UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Atlantic Grid Operations A LLC Atlantic Grid Operations B LLC Atlantic Grid Operations C LLC Atlantic Grid Operations D LLC Atlantic Grid Operations E LLC	Docket No. EL11-13-000

**MOTION TO INTERVENE AND PROTEST OF
NEW JERSEY DIVISION OF RATE COUNSEL AND
OFFICE OF THE PEOPLE'S COUNSEL FOR THE DISTRICT OF COLUMBIA**

Pursuant to Rules 211, 212, and 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. §§ 385.211, 385.212, and 385.214, and the Commission's January 11, 2011 Notice of Extension of Time, the New Jersey Division of Rate Counsel ("NJ Rate Counsel") and the Office of the People's Counsel for the District of Columbia ("DC OPC") (collectively, "Consumer Advocates"), hereby: (1) request leave to intervene in this proceeding, jointly and individually, with full rights as parties; and (2) address the December 10, 2010, "Petition for Declaratory Order" submitted by the "Atlantic Wind Companies" ("AWC"). The Petition states certain requests concerning the base return on equity, incentive rate treatment, and formula rate recovery in connection with the "Atlantic Wind Connection" project, a proposed "offshore transmission highway" (Petition at 2) the purpose of which is link to-be-built wind generation to the PJM Interconnection, L.L.C. ("PJM") grid.

Petitioners anticipate that the PJM regional planning process will be addressing their proposal in time to make a Section 205 rate filing in mid-2011[1] and begin construction in 2013.[2] Consumer Advocates recommend that for the short time remaining between now and then, the Commission either abstain from addressing the Petition, or reject it as premature, without prejudice to re-filing upon RTEP approval. At minimum, the Commission should make clear that no incentive payment by ratepayers will be due unless and until such planning approval issues. Consumer Advocates further recommend that any approval of the Petition be conditioned upon (a) adjustments to the scope and timing of the proposed incentive compensation components, and (b) a reduction in the base return on equity.

I. SUMMARY

While Consumer Advocates share AWC's interesting in ensuring an environmentally-sound energy future for the Mid-Atlantic region, we appear to part company on how best to pursue this important goal. Consumer Advocates support coordinated, regional planning that allows for a thorough assessment of all potential options, including the AWC proposal. Regional planning that gives reasoned consideration to the full range of alternatives is especially important here. The AWC project has not been written on a *tabula rasa*. There have been extensive and ongoing efforts by several of the PJM states (and other states in the Northeast) to advance the development of offshore wind generation without the pre-condition of an offshore transmission grid. These efforts are well underway and, as documented in the affidavit of Professor David E. Dismukes ("Dismukes Affidavit," which is Attachment 1 hereto), are proceeding in accordance with State policy directives, involve the combined construction of

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[1] *See* Petition at 78.

[2] *See* Petition at 24.

generation facilities and related radial transmission lines, and do not allow for the receipt of the costly and extensive incentives sought by AWC. The AWC Project has not gone through the PJM regional planning process, nor has it been the subject of any formal stakeholder process in the potentially affected states. Professor Dismukes cautions that approval of incentives for the AWC project may undermine State efforts and complicate ongoing initiatives to develop new offshore wind projects.

In these circumstances, Consumer Advocates urge that the Commission not undercut or get ahead of the regional planning process. Instead, and consistent with precedent, the Commission should either dismiss the Petition without prejudice to later renewal, defer action on the Petition, or—at a minimum--condition any incentives or other relief awarded for the AWC proposal on the approval of the project for inclusion in the PJM regional plan.

Assuming the Commission decides to address at this time the proposed incentives and the proposed base return on equity ("ROE"), the Commission should:

- Reduce the base ROE, which is substantially above the just and reasonable level, even when assessed using the data offered in this proceeding by AWC witness Villbert;
- Align the proposed incentives such that the reasonable needs of both AWC and ratepayers are more fairly balanced; this can be accomplished through changes in the scope of the proposed incentives and the timing for their recovery, including imposing conditions upon recovery such that:
  - none of AWC's costs are reimbursed through PJM rates before construction begins;
  - no above-cost incentives are flowed through PJM rates or accrued for later collection until the AWC project enters service; and
  - if AWC's project is abandoned, AWC collects no more from ratepayers than the return of its investment in the unfinished project.

II. MOTION TO INTERVENE

A. Interests of the NJ Rate Counsel and DC OPC

The outcome of this proceeding may affect directly the rates charged to New Jersey and District of Columbia ratepayers. The NJ Rate Counsel is the regulatory agency charged with protecting the interests of New Jersey ratepayers, N.J. Stat. Ann. § 52:27E-50 *et seq*., while DC OPC is an independent agency of the District of Columbia government and is the statutory representative of District of Columbia consumers in public utility issues in proceedings before the District of Columbia Public Service Commission, federal regulatory agencies, and state and federal courts. D.C. Code § 34-804 (2001). As such, NJ Rate Counsel and DC OPC are uniquely situated to represent the consumer interests at stake in this matter in New Jersey and the District of Columbia, and these interests are not adequately represented by any other party to this proceeding. Their participation in this proceeding as parties, on both a joint and an individual basis, is therefore in the public interest.

B. Communications

Communications regarding these proceedings should be directed to the following:

Stefanie Brand, Esq.
RATE COUNSEL
Felicia Thomas-Friel, Esq.
DEPUTY RATE COUNSEL
Henry M. Ogden, Esq.
ASSISTANT DEPUTY RATE COUNSEL
NEW JERSEY DIVISION OF RATE COUNSEL
31 Clinton Street
P.O. Box 46005
Newark, New Jersey 07101
Phone: (973) 648-2690
Fax: (973) 624-1047
Email: fthomas@rpa.state.nj.us
hogden@rpa.state.nj.us

Sandra Mattavous-Frye, Esq.
DEPUTY PEOPLE'S COUNSEL
Brian O. Edmonds, Esq.
ASSISTANT PEOPLE'S COUNSEL
OFFICE OF THE PEOPLE'S COUNSEL FOR THE DISTRICT OF COLUMBIA
1133 15th Street, NW, Suite 500
Washington, DC 20005
Phone: (202) 727-3071
Fax: (202) 727-1014
Email: smfrye@opc-dc.gov
bedmonds@opc-dc.gov

Scott H. Strauss, Esq.
David E. Pomper, Esq.
SPIEGEL & MCDIARMID LLP
1333 New Hampshire Avenue, NW
Washington, DC 20036
Phone: (202) 879-4000
Fax: (202) 393-2866
Email: scott.strauss@spiegelmcd.com
david.pomper@spiegelmcd.com

III. PROTEST

A. Background and a Threshold Point

Anyone who searches the internet has seen query responses that look ideal as excerpted on a results page, but turn out to be useless or defunct. The concept presented here by Google and its partners, through AWC and the instant Petition, is similarly enticing. Petitioners propose building a high voltage direct current offshore submarine network, which—we are told—will open new swaths of the Mid-Atlantic Outer Continental Shelf for offshore wind generation while reinforcing the existing land-based grid. While the filing does not lack vision, in addressing it the Commission must be alert to the possibility that the envisioned facilities will ultimately not be completed or will take longer, cost more, or do less than advertised. The Commission therefore must be careful to prevent its response to the present filing from leaving consumers and the environment worse off than if the present filing had never been made. First, do no harm.

At this point, AWC's proposal is highly conceptual proposal, and the Petition generally describes one of the many options for interconnecting potential and as-yet unlicensed wind sites. The filing includes no routing map resembling the large-scale maps that would be required at the start of a natural gas pipeline siting process;[3] it merely identifies seven existing nodes on the land-based grid to which an offshore system could be connected, and refers generally to siting "approximately 20 miles offshore."[4] AWC has received neither approval through any regional planning process nor any of the necessary environmental reviews and siting permits. It has filed no rate formula or other rate specifics, other than specific requests for above-cost rates of return. *See* Dismukes Affidavit ¶¶ 105-06. As the Commission is well aware, even wind transmission projects that have the advantage of an "anchor tenant" wind developer may be abandoned without ever serving consumers. *See, e.g., Central Maine Power Co.*, 125 FERC ¶ 61,182 (2008), *dismissed as moot,* 129 FERC ¶ 61,153 (2009), *reh'g pending.* AWC's project currently has no anchor tenant — nor even one of the many actual anchors that it would need if it were to build at sea.

Given that AWC's proposal is inchoate, any declaration granted by the Commission should be comparably indefinite. Most important, AWC should not be guaranteed a high return for merely performing preliminary work on a project that may never reach the point of construction, much less commercial operation. The prudent course for the Commission to take at

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[3] The Petition does include a very general "Figure 1" presenting a satellite's-eye view of a possible route, but that figure is not at all comparable to the level of detail required for natural gas pipelines by 18 C.F.R. § 157.21(d)(4) and 18 C.F.R. § 380.16(c).

[4] Petition at 18.

this stage would be to await the outcome of a regional planning process that, according to AWC's filing, will take only a few more months. To act now, just ahead of that disposition, would be precipitous and premature. To the extent AWC presses the Commission to act before then on the specific rate requests raised in its Petition, the Commission's response should be to either abstain with an explanation or to dismiss those requests without prejudice to subsequent renewal. At the very least, given the unresolved factual issues raised by the Petition (*e.g.*, as to whether sufficient actually completed wind generation really would subscribe to use of the AWC project in time to make it worth building), the matters it raises should be set for hearing.

B. The AWC's Proposal Raises Fundamental Transmission Planning Issues That Should Be Resolved In the PJM Planning Process, Not Here

AWC's Petition poses an important conceptual-level planning decision: whether to interconnect wind resources through radial lines from particular wind resource areas (either through individual lines connecting individual wind-generators, or radial facilities used to connect "clusters" or multiple farms) or through a coastwise, outer-continental-shelf line. Either configuration would, of course, have to be interconnected to the existing land-based grid, but as AWC points out, the latter configuration would more distinctly separate the siting of the interconnection-to-land lines from the siting of wind farms, and enable wind farms to be sited further from shore.

Rational arguments can be made in support of either configuration. As explained by Professor Dismukes, state policymakers have not sought the development of an offshore grid, but have instead adopted laws that move in the direction of the growth of individual, project-specific wind installations with related radial interconnections to the mainland grid. Dismukes Affidavit ¶¶ 15-57. Professor Dismukes expresses concern that approving incentives for the AWC project may affirmatively harm ongoing state efforts, stating:

> The AWC Companies' request several incentive ratemaking remedies that have been rejected by many states for offshore wind ("OSW") project development. As such, approval of the requested incentives for the AWC Project could be seen as side-stepping the state regulatory ratemaking treatment of various OSW development costs, thereby undermining state OSW policies that seek to balance the risk of OSW generation development between ratepayers and developers. The AWC Companies have failed to enter into any formal discussions with state policy makers and other stakeholders in order to explore synergies and benefits between individual OSW projects and the AWC Companies' proposed project.
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> If approved, the AWC Companies' proposed incentives could work to undermine, not facilitate, the development OSW generation since many of these proposed mechanisms are contrary to those included in existing state OSW policies. There are a large number of announced OSW generation projects along the Atlantic seaboard, most of which have not yet attained state regulatory approval for long term financial support. In addition, the overwhelming majority of these OSW projects currently envision the use of radial transmission lines. If the AWC Companies' incentives are approved, currently-announced OSW projects will have strong incentives to continue to explore direct radial connections to attain project approval given the contradiction of these incentives with existing state OSW financial support mechanisms.

Id. ¶¶ 10-11.

In addition, and in further response to the arguments that AWC has presented in support of a coastwise line, we list here some of the arguments in support of a radial configuration:

- In analogous historical situations, development commonly proceeds radially, with a looping overlay added later if and only if the radial development succeeds and thereby creates an economic basis for a second stage.
  - The eastern and western electrical interconnections developed by first radially connecting central generators to nearby loads; transmission sited for the sake of enabling transmission interconnections came much later.[5]

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[5] *See generally New York v. FERC*, 535 U.S. 1, 7 (2002) (summarizing history of the grid's growth and integration out of a series of radial plant-to-load systems).

- The natural gas gathering system in the Gulf of Mexico consists of a series of feeder and radial trunk lines, and has developed successfully without a coastwise gathering network.[6]

In short, incremental, radially-configured development is the more conservative, tried-and-true approach.

- A radial configuration can be built using a "cluster" approach, under which each sea-to-shore line interconnects multiple wind farms, but is built in conjunction with actual wind farm development. This approach has been recommended by studies done in Europe, where offshore wind turbines have been in operation since 1991.[7]

- If the siting and interconnection planning of the sea-to-land lines is, as AWC asserts[8], a particularly challenging aspect of integrating the offshore wind, then there are pragmatic reasons to favor leaving the role of proponent for siting each such line to the wind generators.

- There remains considerable uncertainty as to the future mix of renewable and other generating resources that will supply capacity and energy to PJM-area and nearby loads. Ongoing development of the Marcellus Shale natural gas resource may lead to a natural gas renaissance; new nuclear power generation may be sited; thin-film solar or other new renewable technologies may come to the fore; near-shore or Appalachian Mountain wind may prove more economical to harvest; and so forth. A coastwise configuration amounts to a centrally-planned, multi-billion-dollar societal bet on the future economics of far-offshore wind. In contrast, a radial configuration, by linking transmission siting to generation siting, relies on the market's forecast of future wind generation sales.

- Radial development is more likely to result in an end-state configuration in which the sea-to-land lines, which all agree are necessary, run through favorable sites for wind generation. Consequently, it may in the long run result in more intensive exploitation of the offshore wind resource.

To be clear, we are not arguing that a radial configuration is necessarily superior; we are, however, arguing the unassailable proposition that the issue is debatable. This debate should be

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[6] See http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngpipeline/southwest.html

[7] *See, e.g.* Djapic, Predrag and Goran Strbac, *Grid Integration Options for Offshore Wind Farms*, DTI Centre for Distributed Generation and Sustainable Electrical Energy (Dec. 2006).

[8] *See* Direct Testimony of Johannes Pfeifenberger and Samuel Newell, Exh. No. AWC-400, at 54.

resolved through the PJM planning process—which was established to address such issues—and not through the issuance of a Commission decision before that process has even begun.[9]

In asking the Commission to weigh in now, AWC asks the Commission not only to anticipate the PJM planning process but also to override past and ongoing government-led planning efforts. The PJM regional planning process will unfold within the context of public planning efforts that bear on the configuration and design of off-shore Mid-Atlantic transmission. These include the Atlantic Offshore Wind Consortium formed through a memorandum of understanding between the Department of the Interior and Governors from eleven states (including all of the Mid-Atlantic seaboard states), whose goals include "Examining regional offshore wind transmission strategies, and producing specific recommendations to address relevant planning and siting processes with Federal regulators, regional transmission organizations, and state officials."[10] More broadly, these public planning efforts include the marine spatial planning process that is now underway pursuant to Executive Order No. 13547, Stewardship of the Ocean Our Coasts and the Great Lakes.[11]

A third relevant public planning effort has recently been completed, namely the "Mid-Atlantic Area National Corridor" ("Corridor") that the Department of Energy defined less than four years ago. AWC's Petition effectively asks that the outcome of that process be revisited and

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[9] In related contexts, the Commission has made clear that it will either dismiss, or otherwise refrain from resolving, claims that are intertwined with issues that require and have not yet received consideration in regional stakeholder processes. *See, e.g., Cal. Indep. Sys. Op. Corp.*, 132 FERC ¶61,196 P 87 (2010); *New York Indep. Sys. Op., Inc.,* 126 FERC ¶ 61,046 PP 53-54 (2009); *Pacific Gas & Elec. Co.*, 123 FERC ¶61,067 (2008). While AWC will, ultimately, have to complete a stakeholder process, an advance Commission decision on the issues raised in the Petition runs the risk of unfairly skewing whatever PJM process ensues.

[10] *See* http://www.boemre.gov/ooc/PDFs/AtlanticConsortiumMOU.pdf.

[11] 75 Fed. Reg. 43023 (July 22, 2010).

revised. The relevant eastern boundary of the Corridor as currently defined runs from Southern Maryland

> northward following the Atlantic shoreline and then up the Hudson River to the northeastern corner of New Jersey. …
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> The Department has extended the draft National Corridor to the actual shoreline not because major new transmission lines are likely to be sited in such areas, but rather because these areas are sink areas, and transmission upgrades in some locations within these areas may be needed to gain the full benefit of improving their access to the source areas.

Dep't of Energy, Office of Electricity Delivery and Energy Reliability*; Draft National Interest Electric Transmission Corridor Designations*, 72 Fed. Reg. 25838, 25903 (May 7, 2007), *final designation*, 72 Fed. Reg. 56992 (Oct. 5, 2007). Although AWC cites the Corridor designation for its identification of a congestion problem that AWC claims to relieve,[12] AWC fails to recognize that its proposed solution to that problem falls outside the geographic scope contemplated in DoE's designation.

That said, Consumer Advocates acknowledge AWC's effort to think broadly and outside of previously-drawn boxes about how best to secure an environmentally-sound energy future for the Mid-Atlantic region. However, that AWC's concept is contrary to recent federally-conducted planning only underscores the need for (a) a careful technical evaluation; and (b) an assessment of both whether the AWC concept is superior to no action and, even more important, whether it is superior to alternative system investments. In particular, the novel nature of the AWC approach emphasizes the need for it to be thoroughly vetted by PJM's transmission planning process. That process has been the subject of Commission review and

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[12] See Petition at 3 & n.6.

approval,[13] and is fully capable of evaluating the pros and cons of AWC's approach. The Commission should not give AWC, or any other project proponent, a leg up in the approved regional-process comparison of alternatives by issuing incentives approvals for a project that has not yet been incorporated in the regional plan.

Although the Commission has in some prior cases issued rulings favorable to a transmission project that has not yet received regional approval,[14] the present case is different. AWC's "Project" is, for now, more a conceptual approach than a specific alternative. It needs to be compared to other conceptual approaches, not only to the status quo. And in that comparison, both the alternatives and the baseline on which they build have to be modeled well in order for that comparison to be meaningful.

A primary focus of this comparison should be on other ways to develop the offshore wind resource, contemporaneously with on-land development of electric and gas pipeline infrastructure directed to relieving existing congestion. AWC's comparison to radial wind development makes unsupported, anecdotally-based assumptions as to where radially-connected wind resources will be located. Moreover, AWC assumes that notwithstanding the ongoing development of the Marcellus Shale and other natural gas resources, and the associated ongoing expansion of pipeline capacity into the Mid-Atlantic seaboard, no new gas-fired generation will be added other than units already under construction or permitted. See Exh. AWC-403 at 5 (AWC's model "includes only existing units and the units that are under construction or permitted. No generic expansion is included except for the offshore wind in AWC Wind and Radial Wind cases …"). The disparate treatment of natural gas development and wind

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[13] *Order Accepting Compliance Filing*, 130 FERC ¶ 61,167 (2010).

[14] *See, e.g., Green Power Express*, 127 FERC ¶ 61, 031 (2009).

development in AWC's studies is striking: AWC conservatively excludes natural gas generators from its study unless they have already been permitted, but includes gigawatts of wind generation that don't yet even have a sponsor or a site.

In short, while it may well be possible for AWC to demonstrate within the planning process that its concept would reduce congestion and improve reliability in comparison to alternative concepts, the record presently before the Commission is not a sound basis on which to make such a finding here.

In these circumstances, Consumer Advocates urge that the Commission not get ahead of the PJM regional planning process. This can be accomplished either by (a) rejecting the Petition pending re-filing, or (b) deferring action on it unless and until PJM RTEP approval is obtained. At minimum, the Commission should condition of any approved incentives on the receipt of PJM RTEP approval. This action would be consistent with the Commission's determination in a somewhat analogous set of circumstances in *Central Maine Power Co*., 125 FERC ¶ 61,182 (2008), *dismissed as moot,* 129 FERC ¶ 61,153 (2009), *reh'g pending.* In *Central Maine Power*, the Commission confronted a request for approval of a set of incentives for the "Maine Power Connection," ("MPC"), which was to connect Maine Public Service Company's northern Maine transmission system to ISO New England and to deliver to it approximately 800 MW of wind power from the proposed Aroostook Wind Energy Project in northern Maine. *Id.*, 129 FERC ¶ 61,153 P 2. The Commission granted the project certain incentives, but conditioned them, stating:

> The … Project did not qualify for a rebuttable presumption of eligibility for incentives under section 219 of the Federal Power Act, and … the Maine Companies failed to make an independent showing that the Project would either ensure reliability or reduce the cost of delivered power by reducing transmission congestion. Consequently, the Commission granted the petition and authorized

> incentives subject to the conditions that: (1) ISO New England include the Project in its Regional System Plan as a Market Efficiency Transmission Upgrade; and (2) the Maine Companies submit a subsequent filing explaining how the Project's designation as a Market Efficiency Transmission Upgrade satisfies section 219's eligibility requirement.

Id. at P 6. The Aroostook wind project was subsequently cancelled and the requisite ISO New England regional planning approvals were never received. Given the uncertainties surrounding the fate of the instant, AWC project, a similar, conditional approval seems minimally appropriate.

C. The Commission Should Ensure that AWC Is Not Rewarded for Failure

As noted above, a radial configuration tightens the connection between wind farm siting and the siting of interconnections to the existing land-based grid, which has both advantages and disadvantages. One clear advantage, however, is that a single wind farm's failure to complete the siting of its connection to land would not undercut other parties' investment-backed reliance. In general, only the wind farm itself, perhaps along with customers who had contracted for its output, would be left worse off than if the radial project had never been proposed.

The same cannot be said for AWC's proposed coastwise configuration. AWC intends, and its cost-benefit studies rely on assuming, that wind generators will begin to site and develop projects in reliance on the expectation that the AWC line will be completed and enter commercial operation, and do so on a timely basis. A wind generator who is beginning to develop and invest in a site must decide whether to optimize the location for radial connection (meaning it will likely be located closer in on the continental shelf and near an appropriate point along the seaboard at which to interconnect to the existing grid) or to pursue a location further out on the continental shelf, closer to the projected AWC route--to the extent it is known. A wind developer who bets on AWC project completion and loses that bet will be left worse off than if the AWC project had never been proposed.

The potential for detrimental reliance by other stakeholders contrasts sharply with the situation of AWC itself, assuming its Petition is granted. Once the proposed rate treatments are implemented, the failure of the AWC project to enter service would *not* leave AWC itself worse off than if the project had never been proposed. Under AWC's proposal, AWC would receive not only 100% of its development costs and CWIP through the proposed abandoned cost incentive, but also rich, above-cost returns on its development cost regulatory expense and CWIP balance. It would also, apparently, avoid a balloon payment of some kind to Atlantic Grid Development, LLC ("AGD"), AWC's contracted development company.[15] AWC's coin would have only an upside, while all offshore wind project developers and other stakeholders would have to take their chances.

