Southern California Edison; Pacific Gas & Electric; San Diego Gas & Electric	Utility annual reports available for 2009, 2010, and 2011 from http://eega.cpuc.ca.gov/. Published in May.
Colorado: Xcel Energy	Xcel Energy Colorado *Demand-Side Management (DSM) Annual Status Reports.* Published in April. http://www.xcelenergy.com/About_Us/Rates_&_Regulations/Regulatory_Filings/CO_DSM
Connecticut: Connecticut Energy Efficiency Fund	*CEEF Annual Legislative Reports* for 2009, 2010, 2011, and 2012. Published from February to April. http://www.ctenergyinfo.com/about/eeboard/annualreports
Hawaii: Hawaii Energy	*Hawaii Energy PY12 Annual Report,* October 1, 2013. also PY11, PY10, and PY9 reports. http://www.hawaiienergy.com/information-reports
Illinois: Ameren Illinois Utilities; ComEd, and DCEO	Ameren: *ActOnEnergy Energy Efficiency and Demand Response Results* (PY 1). *Portfolio Cost-Effectiveness Evaluation* (PY 3). ComEd: Evaluation Reports Prepared by Summit Blue/Navigant for PY 1 (2009), PY 2 (2010), and PY 3 (2011) (savings data and TRC ratios). ComEd PY3 annual report to ICC (cost data for 2011). Some reports available at http://ilsag.org/.
Iowa: MidAmerican Energy and Alliant Energy/Intrastate Power & Light	Energy Efficiency Annual reports for 2009, 2010, 2011, and 2012. Published in May. http://www.state.ia.us/government/com/util/energy/energy_efficiency/ee_plans_reports.html
Massachusetts: All investor-owned utilities	2011 data: Northeast Energy Efficiency Partnership's Regional Energy Efficiency Database (REED). 2012, 2010, and 2009 data: individual utility reports available from www.ma-eeac.org 2011 and 2012 TRC results: "Statewide Electric Results Master Summary" spreadsheets. www.ma-eeac.org
Michigan: All utilities	Michigan PSC. 2012. *Report on the Implementation of P.A. 295 Utility Energy Optimization Programs.* November 30, 2012. Data for 2009, 2010, and 2011. Michigan PSC. 2013 *Report on the Implementation of P.A. 295 Utility Energy Optimization Programs*. November 26, 2013.
Minnesota: Xcel Energy	Xcel Energy annual Status Reports available from https://www.edockets.state.mn.us/EFiling/home.jsp for 2009, 2010, 2011, and 2012 program years

State and administrator	Data sources
New Mexico: Public Service Company of New Mexico (PNM) and Southwestern Public Service Company (SPS)	PNM: *PNM Energy Efficiency Program Annual Report* (available for 2009, 2010, 2011, and 2012), published annually from March-June. SPS: *SPS 2009 Energy Efficiency and Load Management Annual Report* (August 1, 2010). Only 2009 report was readily available. Note: New Mexico's TRC results reported only for PNM.
Nevada: NV Energy (merger of Nevada Power Company (NPC) & Sierra Pacific Power Company (SPPC); but separate EE reporting still)	NPC: DSM Status Update Reports for 2009, 2010, 2011, and 2012 SPPC: DSM Status Update Reports for 2009, 2010, 2011, and 2012
New York: NYSERDA	Cumulative data for 2006-2011: NYSERDA, *New York's System Benefits Charge Programs Evaluation and Status Report: Year Ending December 31, 2011 Report to the Public Service Commission* (March 2012) (Revised April 2012)
Oregon: Energy Trust of Oregon	ETO Annual Reports for 2009, 2010, 2011, and 2012 http://energytrust.org/About/policy-and-reports/Reports.aspx
Pennsylvania: Electric Distribution Companies (EDCs)	Act 129 Market Potential Study, with impacts for PY 1 (June 2009-May 2010) and PY 2 (June 2010–May 2011) http://www.puc.pa.gov/electric/pdf/Act129/Act129-PA_Market_Potential_Study051012.pdf
Rhode Island: National Grid Electric and Natural Gas	National Grid Year-End Reports for 2010, 2011, and 2012. Also for 2011 data: Northeast Energy Efficiency Partnership Regional Energy Efficiency Database (REED).
Texas: Electric IOUs	Frontier Associates; *Energy Efficiency Accomplishments of Texas Investor-Owned Utilities.* Annual reports for 2009, 2010, and 2011 http://www.texasefficiency.com/index.php/publications/reports
Utah: Rocky Mountain Power (PacifiCorp)	PacifiCorp, *Annual Energy Efficiency and Peak Reduction Report: Utah.* Annual reports for 2009, 2010, 2011, and 2012
Vermont: Efficiency Vermont (Vermont Energy Investment Corporation)	Annual Savings Claim Reports http://www.efficiencyvermont.com/about_us/information_reports/annual_reports.aspx
Wisconsin: Focus on Energy	Focus on Energy evaluation reports for 2011 and 2012: *Calendar Year 2011 Evaluation Report* (October 31, 2012), *Calendar Year 2012 Evaluation Report* (April 30, 2013)

Exhibit J

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Best Practices in Electric Utility Integrated Resource Planning

Examples of State Regulations and Recent Utility Plans

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About The Regulatory Assistance Project (RAP)

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.raponline.org.

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Table of Contents

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

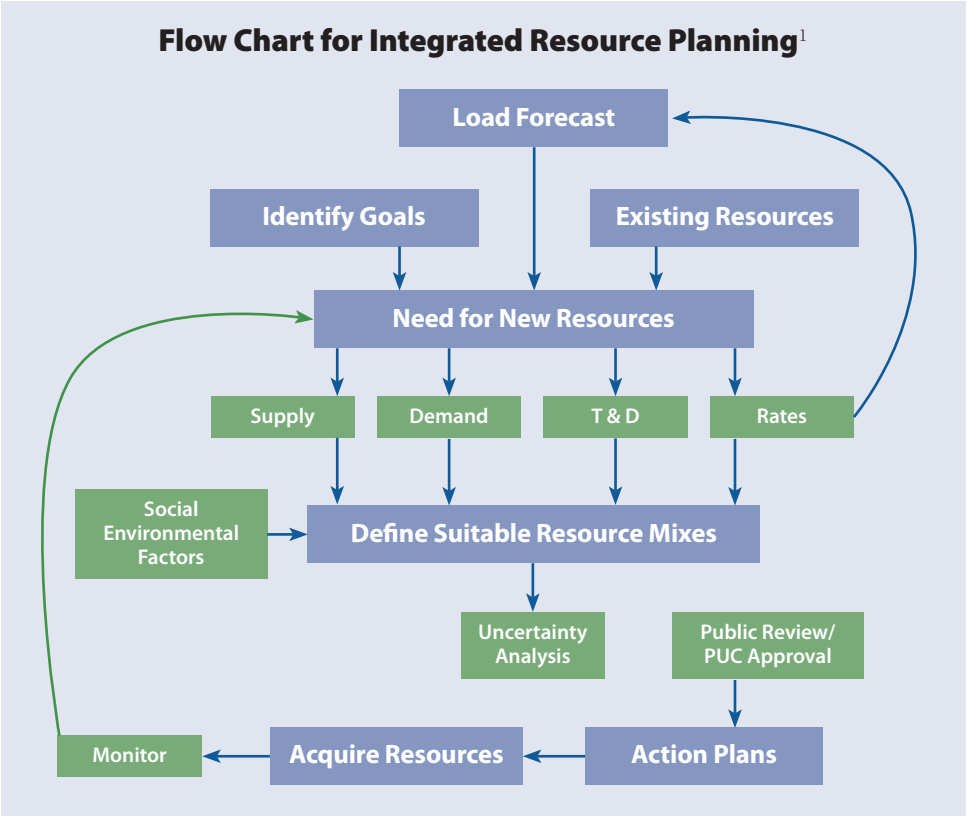
An integrated resource plan, or IRP, is a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period. Steps taken in the creation of an IRP include:

- 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

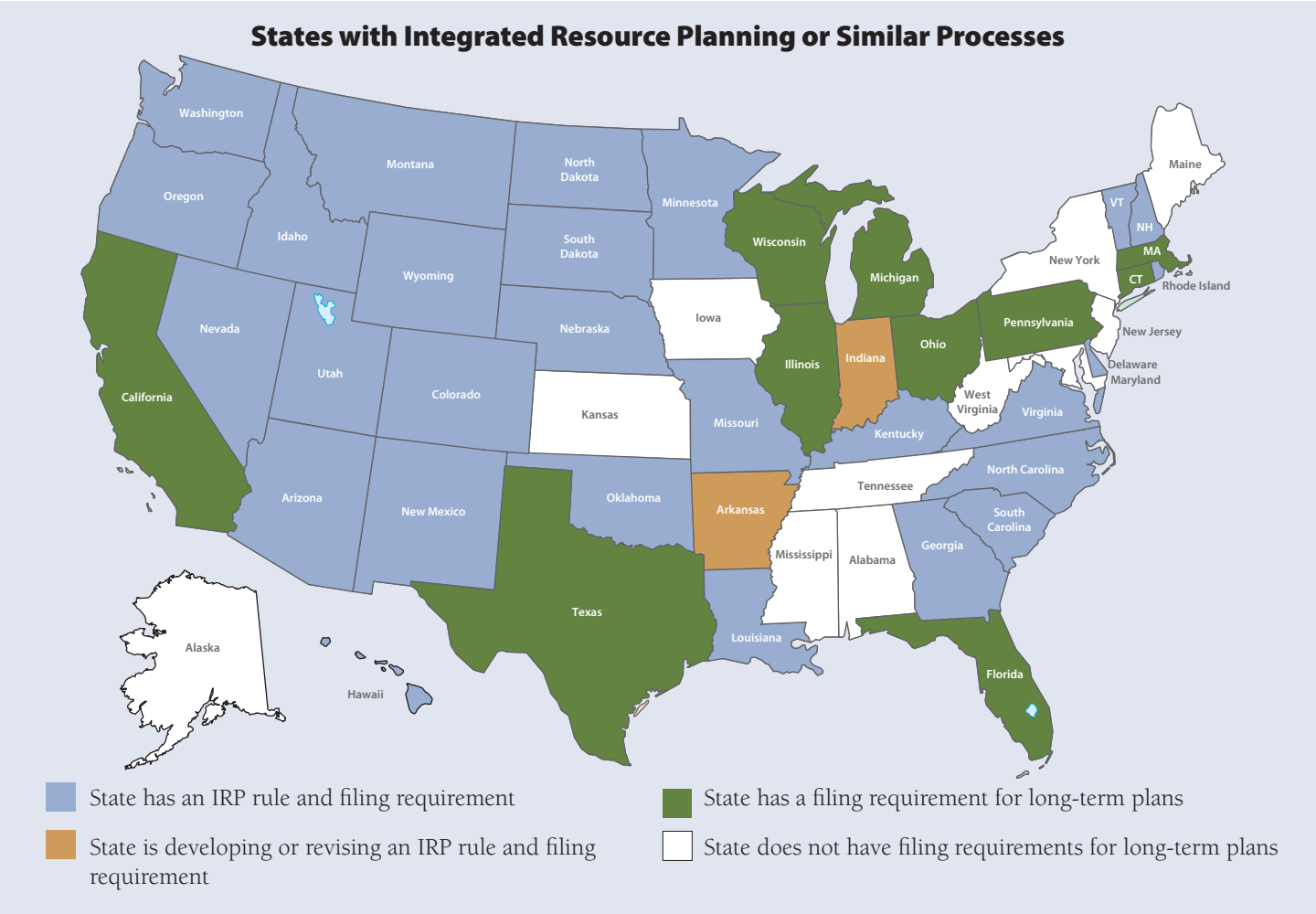
3 Kushler, M. & York, D. Utility Initiatives: Integrated Resource Planning. July 2010. American Council for an Energy-Efficient Economy. Available at: http://aceee.org/policy-brief/utility-initiatives-integrated-resource-planning

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 (CO_2) 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 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.

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

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

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.

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.

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.

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, liming 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.

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.

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.

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.

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 CO_2 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.

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 CO_2 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, CO_2 prices, production and investment tax credits for renewable resources, energy efficiency costs, and monetization of SO_2, 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.

Figure 3:

Portfolios Considered in the APS 2012 IRP[51]

	Base Case (2012 Resource Plan)	Four Corners Contingency	Enhanced Renewable	Coal Retirement
Description	*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*	*Contingency plan depicting the retirement of the Four Corners coal-fired plant; energy replaced by additional natural gas resources*	*Assumes 30% (after EE/DE) of energy needs met by renewable resources; include the consummation of the Four Corners transaction*	*Assumes APS retires all coal-fired generation; energy replaced with a combination of natural gas and renewable resources*
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

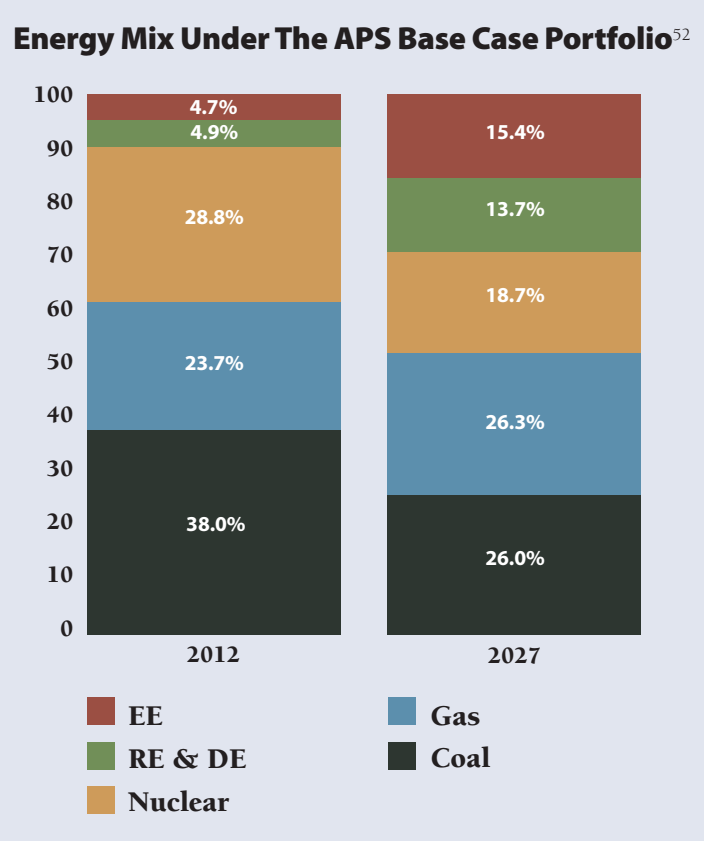
which incorporate the low and high values for all of the variables mentioned above rather than testing them on an individual basis. The results of the sensitivity analysis showed that the four corners contingency and coal retirement portfolios have the most variability in terms of net present value of 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).

