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Clerk's Office
N.C Utilities Commission

February 10, 2016

To: Chief Clerk Gail Mount
The North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, NC 27699-4325

From: North Carolina Sustainable Energy Association
4800 Six Forks Road, Suite 300
Raleigh, NC 27628

Re: Duke Energy Progress, LLC's Application for Certificate of Public Convenience and Need **(Commission Docket No. E-2, Sub 1089)**

Honorable Clerk and Commissioners:

I serve as counsel for the North Carolina Sustainable Energy Association ("NCSEA"). NCSEA has executed a non-disclosure agreement with Duke Energy Progress, LLC ("DEP"), pursuant to which NCSEA was granted access to information designated by DEP as confidential. NCSEA's comments in this proceeding contain information designated by DEP as confidential. NCSEA has filed a public, redacted version of its comments; the public version of NCSEA's comments contains redactions on pages 11, 12, and 13.

Attached hereto are unredacted copies of pages 11, 12, and 13. **NCSEA asks that these unredacted copies be treated as non-public confidential information.**

Sincerely,

Michael D. Youth
Counsel

CERTIFICATE OF SERVICE

I hereby certify that Duke Energy Progress, LLC's attorneys and the Public Staff's attorneys have been served true and accurate copies of the foregoing letter and attached documents by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 10th day of February, 2016.

Michael D. Youth
Counsel for NCSEA
N.C. State Bar No.29533
4800 Six Forks Road, Suite 300
Raleigh, NC 27609
919-832-7601
michael@energync.org

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1089

In the Matter of: Application of Duke Energy Progress, LLC for a Certificate of Public Convenience and Necessity to Construct a 752 Megawatt Natural Gas-Fueled Electric Generation Facility in Buncombe County Near the City of Asheville	**NCSEA'S COMMENTS [PUBLIC VERSION]**

NCSEA'S COMMENTS

Having intervened in this proceeding, the North Carolina Sustainable Energy Association ("NCSEA") submits these comments so that they may be considered by the North Carolina Utilities Commission ("Commission") as it reviews the *Application for Certificate of Public Convenience and Necessity and Motion for Partial Waiver of Commission Rule R8-61* ("CPCN Application" or "Application") filed by Duke Energy Progress, LLC ("DEP") on 15 January 2016. NCSEA's comments are limited to DEP's request for a certificate of public convenience and necessity ("CPCN") for a natural gas-fueled 186 MW simple cycle combustion turbine unit ("186 MW CT") to be constructed at the site of the Asheville Steam Electric Generating Plant located in Buncombe County.[1]

[1] DEP's CPCN Application also requests certification for two 280 MW combined cycle natural gas-fueled electric generating units, together with related upgrades to transmission equipment. While NCSEA's comments do not address the need or lack thereof for the two 280 MW combined cycle units, the Commission should evaluate the need for these two units in light of information presented to the Commission by intervenors like Columbia Energy, LLC, MountainTrue, Sierra Club, and Brad Rouse.

OVERVIEW

The Commission should not grant DEP a CPCN for the 186 MW CT because the record fails to establish anything more than an unripe "contingent" or conditional need for the 186 MW CT at this time. DEP admits that the need for the 186 MW CT is currently "contingent" or conditional. For example, the CPCN Application describes the 186 MW CT as

> a *contingent* natural gas-fueled 186 MW (expected winter rating) simple cycle combustion turbine unit, with fuel oil back up, *whose need may be avoided or delayed* due to the utilization of other technologies and programs to meet the future peak demand requirements of DEP customers in the region[.]

CPCN Application at p. 3 (emphasis added).