Given that difference in exposure to the consequences of non-completion, AWC would have monetary incentives to continue pursuing its project even if technical problems, siting difficulties, or changing power supply economics and requirements removed its purpose or necessitated a long delay. Moreover, as trade-offs arise between the likelihood of delivering the project when scheduled and the likelihood of delivering it eventually, AWC's incentive would be to take whichever options would optimize the latter. But AWC will inevitably have non-public information regarding the project schedule, especially if problems arise. In that case, generation developers relying on AWC would therefore have little choice but to rely on AWC's public statements regarding the project schedule. AWC's incentive will be to present optimistic projections of timely completion, thereby keeping the above-cost recovery going.

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[15] *See* Exh. AGD-100 at 12-13.

AWC suggests that the incentives placed on AGD personnel through the parties' Development Services Agreement ("DSA") would align AGD's interests with those of relying third parties.[16] But there is no basis to conclude that the DSA would create such incentives, nor any basis to conclude that the interests of AGD rather than those of AWC would control the outcome. The Petition does represent that AGD would not be the ultimate decision maker — *i.e.*, that AGD would be "subject to the oversight of the AWC Companies."[17] The language of the DSA would provide highly relevant information on those (and other) points, but it is not part of the Petition available for review by participants and the Commission. While the Petition contains no offer to make the DSA available, the undersigned asked AWC counsel to provide the DSA, or a redacted copy thereof, for review during this process; AWC refused to provide it. On the current record, the only reasonable conclusion is that AWC would continue to pursue its project as long as the pursuit itself was profitable, and that such a state of affairs might continue long after a disinterested observer would conclude that the public interest would be better served by changing direction.

To avoid these mis-aligned incentives, Consumer Advocates recommend several changes to the amounts and timing of any cost collections authorized by the Commission. Specifically, none of AWC's costs should be reimbursed through PJM rates before construction begins; no above-cost incentive should be flowed through PJM rates or accrued for later collection until AWC's project enters service; and if AWC's project is abandoned, AWC should collect from ratepayers no more than the return of its investment in the unfinished project.

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[16] Petition at 61.

[17] Petition at 17.

1. No Charges Should Flow through to Ratepayers Until Construction Begins, at the Earliest

AWC seeks declaratory approval to begin collecting its pre-construction development costs from PJM transmission customers as soon as "the AWC Companies have been included in the PJM RTEP."[18] AWC seeks to book as a regulatory asset "[e]ssentially… all non-capital costs incurred to successfully permit and develop the Project," including "consulting, legal and other development costs associated with obtaining approval and authorizations from state and federal regulators as well as from the regional transmission organization," and "costs associated with engineering, environmental or other studies, as well as costs incurred to educate and reach out to stakeholders."[19] AWC proposed to begin collecting the asset amount from ratepayers--whether or not construction had finished--or even begun. Rather than await construction or commercial operation, "[t]he amortization of the regulatory asset would start when the Project has been included in the PJM RTEP."[20] Notwithstanding AWC's erroneous claim that its proposal "is entirely consistent with recent Commission precedent," such treatment is directly contrary to Commission precedent and is unreasonable.[21]

AWC's testimony cites two cases for the proposition that starting the amortization "[o]nce the Project has been included in the PJM RTEP" "is "consistent with Commission precedent."[22] The first is *Green Power Express*, 127 FERC ¶ 61,031 (2009). In that case, however, Green Power Express was to "begin to include the initial regulatory asset in rate base on January 1 of the year immediately following the year the Project has first recorded CWIP

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[18] Petition at 58.

[19] Direct Testimony of Bente Villadsen, Exh. No. AWC-700, at 9.

[20] *Id*. at 8.

[21] *Id*. at 3.

[22] *Id*. at 6.

charges and will amortize the costs over 10 years." *Id*. P 54. Thus, the first charge to ratepayers for Green Power Express costs is not slated to occur until *after* the start of construction, when CWIP begins to be incurred — which is why no Green Power Express revenue requirement formula has yet been added to Midwest ISO Energy and Ancillary Services Market Tariff Attachment O or PJM Open Access Transmission Tariff Attachment H.[23] AWC's second citation, to *Primary Power*, 131 FERC ¶ 61,015 (2010), likewise does not support the proposed early collection of development costs. In that case, "Primary Power proposes to expense and amortize the regulatory asset over 5 years in rates, *as each SVC facility enters service*."[24]

The three other cases that AWC references for the related proposition that a regulatory asset may include pre-construction costs likewise instruct that recovery of costs should not start as soon as AWC proposes — especially so when those orders are read in light of subsequent decisions in those cases that AWC failed to cite. *See Western Grid Development LLC*, 130 FERC ¶ 61,056 PP 102-03 (ruling that applicant could establish a regulatory asset upon receiving planning approval, but making clear that any rate recovery would begin "later," and only after the subsequent submission and approval of a Section 205 rate filing), *on reh'g*, 133 FERC ¶ 61,029 P 20 (2010) (clarifying and re-affirming that "the Commission reserved judgment regarding the justness and reasonableness of Western Grid's recovery of pre-commercial expenses, if any, until it seeks such recovery in a future FPA section 205 filing"); *ITC Great Plains*, 126 FERC ¶ 61,223 P 71 (2009) ("ITC Great Plains states that the regulatory asset to

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[23] Furthermore, the Commission ordered *Green Power* to make a Section 205 filing before it could start amortizing the initial and vintage year regulatory assets in order to "demonstrate that the costs included in the regulatory asset were prudently incurred and are just and reasonable." *Id.* P 61.

[24] *Id*. P 8 (emphasis added). Moreover, while the Commission in that case made RTEP approval a *necessary* pre-condition to recovery, it did not rule that RTEP approval would be *sufficient* to start charging ratepayers. To the contrary, it rejected as premature the applicant's request for permission to start charging that soon, and provided only that a Section 205 filing to *seek* recovery could be made upon receiving RTEP approval. *See id*. PP 15, 69-70.

recover the start-up costs will be amortized over ten years *commencing upon the in-service date* of the KETA Project, the Kansas V Plan, or when total *in-service* gross property, plant and equipment exceeds $100 million, whichever occurs first" (emphasis added)); *Pioneer Transmission, LLC.*, 126 FERC ¶ 61,281 P 83 (2009) (making any rate recovery contingent on a future Section 205 approval, and contemplating that the applicant would "amortize and recover the regulatory asset *during the construction period*" (emphasis added)).

If the project timeline unfolds as AWC hopes, deferring the amortization period until CWIP recovery begins may not turn out to be a long deferral. AWC contemplates that its formula rate tariff would take effect following a Section 205 application to be made "in the late spring or summer of 2011,"[25] and that upon effectiveness of that filing AWC would begin to "amortize the regulatory asset including carrying costs over 5 years."[26] AWC states that a five-year amortization period that begins that soon "should correspond closely to the period during which the AWC Project is constructed."[27] To be clear, if events were to bear out AWC's optimistic expectation that it will "begin construction of the Project by 2013,"[28] starting amortization upon effectiveness of a mid-2011 filing would not correspond exactly to starting amortization when construction begins. Under AWC's own contemplated timeline, those two events differ by about 9 to 18 months.[29] But that is a fairly short interval in the context of transmission construction timelines.

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[25] Petition at 77.

[26] *Id*. at 59.

[27] *Id*.

[28] *Id*. at 58.

[29] The range of potential difference on those assumptions would extend from 9 months (filing made in August 2011 and suspended until March 2012; construction begins January 2013) to 18 months (filing made in April 2011, not suspended and therefore made effective June 2011; construction begins December 2013).

The larger problem is that the project timeline may *not* unfold as AWC hopes. As AWC admits (indeed, trumpets), it is proposing a very-large-scale project, with many federal and state approvals needed before construction could commence, and corresponding potentials for delay between inclusion in PJM's plan and the start of construction.[30] If the project is held up at that stage, but ratepayers are required to pay for pre-construction costs at that time, AWC's board would be in the position of owning a profitable ongoing business whether or not the pre-construction efforts ever bore fruit. It would be both unfair and poor public policy to place AWC in a position where it would have less financial urgency to bring its project to completion than would prospective wind generators working to develop sites selected in reliance upon AWC's planned route. Moreover, such early amortization would be inter-generationally inequitable; many of the retail customers who would fund the pre-construction costs would never receive any service from the project they would be funding, because they would leave the system before the project entered service.

If and when the AWC project receives PJM planning approval through inclusion in the RTEP, the Commission can then proceed to consider whether the costs of carrying construction investment through the pre-operational period should be covered through CWIP or through AFUDC. At this point, however, planning approval has not been received, and it is therefore premature to reach that question.[31]

2. Pre-Operational ROE Should Be Limited to Cost

The organizing principle of AWC's relationship with its development contractor AGD, as embodied in the Development Services Agreement described in the filing, is that AGD is

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[30] *See* Exh. AWC-600 at 14.

[31] *See* Part III.A above. *See also* Dismukes Affidavit ¶¶ 119-127.

rewarded only if it succeeds in bringing the project through permitting, financing and construction, to the point of commercial operability.[32] As sophisticated businesspeople, those negotiating the DSA surely understood that in structuring an incentive to be effective, it is important to provide that the incentive is paid only if and when the desired performance is completed.

Consumer Advocates urge the Commission to apply this same organizing principle to the incentive that ratepayers are being asked to pay to AWC. As shown above, mere spending on project development and construction does consumers no good until and unless that expenditure succeeds in bringing a facility into service. It would be one thing to determine that, once service commences, AWC should receive more than its capital and other costs as a reward for delivering value to consumers. It is quite another to structure AWC's rates such that it profits handsomely for merely spending money, before or without delivering any tangible "service" to a paying customer. Accordingly, any ROE adder that is approved on incentive grounds should take effect only when the investment to which it applies enters service.

To be clear, we are not contending that AWC should have no eligibility for recovery if the project is abandoned without being completed. AWC remains free to make a Section 205 filing at any time, and can attempt therein to show that all of its costs should be covered by ratepayers even if its project never enters service. What we are contending is that in the event of

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[32] *See* Direct Testimony of Paul McCoy, Exh. AWC-100 at 12-13 ("In exchange for AGD's Project development services, the DSA provides a compensation scheme, with payment largely based on AGD's successful development of the Project. In order to incentivize AGD to complete the AWC Project in a timely manner, a significant portion of AGD's compensation is based on the completion of each phase of the AWC Project. The DSA provides that the AWC Companies will compensate AGD if and only when a particular phase of the Project is fully permitted, financed and constructed. In addition to this incentive-based compensation, AGD's principals will receive a modest hourly compensation during the 10-year development period.").

project abandonment, AWC should receive at *most* its actual costs, and not an increment above costs pursuant to an incentive-increased return.

To implement this principle, AWC's return should be limited as follows.

- The ROE applied to the project development costs regulatory asset, from the time it begins to be booked and then amortized until the date of commercial operation, should be limited to the cost-based component of the allowed return: 11% or 10.58% if AWC's cost of capital study were to be summarily approved, or a lower ROE if the Commission were to find a lower cost.
- The regulatory asset accounting should maintain distinct sub-accounts for principal and interest.
- The ROE applied to any allowed CWIP, from the time it enters rate base until the date of commercial operation, likewise should be limited to the cost-based component of the allowed return.
- In the event of project abandonment, the interest component of the project development costs regulatory asset should be written off.
- Prospectively from the date of commercial operation, the ROE applied to the in-service rate base, and to any then-unamortized project development costs regulatory asset, should increase to include any approved ROE adder(s).

These limitations are a straightforward extension of the established rule — to which AWC's proposal as filed does not adhere — that an ROE incentive for RTO participation should not take effect until the subject facilities are placed under RTO control.[33] The basis of that rule is that a reward for RTO participation should not begin to accrue until the entity or project being rewarded is in fact participating in the RTO. At minimum, that rule demands that the ROE

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[33] *Primary Power* P 132 (RTO adder conditioned on Project being included in the RTEP process and Primary Power taking all the necessary steps to turn over operational control of Grid Plus to PJM and become a Participating Transmission Owner); *Green Power* P 85 (incentive adder based on commitment to join RTO becomes effective on date "Green Power becomes transmission owning member of an RTO and places the Project under an RTO's operational control); *New York Regional Interconnect, Inc.*, 124 FERC ¶61,259, P 38 (2008) ("*NYRI*") (RTO adder conditioned on "NYISO approving NYRI's membership application and on NYRI's continued participation in NYISO," and further conditioning adder on "the final ROE being within the zone of reasonable returns, to be determined when NYRI makes its future section 205 filing, and on the Project receiving state siting approval.")

applicable to AWC costs prior to commercial operation be reduced by at least 50 basis points from the ROE that AWC is seeking.

In the context of this particular case, however, the application of that principle should go further. The 50 basis points of incentive that AWC seeks for "advanced transmission technology"[34] should not be awarded unless that technology *works*, both from a technical engineering standpoint and as a means to overcome siting difficulties. Similarly, the 150 basis points of incentive that AWC seeks due to the "risks facing the Companies in completing the offshore AWC Project"[35] should not be awarded unless the Companies actually do "complet[e]" the project, to the point of bringing it into service. Project risk that affects capital costs can and should be accounted for through a properly designed cost-of-capital study. But where the investing transmission developer is allowed to recover its development and construction costs prior to and irrespective of commercial operation — as AWC seeks here — completion risk does not affect the cost of capital, and any non-cost incentive based on completion risk should be structured as a reward for overcoming that risk.

That leaves the 50 basis point incentive that AWC seeks for its "status as independent transmission companies."[36] Concededly, there is Commission precedent supporting the application of a transco-based incentive prior to commercial operation.[37] But that precedent expressly was based on particular, case-specific facts, and was conditioned on those projects achieving some measure of fruition.[38] Consumer Advocates urge the Commission to rethink that

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[34] Exh. AWC-600 at 13.

[35] *Id*. at 13-14.

[36] *Id*. at 13.

[37] *See, e.g.*, *Western Grid* P 96; *Primary Power* P 132; *NYRI* P 21.

[38] *See, e.g.*, *Western Grid* P. 96 (transmission company-only adder conditioned on Projects "being approved in

precedent in the context of AWC's particular facts. If AWC's facilities fail to enter commercial service, the practical upshot of AWC's independence will turn out to be that AWC, lacking an interest in any particular delivery path to a load area or from a generation area, elected to attempt to build a path to nowhere. It is outcomes--not inputs--that should be rewarded, and such an outcome would not deserve a reward.[39]

3. Abandoned Plant Recovery Should Be Capped at the Amount Invested, and Recovery at that Level Should Not Be Guaranteed

AWC is seeking a declaration of its eligibility to charge ratepayers, pursuant to a future Section 205 filing, even if it is constrained to abandon its project.[40] It is not clear, however, whether its request goes to 100% of costs shown to have been prudently incurred, or to *more* than 100% of costs. On the one hand, the Petition states that "AWC Companies seek the right to file under FPA section 205 to recover 100 percent of prudently incurred costs if the AWC Project, or a component thereof, were to be abandoned for any reasons outside of the control of the AWC Companies."[41] On the other hand, AWC seeks to book a regulatory asset that would compound at the incentive-inflated rate of return until fully amortized, and to make no distinction in its accounting between regulatory asset's principal and its compounded growth, nor

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CAISO's transmission planning process and subject to Western Grid's overall ROE being within the zone of reasonable returns which will be determined when in makes [a] future FPA 205 section filing"); *Primary Power* P 32 (incentive adder for Transco formation conditioned on PJM including project in RTEP); *NYRI* P 21 (transmission company-only adder conditioned on the "ROE being with the zone of reasonable returns (as established in [a future] Section 205 filing), [and] the Project receiving state siting approval.").

[39] *See e.g. Promoting Transmission Investment through Pricing Reform*, Order No. 679, 18 CFR 35, 71 FR 43294, 43320 (July 20, 2006) ("Continuing to allow a Transco, over the long-term, to receive an incentive ROE for all its facilities that recognizes its increased transmission investment *only makes sense if the Transco continues to provide the benefits which [the FERC is] trying to incentive*")(emphasis added), on *reh'g*, Order No. 679-A, 72 Fed. Reg. 1152, 1164 (Jan. 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2006), *clarified*, 119 FERC ¶ 61,062 (2007) ("Eligibility for Transco status and incentive-based rate treatment [will be] based on a showing of how the specific characteristics of a proposed Transco affect its ability and propensity to increase transmission investment in individual case proceedings.").

[40] *See* Petition at 66.

[41] *Id*.

to distinguish which portion of that growth relates to which portion of its rate of return. Indeed, AWC does not even make clear what rate it views as the cost-based component of its proposed ROE: 10.58%, or 11.0%?

Whatever AWC may have in mind, the Commission should make clear now that the maximum post-abandonment collection for which AWC may file is "100 percent of prudently incurred costs," and that in this context "cost" means the principal, out-of-pocket amount spent on the project. At minimum, it should clarify that if post-abandonment collection for interest on booked costs is considered, the interest should break out and be limited to the cost-based component of the interest, thus excluding any amount that results from the incentive component of any otherwise allowed ROE.

The basis on which AWC seeks an abandonment declaration is that ratepayers will benefit through lower capital costs if the Commission protects "the AWC Companies from *losing* prudently-incurred investments."[42] Being held harmless against loss is different from being allowed to get back more than was invested, and the Commission should not provide the latter. The prospect of high returns on investment under a non-bypassable formula rates if the project enters commercial operation, or the return of investment if it does not, should be a sufficiently attractive one from an investor's perspective.

Finally, as it has done in prior cases, the Commission should make clear that a favorable declaration does not guarantee recovery. In Green Power Express, for example, the Commission held:

> [I]f the Project is cancelled before it is completed, it is unclear whether Green Power will have any customers from which to recover the costs it incurred. Before it can recover any abandoned

[42] Exh. AWC-600 at 15 (emphasis added).

> plant costs, Green Power states that it will, and we require it to, make a filing under section 205 of the FPA to demonstrate that the costs were prudently incurred. Green Power must also propose in its section 205 filing a just and reasonable rate and cost allocation method to recover these costs. Order No. 679 specifically requires every utility seeking abandonment recovery to submit such a section 205 filing. Protesters that are concerned about their potential exposure to abandoned plant costs will have an opportunity to comment on any proposal to recover such costs if and when Green Power makes the required section 205 filing. Similarly, arguments about whether it was prudent for Green Power to incur specific costs can be raised at that time.

The Commission should similarly qualify here that in order to recover abandoned plant costs, AWC would have to make and receive approval for a future Section 205 filing, and that in seeking such approval AWC would bear the burden of proof to demonstrate the prudence of its abandoned costs, to establish its lack of responsibility for causing the abandonment, and to otherwise prove the reasonableness of its proposed collections.

One factual issue that may be faced by a future Commission requires particular discussion. It may well be difficult to determine whether AWC is responsible for causing an abandonment, and a future Commission facing that question may find that AWC actions were a contributing but not fully responsible cause. It would not advance the public interest to insure AWC against loss in the event the project is abandoned in circumstances where the cause of abandonment is unclear or mixed.[43] Nor would it be wise to rule now that the apportionment of abandonment costs as between shareholders and ratepayers is an all-or-nothing proposition. To avoid prejudicing the rights of future protesting parties or of the Commission itself, the Commission should expressly reserve the right to reduce recovery of prudent expenditures on abandoned plant to something less than 100%.

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[43] *See* Dismukes Affidavit ¶¶ 128-137.

D. AWC's Proposed ROE Adder Is Excessive on Multiple Dimensions

1. Budget Over-Runs Should Not Receive Incentive Returns

AWC has not filed proposed rates, but has made clear that it contemplates using a rate formula.[44] It is not difficult to infer that AWC contemplates applying its proposed incentivized rate of return to whatever the actual project costs turn out to be, even if they substantially exceed the "currently estimated construction cost of … approximately $5 billion,"[45] and even if they ultimately turn out to exceed project benefits.

Ratepayers should not be placed in a situation where PJM accepts the AWC project into its plans based on rosy projections of cost and feasibility, actual costs come in substantially higher, and customers wind up paying incentives on the larger as-built rate base. Such a reward structure would create perverse incentives, through the well-known "Averch-Johnson Effect."[46] And that perverse incentive would be magnified by the requested hypothetical capital structure: in the event of cost over-run, AWC would likely issue more debt, but would receive return as if it had issued 60% equity.

Instead of exposing ratepayers to that risk, any incentive ROE adder should be structured such that the rate base to which the incentive applies is tied to the projected cost basis on which the project receives planning approval. That is, the adder should apply to the lesser of actual cost or the cost as projected within the PJM regional planning process. Any prudently-incurred cost

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[44] *See* Petition at 76.

[45] Petition at 6.

[46] *See* Averch, H. and L. Johnson, *Behavior of the Firm Under Regulatory Constraint*, AM. ECON. REV. 52 (1962): 1052-1069. *See also* Rouselle Lavado and Changchun Hua, *An Empirical Analysis of the Averch-Johnson Effect in Electricity Generation Plants* (2004), *available at* http://www.eastwestcenter.org/fileadmin/stored/pdfs/IGSCwp007.pdf.

over-run above that level should enter rate base as well, but should receive only a cost-based return, not an incentive-heightened one.

2. 300 Basis Points Is Too Many

AWC seeks 300 basis points of extra return on equity as an above-cost "incentive." To put that in perspective, assume optimistically that AWC keeps project costs down to the currently-projected $5 billion. With that rate base and assuming AWC maintains a 60% equity capital structure and applies an income tax gross-up, the incentive amount would exceed $150 million *per year*,[47] and would amount to many billions of dollars if it continued to apply to the declining rate base over the assets' lives. The 300 basis points consists of four components: (a) 50 basis points for RTO participation, (b) 50 basis points for Transco status, (c) 50 basis points for new technology, and (d) 150 basis points for "risk." Consumer Advocates' objection focuses on the fourth component, and on the 300-basis-point total to which it is the main contributor.[48]

In considering whether the AWC Project is risky, two risk categories must be distinguished. One is the risk of non-completion. That risk is substantial; the AWC project is a large undertaking, with many approvals required before it could proceed. The second is the risk to investors that they will lose their investment. That risk is *not* substantial. The other incentives requested here would all but eliminate it. Unlike wind farm developers, for whom state policies make clear that most financial risks remain with the generator,[49] and unlike radial

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[47] That is, 3% x 60% x $5 billion x 1.67 tax factor = $150.3 million.