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 CO_2 adder consistent with the assumption that federal regulation of CO_2 will occur within the 15-year planning period. In sensitivity scenarios, APS analyzes alternative prices for CO_2 emissions, and also includes adders for SO_2, 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.

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 CO_2 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.

Figure 5

Least-Cost Baseline Case and Alternative Plans During the Resource Acquisition Period (RAP) From Public Service Company of Colorado's 2011 IRP[58]

		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 Co_2, Tax Incentives, and Gas Prices From Public Service Company of Colorado's 2011 IRP[59]

		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
Sensitivities	**CO_2 3-Source Low Esc**	$9	$10	$65	$182	$75	$113	$297	$455
	CO_2 3-Source	$7	$8	$62	$178	$63	$101	$285	$441
	CO_2 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.

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 urchase 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.

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 IRP[68]

	Capacity (MW)										
Resource	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
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

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 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.

Figure 8

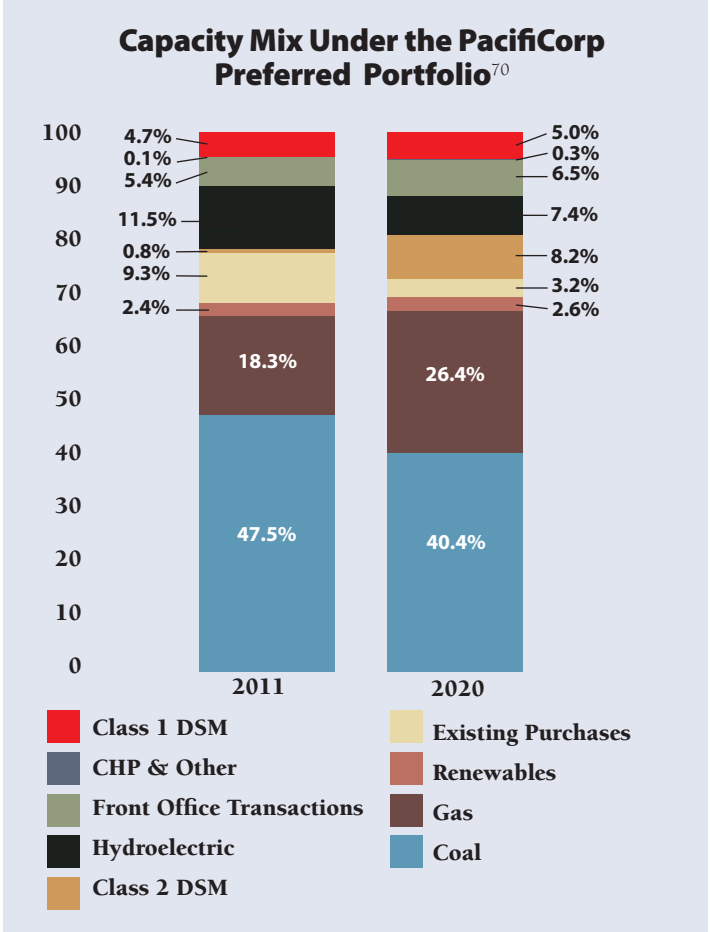
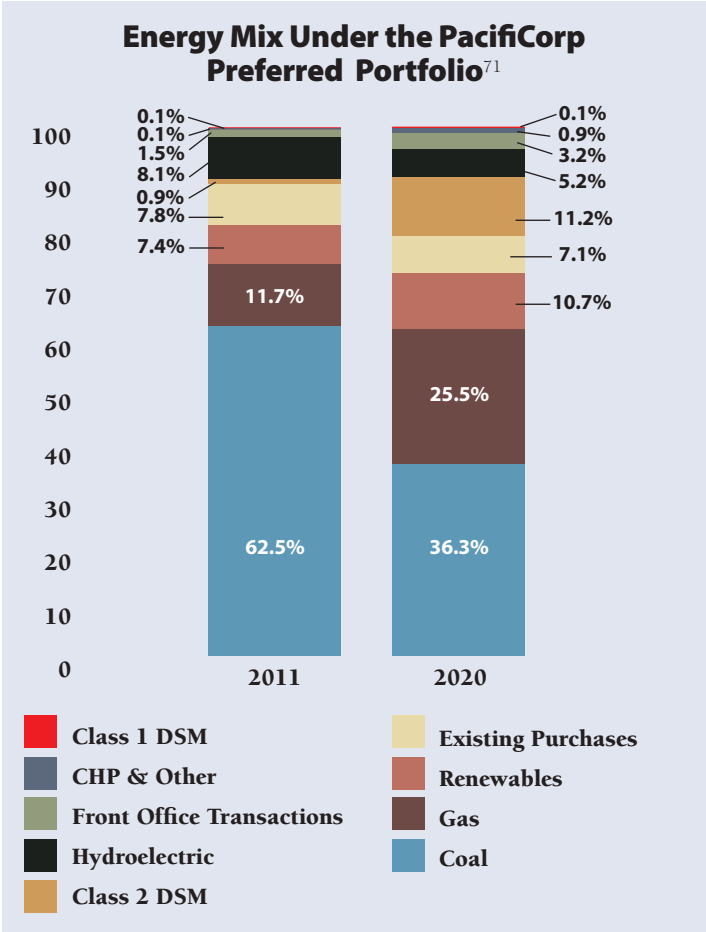


Figure 9



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

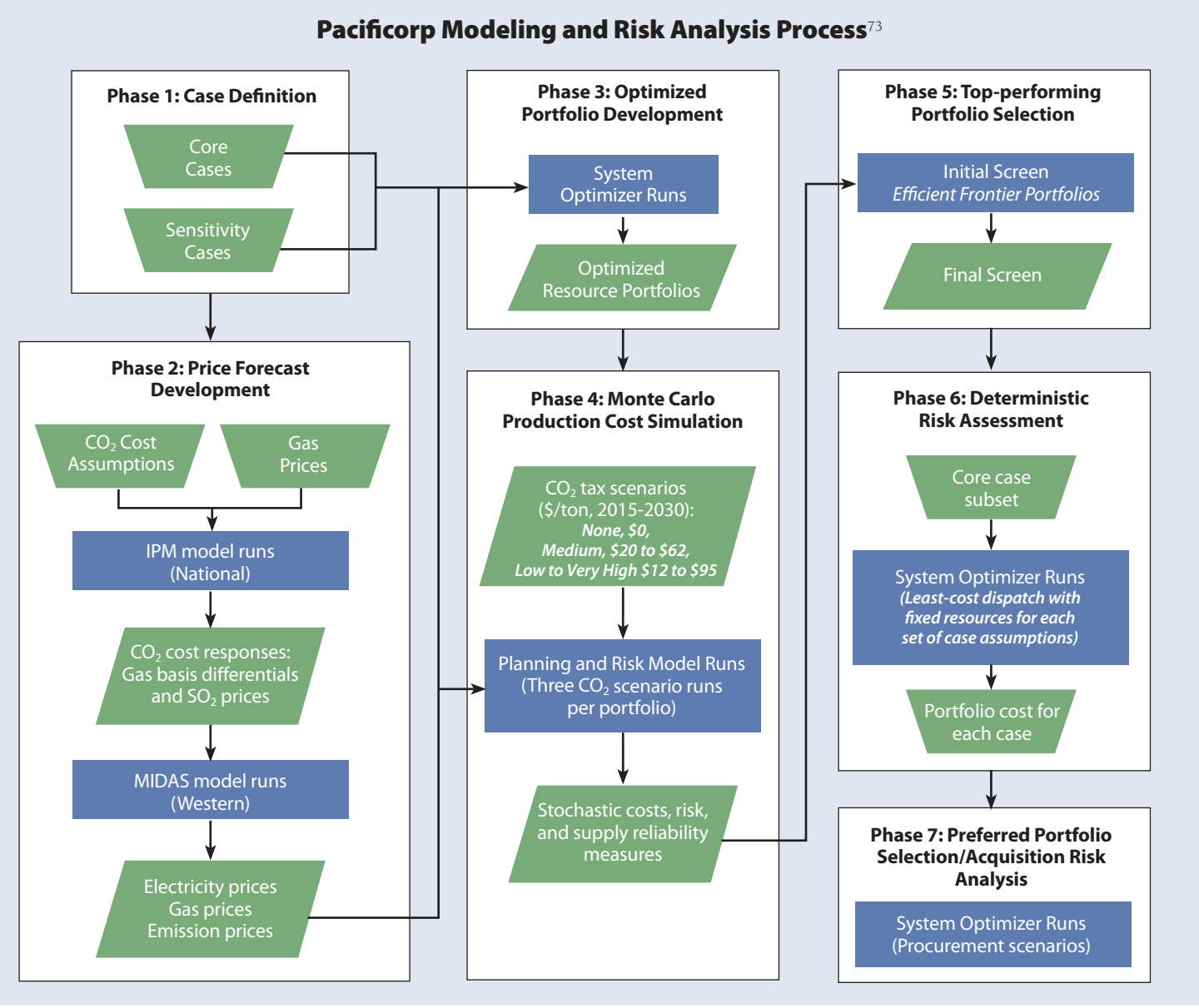
70 Id. Page 10.

71 Id. Page 13.

Altogether, PacifiCorp defined 67 input scenarios for portfolio development. These looked at alternative transmission configurations, CO_2 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, CO_2 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.

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.

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.

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 factors[83] 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 interties 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.

> "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 Commision, 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.

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 levelized 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 SO_2 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.

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

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]

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

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/rsa/html/NHTOC/NHTOC-XXXIV-378.htm

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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Exhibit K

October 10, 2016

Via electronic filing and electronic mail

Chairman Brown, Comm'rs. Brisé, Edgar, Graham, Patronis
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: Planning for least-cost electric service in Florida

Dear Commissioners:

Rapid changes in the electric sector make integrated resource planning more important than ever. Yet Florida electric utilities, especially the investor-owned utilities (IOUs), barely have any plans at all—besides adding natural gas-burning generation, which dwarfs everything else in their plans.[1] Sierra Club respectfully urges the Commission to reject them and require revised plans for four main reasons:

1. Florida law requires utilities to provide least-cost service, but the utilities are unprepared to do so because they fail to perform options analyses; the utilities thus never try to (nor could they) square their gas-laden plans with the alternatives available to them in the market.[2]

2. The proposed gas generation violates the least-cost standard because this generation is inherently high cost and high risk.

3. The proposed gas generation also violates the least-cost standard because it reduces fuel diversity and foregoes cost-effective renewables and energy efficiency, thereby pushing Florida's all-time high gas reliance, 71% of the state generation total, even higher, to 74%.

4. With no shortage of cost-effective alternatives in the market, especially renewables and energy efficiency, the only way to explain the utilities' gas generation proposals is that they aim to benefit entities other than customers.

[1] Unless stated otherwise, "plans" refers to ten-year site plans, and "utilities" refers to those that file them.

[2] To their credit, Staff issued extensive data requests. The responses, however, cannot cure the unlawful plans.

By now, it is unmistakable; the IOUs/their affiliates are investing heavily in every aspect of gas generation and infrastructure with a perverse incentive to continue to do so. They pass the resulting added cost of service onto their captive customers, and the resulting windfall profits to shareholders.

It is imperative that the Commission intervene and reject all of the unlawful plans. Revised plans should follow as soon as practicable. For the IOUs, this should be no later than April 1, 2017, the annual deadline for revised plans, to minimize the fallout from their conflict-ridden plans.

As we discuss below, at least one Florida utility, Lakeland Electric, recently undertook an assessments of its options under different scenarios, showing this is eminently doable. Moreover, practically all of the Florida utilities, with the glaring exception of the IOUs, have issued requests for proposals (RFPs) for renewables and found no shortage of cost-effective solar generation options in the Florida market. When done well, market assessments like these promote competition, stakeholder participation, and ultimately transparent, data-driven options analyses to guide utilities to least-cost investments.

The stakes are high. Every year that passes without plans for least-cost electric service further jeopardizes the competitiveness of Florida's economy and the wellbeing of its residents. This includes the millions of low-income/fixed-income Floridians who already face a disproportionate energy burden.

DISCUSSION

The Commission should reject the plans because they violate the least-cost standard under Florida law; the revised plans should include robust options analyses focusing on renewables and energy efficiency.

We divided this discussion into three parts: First, we discuss the applicable least-cost standard under Florida law. Second, we show that the utility plans violate this standard, and the Commission should reject them. Finally, we conclude by urge the Commission to obtain revised plans, including the chronically missing options analyses, as soon as practicable, so that the Commission can meaningfully audit the utilities and ensure they are prepared to achieve least-cost service.

I. Under Florida's least-cost standard, electric utilities must develop robust options analyses focusing on renewables and energy efficiency to guide the utilities to least-cost investments to serve their customers.

Florida law requires electric utility service to be least-cost. As the Florida Supreme Court affirmed, under this standard, the state's electric utilities must "t[ake] every reasonably

available prudent action to minimize [their cost of service]."[3] Planning is the critical first step. Per Commission rules, the utilities must develop and disclose "sufficient information to reassure the Commission that an adequate and reliable supply of electricity at the lowest cost possible is planned."[4]

A. Utilities must develop robust options analyses to guide them to least-cost investments.

Options analyses are routine in the business world, and essential for the utilities to meet the least-cost standard under Florida law. This is a matter of Commission precedent and common sense.[5][6] Options typically available to utilities include but are not limited to:

- Alternatives to conventional generation, such as renewables[7] and energy efficiency;[8]
- Alternatives identified through market assessments such as the request for proposal process under Rule 25-22.082, F.A.C (i.e., the Commission's competitive "bid rule");[9]

[3] *Gulf Power Co. v. Florida pub. Service Com'n*, 453 So.2d 799, 802 (Fla. 1984).