When the unripe, "contingent" or conditional need for the 186 MW CT is coupled with

- DEP's admission that "[t]he landscape of the electric utility business is rapidly changing thanks to the emergence of new technologies that are quickly enabling alternatives to traditional generation resources[,]" *id.* at p. 13;
- DEP's indication that it has several years during which it can evaluate the rapidly changing landscape before committing, if need be, to a 186 MW CT;[2]
- DEP's express "goal of delaying or eliminating the need for the contingent Asheville CT unit in 2023[,]" *id.* at 13; and, finally,

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[2] The Application indicates that it would take 2-3 years to move a 186 MW CT through permitting and development to commercial operation, meaning DEP could seek a CPCN for the 186 MW CT, if need be, in 2020 and still have it placed in service by 2023. CPCN Application, Exhibit 4 (Partially Confidential) at p. 8 of 10 (¶4.2.1) (indicating that "[t]he construction schedule from start of earthwork to commercial operation is expected to be approximately 24 months"). DEP has also indicated that it plans to file "annual updates" – plural – "on the progress of the community efforts to reduce their peak load growth[.]" *Id.* at p. 13 (¶24). This strongly implies DEP does not have an immediate need for a CPCN for the 186 MW CT and has several years within which to evaluate the landscape.

- DEP's express commitment to "work aggressively to transition to a cleaner and smarter energy future through community engagement, deliberate investment in distributed energy resources ('DER'), and greater promotion of and access to DSM/EE programs in the DEP-Western Region which may delay or eliminate the need for the contingent Asheville CT unit[,]" *id.* at p. 11,

it seems clear that the public convenience and necessity does *not* require issuance of a CPCN for the 186 MW CT at this time and that the Commission, exercising its best judgment, should accordingly decline to issue a CPCN for the 186 MW CT. In so ruling, the Commission should make clear that DEP is free to re-initiate the certificating process for a 186 MW CT in the future if a public need for a CT ripens.

LEGAL BACKGROUND AND STANDARD OF REVIEW

N.C. Sess. Law 2015-110, § 1 provides for an expedited decision on any CPCN application related to "a generating facility to be constructed at the site of the Asheville Steam Electric Generating Plant located in Buncombe County." While N.C. Sess. Law 2015-110 mandates an expedited decision, it does not alter the fundamental determination that the Commission must make when reviewing a CPCN application – namely, whether or not "public convenience and necessity requires, or will require" the "construction of any … facility for the generation of electricity to be directly or indirectly used for the furnishing of public utility service, even though the facility be for furnishing the service already being rendered[.]" N.C. Gen. Stat. § 62-110.1(a); *see Order Granting Certificate of Public Convenience and Necessity Subject to Conditions*, Commission Docket No. E-2, Sub 960 (22 October 2009) (illustrating that the Commission conducts a traditional "public need review" even when operating within the purview of a legislatively-mandated expedited process).

The N.C. Court of Appeals has explained that the fundamental determination requirement

> was enacted in 1965 to help curb overexpansion of generating facilities beyond the needs of the service area. To this end, the General Assembly used the term "public convenience and necessity" to define the standard to be applied by the Utilities Commission to proposed facilities. In reviewing the Commission's application of the standard in other regulatory actions, the Court has held that public convenience and necessity is based on an "element of public need for the proposed service." ... *[I]t is clear that the purpose of requiring a certificate of public convenience and necessity before a generating facility can be built is to prevent costly overbuilding.*

In State ex rel. Utilities Com. v. High Rock Lake Asso., 37 N.C. App. 138, 140, 245 S.E.2d 787, ___ (1978), *cert. denied*, __ N.C. __, 248 S.E.2d 257 (1978) (emphasis added). More recently, the Commission itself has commented on the fundamental determination:

> G.S. 62-110.1 is intended to provide for the orderly expansion of electric generating capacity in order to create a reliable and economical power supply and to avoid the costly overbuilding of generation resources. *State ex rel. Utilities Comm. v. Empire Power Co.*, 112 NCApp 265, 278 (1993), *disc. rev. denied*, 335 NC 564 (1994); *State ex rel. Utilities Comm. v. High Rock Lake Ass'n*, 37 NCApp 138, 141, *disc. rev. denied*, 295 NC 646 (1978). A public need for a proposed generating facility must be established before a certificate is issued. *Empire*, 112 NCApp at 279-80; *High Rock Lake*, 37 NCApp at 140. Beyond need, the Commission must also determine if the public convenience and necessity are best served by the generation option being proposed. The standard of public convenience and necessity is relative or elastic, rather than abstract or absolute, and the facts of each case must be considered. *State ex rel. Utilities Comm. v. Casey*, 245 NC 297, 302 (1957).