[48] Consumer Advocates do not waive their objection to the first three components, but they recognize that those components' 50-basis-point amounts (setting aside the period of their applicability, as discussed in Part III.C.2 above) is not inconsistent with recent Commission policy.

[49] See Dismukes Affidavit ¶¶ 17, 23-30, 33-38, 44, 47.

interconnection facilities associated with particular farms,[50] AWC would have substantial assurance that it could recover its investment from ratepayers whether or not its facilities ever entered service or attracted enough traffic to be cost-justified. Consider, as an instructive analogy, whether the Apollo moon shot was a "risky" program. To an astronaut, it certainly was. To a cost-plus supplier of rocket parts, it was a low-risk proposition. As a Transco, AWC will be in the latter position: profiting from the construction effort and investment, not relying upon its successful completion. AWC's investment risk will be adequately accounted for through a properly-performed DCF analysis. Consequently, no ROE adder for "risk" is necessary or appropriate.

Turning to the "total package," given the low risk and the total package of return and non-return incentives being sought, 300 basis points is more than necessary to induce investment, more than the Commission has awarded in prior cases, and simply too rich. By way of comparison, consider the following examples of prior incentive ROE awards:

- Green Power Express:[51] 160 basis points
- New England RTO:[52] 150 basis points
- PATH:[53] 200 basis points
- Southern California Edison DPV2 and Tehachapi Projects[54]: 175-225 basis points.
- Trans-Elect's Path 15 Project:[55] 200 basis points.

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[50] *See id.*

[51] *Green Power Express, L.P.*, 127 FERC ¶ 61,031 (2009).

[52] *Bangor Hydro-Electric Co.*, 117 FERC ¶ 61,129 (2006)("Opinion No. 489*"), aff'd sub nom. Conn. Dept. of Public Util. Control v. FERC*, 569 F.3d 477 (D. C. Cir. 2009).

[53] *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶61,188 (2008):

[54] *So. Cal. Edison Co.*, 121 FERC ¶ 61,168 (2008).

[55] *Western Area Power Admin.*, 99 FERC ¶ 61,306 p.62,820, *reh'g denied*, 100 FERC ¶ 61,331 (2002), *aff'd sub nom. Pub. Utils. Comm'n of Cal. v. FERC*, 367 F.3d 925 (D.C. Cir. 2004).

AWC offers no basis for exceeding these prior approvals. In addition, any ROE adder should be conditioned as to timing and applicability as discussed elsewhere in this Protest.

E. AWC's Proposed Baseline Return Exceeds the Just and Reasonable Cost-Based Level

AWC proposes that the Commission approve a base (pre-incentive) ROE of 10.58%, while contending that a base ROE of 11% is justified. But neither the 10.58% nor the 11% figure has been shown to be just and reasonable. AWC's own study shows that the base ROE should be no higher than 9.82%. With appropriate adjustments to that study, the indicated base ROE falls to 9.44%.

1. There Is No Substantial Evidentiary Basis for a Base ROE Exceeding the Median Result of AWC's Own Study: 9.82%

AWC witness Villbert presents a Discounted Cash Flow ("DCF") study of 41 publicly-traded firms.[56] This "Full Sample" group is meant to encompass "the universe" of holding-company-level parents of every investor-owned electric transmission owner in the U.S., other than those lacking an investment-grade credit rating or with recent dividend cuts or merger activity.[57] AWC's study performs a DCF study to determine the high and low implied cost of equity ("ICOE") for each of these 41 firms, but discards the ICOEs for ten of those firms, yielding an array of two data points each for 31 retained proxy-group firms, *i.e.*, 62 ICOE data points.[58] *The median of AWC's retained DCF results is 9.82%.*[59]

DCF analysis is the Commission's well-established method for inferring the unobservable cost of equity from financial market data. It is also now well-established that the

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[56] Direct Testimony of Michael J. Vilbert, Exh. No. AWC-600.

[57] *See* Exh. AWC-600 at 33.

[58] *See id.* at 41, Table 2.

[59] *See id.*

median should be used as the measure of central tendency to identify the cost of equity for use by a single set of affiliated transmission owners. *See, e.g., So. Cal. Edison*, 133 FERC ¶ 61,269 P 1 (2010) ("Commission precedent holds that the median is the most accurate measure of central tendency for a single utility of average risk"); *Potomac-Appalachian Transmission Highline, L.L.C.* 133 FERC ¶ 61,152 P 65 (2010). Furthermore, the Commission has long, and correctly, been "skeptical of its ability to make carefully calibrated adjustments within the zone of reasonableness" to reflect "subtle differences in risk," and therefore requires parties to make "a very persuasive case" before it will find that the cost of equity is anything other than the median of the range of reasonable returns. *Northwest Pipeline Corp.,* 92 F.E.R.C. ¶ 61,287, at 62,006 (2000). Consequently, AWC faces a steep challenge in attempting to justify any base ROE higher than 9.82%.

AWC's witness shows some recognition of that difficulty, but asserts that the median of his sample is "downwards biased" as an indicator of the cost of equity for AWC.[60] In his attempt to support a pre-incentive base ROE within "the upper end" of "the Full Sample range of reasonableness,"[61] he makes four arguments. None comes close to carrying AWC's heavy burden.

a) AWC Improperly Relies on the DCF Results for ITC Holdings that its Witness Properly Discarded; Moreover, ITC Holdings is Highly Leveraged and Therefore Not Comparable to AWC

AWC argues that "the best transmission comparable is ITC Holdings Corp., which has an estimate of 12.23 percent as its 'low' implied cost of equity."[62] The claim is contrary to AWC's own testimony, which concedes that ITC Holdings does not meet the Commission's proxy

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[60] See *id*. at 5.

[61] *Id*. at 7.

[62] Id. at 42.

screening criteria and must therefore be excluded from the 31-firm "Full Sample" proxy group.[63] Under well-established Commission precedent,[64] which includes a Commission finding specifically directed to ITC Holdings,[65] the DCF study input data for ITC Holdings does not meet the screening criterion of a sustainable growth rate. The resulting ICOE for that firm therefore proves nothing. While ITC's operating companies do share some relevant characteristics with the AWC operating companies--both will be transmission-only firms whose revenue requirements will be collected through FERC-jurisdictional formula rates--their financial situations, and thus their costs of equity, are not remotely comparable. They differ radically in their capital structures and other relevant financial features. ITC Holdings is highly leveraged, with a roughly 30% equity, 70% debt capital structure.[66] "A key concept in finance is that financial risk increases with leverage (*i.e.*, the use of debt), and as a company increases its financial leverage, its cost of equity also increases. Therefore, a company's financial risk depends on the manner in which the company finances its operations."[67] The high degree of

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[63] *See* Exh. AWC-600 at 40-41 (screening out ITC Holdings because it does not pass the Commission's established test for sustainability of its high-side growth rate).

[64] *See, e.g., Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152 P 64 (2010) (citations omitted):

> The Commission found in the February 29 Order that a growth rate of 13.3 percent was unsustainable over time and, thus, did not meet the test of economic logic. This finding is consistent Commission precedent and was reaffirmed recently in Southern California Edison Co. The Commission continues to find that a 13.3 percent growth rate is unsustainable and serves as a basis for excluding companies from PATH's proxy group.

[65] *ITC Holdings Corp.*, 121 FERC ¶ 61,229 P 43 (2007).

[66] *See* Exh. AWC-603, page 8, col. 1 (showing ITC Holdings' 2010 Common Equity Ratio as 0.30). One can also turn, for example and not without a sense of irony, to Google Finance, at http://www.google.com/finance?q=NYSE:ITC&fstype=ii. It shows that ITC Holdings' capital structure, as of the most recent date for which data is provided (Sept. 30, 2010) consisted of approximately $2.46 billion in long-term debt and $1.09 billion in equity. Thus, the ITC Holdings capital structure at that recent time was 30.7% equity and 69.3% debt. Similarly, the December 24, 2010 Value Line report for ITC Holdings shows a most recent historical capital structure (for 2009) of 29.4% equity, 70.6 debt, and similar forecast ratios for 2010, 2011, and 2013-15.

[67] The Brattle Group, *Understanding Debt Imputation Issues* at 17 (2008) (White Paper for the Edison Electric

leveraging of ITC Holdings' book value equity is consistent with rating analysts' expectations for firms in the low-risk regulated transmission business.[68]

ITC's atypical leveraging drives both ITC Holdings' high realized returns and analysts' expectations of high growth in earnings per share, as ITC Holdings itself has made clear. ITC Holdings Chief Financial Officer Cameron M. Bready recently stated in the Financial Overview & Update section of an ITC Holdings presentation to analysts that ITC Holdings' "Consolidated 70% debt / capital ratio provides incremental equity returns in the low 20% range."[69] In sharp contrast, the ITC operating companies, both individually and in the aggregate, have capital structures consisting of 40% debt, 60% common equity.[70] The high rate of return at the consolidated, holding company level enables ITC to fund an ambitious growth program without issuing new equity, thus increasing its earnings per share. To fund its five-year capital investment program, ITC plans to utilize $2.382 billion of reinvested returns and to issue 1.745 billion in new debt, but does not intend to issue any new equity.[71] Analysts do not expect five-year growth to be quite so high as ITC Holdings' returns; the mean of four analyst forecasts, which forms the basis for the high-side ITC Holdings ICOE on which AWC relies, is 14.8%.

Institute), *available at* http://www.hks.harvard.edu/hepg/Papers/Brattle%20Imputed%20Debt%2025%20May%202008%20final%20.pdf.

[68] *See, e.g.,* Standard & Poor's, *New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised* (June 2, 2004),

[69] ITC Holdings Corp. 2010 Investor Day Presentation (Sept. 27, 2010), at 38 (available at http://files.shareholder.com/downloads/ITC/1126376508x0x405215/fdf23105-f855-4de0-8540-0f0af8b604a8/ITC_IP_9.24.10.pdf).

[70] See the December 2010 "Attachment O" Midwest ISO formula rate information for the ITC companies and other Midwest ISO transmission owners, which is available at http://www.midwestmarket.org/publish/Folder/13b9ea_1265d1d192a_-7f4c0a48324a?rev=1.

[71] *See id.* at 52 (providing debt issuance forecast and zero equity issuance forecast, and stating that "New equity issuances are not anticipated to fund current five-year capital plan").

Both that 14.8% analyst growth forecast and the "20% range" of returns previously discussed reflect the high leveraging of ITC Holdings.

ITC Holdings' leverage explains why its forecast growth substantially exceeds the level that might be sustainable for sufficiently long to be used in a DCF study without violating economic logic, necessitating ITC Holdings' exclusion from the Full Sample. It also explains why ITC Holdings' market-to-book ratio is so far out of line with all 31 members of the Full Sample proxy group. ITC Holdings' current Market-to-Book ratio is 2.63, well above that of any of the retained proxy companies, and doubling those 31 firms' median ratio of 1.30.[72]

Furthermore, a fatal logical circularity precludes relying on analysts' forecasts regarding ITC to identify the *cost-based* component of AWC's return. ITC's operating companies, and thus ITC Holdings itself, benefits from generous return incentives that it receives by virtue of its status as a Transco that belongs to multiple Regional Transmission Organizations. For example, its Michigan operating companies enjoy the highest allowed returns in the Midwest ISO, at 13.88%. Those incentives affect both ITC Holdings' past financial results and analysts' forecast of future results. As ITC's presentation summarizes, it has an "Achieved ROE equal to approved ROE at the operating companies."[73] In short, analysts' forecasts of ITC earnings reflect the returns allowed by regulators — including the non-cost-based, incentive components of those returns. Logically, if AWC could rely on ITC Holdings' cost-plus-incentives earnings per share to establish its baseline return, and then add an incentive bonus to that baseline, it would follow that ITC Holdings could rely on forecasts of AWC's resulting cost-plus-incentives earnings per share to support an increased baseline return in line with AWC's incentivized earnings, atop

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[72] *See* Workpaper No. 6 to Table No. MJV-4, Exh. No. AWC-603 at 10.

[73] *Id*. at 8 (portion of presentation made by ITC Holdings CEO Joseph L. Welch).

which incentives would be added, and on and on. Basing an AWC base return on ITC Holdings' incentivized returns would amount to double-dipping on incentives.

b) Compared to Vertically-Integrated Firms or to Generating Firms, Transcos Face Lower Operating Risk

AWC witness Villbert next argues that "the majority of the companies in my Full Sample are integrated electric distribution, generation and transmission companies," and that such vertically-integrated companies "are of lower overall risk relative to pure electric transmission companies, which have no native customers."[74] AWC is plainly wrong in contending that transcos lack native customers and that transcos have higher risk than vertically-integrated firms. In the economic risk terms that matter to investors, a transco whose revenue requirement is included in a FERC-jurisdictional, non-bypassable regional transmission rate has *only* native customers, unlike generation-owning firms that operated in a de-regulated environment and must compete for customers. The Commission has recognized on numerous occasions that if the risks of each industry segment are considered separately, transmission is less risky than generation. *See, e.g., City of Vernon*, 111 FERC ¶61,092 (2005) ("Vernon's transmission operations are not riskier than the composite operations of the companies in the proxy group which are involved in riskier unregulated business and competitive generation operations"). Rating agencies have the same view, and their view is both probative and (because it influences investors) self-effectuating in determining capital costs. Consider, for example, Moody's January 2010 Industry Outlook for U.S. Electric Utilities. It states that "the benefits of regulation translate roughly into three notches of rating lift and without the benefits of regulation, much of the sector would likely be considered non-investment-grade." *See generally Farmers Union Cent. Exch.,*

[74] Exh. AWC-600 at 5.

Inc. v. FERC, 734 F.2d 1486, 1522-23 & n.70, 1530 (D.C. Cir. 1984) (ROE must "take account of the risks associated with the regulated enterprise"; "Obviously, there are no assurances that the returns to, say, Exxon's non-pipeline operations — which include its office systems manufacturing, oil exploration, etc. — would reflect the risks of an oil pipeline.").

The foregoing also presents another reason not to rely on the economically illogical DCF results for ITC Holdings. Its implied cost of equity reflects the *financial* risk associated with its high degree of leveraging, *i.e.*, that each $3 of ITC Holdings equity investment is subordinated to $7 of debt. Leveraging creates financial risk that is conceptually distinct from operating risk. As AWC's witness testifies, "The high bankruptcy rate of highly leveraged companies during the recent turmoil in the capital markets shows how risky debt can be to the financial health of a company. In fact, less debt for all companies, including regulated companies, may be necessary to restore investor confidence going forward. A company with less reliance on debt can better withstand unexpected variations in earnings, because the company has lower fixed costs."[75] AWC equity will not be comparably leveraged and will not bear comparable financial risk. If it bears risk comparability to ITC Holdings, that is only true as to *operating* risk, which would be low for both firms given their assured recovery of revenue requirements through non-bypassable rates.

c) AWC Improperly Relies on PJM TO Base ROEs that Reflect Long-Past Financial Market Conditions and that Are Not Paired with AWC's Requested Incentives

AWC argues that "the range of base-level ROE formula rates approved by the FERC for member companies of the PJM" extends from "10.8 to 12.3 percent, with a median of 11.0

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[75] Exh. AWC-600 at 16.

percent."[76] But those existing ROEs simply reflect the happenstance of past financial market conditions that prevailed at the time of the Section 205 proceedings to establish those formulas. They pre-dated the financial market sea change that occurred in 2008. Such past information cannot reasonably be relied upon to determine a current, cost-based platform for an incentivized return that would exceed those existing ROEs. The Commission has already so held with respect to a prior application by a Transco for incentive returns, and the same holding applies here. *See ITC Holdings Corp.*, 121 FERC ¶ 61,229 P 41 (2007) ("an updated financial analysis is required to evaluate whether an increase above the 12.38 percent ROE now applicable … is just and reasonable."). Moreover, AWC would, like the utility in *So. Cal. Edison*, 131 FERC ¶ 61,020 P 68 (2010) operate in a region where the Commission has not granted a uniform ROE for all the ISO/RTO constituent transmission owners. Accordingly, AWC must justify its base ROE based on its own current, utility-specific DCF study. Just as SCE's base ROE was not capped by the base ROE of other transmission owners in its ISO, AWC's base ROE should not be elevated by the base ROE of other transmission owners in its ISO.

d) AWC Improperly Relies on Two ROE Orders that Date to Early 2008, Preceding that Year's Dramatic Financial Market Changes

AWC argues that in Dockets Nos. ER08-374 and ER08-413, FERC has "re-affirmed" the incentivized ROEs of 13.5% that it had approved for the subject transmission owners in February and March of 2008. Each of those decisions, however, was limited to two policy issues regarding ROE methodology. Neither considered whether to reduce the 13.5% ROE that had been approved for those particular transmission owners in 2008. To the contrary, in the Docket No. ER08-374 decision, the Commission noted that "SoCal Edison [did] not object to the

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[76] Exh. AWC-600 at 6.

Commission's summary approval of … [a] 13.5 percent ROE."[77] Consequently, each of these decisions simply references, without examining or re-affirming, an ROE determination that had been made prior to the financial market sea change of late 2008, based on then-current market conditions. They add nothing to AWC's misdirected attempt to rely on equally stale ROEs of existing PJM transmission owners.

2. Appropriate Adjustments to AWC's Study Indicate a Base ROE at the Median of a Revised Proxy Group: 9.44%

As summarized above, AWC identified 41 publicly-traded utility-owning firms, assertedly representing "the universe of electric transmission-owning companies in the U.S." that met certain screening criteria, and then discarded the DCF study results from ten firms on the ground that they were either too high or too low to meet tests of economic logic.

Of the ten firms that were eliminated, eight had DCF results that were deemed to be too low; only two were eliminated because their DCF results were too high. We raise this threshold point for two reasons. First, it reinforces the showing made above that the ICOEs for the surviving 31 firms are not "downward biased," and the base ROE therefore should be set no higher than the median of the retained ICOEs. Second, it calls into question the criterion that AWC applied in excluding low-end results. AWC excluded "companies that have costs of equity estimates less than their costs of debt plus 100 bps."[78] That criterion overstates the Commission's standard for excluding low-end results. For example, in *Potomac-Appalachian Transmission Highline, L.L.C.*, 122 FERC ¶ 61,188 PP 101-102 (2008), the Commission retained a 6.7% low-end result for UIL Holdings because its low-end return result was "above the cost of debt," thereby indicating that low-end results may be retained if they exceed the cost of debt.

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[77] *Id*. P 16.

[78] Exh. No. AWC-600 at 39.

While other Commission decisions have included reference to a 100 bps margin, the Commission has made clear that such a margin should be applied only "taking into account the extent to which the excluded low-end ROEs are outliers from the low-end ROEs of other proxy group companies,"[79] *i.e.*, that "the cut-off point for including or excluding a company from the proxy group … depends upon where the natural break is in the array of low-end ROEs of the candidate proxy group companies that would distinguish outliers from non-outliers."[80] Here, the low-end ROEs that AWC concedes should be retained include a 6.97% result for Great Plains Energy, Inc., and a 7.22% result for Integrys Energy, Inc. There is no "natural break" between those results and the next result down, namely the 6.63% result for Black Hills Corp., nor between that result and the next several ones down.[81] If any "natural break" can be identified in AWC's array of DCF results, it is the difference of 75 bps that separates the 6.12% lower result for Black Hills from the 5.37% lower result for Otter Tail. See Attachment 3 hereto, which illustrates this "natural break" by graphing the ICOEs for AWC's 31-company "Full Sample," together with those for six companies[82] that AWC's study excluded on the ground that their ICOEs were too low. That 6.12% result significantly exceeds average yield on investment-grade utility bonds,[83] and should be retained as a non-outlier.

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[79] *Atlantic Path 15, LLC*, 122 FERC ¶ 61,135 P 94 (2008).

[80] *So. Cal. Edison Co.*, 131 FERC ¶61,020 P 56 (2010)

[81] Starting with AWC's lowest retained ICOE and proceeding down from there, the basis points of separation between ICOEs are, respectively, 34, 16, 20, 9, and 6.

[82] Specifically, Black Hills, Constellation, Edison International, Entergy, Otter Tail, and PSEG.

[83] As of January 10, 2011, according to the Commission's Division of Energy Market Oversight, the average yield on investment-grade utility bonds is slightly over 4%, down from the long-term historical average of 5.39% See Federal Energy Regulatory Commission, Division of Energy Market Oversight, *Yields of Utilities, Merchants and Ten Year Treasury Bonds*, *available at* https://www.ferc.gov/market-oversight/othr-mkts/financial/2011/01-2011-othr-fin-archive.pdf/. Even applying Moody's higher measure, taken from a date postdating AWC's rate of return study when bond yields had risen, the current average long-term utility bond yield remains only 5.66%, 46 basis points below the Black Hills lower ICOE. See Moody's Daily Bond Yield for January 27, 2011, as posted that day on http://credittrends.moodys.com/.

Another dubious aspect of AWC's DCF study is its inclusion of CMS Energy Corp., DTE Energy Co., and Centerpoint Energy Inc. AWC's stated intent was to limit the proxy group to "electric transmission-owning companies in the U.S."[84] and to exclude "any company whose operations are primarily related to natural gas transmission or distribution."[85] Nonetheless, none of these three firms owns or operates material Commission-jurisdictional grid transmission assets and, in each case, any such electric transmission business is greatly outweighed by natural gas operations.[86] CMS and DTE sold almost all of their transmission assets years ago to what are now subsidiaries of ITC Holdings. Centerpoint Energy has "local natural gas distribution businesses in six states, a competitive natural gas sales and service business serving customers in the eastern half of the U.S., interstate pipeline operations with two natural gas pipelines in the mid-continent region, and a field services business with natural gas gathering operations, also in the mid-continent region."[87] Centerpoint also includes "an electric transmission and distribution utility serving the Houston metropolitan area,"[88] but those electric operations are located within ERCOT and are therefore not Commission-jurisdictional and not comparable to AWC.

Adjusting AWC's study to reflect the foregoing points yields a substantially lower median result and thus points towards a lower base ROE. As shown in Attachment 2 hereto, retaining the several low-end results that are not outliers while removing CMS, DTE, and Centerpoint reduces the median ROE to 9.44%.

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[84] Exh. No. AWC-600 at 33.

[85] *Id*.

[86] As the most recent Value Line summary for each firm recites, CMS Energy Corp. subsidiary Consumers Energy sells both electricity and gas; DTE Energy Co. owns Michigan Consolidated Gas; and Centerpoint Energy both owns two gas pipelines and, through its local distribution company subsidiaries, has substantially more gas customers (3.2 million) than electric customers (2.1 million).

[87] *See* http://www.centerpointenergy.com/about/.

[88] *Id*.