[4] Rule 25-22.072(1), F.A.C., incorporating by reference Form PSC/RAD 43-E (11/97), at 4; *cf.* Section 366.82(5)(b)(requiring "analysis of various policy options … to achieve least-cost strategy").

[5] Order No. PSC-11-0547-FOF-EI, at 82, issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause; *See also* Order No. PSC-11-0547-FOF-EI (redacted Final Order) (noting approval of utility's rate increase request upon finding "no practical alternative") issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause; *cf.* Order No. PSC-11-0547-FOF-EI (redacted Final Order), at 6 (reviewing whether utilities properly considered "all available" demand-side and supply-side conservation and efficiency measures) issued on December 16, 2014, in Docket No. 130205-EI, In re: Commission review of numeric conservation goals (Florida Public Utilities Company).

[6] Order No. PSC-11-0547-FOF-EI, at 82 (noting the review of "all available options" is "routine procedure in the business world," including the electric utilty industry as it undertakes "long-term, complex project[s]") issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause.

[7] Unless otherwise noted, the terms "renewables" and "renewable energy" refer to the same energy resources. *See generally* Section 366.91(2)(d), F.S, (defining "renewable energy" in pertinent part as "electrical energy produced from a method that uses one or more of the following fuels or energy sources: hydrogen produced from sources other than fossil fuels, biomass, solar energy, geothermal energy, wind energy, ocean energy, and hydroelectric power").

[8] *See, e.g.,* Order No. PSC-14-0696-FOF-EU, at 39, issued on December 16, 2014, in Docket No. 130205-EI, In re: Commission review of numeric conservation goals (Florida Public Utilities Company) ("demand-side management is an alternative resource to generation plants and should be evaluated similarly for reliability and economic impacts."); *See also* Order No. PSC-16-0032-FOF-EI, at 13−15, issued on January 19, 2016, in Docket No. 150196-EI, In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company; *See also* Order No. PSC-11-0547-FOF-EI, issued on November 23, 2011, in Docket No. 11 0009-EI, In re: Nuclear cost recovery clause ("In 2006, we stated that utilities should not assume the automatic approval of natural gas-fired plants.").

- Incremental capacity increases;[10]
- Earlier or later extremes of commercial operations date;[11] and
- Retaining one vendor, retaining multiple vendors, or building the generation itself ("self-build").[12]

Robust options analyses are those that develop information on the economics of these wide ranging options under various scenarios.[13] A simple comparison of the status quo and one option is indefensible.[14]

B. Utilities must focus on renewables and energy efficiency.

Florida Statutes brim with directives to diversify the fuels and the technologies the utilities use to serve customers.[15] More specifically, they emphasize and reiterate that Florida's reliance on inherently risky natural gas imports is a problem, and that cost-effective renewables and energy efficiency are solutions that are in the public interest. As the utilities perform options analysis, they must therefore focus on renewables and energy efficiency as part of their plan to serve customers at the least-cost.

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[9] *See*, *e.g.*, Order No. PSC-06-0779-PAA-EI, at 3, issued on September 19, 2006, in Docket No. 060426-E1, In re: Petition for exemption under Rule 25-22.082(18), F.A.C., from issuing request for proposals (RFPs), by Florida Power & Light Company ("the RFP process provides us with valuable information on the available capacity alternatives and is a valid tool for evaluating the cost-effectiveness of proposed generating units.").

[10] *See*, *e.g.*,Order No. PSC-13-0505-PAA-EI, at 13, issued on October 28, 2013, in Docket No. 130198-EI, In re: Petition for prudence determination regarding new pipeline system by Florida Power & Light Company; *See also* Florida Public Service Commission, *States' Electric Resurfacing Activities* (1997); *See also* F.L. House of Representatives, Committee on Utilities and Communications, *Overview of the Electric Industry*, 27 (2000), *available at* https://goo.gl/uKDBP6.

[11] *See*, *e.g.*, Order No. PSC-11-0547-FOF-EI, at 82.

[12] *See*, *e.g.*, Order No. PSC-08-0749-FOF-E, issued on Nov. 12, 2008, in Docket No. 080009-EI, In re: Nuclear cost recovery clause; *See also* Order No. PSC-09-0783-FOF-EI, issued on Nov. 19, 2009, in Docket No. 090009-EI, In re: Nuclear cost recovery clause; *See also* Order No. PSC-11-0547-FOF-EI.

[13] *See* Sierra Club Comments (Oct. 16, 2013) (hereinafter "Sierra Club 2013 Comments") (discussing best practices in integrated resource planning including options analysis), *available at* http://goo.gl/h9RHeT.

[14] *Gulf Power Co. v. Florida pub. Service Com'n*, 453 So.2d 799 (Fla. 1984) (affirming Commission disallowance of costs incurred pursuant to utility's failure to review other other options beyond its preferred proposal for years).

[15] For a recap of the relevant provisions in Florida Statutes, see Sierra Club Post-Hearing Brief in Docket No. 160021 (Sept. 19, 2016), *available at* https://goo.gl/X6QJ91.

II. The Commission should reject the plans because they are in no way least-cost.

The plans fail to meet the least-cost standard under Florida law for many reasons. The most glaring one is that the utilities failed to present any options analyses. The utilities thus failed to reconcile their inherently high-cost, high-risk gas generation with the abundant, competitive renewables and energy efficiency in the market available to them, and in the case of the IOUs, plainly have a conflict of interest behind the omission.

A. The utilities failed to present any options analyses in their plans.

This year, the utilities continued their practice[16] of presenting the Commission just their preferred generation proposals and asserting they considered/will continue to consider their options.[17] This violates the unambiguous requirement in Florida Statutes that the Commission "shall review"—"possible alternatives to the proposed plan[s]" of the utilities.[18] If the utilities present no data or analyses on the options/alternatives available to them in the market, they preclude the Commission from performing its plain duty under Florida Statutes.

To be sure, the utility responses to Staff data requests do not cure the unlawful plans. For all of the planned generating units, Staff asked the utilities to "identify the next best alternative that was rejected for each unit."[19] The fact that Staff had to ask for this information underscores how devoid the plans are of options analyses. The utility responses do, too. They are high-level comparisons between each planned ***gas*** generating unit and another ***gas*** generating unit. That is all. That is the sum total of the options analyses before the Commission.

No one can square the dearth of information presented by the utilities with the least-cost standard under Florida law. As discussed in Section I (above), the standard requires the utilities to conduct robust options analyses, focusing on renewables and energy efficiency, so that they are prepared to take every reasonably available prudent action to minimize cost of

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[16] *See* Sierra Club 2013 Comments (noting the unlawful practice), *available at* http://goo.gl/h9RHeT; Sierra Club Comments (Dec. 15, 2015) (hereinafter "Sierra Club 2015 Comments") (noting the same), *available at* https://goo.gl/IWbsDH.

[17] *See e.g.*, Florida Power & Light Company's 2016 Ten-Year Power Plant Site Plan (hereinafter "FPL 2016 TYSP"), Chapter III.C (noting "significant factors that either influenced the current resource plan presented in this document or which may result in changes in this resource plan in the future" but omitting data on or comparative analysis of those factors/ changes; i.e., options analysis); *available at* https://goo.gl/wgWn9Y; *see generally* 2016 Ten-Year Site Plans (similar omissions) *available at* https://goo.gl/1y17w9.

[18] Section 186.801(2), F.S.

[19] Staff data request no. 42.

service, and Florida's reliance on inherently risky natural gas imports. Working up the details of just one gas generation plan and then, at Staff's prodding, working up another is nowhere near the robust options analysis that is routine and essential to prepare electric utilities to provide least-cost service. The Commission therefore should reject the plans.

B. The utilities failed to reconcile their inherently high-cost, high-risk gas generation proposals with the abundant, cost-effective renewables and energy efficiency in the market available to them.

The plans are indefensible and the Commission should reject them for the additional reason that they would increase gas generation, which is inherently high cost and high risk, especially as demand is down. The utilities never tried to (nor could they) reconcile their plans with the abundant, cost-effective renewables and energy efficiency in the market available to them.

1. Demand is down and the growth projected by utilities has not materialized for eight straight years, a trend no one can square with adding gas generation in large, inflexible increments.

Since it peaked in 2005, demand for electricity across Florida is down. This is not due to the Recession alone, as the Commission itself noted.[20] Previous utility load forecasts required downward revisions due to slower-than-projected growth for eight straight years, including the last three.[21] The utilities themselves acknowledge that usage per customer is down.[22]

Yet the utilities project peak demand will somehow grow faster than one percent annually between 2016 and 2025 (net firm peak demand)—more than half again the rate experienced between 2004 and 2015 (0.76 percent CAAGR). This is inconsistent with, for example, the U.S. Energy Information Administration's lower projection of a 0.7 percent annual growth rate through 2025.[23]

More importantly and obviously, demand projections are never as good as verified actual data, and the actuals have shown a consistent downward trend. The best options for

[20] FPSC, Review of the 2015 TYSPs, at 22, *available at* https://goo.gl/DTGoX1.

[21] *Compare* FRCC 2014 Presentation, at 7 ("Forecasted energy sales and winter firm peak demands are lower in 2014 TYSP compared to 2013 TYSP and forecasted summer firm peak demands are higher from 2017 forward."), *available at* https://goo.gl/ACqiVT; FRCC 2015 Presentation, at 7, ("forecasted energy sales and firm peak demands are lower in 2015 TYSP compared to 2014 TYSP"), *available at* https://goo.gl/mn4gUf; and FRCC 2016 Presentation, at 8 "forecasted energy sales and firm peak demands are lower in 2016 TYSPs compared to 2015 TYSPs"), *available at* https://goo.gl/UScXlk.

[22] Utility responses to Staff data request no. 10.

[23] This is EIA's projection for Florida as well as other South Atlantic states.

Florida therefore are those that (1) keep demand down to reduce cost (i.e., demand-side management), and (2) meet any growth in demand with incremental supply that closely matches the growth (i.e., flexible supply). The utilities failed to present any such options. The only option the utilities did present—large, inflexible gas generation additions—flies in the face of the market reality just described. It is indefensible also because the additional capacity maintained by the IOUs consistently exceeds the levels needed for an adequate and reliable supply of electricity.[24]

2. Gas generation is inherently high cost and high risk.

The Commission should not accept the utilities' complacency about the costs and risks of gas generation, especially as the state's reliance on natural gas is already at an all-time high—71% of the total generation.[25] The utilities propose to add another five gigawatts—pushing that up to 74% by 2025.[26] Even the smallest proposed increment exceeds 180 MW,[27] with projected capital costs measured in millions of dollars, and book lives in decades. Moreover, with the exception of Orlando Utilities Commission (OUC) and Florida Power & Light Company (FPL), the utilities propose inherently less efficient peaking generation—gas combustion turbines (CTs).[28]

All of the proposed gas generation raises stranded asset risk, but the utilities fail to mention that fact. This is a glaring omission as it is the judgment of Florida's largest utility FPL that in four years, 2020, gas peakers will be obsolete compared to energy storage and renewables.[29] It is even more troubling then that the utilities never present any options analyses for the proposed gas peakers. Nor even the basic data to allow for such a

[24] *See* the detailed briefing by Public Counsel, filed July 15, 2015, in Docket No. 160096-EI, Joint petition for approval of modifications to risk management plans by DEF, FPL, Gulf and TECO; *See also* joint petition filed by Public Council, filed Dec 9., 2015, in Docket No. 150196-EI, In re: Petition for determination of need for Okeechobee Clean Energy Center Unit 1, by Florida Power & Light Company, *available at* https://goo.gl/wBgl2S.

[25] FRCC, 2016 Presentation, at 22.

[26] *Id.*

[27] Tampa Electric Company's 2016 Ten-Year Site Plan (hereinafter "TECO 2016 TYSP") (planning to add 180 MW CT in 2019), *available at* https://goo.gl/zGh1Id.

[28] OUC and FPL propose gas combined cycle generation (CCs) with 2021 and 2024 in-service dates respectively. Like CTs, the CCs involve massive costs and risks, and the utilities can only add them in large, inflexible increments. Thus, beyond the marginal efficiency improvement of CCs over CTs, our discussion of the CTs applies equally to the CCs.

[29] NextEra on Storage: 'Post 2020, There May Never Be Another Peaker Built in the US,' Sept. 30, 2015, GreenTech Media [hereainafter "NextEra on Storage"], https://goo.gl/rQDK0H (referring to judgment of team including FPL executives).

comparison. In response to Staff data requests, for instance, the utilities omitted the inputs and workbooks that would allow independent verification of their summary comparisons between two gas generation options, discussed in Section II.B.1 above, and provided virtually no data on other, non-gas options, as discussed further below in Section II.B.3.

As the Commission maintains separate dockets on the operation and maintenance costs and risks of gas generation, it knows how astronomically high those costs and risks have proven to be. With gas prices at all-time lows—levels so low they are widely expected to only go up from here—Floridians have already lost billions of dollars on risk hedging programs.[30] Still, the hedging programs themselves are mere half-measures against the price and supply risks of Florida's reliance on natural gas imports—and useless against stranded asset risk. The FPL rate case underscores this.[31] FPL supported its request for a $1.3 billion annual rate increase and a 100 basis point return on equity increase with sworn testimony on all the costs and risks associated with managing its out-sized gas generation fleet.

Adding more gas generation is thus indefensible because it would exacerbate the burden on customers who essentially bear all the costs and risks. This includes the tremendous capital outlays required at the outset to add gas generation (recovered through base rates), and the tremendous operations and maintenance, including hedging expenses, over the 30 or more years these plants are supposed to be in service (recovered through separate clauses).

3. Renewables and energy efficiency are abundantly available to meet peak demand, and they can achieve deep cost-savings—unlike gas generation—through their flexible and diverse applications across the electric grid's generation, transmission, and distribution functions.

For alternatives to meet peak demand, such as renewables and energy efficiency, the market is better than ever. Yet the utilities only propose relatively modest amounts of solar, and even less amounts of other alternatives, despite these technologies' maturity, competitiveness, and widespread adoption in neighboring states. Moreover, these technologies can achieve deep cost-savings—unlike gas generation—through their flexible and diverse applications to the grid's electric generation, transmission, and distribution functions. As we discuss below, this is borne out by RFPs and integrated resource plans (IRPs) across our region and the country. We also discuss how the IOUs' refusal to conduct RFPs for renewables makes them particularly unprepared to deliver least-cost service.