Order Granting Certificate of Public Convenience and Necessity with Conditions, p. 10, Commission Docket No. E-7, Sub 790 (21 March 2007).

Because the concept of public need is relative or elastic, the Commission relies on its best judgment in determining whether the public convenience and necessity requires construction of a facility. In arriving at its best judgment, the Commission usually evaluates two key questions whenever an incumbent utility[3] proposes a facility: First, the Commission examines whether the CPCN applicant's most recent integrated resource plan indicates a need for the proposed generating capacity; and, second, if a capacity need is established, the Commission examines whether the CPCN applicant's proposal for meeting the need constitutes the most convenient or balanced approach for achieving the State's various policy priorities set out in N.C. Gen. Stat. § 62-2. *See Order Granting Certificate of Public Convenience and Necessity with Conditions*, p. 32, Commission Docket No. E-7, Sub 790 (21 March 2007).

FACTUAL BACKGROUND

DEP's Western Carolinas Modernization Project

As part of its Western Carolinas Modernization Project ("WCMP"), DEP seeks a certificate – in its CPCN Application – to construct two 280 MW combined cycle natural gas-fueled electric generating units, together with related upgrades to transmission equipment, for a total of 560 MW of replacement/additional generating capacity by 2019. DEP also seeks approval to construct the 186 MW CT by 2023.

In multiple public documents, DEP has described the 186 MW CT as a "contingent" unit that could be "delayed" or "eliminated"/"avoided." *See, e.g.,* CPCN Application at pp. 3, 11, 13; *Notice of Intent to File Application for CPCN for WCMP*, p. 1, Commission Docket No. E-2, Sub 1089 (16 December 2015); *see also, "Duke Energy Progress seeks approval to construct $1.1 billion Western Carolinas Modernization*

[3] The Commission's evaluation of the public need for a facility is different when the facility is proposed by an entity other than the incumbent utility (*e.g.*, the developer of a qualifying facility or a customer installing self-generation). *See, e.g.,* N.C. Gen. Stat. § 62-110.1(g).

Project to support region's energy future," Duke Energy press release (15 January 2016) (accessed on 20 January 2016 at http://news.duke-energy.com/releases/releases-20160115-3124885) (copy attached as **Exhibit A**).

Beyond DEP's repeated admissions of "contingent" need, the CPCN Application contains further indications that a public need for the 186 MW CT has not ripened at this time. Three specific examples follow. First, after referencing the need for the 560 MW of combined cycle generating capacity, DEP goes on to state, "[a]s load continues to grow in the region, the need for more generation, in lieu of new transmission imports, *may be required* to maintain system reliability." CPCN Application at p. 10 (emphasis added). Next, DEP states: "Based on the current load forecast, the new Asheville CC Generation (Two 1x1 Combined Cycle Units, 280 MW each) will provide sufficient capacity and energy to provide for reliable operations and compliance with NERC Reliability Standards BAL0-001, BAL-002, and TOP-004, through 2023 at which time additional generation *may be needed* in the CPLW BA Area." *Id.*, Revised Exhibit 1B/Attachment A (Partially Confidential) at p. 4 (emphasis added). Finally, DEP states: "*If the simple cycle unit is required by system need*, the option could be exercised or the turbine could be rebid." *Id.*, Revised Exhibit 4 (Partially Confidential) at p. 9 of 10 (¶4.2.3) (emphasis added) (indicating that the need has not ripened at present). These DEP statements concede that a need for the 186 MW CT has not ripened at this time.[4]