IV. CONCLUSION AND RECOMMENDED DISPOSITIONS

For the reasons presented above and in the accompanying Affidavit and other Attachments, Consumer Advocates request that the Commission (a) grant Consumer Advocates leave to intervene, jointly and individually, and (b) dispose of AWC's Petition in accordance with the positions asserted herein. Specifically, the Commission should

- Either abstain from addressing the Petition at this time, or reject it as premature, without prejudice to re-filing upon RTEP approval, or at least convene a hearing.
- If the Commission does reach the merits of AWC's incentive requests at this early stage of the project, modify them such that
  - none of AWC's costs are reimbursed through PJM rates before construction begins;
  - no above-cost incentives are flowed through PJM rates or accrued for later collection until the AWC project enters service;
  - if AWC's project is abandoned, AWC collects no more from ratepayers than the return of its investment in the unfinished project; and
  - at minimum, no incentive payment by ratepayers will be due unless and until the project is approved in the PJM RTEP planning process.
- Reduce the base ROE to no more than the median of an appropriately constituted proxy group, *i.e.,* 9.44%.

Respectfully submitted,

/s/ Brenda K. Pennington
Brenda K. Pennington, Esq.
INTERIM PEOPLE'S COUNSEL
Sandra Mattavous-Frye, Esq.
DEPUTY PEOPLE'S COUNSEL
Brian O. Edmonds, Esq.
ASSOCIATE PEOPLE'S COUNSEL
OFFICE OF THE PEOPLE'S COUNSEL FOR THE DISTRICT OF COLUMBIA
1133 15th Street, NW, Suite 500
Washington, DC 20005-2710

/s/ Stefanie Brand
Stefanie Brand, Esq.
DIRECTOR, DIVISION OF RATE COUNSEL
Felicia Thomas-Friel, Esq.
DEPUTY RATE COUNSEL
Henry M. Ogden, Esq.
ASSISTANT DEPUTY RATE COUNSEL
NEW JERSEY DIVISION OF RATE COUNSEL
31 Clinton Street
P.O. Box 46005
Newark, New Jersey 07101

OF COUNSEL:
/s/ Scott H. Strauss
Scott H. Strauss, Esq.
David E. Pomper, Esq.
Law Offices of:
Spiegel & McDiarmid LLP
1333 New Hampshire Avenue, NW
Washington, DC 20036

January 31, 2011

Attachment 1

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Atlantic Grid Operations A LLC	)	
	)	Docket No. EL11-13-000
Atlantic Grid Operations B LLC	)	
	)	
Atlantic Grid Operations C LLC	)	
	)	
Atlantic Grid Operations D LLC	)	
	)	
Atlantic Grid Operations E LLC	)	
	)	

AFFIDAVIT OF DAVID E. DISMUKES, PH.D

ON THE BEHALF OF THE
NEW JERSEY DIVISION OF RATE COUNSEL

I. Introduction

1. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, and public policy issues associated with energy and infrastructure industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

2. I hold both M.S. and Ph.D. degrees in economics from the Florida State University. Over the past 22 years, I have been actively involved in research, government service, and consulting involving energy and infrastructure industries. My professional experience includes the examination of economic, statistical, and public policy issues in regulated and energy industries.

3. I have participated in over 200 regulatory proceedings, in 18 states, and prepared expert witness testimony, reports, and affidavits in Louisiana, Texas, Nevada, Utah, Michigan, Ohio, New Jersey, Mississippi, Kansas, South Carolina, Nebraska, Tennessee, Indiana, Massachusetts, Washington, and Florida. I have also testified before the U.S. Congress and various state legislatures.

4. In addition to my consulting work, I serve as a Professor, Associate Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University ("LSU"). I am also an Adjunct Professor in the E. J. Ourso College of Business Administration (Department of Economics), the co-director of the Coastal Marine Institute in the School of the Coast and Environment, and a full member of the graduate research faculty at LSU.

5. I have published over 120 articles, professional papers, reports, book chapters, books, and manuscripts on energy and infrastructure industries. Over the past 15 years, I have conducted a significant amount of grant-funded

research on a wide range of infrastructure development topics related to offshore energy production and transmission. This research also includes several comprehensive analyses of the onshore economic impacts created by offshore energy infrastructure projects.

6. A copy of my academic vitae has been provided as Attachment 1 to this affidavit and includes a list of my professional experience, publications, technical reports, presentations, and expert reports, testimonies, and affidavits.

7. I have been asked by the New Jersey Division of Rate Counsel ("N.J. Rate Counsel") to examine the Request for a Declaratory Order by Atlantic Wind Operations A LLC, Atlantic Wind Operations B LLC, Atlantic Wind Operations C LLC, Atlantic Wind Operations D LLC, Atlantic Wind Operations E LLC (collectively the "AWC Companies" or "the developers") for incentive rates and ratemaking treatment for the Atlantic Wind Connection Project (the "AWC Project or "the proposed project").

II. Summary of Opinion and Recommendations

8. It is my opinion and recommendation that the Federal Energy Regulatory Commission ("Commission" or "FERC") should defer the AWC Companies' request for incentive ratemaking mechanisms until such time as more concrete inputs critical to the determination of project benefits becomes available. These critical inputs include: approval of the project through the PJM regional transmission expansion planning ("RTEP") process; meaningful engagement with state regulators and other stakeholders; and documented expressions of interest by currently-announced offshore wind ("OSW") projects.

9. The AWC Companies have not participated in any meaningful, independent stakeholder transmission planning process for the proposed project. The proposed AWC project has not been evaluated through, or approved by, the PJM regional transmission planning process.

10. The AWC Companies' request several incentive ratemaking remedies that have been rejected by many states for offshore wind ("OSW") project development. As such, approval of the requested incentives for the AWC Project could be seen as circumventing the state regulatory ratemaking treatment of various OSW development costs, thereby undermining state OSW policies that seek to balance the risk of OSW generation development between ratepayers and developers. The AWC Companies have failed to enter into any formal discussions with state policy makers and other stakeholders in order to explore synergies and benefits between individual OSW projects and the AWC Companies' proposed project.

11. If approved, the AWC Companies' proposed incentives could work to undermine, not facilitate, the development of OSW generation since many of these proposed mechanisms are contrary to those included in existing state OSW policies. There are a large number of announced OSW generation projects along the Atlantic seaboard, most of which have not yet attained state regulatory approval for long term financial support. In addition, the overwhelming majority of these OSW projects currently envision the use of radial transmission lines. If the AWC Companies' incentives are approved, currently-announced OSW projects will have strong incentives to continue to explore direct radial connections to attain project approval given the contradiction of these incentives with existing state OSW financial support mechanisms.

12. The purported benefits of the AWC project, including congestion relief, are speculative at best, and more than likely significantly overstated.

13. The AWC Companies have failed to show that offshore transmission will not be supported in a cost-effective, safe, and reliable manner without its remedies and relief. Most OSW generation projects to date, anticipate the development of their own radial transmission lines based upon anticipated project-specific economics and the anticipated development and expansion outlook for those, as well as potentially neighboring, OSW generation projects.

14. However, if the Commission decides to accept the AWC Companies' request for incentives, it should condition any declaratory ruling on the following conditions:

a. Restrict the expenses booked to the requested regulatory asset to a more clearly-defined set of costs that are amortized across a period consistent with prior Commission decisions (10 years), starting with a period in which project construction begins, not the period in which the project enters the PJM RTEP.

b. Restrict the returns on the regulatory asset, and the Construction Work in Progress ("CWIP") included in rate base, to amounts that are based upon performance, not merely the act of spending cash. Incentive returns should only be applied when the actions those incentives are designed to encourage are actually completed. Thus, incentive returns for advanced technologies should not begin until the installation of working and functional advanced equipment. Likewise, incentive returns for RTO participation should not begin until the AWC Companies turn operational control of their assets over to PJM. Incentive premiums for the development of this project should not be allowed until such time as the project is actually developed.

c. The Commission should also consider additional performance-based conditions on the requested rate base treatment for CWIP. This should include, but not be limited to, a restriction on rate base recovery to only those investment amounts that are within pre-filed project schedule and cost estimates. Rate base treatment should be rejected for all expenditures that are in excess of budget, or incurred for periods beyond the originally-anticipated schedule. Recovery of these excess costs should be deferred to a later period where the assets have become operational and shown to have been prudently-incurred.

d. If any abandoned plant cost recovery incentive is adopted, the Commission should limit the recovery to only those amounts invested. This would exclude all returns, and particularly incentive returns, on a project that did not become operational.

III. The AWC Companies' Requested Relief Undermines Existing and Developing State OSW Generation Policy

15. An unconditional approval of the AWC Companies' requested ratemaking incentives would be contrary to the spirit, if not the specific letter, of

many current and emerging state OSW energy policies. FERC approval of the AWC Companies' proposed incentives would afford the project the benefit of ratemaking mechanisms that have been excluded from many state OSW policies, and would thereby undermine careful and concerted negotiations between stakeholders to balance OSW development risk.

16. Over the past four years, a number of states have pursued initiatives designed to facilitate OSW development off their respective coasts. The breadth of each state's initiatives vary from those attempting to facilitate expedited permitting, to those creating exploratory task forces, to those supporting offshore development research, to those that have actually designed or executed various types of financial support mechanisms.

17. To date, there are at least four states that have relatively well-defined financial support mechanisms for OSW projects including New Jersey, Delaware, Rhode Island, and Massachusetts.[1] While the definition and codification of these financial support mechanisms is still in the early stages of development, a number of common elements are starting to emerge that include:

a. Long term contracts or financial mechanisms to securitize the above market OSW assets.
b. Fixed price arrangements that change only by a known escalation factor. These agreements do not allow developers any cash earnings on CWIP during development, and do not provide for true-up mechanisms on a forward going basis.
c. Allocation of development risks to OSW developers. Ratepayers are protected from OSW plant cancellations as well as development costs overruns.
d. Allocation of operational risks to OSW developers. Financial support for developed projects is tied to project outputs: no outputs (energy, capacity, environmental attributes), no ratepayer financial support.

[1]While Rhode Island and Massachusetts are outside the proposed project's anticipated development area, their recent policies are important since they provide precedents that are likely to be consulted by other states (including those in the AWC Companies' development area) in formulating their own OSW financial support mechanisms.

III.a. New Jersey OSW Development Policy

18. On August 19, 2010, New Jersey Governor Chris Christie signed into law Senate Bill 2036, also known as the "Offshore Wind Economic Development Act" or "OSWEDA." This Act defines the terms and conditions under which "qualified" offshore New Jersey wind projects will be supported by New Jersey ratepayers. The New Jersey Board of Public Utilities ("BPU" or "the Board") is expected to promulgate rules defining a "qualified" OSW project eligible for New Jersey ratepayer financial support, and the terms and conditions under which this financial support will be provided.

19. The BPU is currently engaged in a 180 day rulemaking process defined by the OSWEDA and is required to have a final OSW rule in place by February 15, 2011.

20. The New Jersey OSWEDA is not predicated, nor does it require, "qualified" OSW projects to interconnect into third-party offshore transmission systems. In fact, the current statute defines "qualified" OSW projects as being integrated (i.e., both transmission and generation). A qualified OSW project is one that is defined by the OSWEDA as being located in the Atlantic Ocean and connected to the New Jersey Electric Transmission System including all associated transmission-related interconnection facilities and equipment.[2]

21. The New Jersey OSWEDA envisions a new renewable energy trading system that will be a component part of its overall renewable portfolio standards ("RPS"). These new tradable permits, or certificates, are referred to as "Offshore Wind Renewable Energy Certificates" or "ORECs" and can be used by New Jersey energy suppliers to meet their pro-rata share of the state's new offshore wind requirement.[3]

22. The OSWEDA also requires the BPU to establish an offshore alternative compliance payment ("OACP") should total available ORECs in any

[2] New Jersey P.L.2010, c.57.
[3] Ibid.

given year fall short of the annual compliance requirement.[4] The OACP serves an important function in creating a "backstop" or "circuit breaker" on OSW development costs that are not likely to exist under the formula rate plan being proposed by the AWC Companies. While the AWC Companies are requesting the Commission generally approve a mechanism that will allow their rates to increase over time based upon a yet-to-be-defined formula, integrated New Jersey OSW projects will have their rates capped by the OACP should the market for offshore wind compliance costs reach unacceptable levels.

23. The OACPs provided in the New Jersey legislation also protects ratepayers from integrated OSW project non-performance. The AWC Companies propose that performance risk be shifted entirely to ratepayers through its various incentive mechanisms. The AWC Companies' incentive request is entirely inconsistent with New Jersey OSW policy that allocates performance risks to the party most likely to have information about, and be able to mitigate against those risks (i.e., the OSW developers). It would be incongruous for FERC to approve AWC Project ratemaking mechanisms explicitly rejected in New Jersey offshore wind development policies.

24. New Jersey OSW development policies require integrated OSW projects to bear performance-related risk in a number of additional ways. For instance, OSW projects only receive ORECs (financial support) if they generate electricity from a qualified project: no generation, no financial support. The OSWEDA is explicitly clear in this matter since it directs the BPU to ensure:

> No OREC shall be paid until electricity is produced by the qualified offshore wind project;
>
> ORECs [financial support] shall be paid on the actual electrical output of the project that is delivered into the transmission system of the State.[5]

[4] Ibid.
[5] Ibid.

25. The AWC Companies' request to receive cash earnings on CWIP prior to the Project's commercial operation is also contrary to several provisions of the New Jersey legislation. Integrated OSW projects only receive financial support once they have reached commercial operation, and even at that time, receive support only on the amount of power generated. At one point, the legislature considered mechanisms that would have provided OSW developers greater cost assurances, including allowing cash earnings on CWIP similar to the AWC Companies' request in the instant proceeding.[6] The provision allowing OSW developers to rate base CWIP was excluded from the final version of the legislation.

26. The New Jersey legislature also considered the inclusion of a provision that would have allowed a qualified OSW to recover its prudently-incurred abandoned plant investment costs. This term was omitted from the final legislation.[7]

27. The OSWEDA also requires OSW projects to bear the risk of development cost overruns by explicitly stating that "…ratepayers and the State shall be held harmless for any cost overruns associated with the [qualified] project."[8]

28. The AWC Companies also request a special cost recovery mechanism for all of its non-capital development costs that includes capitalization of these costs, with a return and five-year amortization starting once the project has been included in the PJM Regional Transmission Expansion Plan ("RTEP").[9] These non-capital development costs include development and preconstruction expenses such as costs for attorney and consultant fees, entity formation costs, administrative expenditures, taxes, travel costs, costs associated with

[6] New Jersey Offshore Wind Economic Development Act, An Act concerning development of offshore wind projects and amending P.L. 1999.C.23, Draft dated April 7, 2010; and New Jersey P.L.2010, c.57.
[7] Ibid.
[8] New Jersey P.L.2010, c.57.
[9] Villadsen Testimony, Exh. No. AWC-700 at 5-6.

engineering, environmental or other studies, as well as costs incurred to educate and reach out to stakeholders.[10]

29. The OSWEDA provides no such relief for development costs and, in fact, actually requires OSW developers to bear the burden of these costs, as well as some of the regulatory and permitting costs of other parties. The New Jersey OSWEDA requires qualified integrated OSWs projects to "…reimburse the board and the State for all reasonable costs incurred for regulatory review of the project, including but not limited to consulting services, oversight, inspections and audits."[11]

30. Thus, under New Jersey OSW policy, developers bear the risk for both project development performance and project operational performance. The AWC Companies' proposed incentives in this proceeding are contrary to these policy goals since the proposed incentives would shift a large portion of both risks to ratepayers.

III.b. Delaware OSW Development Policies

31. In Delaware, the ""Electric Utility Retail Customer Supply Act of 2006" required Delmarva Power & Light ("DP&L") to file a proposal to obtain long-term supply contracts by August 1, 2006 and a ten-year Integrated Resource Plan by December 1, 2006.[12] To comply with the Act, DP&L filed a draft Request for Proposal ("RFP") for the construction of new generation resources to serve standard offer service customers. The final version of the RFP was issued on November 1, 2006. Bids were received from Connectiv Energy Supply, Inc., Bluewater Wind, LLC ("Bluewater") and NRG Energy, Inc.

32. In May 2007, after months of review and public comment, DP&L was directed to negotiate a power purchase agreement ("PPA") for approximately 200 to 300 MW of energy and associated capacity from Bluewater's proposed

[10] Ibid., at 9; and Petition at 60.
[11] New Jersey P.L.2010, c.57.
[12] The Electric Utility Retail Customer Supply Act of 2006, 26 *Del. C.* §§ 1001-1019.

offshore wind project. The negotiations resulted in a PPA executed by DP&L and Bluewater on June 23, 2008 and filed by DP&L with state agencies on the same date. The final PPA was approved by state agencies on September 2, 2008.[13]

33. The PPA contains a number of notable ratepayer protection mechanisms. First, the payments made for capacity, energy, and RECs are all negotiated, fixed prices that are only subject to a 2.5 percent annual inflation adjustment rate for each calendar year. The PPA does not include provisions that allow for the creation of a regulatory asset, rate base treatment of CWIP, nor the recovery of cancelled plant investments.

34. If for some reason, at any time during the two years from the execution of the PPA, a government authority amends, modifies, repeals any of the legislation pertaining to adjustable non-bypassable charges or the RPS Act, and DP&L and its ratepayers suffers a material adverse effect as a result of such, DP&L has the right to terminate the PPA on the behalf of its ratepayers.[14]

35. While under construction, Bluewater is responsible for the design and construction of the project. Bluewater is obligated to keep DP&L apprised of the construction schedule and milestones. And, DP&L has the right to inspect the construction site and monitor its progress.[15] If Bluewater is unable to meet its construction permitting deadlines, it may terminate the PPA but will surrender to DP&L $3 million in liquidated damages.[16] Additionally, should Bluewater fail to meet pre-defined construction "Critical Milestones," DP&L will have the right to

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[13] In the matter of integrated resource planning for the provision of standard offer supply service by Delmarva Power & Light Company under 26 *Del. C.* §1007(c) & (d): review and approval of the request for proposals for the construction of new generation resources under 26 *Del. C.* §1007(d) (opened July 25, 2006); Before the Public Service Commission of Delaware, and the Delaware Energy Office, The Office of Management and Budget, and the Controller General; PSC Docket No. 06-241; Order No. 7440; September 2, 2008.

[14] Power Purchase Agreement between Delmarva Power & Light Company ("Buyer") and Bluewater Wind Delaware LLC ("Seller"), June 23, 2008, Section 2.5.

[15] Ibid., Section 5.2(b).

[16] Ibid., Section 5.2(c).

terminate the agreement[17] and retain the then "undrawn amount of Development Period Security" as liquidated damages.[18]

36. Section 3.2(a) of the PPA envisions an integrated (transmission and generation) project and obligates Bluewater to bear the costs of constructing and upgrading all electrical interconnection facilities, including metering and sub-metering facilities. Bluewater is also responsible for any costs required by PJM or otherwise necessary for the performance of its purchase and sale obligations.[19]

37. Once the OSW project is operational, Bluewater will be held to a minimum performance requirement and is required to deliver at least 52 percent of the Minimum Performance Requirement ("MPR") Base Amount of the project.[20] Should Bluewater deliver less than the MPR, it will pay DP&L and is ratepayers $25 per MWh for the deficit amount of energy and associated RECs. These damages are capped at $1.5 million per year and $10 million over the term of the agreement.[21]

38. Recognizing that DP&L's costs under the PPA will be borne by ratepayers, the PPA also includes a "Most Favored Customer Pricing" clause. This protects DP&L's ratepayers should Bluewater sell energy at a lower price to third parties in the future.[22]

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[17] The "Development Period Security" totals $6 million.

[18] Power Purchase Agreement between Delmarva Power & Light Company ("Buyer") and Bluewater Wind Delaware LLC ("Seller"), June 23, 2008, Section 5.2(e).

[19] Ibid., Section 3.2(a).

[20] The MPR Base Amount is defined as the product of the following equation, expressed in MWh: ((Buyer's Percentage of Project Capacity x 8760) x .32).

[21] Power Purchase Agreement between Delmarva Power & Light Company ("Buyer") and Bluewater Wind Delaware LLC ("Seller"), June 23, 2008, Section 5.2(e).

[21] <u>Ibid</u>., Section 3.15.

[22] <u>Ibid</u>., Section 4.3.

III.c. Rhode Island OSW Development Policies

39. In June 2009, the "Long-Term Contracting Standard for Renewable Energy Act" was signed and codified into Rhode Island law.[23] Part of the Act required Narragansett Electric Company d/b/a National Grid to solicit proposals for a newly developed renewable energy resources project. In December 2009 National Grid and Deepwater Wind Block Island, LLC ("Deepwater") filed a signed PPA agreement for Commission review. The Rhode Island Public Utilities Commission rejected the PPA, stating that the project was not commercially reasonable, with contract pricing even higher than what may be expect from transactions involving other types of newly developed renewable energy resources.[24]

40. In June 2010, the General Assembly passed amendments to R.I. Gen. Laws ß 39-26.1-1 to 7. The amendment changed the definition of "commercially reasonable" for the purposes of the Commission's review and created provisions facilitating the construction of a small-scale OSW project.[25]

41. The new statutes authorized National Grid to enter into a new PPA with Deepwater amending pricing terms such that the PPA price would stay the same (24.4 cents per kWh with a 3.5 percent annual escalator), but with a provision that allows the first year price to be reduced if Deepwater realizes certain cost savings in the development and construction of the Project:

> (e) Cap and lower price. (i) The amended power purchase agreement subject to subsection 39-26.1-7(a) shall provide for terms that shall decrease the pricing if savings can be achieved in the actual cost of the project, <u>with all realized savings allocated to the benefit of ratepayers</u>. (ii) The amended power purchase agreement shall also provide that the initial fixed price contained in the signed power purchase agreement submitted in docket 4111 shall be the maximum initial price, and any realized savings shall reduce such price. After making any such reduction to the initial

[23] R.I. Gen. Laws ß 39-26.1-1 to 8.

[24] In re: review of proposed Town of New Shoreham Project pursuant to R.I. Gen. Laws ß 39-26.1-1 to 7; Rhode Island Public Utilities Commission; Docket No. 4111; April 2, 2010.

[25] R.I. Gen. Laws ß 39-26.1-7(a).