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[30] *See* the detailed briefing by Public Counsel, filed July 15, 2015, in Docket No. 160096-EI, Joint petition for approval of modifications to risk management plans by DEF, FPL, Gulf and Tampa Electric Company.

[31] FPSC Docket No. 160021.

a. Solar

Solar generation technologies, especially solar photovoltaics (PV) can meet peak demand[32] and achieve deep cost savings as a hedge against natural gas price volatility.[33] Solar PV is also a flexible resource, precisely what Florida needs as discussed in Section II.B.1 above. With an abundant solar resource—consistently ranked third best in the country for solar generation potential[34]—and ample support for developing it in Florida Statutes, discussed above in Section I.B, the utilities should be planning to "make Florida a leader in [this] new and innovative technolog[y]."[35]

Florida's tremendous solar potential, however, remains largely untapped because, in essence, the IOUs—with their overwhelming control of the state's energy market—sit on the tap. FPL is the sitter in chief. Florida's largest utility has not issued an RFP for renewable energy since 2007 and 2008, and never explains this omission, even though FPL acknowledges the cost of solar PV has since "plunged."[36] Likewise, DEF, the second largest utility, admits that it received "436 inquiries" from third parties interested in developing in-state renewables.[37] As Sierra Club has consistently highlighted, and as the Southern Alliance for Clean Energy (SACE) comments discuss in more detail, a disturbing lack of transparency shrouds such inquiries. This includes the modest solar power purchase agreements (PPAs) that DEF has negotiated to date. DEF refuses to disclose details, even such basic ones as the in-service, start, and end dates of the PPAs.[38] Gulf Power Company (Gulf) and Tampa Electric Company (TECO) are no better.[39]

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[32] *See, e.g.,* FPL 2016 TYSP, at 49-50 (crediting solar PV with 52% nameplate capacity at summer peak).

[33] Lawrence Berkeley National Laboratory, *Utility-Scale Solar 2014: An Empirical Analysis of Project Cost, Performance, and Pricing Trends in the United States* (Sept. 2015) at ii ("At these low levels – which appear to be robust, given the strong response to recent utility solicitations – PV compares favorably to just the fuel costs (i.e., ignoring fixed capital costs) of natural gas-fired generation, and can therefore potentially serve as a [']fuel saver[*'*] alongside existing gas-fired generation (and can also provide a hedge against possible future increases in fuel prices).") (hereinafter "Utility-Scale Solar 2014"), *available at* https://goo.gl/0L2dDOU.

[34] *See, e.g.*, AEE, *Advanced Energy in Florida* (Jun. 11, 2015), *available at* https://goo.gl/BBL5M4.

[35] Section 366.91(1), F.S.

[36] NextEra on Storage, https://goo.gl/eIVoSL.

[37] DEF response to Staff data request no. 35.

[38] DEF response to Staff data request no. 28 (stating "n/a" or "TBD" for in-service, start, and end dates).

[39] *See generally* Gulf Power Company's 2016 Ten-Year Site Plan (hereinafter "Gulf 2016 TYSP"), *available at* https://goo.gl/PE1qbW; Gulf 2016 TYSP Workshop Presentation, *available at* https://goo.gl/GH9rME; TECO 2016 TYSP; TECO 2016 TYSP Workshop Presentation, *available at ht*tps://goo.gl/rQNeYF.

Collectively, the IOUs plan to add in ten years as much solar generation as Gulf's sister subsidiary, Georgia Power, will add by next year—more than a gigawatt.[40] Moreover, through additional RFPs, Georgia Power plans to double its installed capacity again in five years with more solar PV, battery storage, and other renewables.[41] Georgia Power is hardly alone. In 2015, 100% of Alabama Power's new generation came from solar, and that utility just gained approval to issue RFPs for 500 MW more.[42] In fact, RFPs in every single state in the Southeast have returned abundant, cost-effective solar PV bids.[43] These are widely reported precedents, which reputable entities such as the U.S. Department of Energy also verify and publish in market reports.[44] Yet the IOUs never mention them; much less reconcile their refusal to issue RFPs with the relatively modest amounts of solar they propose to build themselves.

Indeed, the utilities present no data or analyses whatsoever to justify the relatively modest amount of solar generation they propose. The RFPs of other Florida utilities, however, confirm there is no shortage of cost-effective solar PV in Florida.[45] As we highlighted last year, on a per customer basis these utilities have already installed far more solar capacity than the IOUs.[46]

The IOUs' proposals to add solar are also mere placeholders. Unlike the solar PV contracts that other utilities are negotiating with third parties, the IOUs have identified no particular process to set the terms of the solar they would build, such as the timing, sizing, siting, sourcing of inputs, and the costs. This gives the Commission—and the public—no reassurance whatsoever that the IOU investments in solar generation will in fact be optimally timed, sized, sited, etc. to achieve least-cost service. [47]

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[40] Georgia Power, Utility-Scale RFP Program, *available at* https://goo.gl/yEKHAu.

[41] Georgia Power 2016 Integrated Resource Plan, at 10-101, *available at* https://goo.gl/CdMFiZ.

[42] *See* Top 10 Solar States (2015), https://goo.gl/F3jIVu; *See also* Alabama Power's plan for 500 MW of renewables approved by regulators, Utility Dive, Sept. 3, 2015, https://goo.gl/uf5Ffm.

[43] *See* Exhibit A: Southeast RFPs for renewables.

[44] *See, e.g.,* Utility-Scale Solar 2014, at 37; *See also* Tracking the Sun IX: The Installed Price of Residential and Non-Residential Photovoltaic Systems in the United States (2016), *available at* https://goo.gl/SpUJY2.

[45] *See* Exhibit B: Florida RFPs for solar.

[46] *See* Sierra Club 2015 Comments, at 12.

[47] Sierra Club supports SACE's comments and shares SACE's concern that, beyond ten-year site plan reviews, the Commission may not get another opportunity to conduct fact-finding until after the utilities have already built whatever solar generation they unilaterally selected.

b. Energy storage

Energy storage is another competitive alternative to gas generation. Tellingly, the states that already use energy storage want to add more of it. This includes Alabama,[48] Georgia,[49] West Virginia,[50] Tennessee,[51] and California.[52] Other states with energy storage market studies, such as Texas and Massachusetts, also report that this technology can provide immense improvements to the electric grid—and deep cost-savings relative to the status quo.

In contrast, there is a glaring omission of energy storage from the Florida utility plans. At the planning workshop, DEF explained that it lumps energy storage with offshore wind,[53] but that technology came online for the first time this summer.[54] Energy storage projects in contrast have been operational for decades. The first advanced compressed air energy storage (CAES) plant came online in 1978, and the first one in the US, in 1991, in

[48] As noted above, Alabama Power recently gained approval to issue additional RFPs for renewables. The company built the country's first compressed air energy storage CAES plant, 110-MW McIntosh plant, in 1991. PowerSouth Energy Cooperative, https://goo.gl/idGTAz. ("The unit captures off-peak energy at night, when utility system demand and costs are lowest. […] PowerSouth uses the stored energy during intermediate and peak energy demand periods to generate electricity.").

[49] As of September of 2015, Georgia has the largest Southern Company battery storage research project, which is testing a 1 MW/2 MWh lithium-ion battery storage system at a solar facility. Southern Company: Cedartown Battery Energy Storage Project, Sept. 17, 2015, https://goo.gl/MvLO7a; Southern Company also has a partnership with Tesla to test energy-storage products for commercial customers. Southern Co. goes all in on solar, storage, smart homes, EnergyWire, May 28, 2015, https://goo.gl/LjxEwD.

[50] In West Virginia, AES Energy Storage installed the Laurel Mountain Energy Storage Project at the Laurel Mountain wind plant, which delivers 32 MW of regulation and wind smoothing. The World's Largest Lithium-Ion Battery Farm Comes Online, Forbes, Oct. 27, 2011, https://goo.gl/L5g8K9.

[51] The Tennessee Valley Authority (TVA) operates the Raccoon Mountain Pumped-Storage Plant in Marion County, Tennessee. With capacity of 1,616 MW, it is TVA's largest hydroelectric facility and "provides critical flexibility." 2015 Tennessee Valley Authority Integrated Resource Plan (hereinafter "2015 TVA IRP"), at 40, *available at* https://goo.gl/GiURX3.

[52] World's Largest Storage Battery Will Power Los Angeles, Scientific American, July 7. 2016, https://goo.gl/cvGXzD; CNBC, Tesla tackles California energy woes with massive energy-storage deal, Sept. 16, 2016, https://goo.gl/z1YELb; California Dreaming: 5,000MW of Applications for 74MW of Energy Storage at PG&E, GreenTech Media, May 28, 2015, https://goo.gl/nuZRT4.

[53] Duke Energy has relegated energy storage has into a third category of "Emerging Technologies," along with offshore wind technologies. Duke Energy, A Brief Overview of DEF Planning. Duke Presentation, given at the Sept. 14, 2016 Ten-Year Site Plan Workshop, *available at* https://goo.gl/STKM0q.

[54] Offshore Wind Arrives in America, Energy.gov, Sept. 9, 2016, https://goo.gl/sqjxpr.

Alabama.[55] Now, as utilities across the country are rapidly procuring storage, Florida utilities are behind, without even a plan to explore procurements of their own.

As noted above, FPL itself acknowledges that energy storage is a competitive alternative to peakers. Market studies commissioned by state energy regulators and by other utilities agree: energy storage investments can save hundreds of millions, if not billions of dollars.[56] These projected savings stem from the wide-ranging applications of this technology, spanning electric generation (on and off peak), transmission, and distribution.

Peak generation is of course the most expensive generation, and storage allows utilities to reduce or avoid that generation altogether by redeploying surplus energy from lower cost, off-peak hours. A 2016 report by the state of Massachusetts concluded that this application alone could save customers in that state more than a billion dollars. Other studies document the cost savings from energy storage's ability to reduce transmission and distribution-related maintenance, as well as defer and even avoid huge capital expenditures.[57] In 2014, Texas utility, Oncor, announced it would seek approval to build 5,000 MW of energy storage citing over $625 million of projected customer savings.[58]

Storage can also reduce risk by providing both flexibility and reliability. Energy storage is in fact highly accommodating with sizing, siting, permitting, and construction time. Because this technology does not produce direct air emissions, or have large land requirements, the permitting and siting processes are far easier.[59] Because individual storage systems are modular, one system can consist of many modules operating simultaneously, and can take on additional modules incrementally, so the system will not fail from the breakdown of one module.[60] Additionally, several types of advanced storage technologies are commercially viable,[61] including batteries, compressed air energy storage, liquid air energy storage, pumped hydroelectric storage, and flywheels.[62] They are also readily available. A

[55] PowerSouth Energy Cooperative, https://goo.gl/idGTAz.

[56] A 2016 report by the state of Massachusetts concludes that 600 megawatts of storage capacity installed by 2025 would save ratepayers $800 million in system costs. Massachusetts Energy Storage Initiative Study (2016), at xvi-xvii, *available at* https://goo.gl/D3zviD.

[57] *Id.* at 86-89.

[58] The Value of Distributed Electricity Storage in Texas Proposed Policy for Enabling Grid-Integrated Storage Investments (2014), at 14, *available at* https://goo.gl/fv2mYF.

[59] Massachusetts Energy Storage Initiative Study, at 9.

[60] Massachusetts Energy Storage Initiative Study, at 10.

[61] This is evidenced by their widespread use in competitive markets without subsidies. *Id.* at 2.

[62] Energy Storage Technologies, https://goo.gl/5vcJTb.

2016 study found utilities could procure these advanced technologies within months—four to six times faster than conventional technologies.[63]

The value of energy storage is also apparent in California's use of it to solve the emergency that resulted from the massive gas facility failure at Aliso Canyon. That failure put the entire region at high risk of far-reaching power outages. State regulators directed utilities to speed up the deployment of large-scale, grid-connected storage. As of August, California utilities have proposed three large-scale battery installations[64]—one with an in-service date just five months after it was proposed.[65]

c. Energy efficiency

Energy efficiency is the lowest-cost energy resource available,[66] and is essential to deliver least-cost electric service. More specifically, the wide-ranging technologies labeled as energy efficiency are part of the demand-side management that Florida needs to keep demand down and electric bills low, as noted in Section II.B.1 above. Yet the utilities continue their practice of ignoring any incremental energy efficiency additions beyond the levels set by the Commission based on information three or more years old.[67] This cannot be squared with the more recent market assessments, including those in other Southeast states, consistently showing that energy efficiency is not only cost-effective, but a critical resource to meet peak demand,[68] reduce risk, and save customers money.[69]

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[63] *Id.* at 10.

[64] They proposed two 20 MW (80 MWh) facilities from SCE and a 37.5 MW (150 MWh) project from SDG&E. 'Eyes wide open': Despite climate risks, utilities bet big on natural gas, Utility Dive, Sept. 27, 2016, https://goo.gl/697hYh.

[65] As Aliso Canyon Gas Shortage Looms, Southern California Looks to Energy Storage, Greentech Media, Jun. 02, 2016, https://goo.gl/JrI0O4; *See also* California Utilities Are Fast-Tracking Battery Projects to Manage Aliso Canyon Shortfall, GreenTech Media, Aug. 18, 2016, https://goo.gl/9XyYx1. (stating that the projects must be grid-ready by year's end, in SCE's case, or by Jan. 31, 2017, in SDG&E's case.).

[66] SEE, Guide For States: Energy Efficiency As A Least-Cost Strategy To Reduce Greenhouse Gases And Air Pollution, And Meet Energy Needs In The Power Sector (2016), *available at* https://goo.gl/ZtQ7pc; *See also* ClimateWorks & Fraunhofer ISI, How Energy Efficiency Cuts Costs for a 2°C Future (2015), *available at* https://goo.gl/fjf0xR; *See also* The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs (2014), *available at* https://goo.gl/GPYhzU.

[67] Here, "utilities" refers to the utilities subject to the Florida Energy Efficiency and Conservation Act (FEECA). The other Florida utilities also have an obligation to provide least-cost service and to that end should develop and disclose robust options analyses focusing on energy efficiency.