> price based on realized savings, the price for each year of the amended power purchase agreement shall be fixed by the terms of said agreement. (iii) The amended power purchase agreement shall require that the costs of the project shall be certified by the developer. An independent third-party acceptable to the division of public utilities and carriers shall within thirty (30) days of this certification by the developer, verify the accuracy of such costs at the completion of the construction of the project. The reasonable costs of this verification, shall be paid for by the developer. Upon receipt of such third-party verification, the division shall notify the Narragansett Electric Company of the final costs. The public utilities commission shall reduce the expense to ratepayers consistent with a verified reduction in the project costs.[26]

42. An amended PPA between National Grid and Deepwater was approved by the Rhode Island Public Utilities Commission in August 2010. The final PPA includes the savings provision for setting the first year price. In reference to the amended law, the Commission stated that "the terms of the amended law make it rather clear that the legislature, in its effort to advance the project, placed considerable focus on ensuring that the PPA prices rejected in Docket No. 4111 would serve as an absolute ceiling for any PPA price considered in this docket."[27]

43. Similar to the Delaware PPA, the National Grid – Deepwater PPA contains a number of protective provisions. According to the agreement, Deepwater is responsible for maintaining a physical interconnection with the Delivery Point; an all electric metering required in connection with the sale of energy (including the Facility meter and any other real-time meters, billing meters and back-up meters) will be installed, operated, maintained and tested at Deepwater's expense.[28]

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[26]R.I. Gen. Laws § 39-26.1-7(e), ***<u>emphasis added</u>***.

[27]In re: review of amended power purchase agreement between Narragansett Electric Company d/b/a National Grid and Deepwater Wind Block Island, LLC pursuant to R.I. Gen. Laws ß 39-26.1-7; Rhode Island Public Utilities Commission; Docket No. 4185; August 16, 2010.

[28]Power Purchase Agreement between the Narragansett Electric Company, d/b/a National grid and Deepwater Wind Block Island, LLC; As of June 30, 2010; Section 3.4(d); and Section 4.7(a).

44. Deepwater will bear all risks, financial and otherwise, associated with it or National Grid's eligibility to receive any federal or state tax credits or qualify for accelerated depreciation for accounting, reporting or tax purposes.[29] Pricing for RECs is based on the Chicago Climate Futures Exchange rather than using Alternative Compliance Payments as included in the first, rejected PPA.[30]

III.d. Massachusetts OSW Development Policies

45. In Massachusetts, the Green Communities Act requires electric distribution companies to solicit proposals for long-term contracts of 10 to 15 years from renewable energy developers. A PPA between National Grid and Cape Wind Associates, LLC ("Cape Wind") was approved by the Massachusetts Department of Public Utilities in November 2010.[31] The agreement is for the purchase of 50 percent of the output of the 468 MW Cape Wind project. Under the contract, National Grid agrees to purchase the energy, capacity and RECs associated with the project at a fixed price, escalating annually at 3.5 percent.

46. The PPA establishes a number of critical milestones for the facility with deadlines for: (1) receipt of all permits; (2) acquisition of property and site control; (3) closing of financing; (4) commencement of construction; and (5) commercial operation date.[32]

47. Unlike the AWC Companies' proposal, Cape Wind will also assume development and construction risk. According to testimony on behalf of Cape Wind:

> Cape Wind remains responsible for constructing, operating, and maintaining the Project and bears the risk of penalties and price

[29] Ibid., Section 5.4(b).
[30] Ibid., Exhibit E.
[31] Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval by the Department of Public Utilities of two long-term contracts to purchase wind power and renewable energy certificates, pursuant to St. 2008, c. 169, § 83 and 220 C.M.R. § 17.00 et seq.; Massachusetts Department of Public Utilities; Docket D.P.U. 10-54; November 22, 2010.
[32] Ibid., at 11.

> adjustments assessed against the Project in the ISO-NE product markets in which the Project participates.[33]

48. And, to ensure against Cape Wind reaping windfall profits, the PPA provides for reductions in price should the project's internal rate of return rise higher than 10.75 percent. Specifically, if the costs to finance and construct the project wind up being lower than originally estimated, causing Cape Wind's after-tax IRR to exceed 10.75 percent, there would be a reduction to PPA-1's initial price. The Commission stated:

> By establishing a threshold on Cape Wind's IRR and limiting Cape Wind's return if it exceeds that threshold, the Cost-Adjusted Price provision makes it likely that customers will not pay excessive rates of return to Cape Wind's project developer or its investors. Moreover, the participation of an independent verification agent who will review Cape Wind's final project costs will serve to ensure that the costs used in determining whether the Cost-Adjusted Price provision is triggered are the actual construction costs incurred by Cape Wind in developing the facility. [34]

49. Similar to the Delaware PPA, the National Grid–Cape Wind agreement also contains a "Most Favored Nation Clause." If Cape Wind enters into an agreement with another party for the sale of the remaining output of the project, this clause requires Cape Wind to:

> (1) allow National Grid to revise PPA-1 to incorporate the terms of the new agreement if the term of the new agreement is for one year or longer; or (2) offer to enter into a new agreement with National Grid on the same terms and conditions as the new agreement if the new agreement is for less than one year.[35]

50. While Massachusetts and earlier referenced Rhode Island are outside the geographic area the AWC Companies anticipate serving, the terms and conditions of their approved PPAs will likely influence future state OSW

[33] Petition of Massachusetts Electric Company and Nantucket Electric Company, each d/b/a National Grid, for approval by the Department of Public Utilities of two long-term contracts to purchase wind power and renewable energy certificates, pursuant to St. 2008, c. 169, § 83 and 220 C.M.R. § 17.00 et seq.; Massachusetts Department of Public Utilities; Docket D.P.U. 10-54; Direct Testimony of Robert B. Stoddard; at 7:18-22.

[34] Ibid., at 245.

[35] Ibid., at 21-22.

policies (and PPA approvals). Further, both recent PPAs include a large number of contract terms comparable to the Delaware PPA potentially reflecting the emergence of some type of consensus on the appropriate contracting terms and degree of risk sharing between ratepayers and OSW developers.

III.e. Potential State Policy Reaction to the AWC Companies' Proposal

51. The Commission should be concerned about the conflicts with state OSW policies that are likely to arise if it approves the AWC Companies' proposed incentives. Approving the AWC Companies' incentives will increase the cost of its project relative to existing state-level integrated OSW proposals that include radial transmission lines to the shore. It is unlikely that existing OSW projects will have considerable incentives to participate in a transmission project more costly than the ones proposed under their existing plans.

52. Further, it is unlikely that state policy makers will "re-enter" their existing, hard-fought agreements and regulatory decisions to accommodate the AWC Companies' still rather preliminary idea. Also questionable is the degree to which state policy makers will reverse themselves on certain policy positions that have already been decided, such as cost recovery for cancelled projects, or immediate rate base treatment for CWIP, on the transmission component of any proposed project.

53. If state policy makers pass on re-evaluating their existing policies, then the scope of interconnection opportunities for the proposed AWC Project (which are likely already overstated) will be reduced, changing assumptions about the project's cost-effectiveness as well as the likelihood that it can be completed.

54. Rejecting the AWC Companies' incentive proposals should not undermine the proposed AWC Project and will force the AWC Companies to actively and aggressively pursue interconnection and long term firm transmission agreements in a manner typical for large scale energy infrastructure projects. It

will also force the AWC Companies into a better engagement with all OSW stakeholder groups including state regulators.

55. Forcing the AWC Companies' into the use of longer-term agreements prior to considering any incentive mechanisms will not prevent OSW projects from materializing along the Atlantic coast: in fact, as the AWC Companies themselves have noted, there are a large number of OSW projects that have materialized over the past few years without any type of offshore transmission backbone. Existing OSW projects are likely to continue to move forward over the next several years and their success will depend very heavily, if not exclusively, on the long-term, secure financial support provided by contracts, not the development of the AWC project.

56. Even if the Commission rejects the AWC Companies' requested incentives, the AWC Project will still have the opportunity to enter into negotiations with existing OSW generation developments along the Atlantic coast. Most currently-approved or likely OSW generation projects include (or are expected to include) some transmission-related cost in their estimated financial support requirements. If the AWC Project is competitive, and offers net transmission-related/facilitated benefits to these developing OSW projects that are greater than those embedded in their integrated cost estimates, it is likely that the AWC Project can secure a long-term firm transmission agreement that corresponds with the earlier-surveyed state funding/securitization plans and policy goals.

57. Long term agreements will be just as critical, if not more critical, for the development of "cost-effective" OSW transmission than the panoply of incentives currently being requested by the AWC Companies in this proceeding. Long-term agreements will provide the regulatory and revenue stability necessary to attain project financing. These agreements will not arise unless the AWC Project can, in fact, deliver a more efficient and beneficial energy transmission product than the existing OSW developers can themselves.

IV. The AWC Companies' Requested Relief May Undermine OSW Generation Development

58. Approval of the AWC Companies' request could actually undermine, as opposed to support, the development of OSW generation along the Atlantic coast.

59. The AWC Companies' goal of developing an offshore wind transmission network has a number of conceptual and theoretic benefits. However, there are a wide range of real world policy considerations that have been overlooked, or simply ignored in the current proposal that undermine the AWC Companies' request for incentives.

60. The AWC Project's goal of maximizing OSW benefits may appear laudable, but the very fact that this project will facilitate the sharing and transmission of benefits across a wide geographic area may be one of its many important undoings given current state initiatives that have focused on tying OSW benefits directly to the ratepayers subsidizing these OSW projects.

61. As noted earlier, many states along the Atlantic Seaboard have pursued or adopted various policies promoting OSW development. The rationale for many states adopting or pursuing these OSW strategies is multi-faceted but include such common themes as fuel diversity, energy security, economic development and environmental benefits, to name a few, broad, and important categories.

62. While all of the above considerations have been important motivating factors for state OSW policy, there are two that have been of particular importance: (1) promoting economic development and green jobs and (2) the use of OSW resources as a means for meeting future generation capacity requirements.

63. One of the first barriers to address in formulating state OSW policy has been, and continues to be cost: OSW generation is considerably more

expensive than traditional fossil fuel generation, as well as a wide range of other renewable energy resources. As a result, policy makers often need to extract every possible OSW benefit in order to justify the large and long-term financial commitments requested from ratepayers to support these projects.

64. To date, two general forms of long-term financial support for OSW have been either approved or proposed including (1) long term contracting through PPAs or (2) alternative/supplemental RPS-based market mechanisms that provide additional revenue streams over and beyond current market-based rates. Most states, to date, have, or are considering, using direct long-term contracting as a means of securitizing OSW development. New Jersey is one of the few states that have adopted a supplemental RPS-based mechanism such as the use of ORECs.

65. State policies securitizing OSW projects have placed considerable emphasis on (1) appropriately balancing OSW risk considerations and (2) on tying ratepayer financial support to project benefits. Maine, for instance, requires project developers to demonstrate "a commitment to invest in manufacturing facilities in Maine that are related to deep-water offshore wind energy."[36] Other states, like New Jersey and Maryland, tie project financial support directly to the delivered energy and environmental attributes of the OSW projects supported by their ratepayers.

66. The terms and conditions for state OSW policy support have come from long and often contentious debates, as well as inputs from a wide range of stakeholder groups. The policy outcomes can be thought of as a consensus of those varied considerations.

67. The AWC Companies' proposed project, and their request for various developer-friendly incentives, ignores many of the carefully negotiated arrangements underpinning many state OSW policies. The filing does not recognize or acknowledge any meetings or discussions that the AWC

[36] Maine P.L, Chapter 615, LD 1810, 124th Maine State Legislature.

Companies have entered into with state regulators or other state policy makers attempting to:

- communicate the need for their requested incentives;
- explain how their proposed incentives differ or are "tailored" to the mechanisms already adopted in these various states;
- articulate state-specific benefits that will arise from the proposed project that are over and beyond those expected from current radial transmission configurations in their respective states; and
- propose alternative mechanisms or assurances on the realization of state-specific benefits necessary to cover ratepayer financial support.

68. Thus, while the AWC Companies should continue to be encouraged to develop their proposed Project, they clearly need to do so within the context of open and broad stakeholder involvement that includes state regulators, consumer groups, OSW developers, utilities, regional transmission organizations, environmental groups, and the public. Investing an additional 12 months in stakeholder development would facilitate better consensus and appreciation for the benefits of this proposed projects and how incentive can be "tailored to address the demonstrable risks or challenges" faced by the AWC Companies.[37]

V. The AWC Project Benefits Are Speculative and Overstated

69. The proposed project attempts to quantify a number of benefits that will arise if completely developed. No sensitivity analyses have been provided that examine how those project benefits would be realized if only a limited number of project phases, or even one phase, were actually completed.

70. The benefits proffered by the developers are clearly speculative, likely overstated, rest upon a questionable development strategy, and are incomplete in explaining the need for its proposed advanced technologies.

[37] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40.

V.a. Assumed OSW Generation Development is Significantly Overstated

71. In Exhibit No. AWC-403, Technical Appendix: Market Simulation Assumptions, the AWC Companies provide their benefit analysis based upon anticipated 2016 market conditions that include the assumption that some 6,600 MW of nameplate offshore wind generation will be developed. This assumption has not been shown to be reasonable, and appears to be unrealistic.

72. A large number of OSW generation projects have been announced in the U.S. for regions including the Atlantic Coast, Great Lakes, Gulf of Mexico, and Pacific Coast. A list of these announced projects is provided in Table 1.

73. While the number and capacity of these announced OSW projects is considerable, the ultimate level of development is highly speculative and will almost certainly be less than what has been assumed by the AWC Companies. If the experience of the merchant generation development of the late 1990s offers any insight, it is likely that less than half of these announced projects will actually get developed.

Table 1. Proposed Offshore Wind Farms and Development Status[38]

Developer	Wind park	Location	Jurisdiction	Capacity (MW)	Online by 2016	Status
EMI	Cape Wind	Cape Cod	Federal	468	Likely	Commercial lease executed; PPA signed; awaiting financing
Coastal Point	Galveston Offshore Wind	Galveston	State	150	Likely	Lease issued; waiting on Corps of Engineers approval
Coastal Point	Jefferson, Brazoria, Corpus Christi, & Brownsville	Texas	State	1800	Unlikely	Lease issued
NYPA	Long Island Offshore Wind Park	Long Island	Federal	350-700	Unlikely	On-hold for several years; recently applied for BOEMRE limited lease
Bluewater Wind		Delaware	Federal	200-600	Likely	PPA signed; BOEMRE limited lease issued
Southern Company		Georgia	Federal		Unlikely	Offered BOEMRE lease; not executed
Hull Municipal	Hull Offshore Wind	Massachusetts	State	12-20	Unlikely	Estimated development costs prohibitive; unlikely to move forward
Deepwater Wind	Block Island	Rhode Island	State	29	Likely	PPA signed
Deepwater Wind	Garden State Offshore Energy	New Jersey	Federal	350	Possible	BOEMRE limited lease issued
Fisherman's Energy		New Jersey	Federal	330	Possible	BOEMRE limited lease issued
Fisherman's Energy	Atlantic City	New Jersey	State	20	Likely	Applied for state permits; launched wind monitoring buoy
Bluewater Wind		New Jersey	Federal	350	Possible	BOEMRE limited lease issued
Baryonyx	Rio Grande	Texas	State	1000-1200	Unlikely	State lease issued
Baryonyx	Mustang Island	Texas	State	1000-1200	Unlikely	State lease issued
GLOW/LEEDCo	Cuyahoga	Lake Erie	State	20	Likely	Agreed to supply contract with GE
NYPA		Great Lakes	State	120-500	Unlikely	Issued RFP

74. Current market and regulatory conditions suggest that OSW generation projects not under significant and meaningful development within the next twelve months will more than likely not reach a commercial operation date before 2016.

75. Demonstration and commercial projects are planned in both state and federal waters. Large-scale developments in state waters are most advanced in Texas, but development could also occur offshore Maine, New York and Rhode Island, and possibly in the Great Lakes.

76. Most OSW generation development, however, is expected to occur in federal waters, particularly the Northern and Mid-Atlantic regions where wind speeds are highest, state renewable portfolio standards exist, high population

[38]Kaiser, M.J. and B. Snyder 2010. Offshore Wind Energy Installation and Decommissioning Cost Estimation in the U.S. Outer Continental Shelf. U.S. Dept. of the Interior, Bureau of Ocean Energy Management, Regulation and Enforcement, Herndon, VA. TA&R study 648.

densities are found, and capacity limitations and transmission bottlenecks in the electricity infrastructure are common.[39]

77. The Bureau of Ocean Energy Management, Regulation, and Enforcement ("BOEMRE"), an agency of the Department of Interior ("DOI") responsible for offshore energy development in federal waters, has issued five limited leases: four offshore New Jersey and one lease off Delaware. All five leases were issued for resource evaluation purposes. Limited leases allow for the construction of met towers and other monitoring activities, but do not allow for commercial development.[40]

78. The New Jersey leases were awarded to Fisherman's Energy, Bluewater Wind and Deepwater Wind. The Delaware lease was issued to Bluewater Wind. Southern Company was offered a limited lease offshore Georgia but it has not been executed.

79. One Virginia project (Apex Hampton) allegedly submitted an unsolicited letter of interest, yet no permitting decision has been taken on this project to date. Another Virginia proposal (Seawind Renewable Energy; 400 MW), along with a Maryland proposal (Ocean City; 600 MW), are considered highly speculative and are in the concept/early planning stages.

80. Table 1 also summarizes the most advanced OSW generation projects in federal and state waters that have been announced to date. The development outlooks for each of these projects have been categorized as "likely," "possible," and "unlikely" by 2016.

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[39] Kaiser, M.J. and B. Snyder 2010. Offshore Wind Energy Installation and Decommissioning Cost Estimation in the U.S. Outer Continental Shelf. U.S. Dept. of the Interior, Bureau of Ocean Energy Management, Regulation and Enforcement, Herndon, VA. TA&R study 648; and Musial, W. and B. Ram. 2010. Large Scale Offshore Wind Power in the United States: Assessment of Opportunities and Barriers. National Renewable Energy Laboratory. Golden, CO. NREL/TP-500-40745.

[40] Recently, Cape Wind Associates, LLC received a commercial lease from BOEMRE, however it is outside the AWC Companies' geographic development area.

81. While admittedly subjective, the development categorization provided on Table 1 is based upon a number of quantifiable metrics that include self-identified status and size of the project, the financial capacity of the developer, regulatory evolution, local political enthusiasm, and economic conditions that currently exist.

82. The development categorization assumes an adequate supply chain will develop in the region to service these projects, as well as relatively stable regulatory and tax environment. Changes in any of these factors, as well as continued low natural gas prices, will likely slow OSW development progress.

83. Given these factors, and the development categorization in Table 1 total nameplate OSW generation capacity likely to be online in 2016 will range between 887 to 1,287 MW. Clearly lower than the 6,600 MW assumed by the AWC Companies.

84. Projects most likely to begin construction within 2012-2015 include: Cape Wind (Nantucket Sound, Massachusetts; 468 MW); Coastal Point Energy (Galveston, TX; 150 MW); Bluewater Wind (Delaware; 200-450 MW); and Deepwater Wind (Rhode Island; 29 MW).

85. Given current conditions, Garden State Offshore Energy[41] (New Jersey; 350 MW), Fisherman's Energy (New Jersey; 330 MW), and Bluewater Wind[42] (New Jersey; 350 MW) are just as likely to be developed as not

[41]Deepwater Wind and PSEG Global, a sister company of New Jersey's major regulated gas and electricity provider, plan to develop the Garden State Offshore Energy (GSOE) project, a 350 MW facility 17 miles off of New Jersey. GSOE began in response to a solicitation from the New Jersey Board of Public Utilities. The proposed technology is similar to that used in the Deepwater Rhode Island project. Deepwater received a limited lease from BOEMRE and plans to install a mobile wind monitoring buoy on the site in the near future.

[42]In May 2007, Bluewater was selected to negotiate a PPA and in 2008, signed an agreement with Delmarva Power for the purchase of at least 200 MW of offshore wind power with the option to build up to 600 MW. The final PPA sets a price of approximately 0.12 $/kWh including energy and RECs, and gives Delmarva Power 3.5 RECs for every credit purchased. Bluewater Wind is expected to be 11.5 miles offshore. In 2009, Bluewater received a limited lease from BOEMRE to establish meteorological towers at the site. In late April 2010, BOEMRE published a request for interest in the Bluewater site, the first step in determining if there is a competitive or conflicting interest in the site prior to commercial leasing. BOEMRE received

developed, and are listed as "possible." The Commission's decision in this proceeding and its impact on New Jersey development policies will likely influence the development of these three projects. The pending New Jersey BPU's rules promulgating the provisions of the recently-passed OSWEDA will also have a big influence on this development.

86. Thus, the AWC Companies' assumption of 6,600 MW of nameplate OSW generation operational by 2016 is likely unrealistic, and suggests that the estimated model benefits are overstated by a factor of at least 5 to 10. Table 2 provides a summary of the AWC Companies' assumptions relative to the likely OSW generation development scenario.

Table 2. AWC Project Benefits Assumes 6,600 MW Wind Capacity by 2016[43]

State	Proposed Capacity (MW)	Expected Capacity Probable	Possible	Unlikely
		---------------- (MW) ----------------		
New Jersey	3,850		1,050	2,800
Delaware	550	200-600		
Maryland	1,100			1,100
Virginia	1,100			1,100
Total	**6,600**	**200-600**	**1,050**	**4,000**

V.b. AWC Project Benefits Are Modeled On An Unrealistic "Build It and They Will Come" Assumption

87. Offshore energy transmission infrastructure has traditionally not been developed without some type of firm assurance (or contractual agreement) on the corresponding development of upstream production assets.

88. For instance, over the 60 year history of the offshore oil and gas industry, very few if any major gathering line systems have been developed without a corresponding upstream resource delineation, wells drilled and processing facilities installed. The capital risk of pursuing mid-stream

responses from two commercial developers and several government agencies and private stakeholders.

[43] Exhibit No. AWC-403 at 13, Table 7, Column 2; and Table 1.

transportation development, without any corresponding upstream commitment, is typically too great in most competitive energy markets. Yet the AWC Companies explicitly request that the Commission approve a regulatory framework that is typically not prevalent in other offshore energy applications.

89. From a modeling perspective, the AWC Companies offer the Commission a wide range of benefits calculated almost out of thin air since the specific location, number, size, and timing of OSW generation development in the Mid-Atlantic is not known. An exceptionally small number of these currently announced OSW projects have state financial support commitments in place or commercial operating licenses. None have made interconnection requests with PJM: usually a necessary and sufficient condition for any power generation project to be considered even "probable."

90. While the AWC Project may be viewed as one based upon a "big vision," it is also one fraught with risks that the project developers seek to mitigate by requesting proposed incentives that will shift these risks onto ratepayers. Moreover, in its current form the problem with the proposed AWC Project is not that it carries risk, per se, but that it carries risks that are avoidable and are a function of the Project's exceptionally preliminary and incomplete nature. Building-out a transmission infrastructure before the location, size, and nature of any corresponding OSW generation capacity is known is unreasonable and, when coupled with the incentives sought in the Petition, unnecessarily and shifts considerable risk onto ratepayers.

V.c. The Purported Technology Benefits Fail to Address Whether or Why "Advanced" Technologies Are Needed

91. In total, approximately 5 gigawatts ("GW") of capacity are operational, or under construction, by nine countries in the North Sea region in 2010. The UK had the largest wind generation capacity in Europe with 1,341 MW of nameplate capacity and 971 MW under construction, representing 44

percent of all operational European offshore wind capacity and 41 percent of the continent's capacity under construction.

92. To date, DC technology has played no significant role in European OSW development. Only two projects out of 55 offshore wind farms utilize or plan to utilize DC to shore, raising questions about the technology's economics and operational viability.

93. VSC-HVDC technology, compared to AC alternatives, is substantially more expensive for near-shore wind farm development. Two HVDC lines are planned to be constructed in two future offshore wind – both of which are considered "demonstration projects:" BorWin2 (800 MW) and HelWin1 (576MW). These are ultimately intended to be linked to four wind farms (Veja Mate, GlobalTech 1, Nordee Ost, Meerwind) in two separate DC links to shore. In the German developments where DC technology is being applied, the systems are considered demonstration projects (not commercial developments).

94. VSC-HVDC technology is expected to become more favorable with increasing wind farm sizes and distances. However, for the foreseeable future, until wind farms are developed in deepwater and far from shore, such systems will not be economically viable. DC transmission is recognized as more economic and reliable than AC transmission as the distance to shore increases and the wind farm grows in size.

95. The European offshore wind development experience to date would suggest that a HVDC transmission backbone is only likely after (not before) regional build-outs are complete. While European wind farms are geographically concentrated, none to date have been built with a common DC network, despite theoretic economies.

96. Figure 2 shows the planned offshore wind farms in the German sector of the North Sea; Figure 3 shows development for Round 1 and 2 in the UK's Thames estuary. Similar patterns hold for parts of Denmark, the

Netherlands and Belgium. The density of these offshore wind projects illustrates the enthusiasm for offshore wind development among European policy makers and the relative lack of conflict with other users of the North Sea.

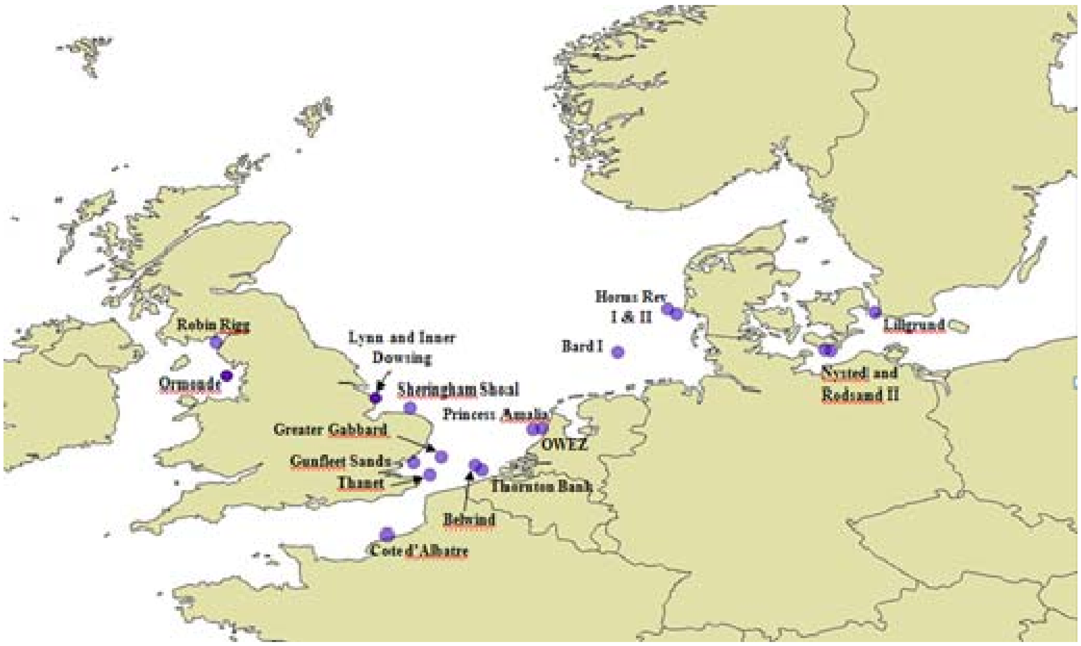

Figure 1. Wind Farms over 100 MW Online and Under Construction (as of October 2010)[44]

[44]Kaiser, M.J. and B. Snyder 2010. Offshore Wind Energy Installation and Decommissioning Cost Estimation in the U.S. Outer Continental Shelf. U.S. Dept. of the Interior, Bureau of Ocean Energy Management, Regulation and Enforcement, Herndon, VA. TA&R study 648; and Musial, W. and B. Ram. 2010. Large Scale Offshore Wind Power in the United States: Assessment of Opportunities and Barriers. National Renewable Energy Laboratory. Golden, CO. NREL/TP-500-40745.

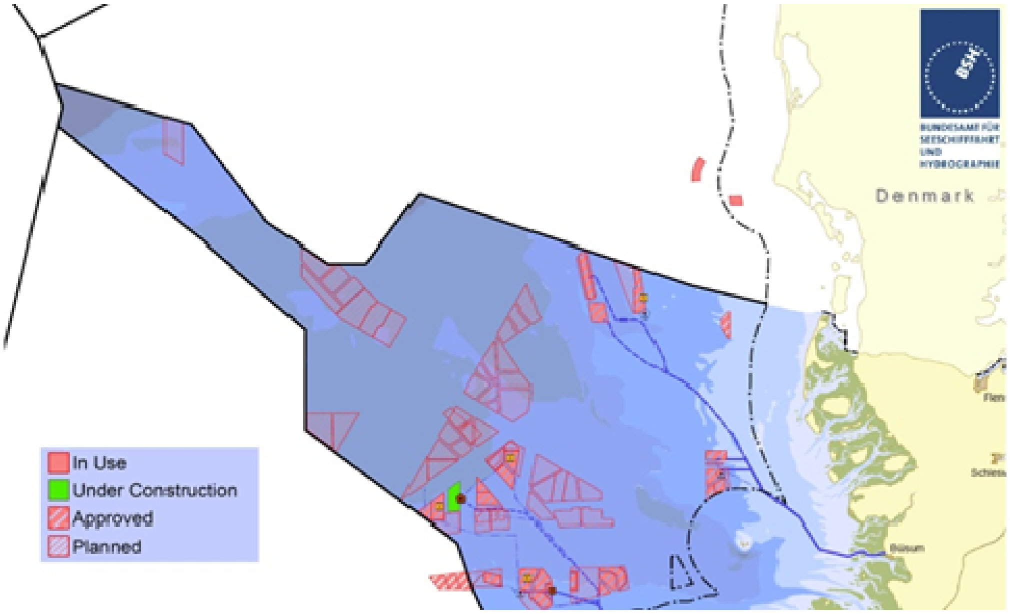

Figure 2. Offshore Wind Farms Planned for the German Sector of the North Sea[45]

97. VSC-HVDC technology can be adopted to operate with several terminals on the DC side so that power can be injected or extracted at each terminal. This proposed mode of operation has encouraged feasibility studies for a European DC supergrid (Figure 3), and there has been the suggestion that such a grid would be highly beneficial.[46] However, no significant progress has been made on financing such a system or performing advanced feasibility studies.[47]

98. The European experience to date confirms that it is unrealistic to assume offshore development will distribute itself around a transmission link solely to avoid the transmission cost. The failure of these offshore grids to materialize are likely a function of the fact that transmission investment costs are typically only 15 to 20 percent of an overall offshore wind project. Indeed, the

[45] BSH. 2010. North Sea: offshore wind farms. Internet website: http://www.bsh.de/en/Marine_uses/Industry/CONTIS_maps/NorthSeaOffshoreWindfarmsPilotProjects.pdf.

[46] O'Connor, E. 2006. European Unity, a Vision for Sustainable Power in Europe, Renewable Energy World, March-April, 124-127.

[47] Cameron, A. 2011. European Supergrid Slowly to Become Reality, Offshore Wind Biz, January 11, 2011.

experience of offshore wind development in Europe suggests that a range of possible designs and models will likely be explored before any offshore DC super-grid is found to make economic sense. Given the experience to date in the relatively mature, developed European markets, it is unrealistic to assume that a transmission super-grid will be economic in an immature market like the offshore U.S. and before a significant asset base is in place.

VI. The AWC Companies Fail to Meet The Commission's Nexus Requirements

99. The Commission's policy for awarding ratemaking incentives to new transmission projects starts with an evaluation of whether or not the proposed project is "routine." A non-routine transmission project is defined as one that (1) improves reliability or reduces congestion costs, (2) has significant scope which can be defined by size, transfer capability, jurisdictions, dollar investment, participants, and effect on the region, and (3) faces challenges or risks that can include siting, financing requirement, lead times, regulatory and political risks, other specific financing challenges, and other impediments.[48]

100. The Commission has stated that non-routine transmission investments that help to ensure reliability, or reduce congestion, can qualify for incentives where a "nexus" can be made between the incentives requested, and the investment being made.[49]

101. However, the Commission has also noted that incentives will not be offered merely as "bonuses" for routine good behavior, but must be constructed and "tailored" to address demonstrable risks or challenges faced by the transmission developer.[50]

[48] Public Service Electric and Gas Co., 123 FERC ¶ 61,068 at P 31.
[49] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 26; and Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 22 and 23.
[50] Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 at P 40.

VI.a. The AWC Project Is Unique Because it is Speculative Which Should Not Serve as a Basis for Incentives

102. The proposed AWC Project, while offshore, is still orders of magnitude smaller, and more limited in scope, that the Green Power Express, which requested, and received, various regulatory and ratemaking incentives in 2009.[51]

103. The Green Power Express was designed to span approximately 3,000 miles, over a seven states, projected to cost between $10 and $12 billion, deliver about 62 GW of wind capacity, and provide access to remote, location-constrained renewable resources.[52] The AWC Project, as noted earlier, is considerably smaller in total investment, geographic scope, and purpose than the Green Power Express.

104. While the Green Power Express project certainly exhibited some risks, the development can hardly be characterized as equivalent to the highly speculative nature of the AWC Companies' proposal. For instance, the Green Power Express was developed to support some 62.8 GW of announced onshore wind projects that were active in the MISO interconnection queue. The total active offshore wind capacity currently in the PJM interconnection queue is zero.

105. The only characteristic that is unique about the AWC Companies' proposed project is its business development strategy of committing significant levels of capital to an offshore energy transmission network prior to the formal and accurate delineation of wind resources from actual meteorological data, before any commercial offshore wind leases have been attained, before any offshore structures have been constructed and installed, and, most importantly, before any long-term transmission service agreements have been signed with a specific offshore wind producer. Additionally unique is the proposal to effectively flip all of the risks of this speculative project onto ratepayers: an outcome rarely possible in other infrastructure industries, much less competitive markets.

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[51] Green Power Express LP, 127 FERC ¶ 61,031.
[52] Ibid., at P 46.

106. The AWC Companies' development approach stands in stark contrast with how the thousands of miles of FERC-regulated offshore transmission lines in the Gulf of Mexico were developed which tended to be after producers received leases, geophysical and geological surveys were completed, offshore production structures were fabricated and installed, and production wells were drilled and completed.

107. The AWC Project is simply speculative and if its proposed incentives are approved, that will shift the burden of its unorthodox development approach entirely on ratepayers in one form or another.

VI.b. The AWC Companies' Deferral and Recovery of a Regulatory Asset Should be Denied

108. The AWC Companies are seeking authorization to establish a regulatory asset. The asset will consist of all AWC Project expenses that are not capitalized and included in CWIP prior to the date its formula rate becomes effective.[53]

109. The AWC Companies are also seeking authorization to capitalize the associated carrying charges from the date the Commission accepts the regulatory asset until the date it is fully amortized. They claim this treatment is necessary because of the substantial investments needed to be made during the development and start-up stages of the Project.[54]

110. The AWC Companies note that the development and preconstruction expenses proposed for recovery as part of the regulatory asset would include, <u>but are not limited to</u>: "costs for attorney and consultant fees; entity formation costs; administrative expenditures; taxes (other than income taxes); travel costs and other expenditures related to the corporate structure; development of the necessary surveys, studies and investigations; support of local and regional transmission planning activities and local outreach programs;

[53] Vilbert Testimony, Exh. No. AWC-600 at 10-11; and Villadsen Testimony, Exh. No. AWC-700 at 1-2.
[54] Petition at 59.

regulatory efforts made for the purpose of determining the feasibility of utility projects and the analyses mandated by regulatory bodies and regional planning processes related to pre-construction approvals; and all other costs incurred to obtain permits, approvals, licenses, or other clearances needed to proceed to construction." [55]

111. The AWC Companies claim that recognition of these costs as a regulatory asset is necessary because the costs: "(1) would otherwise be chargeable to expense in the period incurred; (2) are not recoverable in current rates; and (3) are ones for which future recovery is probable." [56]

112. The AWC Companies' request is not supported by any concrete factual evidence and should be dismissed because they have failed to meet the Commission's requirements that the costs requested for recovery in the regulatory asset be explicitly quantified, estimated, or even offered on a "not to exceed" basis. The Commission has ruled in its past incentive rulings that its nexus requirements are not general, but "fact-specific" and the AWC Companies have offered no facts to support their request.[57]

113. Further, the Companies have provided no authority for their assertion that the claimed costs would be chargeable to expense in the period incurred. This request is essentially an appeal for *carte blanche* spending on development, start-up, and preconstruction activities. Such a proposal will unquestionably create strong incentives for inefficiencies and cost excesses that regulation has historically sought to avoid.

114. The request is also problematic given the highly speculative and preliminary nature of the AWC Companies' proposal. The nature of the costs proposed to be recovered through this regulatory asset would appear to include those associated with litigation, permitting, and regulatory expenses. If the

[55] Petition at 60.
[56] Ibid.
[57] Green Power Express LP, 127 FERC ¶ 61,031 at P 44.

Commission approves the creation of this regulatory asset (and its corresponding ratemaking treatment) ratepayers and their agents will have to pay for any litigation and regulatory costs associating with opposing this currently-questionable project up to, and including, the costs associated with the instant proceeding. This mechanism will likely create incentives to use the regulatory process and litigation to solve project deficiency problems rather than workable solutions through traditional stakeholder processes.

115. Approving and allowing recovery of these costs over five years violates the traditional matching principle of cost and benefits since these developmental, start-up, and pre-construction costs will benefit the customers of the AWC Project for its entire useful life, not just a five year period. If approved, the project will require near-term ratepayers to fund costs that provide long term benefits to future ratepayers, who, in turn, will also benefit from the upfront sacrifice today's ratepayers have made to support the above-market cost offshore wind power. This potential outcome is neither fair, nor reasonable, nor equitable and should be rejected out of hand by the Commission.

116. However, if the Commission finds that regulatory asset should be approved, it should reject the five-year request and authorize a ten-year amortization period similar to that authorized for Green Power Express.[58] The Companies have offered no rationale for deviation from the Commission's decision in this prior matter, and it should be utilized as an alternative should the Commission be inclined to offer some type of incentive in this regard.

117. Further, the Commission should only allow the recovery of this asset once the AWC Companies have actually begun construction on the project, and not at the time the project is included in the PJM regional plan. This will give the AWC Companies an active incentive to get the proposed project under construction as quickly as possible, minimizing development and pre-construction expenditures and the accumulated earnings that could materialize

[58]Green Power Express LP, 127 FERC ¶ 61,031 at P 60.

over an unusually long pre-construction period. The Commission should also adopt a performance-based earnings approach for these regulatory assets. For instance, incentive returns for this project should not be allowed to materialize until certain goals have been attained. The RTO incentive return should not be applied to these regulatory assets until such time as their operational control is turned over to PJM. No technology-based incentives should be allowed until such time that the advanced technologies developed for this project are proved to be working and operational. No market risk adjustments for project development should be applied to this asset until such time as the project comes on-line.

118. A performance-based incentive return is reasonable and consistent with good regulatory policy since it only rewards the AWC Companies when a successful action has been achieved, not when dollars have been spent. This approach will assist in creating positive incentives for the AWC Companies to attain the Commission's goals of developing a cost-effective, efficient, operational, advanced offshore transmission grid. Ratepayers will also be further protected if returns are tied to actions, not expenditures, since performance-based approaches only require ratepayers to make incentive payments once a service has been rendered: an outcome consistent with competitive markets.

VI.c. The AWC Companies' Request for CWIP Rate Base Treatment Should be Rejected

119. The AWC Companies cite prior Commission precedent for its incentive proposal to include 100 percent of its CWIP in rate base. The Commission, however, has stated that inclusion of CWIP in rate base will be decided on a case-by-case basis.[59] In addition, the Commission has not stated that 100 percent will be included in rate base, but that it would consider inclusion

[59] Southern California Edison Company, 121 FERC ¶ 61,168, at P 46.

of "up to" 100 percent of "prudently incurred" transmission-related "CWIP in rate base."[60]

120. The Commission has authorized inclusion of CWIP in rate base for several reasons, none of which have been demonstrated by the AWC Project: (1) if there is a threat of a company's bonds being downgraded as a result of the project; (2) if the cost and time frame for completing the project will put pressure on a company's finances; and (3) if an applicant can show that the proposed project is relatively large compared to its current transmission rate base and has long lead-times.[61]

121. AWC has not demonstrated, nor provided any record evidence, that its proposed project meets any of the Commission's pre-requisites for the inclusion of CWIP in rate base. Thus, the AWC Companies' filing is deficient and should be dismissed.

122. For instance, the AWC Companies have not demonstrated, despite Commission requirements, that there is a threat of their bonds being downgraded, as they have not issued any bonds. They have provided no interest coverage ratios, capital structure ratios, or other metrics that examine financial integrity with and without inclusion of CWIP in rate base. They have therefore not met this test for inclusion of CWIP in rate base.

123. AWC states that its costs are substantial, but fails to quantify the costs or put "substantial" into perspective. They have provided no comparison or projections of the amount of CWIP that will be incurred by year compared to rate base. They have therefore not met this test for inclusion of CWIP in rate base.

124. Moreover, the costs associated with the transmission project pale in comparison to the offshore wind projects that will be built to generate the electricity transported by the AWC Companies. While the AWC Companies seek

[60] Ibid., at P 60.
[61] Order No. 679, FERC Stats. & Regs. ¶ 31,222 at P 103 and 115.

authority to include CWIP in rate base for a $5.0 billion project, no such award is likely to be granted for the wind projects with will cost 10 times more on a proportional basis. As noted earlier, most states to date have either explicitly rejected such ratemaking treatment, or simply not approved contracts that include such provisions. The need for rate base treatment of CWIP is questionable for offshore energy transmission, particularly when relatively more expensive, and risky offshore generation being supported by that investment, is not afforded similar ratemaking treatment.

125. AWC claims that inclusion of CWIP in rate base will enhance cash-flow, but, contrary to Commission requirements, fails to quantify the impact. The Companies have not provided any projected cash-flows, cash-flow ratios, or other metrics that examine cash-flow integrity with and without CWIP in rate base. It has not demonstrated that its cash-flow ratios will decline unless CWIP is included in rate base. This simply represents a filing deficiency and serves as further support for dismissing the AWC Companies' incentives request.

126. If the Commission opts to allow the AWC Companies' rate base treatment for its CWIP, it should impose certain performance-based conditions. First, the allowed returns on the CWIP balances should be restricted to an appropriately-determined base rate of return. No incentive returns should be allowed on these balances until such time that the AWC Companies reach the goals these incentives are designed to promote. This recommendation is consistent with my earlier recommendations regarding the returns allowed on the AWC Companies' proposed regulatory asset. Thus, incentive returns associated with joining an RTO should not be allowed until such time that operational control of a working set of assets has been transferred to an RTO. Likewise, incentive returns associated with advanced technologies should not be generated until such time as the assets are in place and operational.

127. Second, the Commission should also consider further performance-based conditions on the rate base treatment for CWIP. This should include, but

is not necessarily limited to restricting recovery to only those investments that are within pre-filed project schedule and cost estimates. Rate base treatment should be rejected for all expenditures that are in excess of budget, or incurred for time periods beyond originally-anticipated schedule. Recovery of these excess costs should be deferred, and restricted to periods when the assets have become operational and shown to have been prudently-incurred. Developing a performance-based approach to CWIP in rate base would better balance the interests of ratepayer and developers and would also provide the Companies with the incentives to meet their cost and schedule objectives.

VI.d. The Commission Should Reject the Abandonment Incentive

128. The AWC Companies also request an abandoned plant incentive. This incentive allows recovery of prudently-incurred associated with the proposed project should it be cancelled or abandoned for reasons beyond the AWC Companies' control.[62]

129. It is premature for the Commission to grant the AWC Companies' abandoned plant incentive since no evidence has been provided in this proceeding, particularly by the AWC Companies, that this project is needed nor that is has a high likelihood of being be used and useful. If anything, the AWC Companies' application raises considerable concerns about the preliminary and speculative nature of the proposal.

130. The speculative and preliminary nature of the AWC Companies' proposal shifts considerable risk onto ratepayers and may lead to significant moral hazard-related problems.

131. Moral hazard is said to occur in instances where an economic agent facing a certain degree of risk behaves differently when it is insulated from that risk than it would if the risk were not insured.[63] Moral hazard is, in effect, the

[62] Vilbert Testimony, Exh. No. AWC-600 at 10.
[63] W. Nicholson. *Intermediate Microeconomics and Its Applications*. 5th Edition. (1990) Chicago: Dryden Press, 695.

behavioral difference that results from the presence or introduction of insurance. Moral hazard results in a "market failure" or inefficiency because the agent receiving the insurance does not have to bear the full responsibility for its actions. As Bonbright, et.al. notes:

> A moral hazard is involved when someone other than the purchaser pays for the purchase and hence the purchaser acts, unconstrained by ethics or other institutions, as if there is no resource cost on society from his or her purchases. In other words, moral hazard increases the risk of an event turning out favorably because there may be positive rewards or at least insufficient penalties for opportunistic behavior.[64]

132. A recent example of moral hazard in public policy can be found in the outcome of the recent banking and financial crisis that led to policies bailing out banks and other financial institutions that were considered "too big to fail."