[68] At very low cost and risk, efficiency offers flexibility in meeting peak demand. Florida utilities can quickly ramp up efficiency to meet demand growth and thereby reduce or entirely avoid costly infrastructure improvements and expansion. RAP, Recognizing the Full Value of Energy Efficiency (What's Under the Feel-

Energy efficiency programs are inherently less risky since they consist of many discrete resources that will not fail all at once.[70] Additionally, efficiency increases system reliability by reducing the stress on it. Many utilities give energy efficiency resources a risk credit, meaning the risk reduction effects of implementing efficiency reduced the cost of energy efficiency.[71] Thus, efficiency is a highly predictable and reliable cost-effective resource that enables the utility system to avoid the risk of surpluses, shortages, and periodic outages.

The utilities' refusal to consider incremental energy efficiency additions is even more alarming given the highly publicized, rapid changes in the market, and the billions of dollars that other utilities reported saving in recent years from geographically targeted energy efficiency programs, especially those that defer or avoid large transmission and distribution expenditures.[72] This Commission itself stated that, "at any time," it is ready to "reexamine and then adopt new [energy efficiency/demand-side management] goals or changes to those goals." [73] It is the responsibility of the utilities to develop data and analysis to allow the Commission to do so.

Indeed, if the utilities and the Commission are serious about closing the gap that minority and low-income households spend on energy, then they will rapidly develop plans to increase investment in energy efficiency, as leading energy efficiency experts have recommended.[74]

Good Frosting of the World's Most Valuable Layer Cake of Benefits) (2013) (hereinafter "2013 RAP Energy Efficiency Report"), at 41, *available at* https://goo.gl/APjr2s.

[69] Because efficiency reduces all pollutants, it can also save ratepayers money by satisfying environmental regulations without building new power plants, which require huge, inflexible capital outlays.

[70] 2013 RAP Energy Efficiency Report, at 41.

[71] The 2013 PacifiCorp IRP and the Northwest Power Council both give energy efficiency resources risk credit. ACEEE Comments on 2015 Tennessee Valley Authority Draft Integrated Resource Plan, at 3.

[72] For instance, in 2011, Consolidated Edison estimated that including the effects of geographically-targeted efficiency programs in its 10-year forecast reduced costs by over $1 billion. Additionally, since 2012, ISO New England identified over $400 million in deferred transmission investments due to efficiency. NEEP Northeast Energy Efficiency Partnerships: Energy Efficiency as a T&D Resource: Lessons from Recent U.S. Efforts to Use Geographically (2015), at 12 available at https://goo.gl/AXRf3m.

[73] FPSC Transcript Document No. 06614-14, at 21, Order No. PSC-14-0696-FOF-EU, filed Dec. 5, 2014, in Docket No. 130205-EI.

[74] ACEE, Lifting the High Energy Burden in America's Largest Cities: How Energy Efficiency Can Improve Low-Income and Underserved Communities, Apr. 20, 2016, at 3-4. (For African-American, Latino, and renting households, 42%, 68%, and 97% of their excess energy burdens, respectively, could be eliminated by raising household efficiency to the median.).

C. Rather than minimize cost of service to customers, the plans pave the way for windfalls for the IOUs/their affiliates at the expense of the captive customer base; it is imperative for the Commission to intervene and reject the plans.

As discussed above, the plans are in no way least-cost from an electric utility customer perspective. Others, however, certainly profit from these gas-laden proposals. The most obvious profiteers are the shareholders of the IOUs/their affiliates—together they are heavily investing in gas generation and infrastructure, such as inter-state pipelines. This gives the IOUs a perverse incentive to increase their reliance on and subsidize the inefficient production and distribution of natural gas as they pass increases in fuel costs directly to customers.

In his testimony before the Senate Energy and Natural Resources Committee, Jonathan Peress highlights "a disturbing trend of utilities pursuing a capacity expansion strategy by imposing transportation contract costs on state-regulated retail utility ratepayers so that affiliates of those same utilities can earn shareholder returns as pipeline developers. . . . Thus ratepayer costs which may not be justified by ratepayer demand are being converted into shareholder return."[75] Mr. Peress further explains, "the effect of these affiliate transactions, whereby utilities commit their captive customers to pay for pipelines being developed by the same corporate group, is that customers are saddled with risky 20 year financial obligations to provide nearly risk free shareholder returns of 14% per year or more."[76]

Ultimately, Mr. Peress warns, affiliate transactions can hurt not only customers but also market participants. In Florida, this includes business, large or small, that lose opportunities to provide efficient solutions for electric service due to the control that the IOUs/their affiliates exert over the state's energy market. This is the rub, for instance, in FPL and DEF's decision to import more gas through the Southeast Market Pipeline Project instead of less costly, Florida-made solutions for them to provide an adequate and reliable supply of electricity.

In recent years, mergers between the IOUs and pipeline companies have proliferated[77]—growing the potential for the fallout described by Mr. Peress. Again, the Southeast Market Pipeline Project [78] is case in point: FPL and DEF back this pipeline even

[75] Jonathan Peress, Testimony Before the Senate Energy and Natural Resources Committee (June 14, 2016), at 5, https://goo.gl/rPoudE.

[76] *Id.*

[77] *See* Exhibit C: Mergers between pipeline companies and IOUs/their affiliates.

[78] Sabal Trail is part of multiple pipeline expansions and a joint venture of DEF's parent, Duke Energy Corporation, and FPL's parent, NextEra.

though it would more than double the amount of natural gas that FPL and Duke themselves project needing.[79]

Coupled with the utilities' hedging programs, the recent mergers and affiliate transactions raise an acute threat of improper subsidization of pipeline companies by Florida electric utility customers.[80] Between 2002 and 2015, the four IOUs saddled their customers with more than a $6 billion bill for fuel costs higher than market price.[81] Public Counsel has protested this, citing the IOUs' own estimates of another $559 million in losses-borne again by customers.[82] If the Commission were to allow the utilities, now merged with pipeline companies, to increase their gas generation, customer bill could soar even higher.

As the Antitrust Division of the United States Department of Justice recognizes, this type of vertical integration "may be used by monopoly public utilities subject to rate regulation as a tool for circumventing that regulation. The clearest example is the acquisition by a regulated utility of a supplier of its fixed or variable inputs. After the merger, the utility would be selling to itself and might be able arbitrarily to inflate the prices of internal transactions. Regulators may have great difficulty in policing these practices, particularly if there is no independent market for the product (or service) purchased from the affiliate."[83] Vertical integration of the retail distribution and generation markets plus financial hedging of natural gas thus presents a clear conflict of interest whereby self-dealing practices can rampantly exploit the captive customer base.

To protect customers and diverse businesses in Florida, it is imperative for the Commission to reject the plans, and put all the utilities on a path to reduce, not increase, Florida's generation.

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[79] FPL admitted that it would only require 400,000 Dth/day by 2017 and 600,000 Dth/day by 2020, yet it moved forward with the construction of Sabal Trail, which will ship double that amount—800,000 Dth/day by 2017 and 1.1 billion Dth/day by 2020. *Compare* Testimony of Heather C. Stubblefield on behalf of the Florida Power & Light Co., FPSC Docket No. 130198, July 26, 2013 at 9:10-13, (testifying that FPL requested these amounts "based on FPL's analyses of its future gas transportation requirements"); Application by Florida Southeast Connection, LLC ("FSC") to FERC for a Certificate of Public Convenience and Necessity and for Related Authorizations, Sept, 26, 2014 at 2, (stating amount that Sabal Trail will ship).

[80] For example, the $3 billion Atlantic Sunrise gas pipeline expansion proposal pending before the Federal Energy Regulatory Commission (Docket No. CP15-138) would connect to delivery points in Florida, and FPL and DEF have intervened in the FERC proceeding, indicating they have a material interest in this pipeline.

[81] Office of Public Counsel Protest, Document No. 05102-16, at 2, filed July 15, 2016, in Docket No. 160096-EI (hereinafter "Public Counsel Protest of Hedging Losses").

[82] Public Counsel Protest of Hedging Losses, at 2.

[83] United States Department of Justice, Antitrust Division, Non-Horizontal Merger Guidelines § 4.3 Evasion of Rate Regulation, *available at* https://goo.gl/9xw0QB.

D. The utilities acknowledge they can wait many months, even years before committing resources to add any gas generation, so they have time to pursue alternatives instead.

The utilities cite no reason to move forward now with their proposals to add gas generation.[84] Indeed, the purpose of this generation is mainly to meet projected growth in peak demand.[85] We reiterate that this growth may never materialize. Even if it did, the utilities acknowledge they can wait many months, even years, before committing any resources to adding gas generation.[86] More specifically, November 2017 is the earliest "drop dead" date (for a 200 MW CT with a May 2020 in-service date), and that could be pushed back by six months.[87] The utilities thus have ample time to complete the missing RFPs and options analyses and revise their plans to pursue cost-effective alternatives instead.

E. Florida's high-cost, high-risk coal generation reinforces the need for revised plans including the chronically missing options analyses.

While the utilities are not proposing any new coal generation, their existing coal burning generation undermines their ability to provide least-cost service. Burning coal to generate electricity lost whatever economic edge it once had, as evidenced by the overwhelming national coal divestment trend.[88] To be sure, coal is a terrible deal: Not only is burning coal one of the priciest[89] and most polluting[90] ways to generate electricity, importing coal from out of state also stunts local economic growth.[91]

With no shortage of low-cost, low-risk alternatives in the market, all remaining coal owners and operators owe their regulators robust options analyses focusing on options for transitioning to the alternatives as soon as practicable. The regulators, in turn, are wise to

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[84] Staff data request no. 42.

[85] As noted above, OUC and FPL propose adding CCs as well.

[86] *See* response to Staff data request no. 40; *See also* 2016 TYSP Schedule 9s.

[87] TECO 2016 TYSP; *See also* TECO response to Staff data request no. 40.

[88] *See*, *e.g.*, EIA, 'Coal made up more than 80% of retired electricity generating capacity in 2015' (Mar. 8, 2016) available at https://goo.gl/b0xcAq; *See also* Sierra Club, Open letter to coal industry: United States and the world are moving away from coal, toward clean energy (Apr. 21. 2016) *available at* http://goo.gl/kE94J6.

[89] *See* 2016 TYSP Comments, *supra* n. 3 (citing sources on how coal generation costs compare to alternatives).

[90] *See* Mother Jones, 'Environmentalists Hate Fracking. Are They Right?' (May 11, 2016) *available at* http://goo.gl/dGtFju.

[91] *See* Union of Concerned Scientists, Burning Coal, Burning Cash: 2014 Update; Fact Sheet: Florida's Dependence on Imported Coal (Jan. 2014) *available at* http://goo.gl/Y3Yw21.

disallow further expenditures on uncompetitive coal generation, as the Georgia Public Service Commission just did in the integrated resource planning proceeding it recently concluded for that state's largest electric utility Georgia Power.[92]

Yet in Florida, the utilities have continued their practice of presenting no options analyses regarding their existing coal generation. This is a grave omission, as we have consistently warned, because the utilities' own, incomplete regulatory compliance cost estimates for this generation range in the hundreds of millions to billions of dollars.[93] Moreover, when Staff asked for up-to-date information—underscoring the dearth of information in the plans—the utilities indicated that their analyses are still incomplete, and they failed to provide any estimate whatsoever for several existing regulations.[94]

One glaring omission concerns the Effluent Limitations Guidelines (ELGs), the new U.S. Environmental Protection Agency rule to protect our waters from the toxic pollutants in the discharge of coal generators. The ELGs became effective on January 4, 2016, and the default deadline is November 2018. As it took EPA decades to issue this rule, utilities have long anticipated and planned for it.[95] Indeed, the IOUs must report their compliance estimates under federal financial disclosure rules, and have in fact reported such estimates for ELGs, which are as high as $50 million for just one of a dozen Florida coal plants.[96]

With such massive costs looming over them, it is unacceptable for the utilities to continue to delay studying their options to transition to non-fossil generation.[97] Indeed, as we highlighted last year, Lakeland Electric stands out as the one Florida utility that already commissioned such a study. Lakeland compared several retrofit and retirement scenarios for its aging coal plant, showing that the analysis itself is eminently doable.[98] Predictably, Lakeland's conclusion, which the utility is now refining with further studies, is that

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[92] *See* Exhibit D – Georgia Power IRP Stipulation, at 3 ("minimiz[ing] all capital expenditures" on two large coal generation facilities); *See also* GPSC Docket No. 40161, Direct Testimony of T. Newsome and P. Hayet, at 7 and 51 (Commission staff expert recommending "all capital investment" on costly coal plants be "minimize[d]") (May 6, 2016) *available at* http://goo.gl/SF9rba.

[93] *See* Sierra Club 2015 Comments, at 7.

[94] *See generally* Utility responses to Staff data requests nos. 50-62.

[95] *See* Exhibit E – Sierra Club Comments to Florida Dep't of Environmental Protection (FDEP) re: ELGs.

[96] *See* Exhibit F – Sierra Club Comments to FDEP re: Crystal River Energy Center.

[97] To be clear, Sierra Club does not support new nuclear generation as it extremely high cost and high risk and thus a nonsensical choice given all of the better alternatives available in the market.

[98] nFront Consulting LLC, "Strategic Resource Plan, Lakeland Electric,"(Mar. 2015), *available at* http://goo.gl/B2BmRK.

renewables and energy efficiency will meet its load growth over the next 20 years more cost-effectively than all three fossil fuel expansion scenarios studied.[99]

III. The Commission should require the utilities to file revised plans as soon as practicable.

For all the foregoing reasons, the Commission should reject the plans and require all the utilities to file revised plans as soon as practicable, including the chronically missing options analyses. The IOUs should file revised plans no later April 1, 2017, the annual deadline for plan revisions, to minimize the fallout from their conflict-ridden plans.

Thank you for your consideration.

Respectfully submitted,

/s/ Diana A. Csank

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[99] *Id.* at 3-13, 3-24.

Exhibit L

December 15, 2015

Via Electronic Mail

Chairman Graham, Comm'rs. Brisé, Edgar, Brown, and Patronis
Florida Public Service Commission
2540 Shumard Oak Blvd.
Tallahassee, Florida 32399-0850

Re: Missing alternatives in 10-Year Site Plans

Dear Commissioners:

On behalf of its more than 30,000 Florida members, the Sierra Club respectfully requests that in advance of next April's 10-year site plan deadline, the Commission direct each utility[1] to submit "possible alternatives to the proposed plan" as required by Section 186.801(2), Florida Statutes ("F.S."), as well as supporting information to evaluate those alternatives. To date, utilities have not provided such alternatives analyses to the Commission.

Florida law requires that at least every two years utilities submit "10-year site plans" to the Commission that outline the utilities' plans for ensuring that they deliver Floridian's electricity in a manner compliant with state law. The Commission must study the plans using a set of 10 criteria specified by statute. If the plans comply with those criteria and meet other objectives specified under state law, the Commission is to find the plans "suitable." Otherwise, the Commission is to determine the plans are "unsuitable."

For the reasons discussed below, to fulfill its duty the Commission should direct the utilities to submit robust alternatives analyses and supporting information. If the utilities fail to do so, the Commission must reject those plans as unsuitable. Consideration of alternatives is a mandatory part of the Commission's 10-year site plan reviews under Florida law, a common practice of regulatory utility commissions nationwide, and a matter of common sense. Just as smart consumers conduct comparison shopping before making purchases, especially of big ticket items, the utilities must allow the Commission—on behalf of Florida's electricity consumers—to do so.

[1] The Commission's Rule 25-22.071, Florida Administrative Code ("F.A.C") specifies the utilities that are subject to the 10-year site plan filing requirements.

Thus far meaningful comparisons between the utilities' proposals and alternatives have been precluded by the utilities' practice of presenting the Commission just their preferred generation plans and simply asserting that alternatives were considered but discarded as inferior. Without more information on the possible alternatives—including enough details for independent comparison of alternatives to the plans proposed by the utilities—the Commission cannot fulfill its oversight duty to ensure that Floridians are getting the best deal, as the Commission is required to do under the law. This is particularly true with respect to renewable energy and energy efficiency resources, which the Florida legislature has repeatedly and expressly asked the Commission to analyze.

The lack of robust alternatives analyses carries significant consequences. For example, the utilities have proposed to add large conventional power plants in their preferred plans. This commits significant amounts of Floridians' money to building out fossil fuel and nuclear infrastructure with payback periods measuring in the decades at a time of great change in the energy sector. It presents outsized risks, especially given an evolving regulatory environment around coal and carbon, and Florida's over-reliance on natural gas.

In contrast, Florida has an unprecedented opportunity to meet its electricity needs through low-cost, low-risk renewable energy and energy efficiency resource alternatives. This opportunity—and the need for Commission oversight to ensure that all utilities pursue it optimally—is perhaps best illustrated by the state's municipal utilities citing historic cost savings as they add in-state solar photovoltaics ("PV") to the grid at more than five times the speed (kWh of per customer) at which investor owned utilities are doing so in Florida. Indeed, across the country commissions and utilities are investing in renewable energy and energy efficiency at far greater speed than Florida's investor owned utilities, and they are doing so because it is more economical than Florida's heavy investments in natural gas. It is particularly notable that investor owned utilities such as Florida Power and Light and Duke Energy Florida are proposing so little renewable energy in Florida when in other states NextEra (FPL's parent company) and Duke are building out these resources as a cost-competitive option.

Timing is critical. Once a utility invests substantial resources into pursuing its proposed plan, it often constrains the possible alternatives that can be pursued, due in part to resource constraints and in part to the time it takes to plan, permit, and implement changes to the electric grid. Therefore, the Commission has a time-sensitive duty to require meaningful analyses and data regarding possible alternatives to the utilities' proposed plans, and further, it has a time-sensitive duty to require that those alternatives be implemented if they prove to be in the public's interest, as so many other commissions have concluded.

Section 1, below, recaps the standards governing 10-year site reviews, while Section 2 shows how, in the absence of robust alternatives analyses, the proposed plans are departing from these standards, and the Commission needs to correct course. With these comments, Sierra Club respectfully urges the Commission to take the critical first step of collecting from the utilities the

missing alternatives analyses, starting with the plans that are due in April 2016. Only with this information in hand will the Commission—and the public—be able to conduct the oversight that is required and essential to serve the interest of Florida's electric consumers.

I. The Commission is expressly required by Florida law to review possible alternatives to the utilities' proposed plans, and this necessarily requires that the utilities provide the information needed to conduct the mandatory alternatives analysis, particularly with respect to renewable energy and energy efficiency.

As Florida's electric utility regulators, the Commissioners have the primary responsibility to oversee long-term planning by the state's electric utilities.[2] This starts with collecting information during the 10-year site plan review.[3] At least every two years, Section 186.801, F.S., requires that the state's electric utilities submit "10-year site plans" to the Commission estimating their power-generating needs and the general location of their proposed power plant sites.[4] Section 186.801, F.S., unambiguously mandates that the Commission "shall review"-- "possible alternatives to the proposed plan[s]" of the utilities.[5]

Section 186.801 also provides nine other criteria that the Commission "shall review," which inform not only Commission's review of the utilities' own preferred proposals, but the alternatives that the Commission must consider. Fully one third of the nine criteria require the Commission to consider ways to advance renewable energy resource additions to the grid:

> (a) The need, including the need as determined by the commission, for electrical power in the area to be served.
>
> (b) The effect on fuel diversity within the state.
>
> (c) The anticipated environmental impact of each proposed electrical power plant site.
>
> (d) Possible alternatives to the proposed plan.
>
> (e) The views of appropriate local, state, and federal agencies, including 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.
>
> (f) The extent to which the plan is consistent with the state comprehensive plan.

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[2] *See e.g.,* Rule 25-22.072, F.A.C., incorporating by reference Form PSC/RAD 43-E (11/97), 1 (discussing Commission's oversight responsibilities) [hereinafter "Form"].
[3] *Id.*
[4] *See* Section 186.801(1), F.S.
[5] Section 186.801(2), F.S.

> (g) The plan with respect to the information of the state on energy availability and consumption.
>
> (h) The amount of renewable energy resources the utility produces or purchases.
>
> (i) The amount of renewable energy resources the utility plans to produce or purchase over the 10-year planning horizon and the means by which the production or purchases will be achieved.
>
> (j) A statement describing how the production and purchase of renewable energy resources impact the utility's present and future capacity and energy needs.[6]

Criteria (h) requires that the Commission review the "amount of renewable energy resources" utilities currently produce or purchase; (i) requires the Commission to consider the "amount of renewable energy resources" the utilities propose to produce or purchase, and the means, and; (j) requires the Commission to consider future energy and capacity needs.

If the Commission is to fulfill its duty to review not only the utilities' preferred plans but alternatives as well and, moreover, to fulfill its duty to specifically review renewable energy resources, the Commission necessarily must be provided information about those renewable energy resources, both as proposed by each utility and as potential alternative scenarios. Failure to do so reduces the Commissions' review to a make-work exercise. The Commission—and the public—need meaningful data on renewable energy resources and conventional energy resources to critically analyze the utilities' proposals. Otherwise the Commission—and the public—lack the information necessary to perform an informed assessment of the plans that the utilities' are proposing to implement.

This is only reinforced—and expanded to include energy efficiency—by criterion (f), which requires the Commission to review each plan for consistency with the state comprehensive plan, Florida's "direction-setting document,"[7] which sets out energy goal and policies that all aim to advance energy efficiency and renewable energy resources. The plan's section on energy states:

> Goal.—Florida shall reduce its energy requirements through enhanced conservation and efficiency measures in all end-use sectors and shall reduce atmospheric carbon dioxide by promoting an increased use of renewable energy resources and low-carbon-emitting electric power plants.
>
> (b) Policies.—

[6] Section 186.801 (2)(e), F.S. (emphasis added).
[7] Section 187.101, F.S.; *see also id.* ("The State Comprehensive Plan shall provide long-range policy guidance for the orderly social, economic, and physical growth of the state.")

1. Continue to reduce per capita energy consumption.

2. Encourage and provide incentives for consumer and producer energy conservation and establish acceptable energy performance standards for buildings and energy consuming items.

3. Improve the efficiency of traffic flow on existing roads.

4. Ensure energy efficiency in transportation design and planning and increase the availability of more efficient modes of transportation.

5. Reduce the need for new power plants by encouraging end-use efficiency, reducing peak demand, and using cost-effective alternatives.

6. Increase the efficient use of energy in design and operation of buildings, public utility systems, and other infrastructure and related equipment.

7. Promote the development and application of solar energy technologies and passive solar design techniques.

8. Provide information on energy conservation through active media campaigns.

9. Promote the use and development of renewable energy resources and low-carbon-emitting electric power plants.

10. Develop and maintain energy preparedness plans that will be both practical and effective under circumstances of disrupted energy supplies or unexpected price surges.[8]

The Commission's own guidance likewise requires the utilities to provide alternatives and supporting information.[9] Per the guidance, the utilities' annual plan submittals should include planning assumptions, methodologies, and outcomes. The submittals also should show that the supply of electricity contemplated in each plan is the "lowest cost possible."[10] This showing cannot be made without sufficient information about the possible alternatives to each proposed plan to allow the Commission—and the public—to verify that this critical criterion has been met.[11]

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[8] *See* Section 187.201(11), F.S. Note, subpart (11)(b)(10) raises price and supply risks that are commonly associated with out-of-state fuel imports (coal, gas, nuclear), and for which energy efficiency, solar, or other renewable technologies are solutions.

[9] See generally Form, supra n. 2.

[10] Form at 4.

[11] *See* Sierra Club comments of Oct. 16, 2013, at 5-6 (discussing need to consider cost over the life of the investment, and to quantify the risks that could materially affect the cost, including factors that are routinely considered during IRPs, such as fuel price surges and regulatory risks) *available at* http://goo.gl/h9RHeT.

Moreover, because investments in conventional generation resources—particularly coal, natural gas, and nuclear resources—require outlays of significant amounts of Floridians' money with payback periods that can span decades, for resources with very long book lives, the lowest cost showing should account for not only the current requirements and constraints, but also a range of those likely to exist five, ten, and twenty years (or more) into the future, even if this has not been the utilities' practice. These are the "future conditions" referred to above and throughout this letter.

If the utilities fail to meet these information requirements, the Commission should find the plans unsuitable and exercise its broad powers to collect the information from the utilities.[12] The Commission should "suggest alternatives"[13] to the plans to assure that they can be classified as "suitable," consistent with the statutory directive for adding clean energy to Florida's electric grid in a coordinated, cost-effective manner.[14] Ultimately, if a utility refuses to provide information on the possible alternatives and future conditions, or refuses to adopt the Commission's suggested alternatives, the Commission can classify its plan as "unsuitable." Even if the plans may not be considered binding, such a classification can carry great weight, warning the utility that the Commission may reject its proposals in subsequent dockets until the plan's shortcomings are fixed.

II. Absent robust alternatives analysis, 10-year site plans have and will continue to undercut the Commission's ability to conduct its review consistent with the mandatory statutory criteria and the corresponding directive to oversee coordinated, cost-effective renewable energy and energy efficiency resource additions to Florida's electric grid.

As Sierra Club commented at the most recent 10-year site plan workshop, the missing information on alternatives undercuts the Commission's ability to fulfill its mandatory electric utility oversight. Information on alternatives is most meaningful when coupled with information on future conditions, as noted above. However, in past 10-year site plan submittals, this information is missing, and the most acute information gaps are as follows:

- **Retire-or-retrofit analyses for Florida's coal generation**. Due to upcoming environmental compliance deadlines and multi-billion dollar retrofits contemplated in the utilities' own incomplete compliance plans, this is particularly urgent.

- **Alternatives to the approximately 11 gigawatts ("GW") of planned natural gas generation additions**. This is urgent because of Florida's existing, financially risky over-reliance on natural gas and the utilities' failure to use, or discuss how they used, a high case for natural gas prices and other future conditions to identify their preferred generation and to eliminate alternatives.

[12] *See* Section 366.04(2)(f), F.S. (Commission "shall have the power"—"[t]o prescribe and require the filing of periodic reports and other data as may be reasonably available and as necessary to exercise its jurisdiction").
[13] Section 186.801 (1), F.S.
[14] *See* Section 187.201(11), F.S.; *see also* Section 366.04, F.S. (directing Commission to oversee "planning, development, and maintenance of a coordinated electric power grid throughout Florida to assure an adequate and reliable source of energy for operational and emergency purposes in Florida and the avoidance of further uneconomic duplication of generation, transmission, and distribution facilities." [emphasis added]).

◊ **Detailed information on renewable energy and energy efficiency resources, including the results of competitive solar and wind procurements and the modeling assumptions used to assess alternatives that would allow for faster grid integration of these resources.** This is urgent because these zero-fuel cost resources offer a great value relative to fuel imports, and delay will needlessly expose Floridians to higher priced power while robbing them of clean energy's wide-ranging benefits.

A. The Commission should require the utilities to submit retire-or-retrofit analyses for Florida's coal generation to prepare for fast-approaching regulatory compliance deadlines, and to assess whether retirements are more prudent than the multi-billion dollar retrofits contemplated by the utilities.

The alternatives of retrofitting or retiring coal plants are hardly discussed in the 10-year site plans. Most plans simply defer the development or disclosure of this information. The same is true for the utilities' responses to Staff Data Requests regarding their plans. The responses even fail to identify the U.S. Environmental Protection Agency ("EPA") rules that will apply to coal plants over the planning horizon: the Greenhouse Gas Rules; the Coal Combustion Residuals Rule; the Cooling Water Intake Structure Rule; the Cross-State Air Pollution Rule and Successor Cross-State Air Pollution Rule; the Effluent Limitation Guidelines; the Mercury and Air Toxics Standard; the Regional Haze Rule; and the Startup, Shutdown, and Malfunction Rule. However, based on their incomplete regulatory compliance analyses, the utilities estimate that over the next decade coal retrofits may cost billions of dollars, as shown in Table 1 below.

Table 1, Preliminary Regulatory Compliance Cost Estimates for Coal Generation ($ Millions)[15]

Utility	Low MATS	High MATS	Low CSAPR	High CSAPR	Low CWIS	High CWIS	Low CCR	High CCR	Low Total	High Total
FPL	N/A	N/A	N/A	N/A	86.31	1068.31	N/A	N/A	225.81	1607.81
DEF*	157	165	0	0	26.6	301.6	N/A	N/A	183.6	465.88
TECO	3.9	3.9	0	0	800	800	18	18	821.9	821.9
GPC	565				35	38.1	N/A	N/A	681	684
FMPA	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
GRU	1.5	1.5	175	175	N/A	N/A	N/A	N/A	176.5	176.5
JEA	N/A	N/A	0	0	5	30	25	25	30	55
LE	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
OUC	2	2	N/A**	N/A	N/A	N/A	17.2	17.2	19.2	19.2
SEC	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	600	600
TAL	N/A	N/A	<.01	<.01	N/A	N/A	N/A	N/A	<.01	<.01
Total	164.4-729.4	172.4-737.4	175.01-740	175.01-740	952.91	2238.01	60.2	60.2	**2738.01**	**4430.29**

[15] This table reflects 2015 TYSP First Supplemental Staff Data Request No. 38. (*) Duke reported capital costs only. (**) OUC notes $11 million in stranded costs associated with selective catalytic reduction, which has been postponed following the vacatur of CSAPR.