133. Many financial institutions were given billions of dollars in bail-outs and other forms of financial support to buttress their financial positions devastated by past risky lending actions. Some analysts have argued that these policy actions have done nothing to correct the underlying problem leading to the 2009 financial crisis and in fact, in the long run, may have exacerbated these problems since in the future, banks may use this policy precedent as support for future rescue actions from continued risky practices.[65]

134. The AWC Companies' plant abandonment incentive, if adopted, could lead to an opportunity for moral hazard because it would give the project developers free insurance against negative project outcomes (i.e., development failure). If the AWC Companies' know that the economic consequences of these negative outcomes (failure to recover abandoned plant investments) are not

[64] J. Bonbright, A. Danielsen, and D. Kamerschen. (1988) *Principles of Public Utility Rates*. Arlington, VA: Public Utility Reports, 138.

[65] Wilson, L. and Wu, Y. Common (stock) Sense About Risk-Shifting and Bank Bailouts. *Financial Markets and Portfolio Management*, Forthcoming; Hakenes, H. and Schnabel, I. Banks Without Parachutes: Competitive Effects of Government Bail-Out Policies. *Journal of Financial Stability.* May 21, 2009; and Helwege, J. Financial Firm Bankruptcy and Systemic Risk. *Journal of International Financial Markets, Institutions & Money.* November 14, 2009.

valued at their true costs, it will reduce their incentives to take actions avoiding these negative outcomes.

135. Lastly, it is worth re-iterating that the AWC Companies' request for plant abandonment incentives stands in direct opposition to some state OSW policies, particularly New Jersey where plant abandonment incentives were also considered but rejected. While the removal of the abandoned plant incentive is a well-known outcome associated with the OSWEDA, not one OSW developer, to date, has announced that it will withdraw from an offshore New Jersey project because of this explicit exclusion.

136. The Commission should reject the AWC Companies request for an abandoned plant cost recovery incentive given the preliminary nature of their filing.

137. If the Commission allows for some type of abandoned plant investment recovery it should restrict that recovery to actual plant investment expenditures (i.e., costs). All returns, particularly incentive returns, should be rejected as being eligible for recovery if all or parts of this project are abandoned.

VII. Opinion and Recommendations

138. It is my opinion and recommendation that the Commission should defer the AWC Companies' request for incentive ratemaking mechanisms until such time as more concrete inputs critical to the determination of project benefits becomes available. These critical inputs include: approval of the project through the PJM RTEP process; meaningful engagement with state regulators and other stakeholders, and documented expressions of interest by currently-announced OSW projects.

139. The AWC Companies have not participated in any meaningful, independent stakeholder transmission planning process for the proposed project. The proposed AWC project has not been evaluated through, or approved by, the PJM regional transmission planning process.

140. The AWC Companies' request several incentive ratemaking remedies that have been rejected by many states for OSW project development. As such, approval of the requested incentives for the AWC Project could be seen as side-stepping the state regulatory ratemaking treatment of various OSW development costs, thereby undermining state OSW policies that seek to balance the risk of OSW generation development between ratepayers and developers. The AWC Companies have failed to enter into any formal discussions with state policy makers and other stakeholders in order to explore synergies and benefits between individual OSW projects and the AWC Companies' proposed project.

141. If approved, the AWC Companies' proposed incentives could work to undermine, not facilitate, the development OSW generation since many of these proposed mechanisms are contrary to those included in existing state OSW policies. There are a large number of announced OSW generation projects along the Atlantic seaboard, most of which have not yet attained state regulatory approval for long term financial support. In addition, the overwhelming majority of these OSW projects currently envision the use of radial transmission lines. If the AWC Companies' incentives are approved, currently-announced OSW projects will have strong incentives to continue to explore direct radial connections to attain project approval given the contradiction of these incentives with existing state OSW financial support mechanisms.

142. The purported benefits of the AWC project, including congestion relief, are speculative at best, and more than likely significantly overstated.

143. The AWC Companies have failed to show that offshore transmission will not be supported in a cost-effective, safe, and reliable manner without its remedies and relief. Most OSW generation projects to date, anticipate the development of their own radial transmission lines based upon anticipated project-specific economics and the anticipated development and expansion outlook for those, as well as potentially neighboring, OSW generation projects.

144. However, if the Commission decides to accept the AWC Companies' request for incentives, it should condition any declaratory ruling on the following conditions:

a. Restrict the expenses booked to the requested regulatory asset to a more clearly-defined set of costs that are amortized across a period consistent with prior Commission decisions (10 years), starting with a period in which project construction begins, not the period in which the project enters the PJM RTEP.

b. Restrict the returns on the regulatory asset, and the CWIP included in rate base, to amounts that are based upon performance, not merely the act of spending cash. Incentive returns should only be applied when the actions those incentives are designed to encourage are actually completed. Thus, incentive returns for advanced technologies should not begin until the installation of working and functional advanced equipment. Likewise, incentive returns for RTO participation should not begin until the AWC Companies turn operational control of their assets over to PJM. Incentive premiums for the risky nature of developing this project should not be allowed until such time as the project is actually developed.

c. The Commission should also consider additional performance-based conditions on the requested rate base treatment for CWIP. This should include, but not be limited to, a restriction on rate base recovery to only those investments amounts that are within pre-filed project schedule and cost estimates. Rate base treatment should be rejected for all expenditures that are in excess of budget, or incurred for periods beyond originally-anticipated schedule. Recovery of these excess costs should be deferred and to a later period where the assets have become operational and shown to have been prudently-incurred.

d. If any abandoned plant cost recovery incentive is adopted, the Commission should limit the recovery to only those amounts invested. This would exclude all returns, and particularly incentive returns, on a project that did not become operational.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Atlantic Grid Operations A LLC	)	
	)	Docket No. EL-11-13
Atlantic Grid Operations B LLC	)	
	)	
Atlantic Grid Operations C LLC	)	
	)	
Atlantic Grid Operations D LLC	)	
	)	
Atlantic Grid Operations E LLC	)	
	)	
	)	
State of Louisiana	)	
Parish of East Baton Rouge	)	

AFFIDAVIT OF DAVID E. DISMUKES, PH.D

I, David E. Dismukes, being duly sworn, depose, and state that the contents of the foregoing Affidavit on behalf of the Consumer Advocates, are true, correct, accurate, and complete to the best of my knowledge, information, and belief.

David E. Dismukes

David E. Dismukes, Ph.D.

SUBSCRIBED AND SWORN TO before me, the undersigned Notary Public, this 08 th day of January 2011.

Andrea Knouse

Notary Public

ANDREA M. KNOUSE
Notary Public
State of Louisiana
Notary ID Number 90860
My Commission is for Life

5800 One Perkins Place Dr. Ste 2B
Baton Rouge, LA 70808

(Address of Notary)

(SEAL)
My Commission Expires:

death

Attachment 1

Qualifications:

David E. Dismukes, Ph.D.

DAVID E. DISMUKES, PH.D.

Professor, Associate Executive Director &
Director of Policy Analysis
Center for Energy Studies
Louisiana State University
Baton Rouge, LA 70803-0301
Phone: (225) 578-4343
dismukes@lsu.edu

URL: www.enrg.lsu.edu

Consulting Economist
Acadian Consulting Group
5800 One Perkins Place Drive
Suite 5-F
Baton Rouge, LA 70808
Phone: (225) 769-2603
daviddismukes@acadianconsulting.com

URL: www.acadianconsulting.com

EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola State College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-Current	Associate Executive Director
2001-2006	Associate Professor
2000-2001	Research Fellow and Adjunct Assistant Professor
1999-2000	Managing Director, Distributed Energy Resources Initiative
1995-2000	Assistant Professor

E.J. Ourso College of Business Administration, Department of Economics

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Florida State University, Tallahassee, Florida
College of Social Sciences, Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-2000	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

2000-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

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35. “The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978.” (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.

36. “Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS.” (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.

37. “Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS.” (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

38. “Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry” (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

39. “Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries” (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.

40. “Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry.” (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.

41. “Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators.” (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.

42. “Empirical Determinants of Nuclear Power Plant Disallowances.” (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

43. “A Cross-Sectional Model of IntraLATA MTS Demand.” (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. “Energy Regulation: Overview of Power and Gas Regulation.” Lecture before School of the Coast & Environment, Course in Energy Policy and Law. October 5, 2009.

2. “Trends and Issues in Renewable Energy.” Presentation before the School of the Coast & Environment, Louisiana State University. Spring Guest Lecture Series. May 4, 2007.

3. “CES Research Projects and Status.” Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New Orleans, LA May 22, 2007.

4. “Hurricane Impacts on Energy Production and Infrastructure.” Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.

5. “Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.

6. “Electric Restructuring and Conservation.” (2001). Presentation before the Department of Electrical Engineering, McNesse State University. Lake Charles, Louisiana. May 2, 2001.

7. “Electric Restructuring and the Environment.” (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.

8. “Electric Restructuring and Nuclear Power.” (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.

9. “The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring.” (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. “Regulatory Issues in Inflation Adjustment Mechanisms and Allowances.” (2010). 2010 Annual Meeting, National Association of State Utility Consumer Advocates (“NASUCA”), Omni at CNN Center, Atlanta, Georgia, November 16, 2010.

2. “How Current and Proposed Energy Policy Impacts Consumers and Ratepayers.” (2010). 122nd Annual Meeting, National Association of Regulatory Utility Commissioners (“NARUC”), Omni at CNN Center, Atlanta, Georgia, November 15, 2010.

3. “Energy Outlook: Trends and Policies.” (2010). 2010 Tri-State Member Service Conference; Arkansas, Louisiana, and Mississippi Electric Cooperatives. L’Auberge du Lac Casino Resort, Lake Charles, Louisiana, October 14, 2010.

4. “Deepwater Moratorium and Louisiana Impacts.” (2010). The Energy Council Annual Meeting. Gulf of Mexico Deepwater Horizon Accident, Response, and Policy. Beau Rivage Conference Center. Biloxi, Mississippi. September 25, 2010.

5. “Overview on Offshore Drilling and Production Activities in the Aftermath of Deepwater Horizon.” (2010) Jones Walker Banking Symposium. The Oil Spill: What Will it Mean for Banks in the Region? New Orleans, Louisiana. August 31, 2010.

6. “Long-Term Energy Sector Impacts from the Oil Spill.” (2010). Second Annual Louisiana Oil & Gas Symposium. The BP Gulf Oil Spill: Long-Term Impacts and Strategies. Baton Rouge Geological Society. August 16, 2010.

7. “Overview and Issues Associated with the Deepwater Horizon Accident.” (2010). Global Interdependence Meeting on Energy Issues. Baton Rouge, LA. August 12, 2010.

8. “Overview and Issues Associated with the Deepwater Horizon Accident.” (2010). Regional Roundtable Webinar. National Association for Business Economics. August 10, 2010.

9. “Deepwater Moratorium: Overview of Impacts for Louisiana.” Louisiana Association of Business and Industry Meeting. Baton Rouge, LA. June 25, 2010.

10. Moderator. Senior Executive Roundtable on Industrial Energy Efficiency. U.S. Department of Energy Conference on Industrial Efficiency. Office of Renewable Energy and Energy Efficiency. Royal Sonesta Hotel, New Orleans, LA. May 21, 2010.

11. “The Energy Outlook: Trends and Policies Impacting Southeastern Natural Gas Supply and Demand Growth.” Second Annual Local Economic Analysis and Research Network

("LEARN") Conference. Federal Reserve Bank of Atlanta. March 29, 2010.

12. "Natural Gas Supply Issues: Gulf Coast Supply Trends and Implications for Louisiana." Energy Bar Association, New Orleans Chapter Meeting. Jones Walker Law Firm. January 28, 2010, New Orleans, LA.

13. "Potential Impacts of Federal Greenhouse Gas Legislation on Louisiana Industry." LCA Government Affairs Committee Meeting. November 10, 2009. Baton Rouge, LA

14. "Regulatory and Ratemaking Issues Associated with Cost and Revenue Tracker Mechanisms." National Association of State Utility Consumer Advocates ("NASUCA") Annual Meeting. November 10, 2009.

15. "Louisiana's Stakes in the Greenhouse Gas Debate." Louisiana Chemical Association and Louisiana Chemical Industry Alliance Annual Meeting: The Billing Dollar Budget Crisis: Catastrophe or Change? New Orleans, LA.

16. "Gulf Coast Energy Outlook: Issues and Trends." Women's Energy Network, Louisiana Chapter. September 17, 2009. Baton Rouge, LA.

17. "Gulf Coast Energy Outlook: Issues and Trends." Natchez Area Association of Energy Service Companies. September 15, 2009, Natchez, MS.

18. "The Small Picture: The Cost of Climate Change to Louisiana." Louisiana Association of Business and Industry, U.S. Chamber of Commerce, Louisiana Oil and Gas Association, and LSU Center for Energy Studies Conference: Can Louisiana Make a Buck After Climate Change Legislation? August 21, 2009. Baton Rouge, LA.

19. "Carbon Legislation and Clean Energy Markets: Policy and Impacts." National Association of Conservation Districts, South Central Region Meeting. August 14, 2009. Baton Rouge, LA.

20. "Evolving Carbon and Clean Energy Markets." The Carbon Emissions Continuum: From Production to Consumption." Jones Walker Law Firm and LSU Center for Energy Studies Workshop. June 23, 2009. Baton Rouge, LA

21. "Potential Impacts of Cap and Trade on Louisiana Ratepayers: Preliminary Results." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

22. "Natural Gas Outlook." (2009). Briefing before the Louisiana Public Service Commission. Business and Executive Meeting, May 12, 2009. Baton Rouge, LA.

23. "Gulf Coast Energy Outlook: Issues and Trends." (2009). ISA-Lafayette Technical Conference & Expo. Cajundome Conference Center. Lafayette, Louisiana. March 12, 2009.

24. "The Cost of Energy Independence, Climate Change, and Clean Energy Initiatives on Utility Ratepayers." (2009). National Association of Business Economists (NABE). 25th Annual

Washington Economic Policy Conference: Restoring Financial and Economic Stability. Arlington, VA March 2, 2009.

25. Panelist, "Expanding Exploration of the U.S. OCS" (2009). Deep Offshore Technology International Conference and Exhibition. PennWell. New Orleans, Louisiana. February 4, 2009.

26. "Gulf Coast Energy Outlook." (2008.) Atmos Energy Regional Management Meeting. Louisiana and Mississippi Division. New Orleans, Louisiana. October 8, 2008.

27. "Background, Issues, and Trends in Underground Hydrocarbon Storage." (2008). Presentation before the LSU Center for Energy Studies Industry Advisory Board Meeting. Baton Rouge, Louisiana. August 27, 2008.

28. "Greenhouse Gas Regulations and Policy: Implications for Louisiana." (2008). Presentation before the Praxair Customer Seminar. Houston, Texas, August 14, 2008.

29. "Market and Regulatory Issues in Alternative Energy and Louisiana Initiatives." (2008). Presentation before the 2008 Statewide Clean Cities Coalition Conference: Making Sense of Alternative Fuels and Advanced Technologies. New Orleans, Louisiana, March 27, 2008.

30. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007) Presentation before the New Hampshire Public Utilities Commission. Workshop on Energy Efficiency and Revenue Decoupling. November 7, 2007.

31. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives, and Energy Efficiency." (2007). National Association of State Utility Consumer Advocates, Mid-Year Meeting. June 12, 2007.

32. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.

33. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.

34. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.

35. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.

36. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.

37. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.

38. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military

Institute, Lexington, VA October 17, 2006.

39. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.

40. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

41. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.

42. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.

43. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.

44. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.

45. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.

46. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.

47. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.

48. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.

49. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.

50. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.

51. “LNG—A Premier.” Presentation Given to the U.S. Department of Energy’s “LNG Forums.” Astoria, Washington. April 28, 2006.

52. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.

53. The Impacts of Hurricanes Katrina and Rita on Louisiana’s Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

54. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L’Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006

55. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.

56. “Putting Our Energy Infrastructure Back Together Again.” Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA

57. “Hurricanes and the Outlook for Energy Markets.” Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.

58. “Hurricanes, Energy Supplies and Prices.” Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.

59. “The Impact of the Recent Hurricane’s on Louisiana’s Energy Industry.” Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.

60. “The Impact of the Recent Hurricanes on Louisiana’s Infrastructure and National Energy Markets.” Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.

61. “The Impact of the Recent Hurricanes on Louisiana’s Infrastructure and National Energy Markets.” Presentation before Powering Up: A Discussion About the Future of Louisiana’s Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.

62. “The Impact of Hurricane Katrina on Louisiana’s Energy Infrastructure and National Energy Markets.” Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.

63. “Louisiana Power Industry Overview.” Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.

64. “CES 2005 Legislative Support and Outlook for Energy Markets and Policy.” Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.

65. “Electric Restructuring: Past, Present, and Future.” Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

66. “The Outlook for Energy.” Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.

67. “The Outlook for Energy.” Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.

68. “Background and Overview of LNG Development.” Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.

69. “Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry.” Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.

70. “The Economic Opportunities for a Limited Industrial Retail Choice Plan.” Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.

71. “Energy Issues for Industrial Customers of Gas and Power.” Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.

72. “Energy Issues for Industrial Customers of Gas and Power.” Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.

73. “Energy Issues for Industrial Customers of Gas and Power.” American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.

74. “Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry.” Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.

75. “Energy Issues for Industrial Customers of Gas and Power.” Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.

76. “LNG In Louisiana.” Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.

77. “Louisiana Energy Issues.” Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.

78. “The Gulf South: Economic Opportunities Related to LNG.” Presentation before the Energy Council’s 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.

79. “Natural Gas and LNG Issues for Louisiana.” Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

80. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.

81. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

82. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.

83. “Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy.” Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.

84. “The Economic Opportunities for LNG Development in Louisiana.” Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.

85. “Natural Gas Outlook: Trends and Issues for Louisiana.” Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.

86. “Natural Gas Outlook” Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.

87. “Competitive Bidding in the Electric Power Industry.” Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.

88. “Regional Transmission Organization in the South: The Demise of SeTrans” Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.

89. “Affordable Energy: The Key Component to a Strong Economy.” Presentation before the National Association of Regulatory Utility Commissioners (“NARUC”), November 18, 2003, Atlanta, Georgia.

90. “Natural Gas Outlook.” Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.

91. “Issues and Opportunities with Distributed Energy Resources.” Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.

92. “What’s Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook” Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.

93. “An Introduction to Distributed Energy Resources.” Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.

94. “Merchant Energy Development Issues in Louisiana.” Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

95. “Power Plant Siting Issues in Louisiana.” Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.

96. “Merchant Power and Deregulation: Issues and Impacts.” Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.

97. “Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana.” Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.

98. “Economic Impacts of Merchant Power Plant Development in Mississippi.” Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.

99. “Economic Opportunities for Merchant Power Development in the South.” Presentation before the Southern Governor’s Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.

100. “The Changing Nature of the Electric Power Business in Louisiana.” Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.

101. “Power Business in Louisiana: Background and Issues.” Presentation before the Louisiana Interagency Group on Merchant Power Development . Baton Rouge, LA, July 16, 2001.

102. “The Changing Nature of the Electric Power Business in Louisiana: Background and Issues.” Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.

103. “The Changing Nature of the Electric Power Business in Louisiana: Background and Issues.” Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.

104. “The Economic Impacts of Merchant Power Plant Development In Mississippi.” Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.

105. “Energy Conservation and Electric Restructuring.” With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.

106. “Pricing and Regulatory Issues Associated with Distributed Energy.” Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: “Is the Window Closing for Distributed Energy?” Houston, Texas, October 13, 2000.

107. “Electric Reliability and Merchant Power Development Issues.” Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.

108. “A Introduction to Distributed Energy Resources.” Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

109. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.

110. “Electricity 101: Definitions, Precedents, and Issues.” Energy Council’s 2000 Federal Energy and Environmental Matters Conference. Loews L’Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.

111. “LSU/CES Distributed Energy Resources Initiatives.” Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.

112. “Distributed Energy Resources Initiatives.” Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.

113. “Merchant Power Opportunities in Louisiana.” Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.

114. Roundtable Discussant. “Environmental Regulation in a Restructured Market” The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.

115. “The Political Economy of Electric Restructuring In the South” Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.

116. “The Dynamics of Electric Restructuring in Louisiana.” Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.

117. “The Implications of Electric Restructuring on Independent Oil and Gas Operations.” Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.

118. “What’s Happened to Electricity Restructuring in Louisiana?” Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.

119. “A Short Course on Electric Restructuring.” Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.

120. “The Implications of Electric Restructuring on Independent Oil and Gas Operations.” Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.

121. “How Will Utility Deregulation Affect Tourism.” Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.

122. “Reflections and Predictions on Electric Utility Restructuring in Louisiana.” With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

123. “Electric Utility Restructuring in Louisiana.” Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.

124. “Electric Utility Restructuring.” Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.

125. “Electric Utility Restructuring: Issues and Trends for Louisiana.” Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.

126. “The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues.” Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.

127. “Electric Restructuring: Louisiana Issues and Outlook for 1997.” Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.

128. “Restructuring the Electric Utility Industry.” Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.

129. “Deregulating the Electric Utility Industry.” Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.

130. “Electric Utility Restructuring in Louisiana.” Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.

131. “Electric Utility Restructuring in Louisiana.” Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996

132. “Electric Utility Restructuring” Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.

133. “Electric Utility Restructuring -- Background and Overview.” Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.

134. “Electric Utility Restructuring.” Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.

135. Roundtable Moderator, “Stakeholder Perspectives on Electric Utility Stranded Costs.” Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.

136. Panelist, “Deregulation and Competition.” American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

<u>EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS, RECOMMENDATIONS, AND AFFIDAVITS</u>

1. Expert Testimony. D.P.U. 10-114. (2010). Before the Massachusetts Department of Public Utilities. Petition of the New England Gas Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: infrastructure replacement rider.

2. Expert Testimony. D.P.U. 10-70. (2010). Before the Massachusetts Department of Public Utilities. Petition of the Western Massachusetts Electric Company for Approval of A General Increase in Electric Distribution Rates and Approval of a Revenue Decoupling Mechanism. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure replacement rider; performance-based regulation; inflation adjustment mechanisms; and rate design.

3. Expert Testimony. G.U.D. Nos. 998 & 9992. (2010). Before the Texas Railroad Commission. In the Matter of the Rate Case Petition of Texas Gas Services, Inc. On the Behalf of the City of El Paso, Texas. Issues: Cost of service, revenue distribution, rate design, and weather normalization.

4. Expert Testimony. B.P.U Docket No. GR10030225. (2010). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of New Jersey Natural Gas Company for Approval of Regional Greenhouse Gas Initiative Programs and Associated Cost Recovery Mechanisms Pursuant to N.J.S.A. 48:3-98.1. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy proposals, solar securitization issues, solar energy policy issues.

5. Expert Testimony. D.P.U. 10-55. (2010). Before the Massachusetts Department of Public Utilities. Investigation Into the Propriety of Proposed Tariff Changes for Boston Gas Company, Essex Gas Company, and Colonial Gas Company. (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; pipeline-replacement rider; performance-based regulation; partial productivity factor estimates, inflation adjustment mechanisms; and rate design.

6. Expert Testimony. Cause No.43839. (2010). Before the Indiana Utility Regulatory Commission. In the Matter of Southern Indiana Gas and Electric Company d/b/a/ Vectren Energy Delivery of Indiana, Inc. (Vectren South-Electric). On the behalf of the Indiana Office of Utility Consumer

Counselor (OUCC). Issues: revenue decoupling, variable production cost riders, gains on off-system sales, transmission cost riders.

7. Congressional Testimony. Before the United States Congress. (2010). U.S. House of Representatives, Committee on Natural Resources. Hearing on the Consolidated Land, Energy, and Aquatic Resources Act. June 30, 2010.

8. Expert Testimony. Before the City Counsel of El Paso, Texas; Public Utility Regulatory Board. (2010). On the Behalf of the City of El Paso. In Re: Rate Application of Texas Gas Services, Inc. Issues: class cost of service study (minimum system and zero intercept analysis), rate design proposals, weather normalization adjustment, and its cost of service adjustment clause, conservation adjustment clause proposals, and other cost tracker policy issues.

9. Expert Testimony. Docket 09-00183. (2010). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Chattanooga Gas Company for a General Rate Increase, Implementation of the EnergySMART Conservation Programs, and Implementation of a Revenue Decoupling Mechanism. On the Behalf of Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling and energy efficiency program review and cost effectiveness analysis.

10. Expert Testimony and Exhibits. Docket No. 10-240. (2010). Before the Louisiana Office of Conservation. In Re: Cadeville Gas Storage, LLC. On the Behalf of Cardinal Gas Storage, LLC. Issues: alternative uses and relative economic benefits of conversion of depleted hydrocarbon reservoir for natural gas storage purposes.

11. Expert Testimony. Docket No. 09505-EI. (2010). Before the Florida Public Service Commission. In Re: Review of Replacement Fuel Costs Associated with the February 26, 2008 outage on Florida Power & Light's Electrical System. On the Behalf of the Florida Office of Public Counsel for the Citizens of the State of Florida. Issues: Replacement costs for power outage, regulatory policy/generation development incentives, renewable and energy efficiency incentives.

12. Expert Testimony. Docket 09-00104. (2009). Before the Tennessee Regulatory Authority. In the Matter of the Petition of Piedmont Natural Gas Company, Inc. to Implement a Margin Decoupling Tracker Rider and Related Energy Efficiency and Conservation Programs. On the Behalf of the Tennessee Attorney General, Consumer Advocate & Protection Division. Issues: revenue decoupling, energy efficiency program review, weather normalization.

13. Expert Testimony. Docket Number NG-0060. (2009). Before the Nebraska Public Service Commission. In the Matter of SourceGas Distribution, LLC Approval for a General Rate Increase. On the Behalf of the Nebraska Public Advocate. October 29, 2009. Issues: revenue decoupling, inflation trackers, infrastructure replacement riders, customer adjustment rider, weather normalization rider, weather normalization adjustments, estimation of normal weather for ratemaking purposes.

14. Expert Report and Deposition. Before the 23rd Judicial District Court, Parish of Assumption, State of Louisiana. On the Behalf of Dow Hydrocarbons and Resources, Inc. September 1, 2009. (Deposition, November 23-24, 2009). Issues: replacement and repair costs for underground salt cavern hydrocarbon storage.

15. Expert Testimony. D.P.U. 09-39. Before the Massachusetts Department of Public Utilities. (2009). Investigation Into the Propriety of Proposed Tariff Changes for Massachusetts Electric Company and Nantucket Electric Company (d./b./a. National Grid). On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; infrastructure rider; performance-based regulation; inflation adjustment mechanisms; revenue distribution; and rate design.

16. Expert Testimony. D.P.U. 09-30. Before the Massachusetts Department of Public Utilities. (2009). In the Matter of Bay State Gas Company Request for Increase in Rates. On the Behalf of the Office of the Attorney General, Office of Ratepayer Advocacy. Issues: Revenue decoupling; target infrastructure replacement program rider; revenue distribution; and rate design.

17. Expert Testimony. Docket EO09030249. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric and Gas Company for Approval of a Solar Loan II Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design, renewable portfolio standards, solar energy, and renewable financing/loan program design.

18. Expert Testimony. Docket EO0920097. (2009). Before the New Jersey Board of Public Utilities. In the Matter of the Verified Petition of Rockland Electric Company for Approval of an SREC-Based Financing Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: solar energy market design; renewable energy portfolio standards; solar energy.

19. Expert Rebuttal Report. Civil Action No.: 2:07-CV-2165. (2009). Before the U.S. District Court, Western Division of Louisiana, Lake Charles Division. Prepared on the Behalf of the Transcontinental Pipeline Corporation. Issues: expropriation and industrial use of property.

20. Expert Testimony. Docket EO06100744. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Atlantic City Electric Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

21. Expert Testimony. Docket EO08090840. (2008). Before the New Jersey Board of Public Utilities. In the Matter of the Renewable Portfolio Standard – Amendments to the Minimum filing Requirements for Energy Efficiency, Renewable Energy, and Conservation Programs and For Electric Distribution Company Submittals of Filings in connection with Solar Financing (Jersey Central Power & Light Company). On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: Solar energy market design; renewable energy portfolio standards; solar energy. (Rebuttal and Surrebuttal)

22. Expert Testimony. Docket UG-080546. (2008). Before the Washington Utilities and Transportation Commission. On the Behalf of the Washington Attorney General (Public

Counsel Section). Issues: Rate Design, Cost of Service, Revenue Decoupling, Weather Normalization.

23. Congressional Testimony. (2008). Senate Republican Conference: Panel on Offshore Drilling in the Restricted Areas of the Outer Continental Shelf. September 18, 2008.

24. Expert Testimony. Appeal Number 2007-125 and 2007-299. (2008). Before the Louisiana Tax Commission. On the Behalf of Jefferson Island Storage and Hub, LLC (AGL Resources). Issues: Valuation Methodologies, Underground Storage Valuation, LTC Guidelines and Policies, Public Purpose of Natural Gas Storage. July 15, 2008 and August 20, 2008.

25. Expert Testimony. Docket Number 07-057-13. (2008). Before the Utah Public Service Commission. In the Matter of the Application of Questar Gas Company to File a General Rate Case. On the Behalf of the Utah Committee of Consumer Services. Issues: Cost of Service, Rate Design. August 18, 2008 (Direct, Rebuttal, Surrebuttal).

26. Rulemaking Testimony. (2008). Before the Louisiana Tax Commission. Examination of Replacement Cost Tables, Depreciation and Useful Lives for Oil and Gas Properties. Chapter 9 (Oil and Gas Properties) Section. August 5, 2008.

27. Legislative Testimony. (2008). Examination of Proposal to Change Offshore Natural Gas Severance Taxes (HB 326 and Amendments). Joint Finance and Appropriations Committee of the Alabama Legislature. March 13, 2008.

28. Public Testimony. (2007). Issues in Environmental Regulation. Testimony before Gubernatorial Transition Committee on Environmental Regulation (Governor-Elect Bobby Jindal). December 17, 2007.

29. Public Testimony. (2007). Trends and Issues in Alternative Energy: Opportunities for Louisiana. Testimony before Gubernatorial Transition Committee on Natural Resources (Governor-Elect Bobby Jindal). December 13, 2007.

30. Expert Report and Recommendation: Docket Number S-30336 (2007). Before the Louisiana Public Service Commission. In re: Entergy Gulf States, Inc. Application for Approval of Advanced Metering Pilot Program. Issues: pilot program for demand response programs and advanced metering systems.

31. Expert Testimony. Docket EO07040278 (2007). Before the New Jersey Board of Public Utilities. In the Matter of the Petition of Public Service Electric & Gas Company for Approval of a Solar Energy Program and An Associated Cost Recovery Mechanism. On the Behalf of the Department of the Public Advocate, Division of Rate Counsel. Issues: renewable energy market development, solar energy development, SREC markets, rate impact analysis, cost recovery issues.

32. Expert Testimony: Docket Number 05-057-T01 (2007). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Direct,

Rebuttal, and Surrebuttal Testimony)

33. Expert Testimony (Non-sworn rulemaking testimony) Docket Number RR-2008, (2007). Before the Louisiana Tax Commission. In re: Commission Consideration of Amendment and/or Adoption of Tax Commission Real/Personal Property Rules and Regulations. Issues: Louisiana oil and natural gas production trends, appropriate cost measures for wells and subsurface property, economic lives and production decline curve trends.

34. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29213 & 29213-A, ex parte, (2007). Before the Louisiana Public Service Commission. In re: In re: Investigation to determine if it is appropriate for LPSC jurisdictional electric utilities to provide and install time-based meters and communication devices for each of their customers which enable such customers to participate in time-based pricing rate schedules and other demand response programs. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: demand response programs, advanced meter systems, cost recovery issues, energy efficiency issues, regulatory issues.

35. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte, (2007) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.

36. Expert Testimony, Case Number U-14893, (2006). Before the Michigan Public Service Commission. In the Matter of SEMCO Energy Gas Company for Authority to Redesign and Increase Its Rates for the Sale and Transportation of Natural Gas In its MPSC Division and for Other Relief. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).

37. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29380, ex parte, (2006). Before the Louisiana Public Service Commission. In re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayer impacts of new environmental regulations.

38. Expert Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.

39. Expert Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.

40. Expert Testimony: Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment

Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)

41. Legislative Testimony (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.

42. Expert Report: Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.

43. Expert Testimony: Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).

44. Expert Testimony: Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.

45. Expert Testimony: Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.

46. Expert Testimony (non-sworn, rulemaking): Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005

47. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

48. Public Testimony. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission on an Investigation for a Limited Industrial Retail Choice Plan.

49. Expert Testimony: Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.

50. Expert Report and Testimony: Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al*. (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th

Judicial District Court, Lafayette, Louisiana.

51. Expert Testimony: ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776;480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778;489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912;503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.

52. Expert Report and Recommendation: Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.

53. Expert Testimony: Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)

54. Expert Testimony: Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.

55. Expert Affidavit: Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.

56. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

57. Expert Report and Testimony: Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.

58. Expert Testimony: Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.

59. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.

60. Expert Testimony: Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.

61. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).

62. Expert Testimony: Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.

63. Expert Affidavit: Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.

64. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.

65. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.

66. Expert Testimony: Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.

67. Expert Testimony: Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.

68. Expert Testimony: Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

69. Expert Testimony: Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

70. Expert Testimony: Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.

71. Legislative Testimony. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.

72. Expert Testimony: Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.

73. Expert Testimony: Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

74. Expert Testimony: Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Referee, 1995-Current*, Energy Journal*
Contributing Editor, 2000-Current, *Oil, Gas and Energy Quarterly*
Referee, 2005, *Energy Policy*
Referee, 2004, *Southern Economic Journal*
Referee, 2002, *Resource & Energy Economics*
Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Southern Economic Association, Western Economic Association, International Association of Energy Economists (IAEE), and the National Association for Business Economics (NABE).

HONORS AND AWARDS

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation* (2004).

Baton Rouge Business Report, Selected as “Top 40 Under 40” (2003).

Omicron Delta Epsilon (1992-Current)

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

TEACHING EXPERIENCE

Principles of Microeconomic Theory
Principles of Macroeconomic Theory

Lecturer, Environmental Management and Permitting. Lecture in Natural Gas Industry, LNG and Markets.

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Lecturer, LSU Honors College, Senior Course on “Society and the Coast.”

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

“The Gulf Coast Energy Situation: Outlook for Production and Consumption.” Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

“The Impact of Hurricane Katrina on Louisiana’s Energy Infrastructure and National Energy Markets.” Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

“Forecasting for Regulators: Current Issues and Trends in the Use of Forecasts, Statistical, and Empirical Analyses in Energy Regulation.” Instructional Course for State Regulatory Commission Staff. Institute of Public Utilities, Kellogg Center, Michigan State University. July 8-9, 2010.

“Regulatory and Ratemaking Issues with Cost and Revenue Trackers.” Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 29, 2010.

“Demand Modeling and Forecasting for Regulators.” Michigan State University, Institute of Public Utilities. Advanced Regulatory Studies Program. September 30, 2010.

THESIS/DISSERTATIONS COMMITTEES

5 Thesis Committee Memberships (Environmental Studies, Geography)
3 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics).
1 Doctoral Examination Committee Membership (Information Systems & Decision Sciences)
1 Senior Honors Thesis (Journalism, Loyola University)

LSU SERVICE AND COMMITTEE MEMBERSHIPS

Co-Director/Steering Committee Member, LSU Coastal Marine Institute (2009-Current).

CES Promotion Committee, Division of Radiation Safety (2006).

Search Committee Chair (2006), Research Associate 4 Position.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Member (2005), CES Communications Manager.

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-Current)

LSU Faculty Senate (2003-2006)

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU CES/SCE Public Art Selection Committee (2003-2005).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

LSU InterCollege Environmental Cooperative. (1999-2001).

LSU Faculty Senate Committee on Public Relations (1997-1999).

LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).

PROFESSIONAL SERVICE

Advisor (2008). National Association of Regulatory Utility Commissioners ("NARUC"). Study Committee on the Impact of Executive Drilling Moratoria on Federal Lands.

Steering Committee Member, Louisiana Representative (2008-Current). Southeast Agriculture & Forestry Energy Resources Alliance. Southern Policies Growth Board.

Advisor (2007-Current). National Association of State Utility Consumer Advocates ("NASUCA"), Natural Gas Committee.

Program Committee Chairman (2007-2008). U.S. Association of Energy Economics ("USAEE") Annual Conference, New Orleans, LA

Finance Committee Chairman (2007-2008). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), International Association for Energy Economics ("IAEE") Nominating Committee.

Founding President (2005-2007) Louisiana Chapter, USAEE.

Secretary (2001) Houston Chapter, USAEE.

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

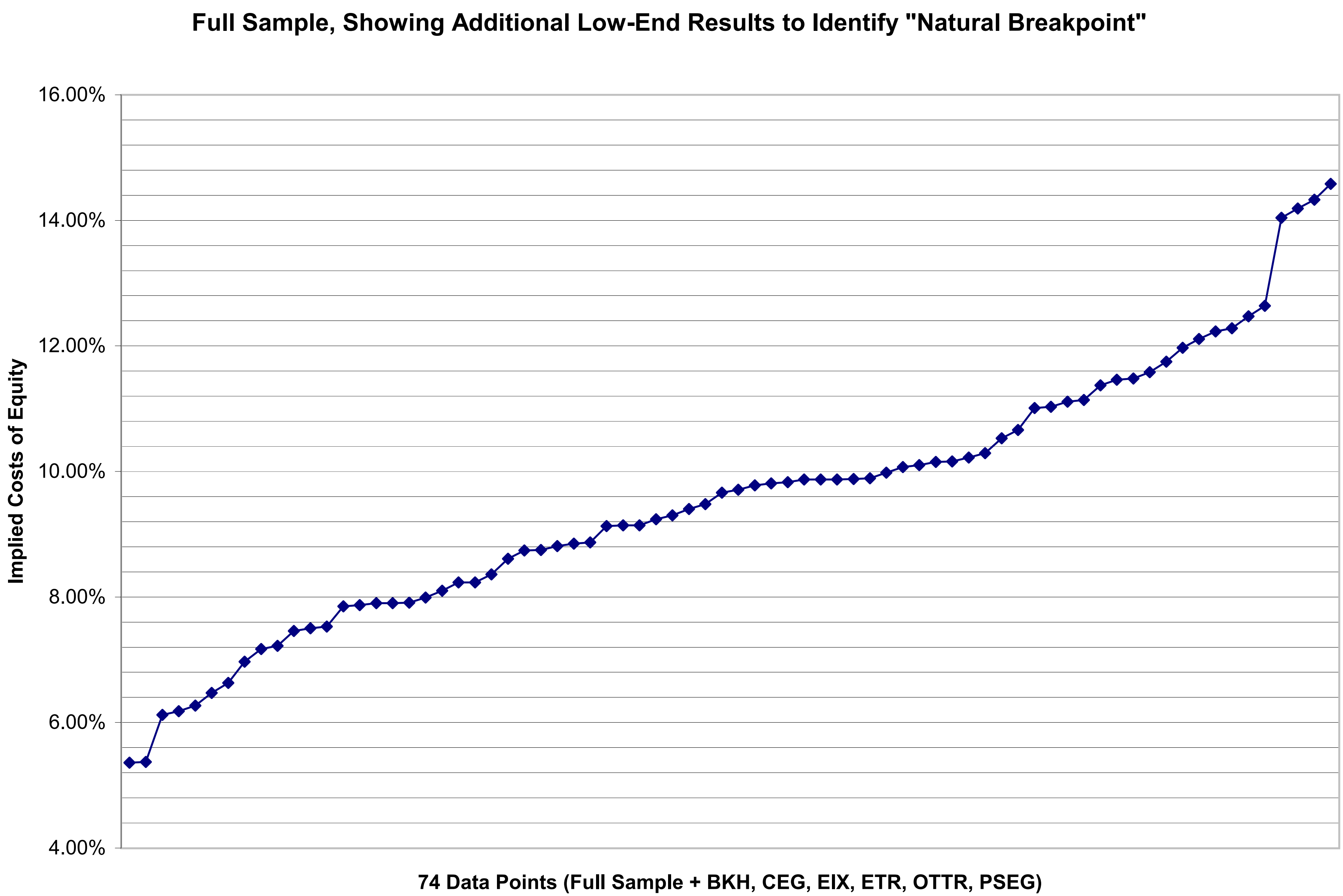
Attachment 2

Consumer Advocates Attachment 2

Table 2
Full Sample: Summary Results

Company	Entire "Full Sample" High	Entire "Full Sample" Low	AWC Array High	AWC Array Low	Adjusted Array High	Adjusted Array Low
AEP Co. Inc.	10.10%	8.81%	10.10%	8.81%	10.10%	8.81%
CMS Energy Corp.	11.46%	9.87%	11.46%	9.87%		
Cleo Corp.	10.16%	7.50%	10.16%	7.50%	10.16%	7.50%
DPL Inc.	20.00%	19.64%				
DTE Energy Co.	9.87%	8.75%	9.87%	8.75%		
Empire Dist. Elec. Co.	7.91%	7.53%	7.91%	7.53%	7.91%	7.53%
Entergy Corp.	10.53%	*6.47%*			10.53%	6.47%
Great Plains Energy Inc.	14.58%	6.97%	14.58%	6.97%	14.58%	6.97%
MGE Energy Inc.	9.24%	8.61%	9.24%	8.61%	9.24%	8.61%
OGE Energy Corp,.	12.11%	9.13%	12.11%	9.13%	12.11%	9.13%
Otter Tail Corp.	11.37%	*5.37%*				
Ameren Corp.	8.57%	*2.28%*				
Alliant Energy Corp.	14.19%	9.48%	14.19%	9.48%	14.19%	9.48%
Integrys Energy Group Inc.	14.33%	7.22%	14.33%	7.22%	14.33%	7.22%
Westar Energy Inc.	14.04%	8.10%	14.04%	8.10%	14.04%	8.10%
Wisconsin Energy Corp.	12.23%	9.83%	12.23%	9.83%	12.23%	9.83%
Vectren Corp.	11.97%	8.36%	11.97%	8.36%	11.97%	8.36%
Centerpoint Energy Inc.	12.47%	11.75%	12.47%	11.75%		
Allete Inc.	10.22%	8.87%	10.22%	8.87%	10.22%	8.87%
ITC Holdings Corp.	17.38%	12.23%				
Constellation	7.17%	*6.18%*			7.17%	6.18%
Progress Energy Inc.	9.98%	7.90%	9.98%	7.90%	9.98%	7.90%
CH Energy Group Inc.	7.85%	7.46%	7.85%	7.46%	7.85%	7.46%
Consolidated Edison Inc.	9.89%	8.23%	9.89%	8.23%	9.89%	8.23%
Dominion Resources Inc.	11.11%	9.30%	11.11%	9.30%	11.11%	9.30%
NextEra Energy Inc.	11.48%	9.78%	11.48%	9.78%	11.48%	9.78%
Exelon corp.	12.13%	*3.18%*				
PSEG	12.64%	*5.36%*				
SCANA Corp.	10.29%	9.71%	10.29%	9.71%	10.29%	9.71%
Southern Co.	10.66%	10.15%	10.66%	10.15%	10.66%	10.15%
TECO Energy Inc.	11.58%	9.87%	11.58%	9.87%	11.58%	9.87%
Duke Energy Corp.	9.88%	7.90%	9.88%	7.90%	9.88%	7.90%
Black Hills Corp.	*6.63%*	*6.12%*			6.63%	6.12%
Edison International	9.40%	*6.27%*			9.40%	6.27%
Sempra Energy	9.81%	8.74%	9.81%	8.74%	9.81%	8.74%
IDACORP Inc.	9.14%	7.87%	9.14%	7.87%	9.14%	7.87%
Excel Energy Inc.	11.03%	9.14%	11.03%	9.14%	11.03%	9.14%
PG&E Corp.	11.14%	10.07%	11.14%	10.07%	11.14%	10.07%
Pinnacle West Capital Corp	12.28%	8.85%	12.28%	8.85%	12.28%	8.85%
Avista Corp.	9.66%	7.99%	9.66%	7.99%	9.66%	7.99%
Portland General Electric Co.	11.01%	8.23%	11.01%	8.23%	11.01%	8.23%
Range	14.58%	6.97%	14.58%	6.97%	14.58%	6.12%
Median		**9.75%**	**9.82%**	**9.82%**	**9.44%**	**9.44%**
Midpoint		10.78%	10.78%	10.78%	10.35%	10.35%
Mean		9.79%	9.90%	9.90%	9.50%	9.50%
Number of Cos Kept in Array		41	41 31	31		32

Attachment 3



Full Sample, Showing Additional Low-End Results to Identify "Natural Breakpoint"
16.00%
14.00%
12.00%
10.00%
8.00%
6.00%
4.00%
Implied Costs of Equity
74 Data Points (Full Sample + BKH, CEG, EIX, ETR, OTTR, PSEG)

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated on this 31st day of January, 2011.

/s/ Scott H. Strauss
Scott H. Strauss

Law Offices of:
Spiegel & McDiarmid LLP
1333 New Hampshire Avenue, NW
Washington, DC 20036
(202) 879-4000