In addition, the utilities' estimates provide an incomplete picture because they do not distinguish between one-time capital expenditures and the increases to recurring operating costs and others costs associated with reduced power output and generation. This omission is illustrated in TECO's response to Staff Data Request no. 36 regarding the cost of retrofitting the coal-burning Big Bend Generating Station (including four coal-burning electric generating units) with cooling towers:

> Tampa Electric is currently finalizing its compliance strategy for the CWIS Rule and is working with the regulating authority to determine scheduling for biological, financial, and technical study elements necessary to comply with the rule. These elements will ultimately be used by the regulating authority to determine the necessity of cooling water system retrofits for Big Bend and Bayside Power Stations. Based on the final rule, requirements could include retrofitting closed cycle cooling towers at regulated facilities. Few utilities, including Tampa Electric, would be in a position, either financially or due to space (land) limitations, to implement this option. As an alternative, the regulating authority may allow for modifications of existing intake structures and circulating water equipment to reduce measured impacts. <u>If required to install closed cycle cooling at Big Bend and Bayside, the cost could run as high as one-half billion dollars per facility. Tampa Electric has not conducted a formal cost study on intake and circulator modifications. However, such modifications could easily total as much as one hundred million dollars per station</u>.[16]

The information gap regarding coal generation in all of the 10-year site plans is significant and needs to be filled: There are over 9 GW of coal generation in Florida, which are growing increasingly uneconomic for reasons that are not limited to the potential need for multi-billion dollar retrofits. This coal generation is also: (1) growing older, with several coal electric generating units well past their book lives (e.g., Crist Units 4 and 5, already 56 and 58 years old, respectively); (2) growing less efficient notwithstanding the Commission's incentive program for improving heat rates (e.g., Indiantown, with an average heat rate consistently over 13,000 Btu/kWh in 2011-2014); and (3) already more expensive relative to clean energy alternatives, as evidenced by the Orlando Utilities Commission's recent resource procurement returning solar power for 7 cents/kWh—less than energy from existing coal <u>and</u> natural gas generation (8 cents/kWh), and exerting downward pressure on rates (10 cents/kWh).[17]

[16] TECO letter of May 15, 2015, Supplemental Data Request, Request No. 36, at 46.
[17] *See* Herman K. Trabish, Utility DIVE, *'Tipping point' for FL solar? Orlando utility buys at under fossil generation prices* (Aug. 2015) *available at* http://goo.gl/NiXNLh.

Therefore, Sierra Club respectfully urges the Commission to collect the missing information on the alternatives of retrofitting versus retiring Florida's coal generation so that the Commission can conduct its mandatory review of such alternatives. Giving the utilities a pass to provide this information piecemeal in the environmental cost recovery dockets is unlawful and unwise. Without a comprehensive look at Florida's coal generation, the Commission may soon find itself in a position where it has little choice but to approve exorbitant retrofits because there has not been sufficient planning and coordination to rapidly retire multiple coal plants while maintaining adequate reliability, even though the latter would be the least cost option.

B. The Commission should direct the utilities to submit robust alternatives analyses for the approximately 11 GW of planned natural gas generation additions, and should specifically require the analyses to account for a high case for natural gas prices, which the utilities' proposed plans have not done to date.

Despite the Commission's strategic concern about Florida's over-reliance on out-of-state natural gas imports, the utilities' plans overwhelmingly favor natural gas generation additions; approximately 11,548 MW are proposed in the 2015 10-year site plans. Yet the plans hardly discuss the possible alternatives, as illustrated by TECO's statement:

> Early in the study process, many alternatives were screened on a qualitative and quantitative basis to determine the options that were the most feasible overall. Those alternatives that failed to meet the qualitative and quantitative considerations were eliminated. This phase of the study resulted in a set of feasible alternatives that were considered in more detailed economic analyses.[18]
>
> …
>
> Tampa Electric Company continually analyzes renewable energy and distributed generation alternatives with the objective to integrate them into its resource portfolio.[19]

The problem with these statements, without more, is that they bar the Commission—or the public—from evaluating the possible alternatives to TECO's proposed plan.

At a minimum, the Commission needs each utility to provide enough information about the alternatives considered and the screening criteria used to allow the Commission—and other stakeholders—to independently review the utilities' conclusions that those alternatives should not be pursued.

[18] 2015 TECO TYSP, at 61 *available at* http://goo.gl/wDSd2X.
[19] *Id.* at 54 (notes to Schedule 8.1).

Additionally, to aid its review, the Commission needs more information on future conditions. A robust long-term planning analysis is needed because the book life of many investments that will be made over the next ten years will extend out well beyond those ten years, and even beyond 2050. Therefore, it is important for the Commission to develop some understanding of whether the proposed investments—or the possible alternatives—are the most compatible with future conditions and the Commission's statutory directive to spur coordinated, cost-effective clean energy additions to Florida's electric grid. To be sure, Sierra Club understands that confidence around the accuracy of modeled outcomes decreases as timeframes extend further into the future. Yet there is no uncertainty about the multi-decadal book lives and payback periods associated with many electric utility investments. If the Commission is to fulfill its duty to oversee electric utility planning, the 10-year site plan review process should incorporate and be informed by future conditions within and beyond the next ten years.

With these future conditions in mind, the proposed long-lived combined cycle natural gas plants and supporting infrastructure are clearly in tension with the state's goal of optimizing its investment in clean energy alternatives for any number of reasons, including the following:

- The proposed investments in natural gas-based resources dwarf those proposed for clean energy resources.

- Doubling down on Florida's reliance on out-of-state natural gas imports would limit the available funds for clean energy alternatives, such as renewable solar and wind energy, energy efficiency, and rapidly emerging and transformative technologies, such as storage—for decades.

- Doubling down on Florida's reliance on out-of-state natural gas imports would heighten Florida electric utility customers' exposure to expensive hedging measures in the short-term, and to even greater fuel price volatility in the long-term.

- Florida's heavy reliance on natural gas may prove to be incompatible with achieving compliance with existing and anticipated public health, safety, and environmental rules, and may leave electric utility customers on the hook for replacing some of these resources before the end of their book lives (i.e., stranded assets).

Sierra Club is particularly concerned by the utilities failure to use, or discuss how they used, a high case for natural gas prices in their plans. For example, in response to Staff Data Requests, Duke Energy Florida ("Duke") states: "DUKE ENERGY FLORIDA DID NOT DEVELOP OR UTILIZE HIGH CASE - NATURAL GAS PRICES."[20] Duke's use of all capitals in the original is apt; it is extraordinary for a utility as big and sophisticated as Duke to omit a high case for natural

[20] DEF letter of May 15, 2015, Supplemental Data Request, Appendix A.

gas prices from its planning.[21] However, Duke is not alone. Even the Florida utilities that developed such a case do not fully explain how that factored in their proposed plans or development of possible alternatives.

To fill this critical information gap, the Commission should require the utilities, starting with April 2016 submittals, to provide their high case for natural gas prices, and provide a detailed explanation of how that case and other future conditions are used to develop the proposed plans and the possible alternatives. After collecting this information, the Commission may very well find that clean energy alternatives such as energy efficiency, solar, wind, and even storage are a better deal than the planned natural gas resources. Indeed, the U.S. Energy Information Administration (EIA) concluded earlier this year: "Rising long-term natural gas prices, the high capital costs of new coal and nuclear generation capacity, state-level policies, and cost reductions for renewable generation in a market characterized by relatively slow electricity demand growth favor increased use of renewables."[22] The EIA's underlying study "focus[es] on the factors expected to shape U.S. energy markets through 2040."[23] This is exactly the long view that should inform the Commission's 10-year site plan review because the utilities are proposing to spend significant amounts of Floridians' money on resources with long book lives and multi-decadal payback periods.

C. The Commission should require the utilities to submit detailed information on the available renewable energy and energy efficiency resources, including the results of competitive solar and wind power procurements and the modeling assumptions used to identify and evaluate alternatives that would integrate these resources into the grid at faster speeds.

a. Disclosing the results of competitive solar and wind power procurements.

The 2015 plans include Florida's first-ever wind power purchase agreement (Gulf Power's 178 MW PPA) and more than 1 GW of proposed solar capacity additions, "the largest amount ever included" in the 10-year site plans.[24] This is a good start but it hardly comports with the mandatory information requirements for such plans or the statutory directive to optimize clean energy additions to the grid. As noted above, the utilities consistently fail to disclose information about the possible clean energy alternatives that they have eliminated for one reason or another from their proposed plans. A passage from Duke's plan underscores this fact:

> DEF continues to seek out renewable suppliers that can provide reliable capacity and energy at economic rates. DEF continues to keep an open Request for Renewables (RFR) soliciting proposals for

[21] In response to Staff Data Requests, Duke provides some high-level description of the natural gas price forecast that it uses in its resource planning, but not nearly enough information to allow the Commission to evaluate the proposed plan or the possible alternatives that Duke considered. *See id.* at 29 (Response. No. 48).
[22] EIA, Annual Energy Outlook 2015 (Apr. 2015), at ES-1, *available at* http://goo.gl/92uyCB.
[23] *Id.*
[24] 2015 TYSP Review, at 3, *available at* http://goo.gl/HsIfeh.

> renewable energy projects. DEF's open RFR continues to receive interest and to date has logged over 400 responses.[25]

The 400 responses to Duke's renewable procurement are impressive, and they demonstrate that there is a robust and competitive renewable energy market. Yet the Commission can do little with Duke's statement because Duke did not enclose the responses or otherwise provide enough details about them for the Commission—and the public—to conduct their own review. Unfortunately, the same is true for the other utilities' plans.

As noted above, Commission oversight is urgently needed with respect to renewable energy and energy efficiency because of the Commission's statutory directive to advance these resources and market conditions that favor doing so as well. More specifically, zero-fuel cost resources such as energy efficiency, solar, wind and even energy storage offer a great value relative to out-of-state fuel imports (coal, natural gas, and nuclear), as discussed below, and delaying the integration of these clean energy alternatives will needlessly expose Floridians to higher priced power while robbing them of clean energy's wide-ranging benefits.[26] Indeed, there is evidence of the utilities, particularly the investor owned utilities, not optimizing their clean energy additions to Florida's grid. Perhaps most notably, Florida's municipal utilities are adding solar PV at more than five times the speed (kWh per customer) than the investor owned utilities,[27] while the latter are rapidly adding solar and wind to the grid outside Florida, showing that they too can be develop these resources cost-effectively at faster speeds.[28]

Therefore, Sierra Club respectfully urges the Commission to require all utilities to provide detailed information on, if not the actual results of, their competitive solar and wind procurements by next April's 10-year site plan deadline. Additionally, Sierra Club urges the Commission to collect more information from the utilities on their modeling inputs and outputs to verify that the utilities' are, in fact, rigorously identifying all possible clean energy alternatives (including self-builds and purchases), as detailed below.

b. Modeling realistic trajectories of improving performance and declining cost of clean energy alternatives.

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[25] 2015 DEF TYSP, 3-20, available at http://goo.gl/pC8Tbv.

[26] For a discussion of the wide-ranging benefits of energy efficiency see, for example, Sierra Club post-hearing brief of Sept. 30, 2014, *available at* http://goo.gl/6O3Obh; for the benefits of solar, wind, and energy storage, see, for example, Sierra Club comments of Sept. 9, 2015, and Sept. 25, 2015, *available at* http://goo.gl/yVBbAO.

[27] The Florida Municipal Energy Association reports that Florida's municipal utilities will install 135.7 MW AC of solar by mid-2016. Further, on a per customer basis, the municipal utilities currently have 136 kWh of PV—more than 5 times more PV than Florida's investor owned utilities; they collectively have 25.8 kWh.

[28] *See, e.g.,* UBS, *NextEra Energy, Still the Industry Leader* (Sept. 2015), at 3 ("While PTCs could yet add 500MW/yr to its baseline of 300-500MW/yr baseline without the PTCs, [NextEra] mgmt. suggests it could eventually scale the business to 1.5GW-2.0GW/yr as Carbon CPP targets become a reality (mostly wind, but some solar)") *available at* https://goo.gl/96By1E; *see also* Toni Nelson, Southern Alliance for Clean Energy, *Duke, Southern, and NextEra Go Big on Wind and Solar – Just Not in the Southeast* (Nov. 2015) (citing multi-billion dollar investments in out-of-state solar and wind resources by Duke, NextEra, and Southern Company) *available at* http://goo.gl/QL0BBS.

Given the dramatic improvements in the performance of renewable technologies and the declines in levelized cost,[29] it would be easy to underestimate the performance and overestimate the cost of renewable technologies when attempting to look out ten years or more. Trends in unsubsidized levelized costs for both wind and solar are truly dramatic: Lazard's recently released unsubsidized levelized cost of energy comparison identifies the levelized cost of onshore wind at $32-77/MWh.[30] Thin film utility scale solar is $50-60/MWh.[31] These unsubsidized ranges compare very favorably with the cost of natural gas combined cycle at $52-78/MWh.[32] Moreover, in the past six years, Lazard documents a 61% decrease in the levelized cost of wind and an 82% decrease in the levelized cost of solar photovoltaics.[33] While these trends are not strictly linear, Lazard's analysis shows that the low-end levelized cost for both wind and solar has uniformly declined year-on-year for the past six years, driven by "material declines in the pricing of system components (e.g., panels, inverters, racking, turbines, etc.), and dramatic improvements in efficiency, among other factors."[34]

As these trends are expected to continue into the future, it is important that the utilities' modeling not freeze cost and performance figures at 2015 levels for the next ten years, but instead project forward realistic trajectories of improving performance and declining cost consistent with the history of the technologies and best analysis of future performance.

c. Disclosing screening criteria and other modeling assumptions regarding clean energy alternatives.

The qualitative and quantitative screening criteria and other modeling assumptions used to eliminate clean energy alternatives from the utilities' proposed plans require Commission oversight. Sierra Club respectfully urges the Commission to take the critical first step of requiring disclosure and, as appropriate, adjusting these criteria and assumptions to ensure that the utilities develop proposed plans and possible alternatives that value clean energy fairly relative to conventional power plants.

Other IRPs in the region can be instructive in this regard. For example, in advance of its IRP next year, the Georgia Commission is working with stakeholders and the regulated utility in that state through public comments and a workshop on appropriate modeling assumptions and methodologies for valuing renewables technologies.[35]

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[29] For further information on the merits of levelized cost comparisons see, for example, Sierra Club comments of Oct. 16, 2013, at 3-4 (citing literature on IRP best practices) *available at* http://goo.gl/h9RHeT, and Sierra Club post-hearing brief of Sept. 30, 2014, at 9 (identifying institutions that develop levelized cost comparisons) *available at* http://goo.gl/6O3Obh.
[30] Lazard, Levelized Cost of Energy Analysis—Version 9.0 (Nov. 2015), 9, *available at* https://goo.gl/z0xFJw [hereinafter "2015 Lazard"].
[31] *Id.* at 5.
[32] *Id.* at 2.
[33] *Id.*.
[34] *Id.* at 10.
[35] *See* Georgia Public Service Commission, Docket No: 39732, *available at* http://goo.gl/nX3USx.

The IRP concluded by the Tennessee Valley Authority[36] in August 2015 is also instructive because it is an extremely recent, comprehensive planning effort concerning a region and generation portfolio similar to that of Florida: TVA modeled multiple different resource strategies against a series of different scenarios (such as a high-growth future, a low-growth future, and a future heavily reliant on distributed generation). TVA elected to model several strategies that emphasized renewables, and a strategy that emphasized energy efficiency. What TVA found in its modeling was that strategies that emphasized renewables and energy efficiency saw marked reductions in water use[37] and in carbon emissions, among other environmental benefits, at essentially similar overall cost to more fossil fuel-oriented strategies. What is notable is that this was against a background in which all modeled strategies involved significant shifts away from carbon-intensive generation: TVA's overall analysis showed that, no matter the scenario examined, the most economically prudent thing for the utility to do would be to decrease coal-burning in favor of lower-carbon sources of electricity, such as solar, wind, and energy efficiency.

As for Florida-specific considerations regarding clean energy resources, because the Commission has received extensive comments on the improvements in the performance and cost of solar generation, and on the terrific value of energy efficiency, Sierra Club will not repeat this information here, except to provide a very brief summary. However, there are other clean energy technologies that (also) require more attention in the utilities' plans that we will highlight.

i. Energy Efficiency

Notwithstanding the weak energy savings goals set in the FEECA docket, the utilities should continue to evaluate the alternatives to their proposed plans that rapidly ramp up energy efficiency. This is particularly important because energy efficiency continues to be a very low cost, low-risk resource that compares very favorably to natural gas combined cycle as shown, for example, in Lakeland Electric 2015 Strategy Resource Plan[38] and Lazard's levelized cost comparison.[39]

Additionally, Florida continues experiencing slowing demand and excess capacity. Total national generation is about the same today as it was in 2005 even though population and the economy have grown. Florida is consistent with these national trends despite some pockets of growth. In this low growth environment, utility planners are increasingly finding that the most needed generation sources in their portfolio are not baseload or shoulder generators that have long,

[36] More information on TVA's IRP is available at https://goo.gl/Bk7p1u.
[37] Water use is one of the mandatory criterion of this Commission's 10-year site plan review pursuant to Section 186.801(2)(e), F.S.
[38] Lakeland Electric found that energy efficiency, solar power, and other clean energy alternatives will meet its load growth over the next 20 years more cost-effectively than all three fossil fuel expansion scenarios studied. *See* nFront Consulting LLC, "Strategic Resource Plan, Lakeland Electric," at 3-13, 3-24 (Mar. 2015), *available at* http://goo.gl/B2BmRK.
[39] *See* 2015 Lazard, at 2 (showing energy efficiency remains the lowest cost resource, at $0-50/ MWh in unsubsidized levelized cost of energy comparison).

slow response times, but resources that can be quickly added to the system, such as energy efficiency.

ii. Solar

Florida has vast solar potential that is already being developed cost-effectively, albeit slowly, with wide-ranging benefits, including, not limited to cost savings, water savings, fuel diversity, fuel price hedging, increased local economic growth, and increased reliability.[40] In fact, Florida is the least expensive market to invest in solar PV according to the U.S. Department of Energy,[41] with pricing as low as $0.7 per kWh.[42] This underscores the need for Commission oversight to ensure that all utilities are pursuing optimal levels of solar generation additions.

iii. Wind

Taller wind turbines with longer blades are already projected to enable capacity factors in excess of 60% for land-based wind in the near future: With 140 meter hub heights, the National Renewable Energy Laboratory estimates nearly 2 million square kilometers in the contiguous United States that would support capacity factors of over 60%.[43] As the map in Figure 1 below shows,[44] Florida's wind generation potential has dramatically increased as a result of these technological advancements. This underscores the need to not only incorporate recent technological advances into the utilities' plans, but also for their modeling to assume some trajectory for future improvements in performance and reductions in levelized cost for wind and solar--for both in-state generation and imports.

Indeed, Florida has access to some of the lowest cost wind resources in the country, from the Mid-West, as evidenced by Gulf Power's 178 MW wind purchase from Oklahoma—with pricing below its avoided cost.[45] A high voltage direct current ("HVDC") transmission line (Plains & Eastern Clean Line) is projected to come online by 2019 to deliver approximately 3,500 MW of additional high capacity factor, low cost wind generation to the Southeast, including Florida.[46]

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[40] *See*, *e.g.*, Solar Energy Industries Association--Vote Solar et al. comments of June 2015, *available at* http://goo.gl/sQOEWa; Southern Alliance for Clean Energy comments of June 2015, *available at* http://goo.gl/IJUHeu.

[41] *See* DOE, *Photovoltaic System Pricing Trends: Historical, Recent, and Near-Term Projections*, 2014 Edition (Sept. 2014), at 11 *available at* http://goo.gl/W1dJ8z.

[42] *See* Herman K. Trabish, Utility DIVE, *'Tipping point' for FL solar? Orlando utility buys at under fossil generation prices* (Aug. 2015) *available at* http://goo.gl/NiXNLh.

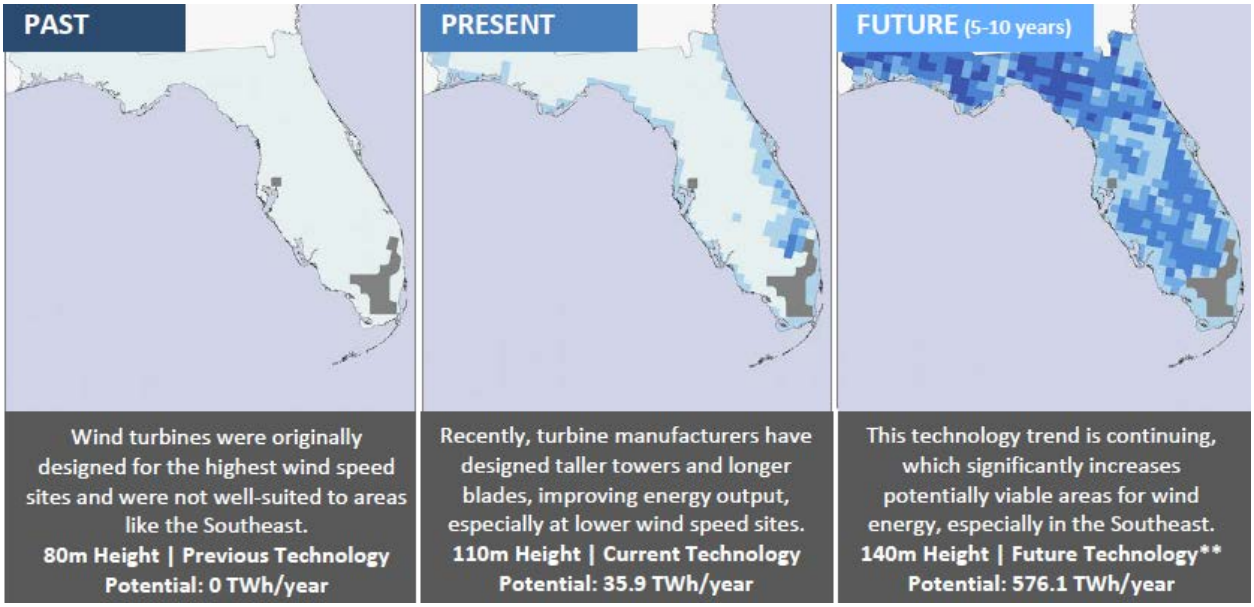
[43] NREL, United States (48 Contiguous States) – Potential Wind Capacity; Cumulative Area vs. Gross Capacity Factor, *available at* http://goo.gl/KesbYK.

[44] The map in Figure 1 is adopted from the "Florida Wind Energy Fact Sheet" prepared by The Southeastern Wind Coalition and The Southeast Wind Energy Resource Center using data from the Lawrence Berkeley National Lab, U.S. Energy Information Administration, and American Wind Energy Association. Maps estimate areas where wind energy could be economically viable (estimated gross capacity factor greater than 35%) when using available turbine technology. Not all areas shown can be developed. (**) 150 W/m2 machine. The Fact Sheet is available at http://goo.gl/TlGgQJ.

[45] *See, e.g.,* Sierra Club and Southern Alliance for Clean Energy letter of May 1, 2015 (discussing benefits of wind power purchases for Florida's electric customers) *available at* http://goo.gl/MYSsxw.

[46] Additional information on the Clean Line is available at http://www.cleanlineenergy.com/.

Figure 1, Florida Wind Energy Resource Potential



iv. Energy Storage

Similarly, 10-year site plans should address rapidly emerging and transformative renewable energy technologies, such as energy storage. Used appropriately, energy storage can increase grid efficiency, reduce the delivered cost of energy and ancillary services, increase reliability, and reduce infrastructure requirements. Compared to traditional generation or transmission resources, energy storage is typically highly accommodating with regard to sizing, siting, and permitting, so it can be located closer to load, or closer to grid congestion points, than other options. Recent energy storage procurement has shown that costs are lower than anticipated, and energy technology costs continue to fall as production and integration of resources increases.[47]

III. Conclusion

For all the foregoing reasons, the Commission has a time-sensitive duty to collect from the state's electric utilities information on the possible alternatives to their preferred generation plans, including supporting information that will allow the Commission—and the public—to critically evaluate those plans. Further, the Commission has a time-sensitive duty to require that renewable energy and energy efficiency alternatives be implemented if they prove to be in the public's interest, as so many other commissions have concluded. So that the Commission may fulfill these critical oversight duties, the Sierra Club respectfully requests that in advance of next April's 10-year site plan deadline, the Commission take the critical first step of requiring the utilities to submit the missing information regarding alternatives.

[47] Aachen University, Battery Storage for Grid Stabilization (October 2014), *available at* http://www.iea.org/media/workshops/2014/egrdenergystorage/Leuthold.pdf.

Thank you for your consideration.

Respectfully submitted,

/s/
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Exhibit M

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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 RiskAware 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, NOx, 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/resource-planning.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 intervener'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 at 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 reviews 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 prices 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.

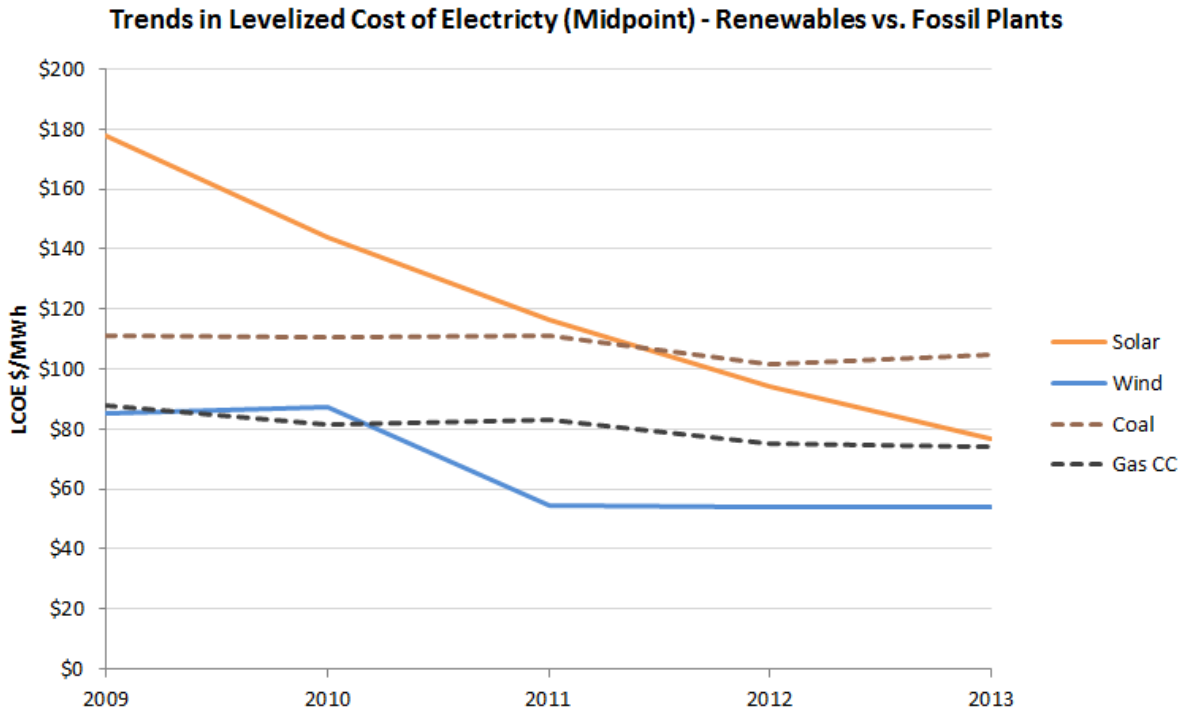
Although at the Workshop we spent a considerable amount of time addressing risks of further natural gas development, the other half of a cost and risk analysis is cost. As discussed at the Workshop, energy markets—and the costs of various types of energy resources, both supply and demand—are rapidly 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 cost**s**. 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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