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[4] It is also worth noting that, prior to the filing of the CPCN Application, DEP indicated publicly, in November 2015, that the Asheville CT was an "option," not a necessity. "*Duke Energy responds to community concerns; creates new plan for Western Carolinas Modernization Project,*" Duke Energy press release (4 November 2015) (accessed on 20 January 2016 at http://www.duke-energy.com/news/releases/2015110402.asp) (copy attached as **Exhibit B**). In a second document made public in November 2015 – a DEP fact sheet for the WCMP – DEP does not even mention a contingent CT or a need for any

Furthermore, DEP acknowledges in the public portions of the Application that alternatives may obviate any need for a 186 MW CT: "The *contingent* Asheville Combustion Turbine unit would *potentially* begin commercial operation in 2023 *if the current peak demand growth is not sufficiently reduced by the alternative approach discussed herein.*" *Id.* at p. 4 (¶4) (emphasis added). DEP has indicated that the WCMP will include the installation of at least 5 MW of utility-scale electricity storage, stating that "[s]ubject to appropriate Commission approval, DEP is committed to investing in a minimum of 5 MW utility-scale storage pilot in the DEP-Western Region within the next 7 years consistent *with the goal of delaying or eliminating the need for the contingent Asheville CT unit in 2023.*" CPCN Application at p. 13 (¶23c) (emphasis added).[5]

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generation beyond the two combined cycle units. "*Western Carolinas Modernization Project,*" Duke Energy fact sheet (November 2015) (accessed on 20 January 2016 at http://www.duke-energy.com/pdfs/WCMP-FactSheet.pdf) (copy attached as **Exhibit C**).

[5] DEP has not asked in this proceeding for issuance of a CPCN (or for any other Commission approval) to install utility-scale batteries as part of the WCMP; it has instead asked for approval to construct the very generating unit it aspires not to build at all. As such, the Western North Carolina communities engaging with DEP are justified in questioning DEP's aggressive commitment to the "goal of delaying or eliminating the need for the contingent Asheville CT unit in 2023." *See* CPCN Application at p. 13 (¶23c).

DEP's Most Recently Filed Integrated Resource Plan

As already mentioned, in reviewing a CPCN application, the Commission usually evaluates the need for the proposed generation by, among other things, looking at the CPCN applicant's most recent integrated resource plan ("IRP").[6]

In this case, the CPCN Application asserts that DEP's 2015 IRP shows a need for 733 MW of combined cycle generating capacity in Asheville. Specifically, the Application provides: "The Duke Energy Progress 2015 IRP Short Term Action Plan includes *a single 733 MW* (winter rating) Asheville combined cycle unit … ." *Id.* at p. 9 (¶17) (emphasis added). In actuality, DEP's 2015 IRP does not expressly use the 733 MW figure; instead, DEP's 2015 IRP indicates a need for 663 MW of additional capacity in Asheville. Thus, for example, DEP's 2015 IRP provides:

> As part of the Western Carolinas Modernization Project (WCMP) announced in the spring of 2015, the combined 376 MW Asheville 1 & 2 coal units are planned to be retired no later than January 31, 2020. The retired units are expected to be replaced with *a 663 MW natural gas combined cycle unit* on site in November 2019, along with necessary and associated natural gas delivery and electric transmission infrastructure projects.

CPCN Application, Exhibit 1A (Public Version) at p. 14 (emphasis added). The 663 MW figure appears to be a summer rating, *see id.* at p. 45 (DEP's base plan table clarifying that the 663 MW need in 2020 in Asheville is a summer rating), and it may reasonably convert to a 733 MW winter rating.

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[6] DEP's 2014 IRP is DEP's last Commission-approved IRP. However, DEP's 2014 IRP does not include the WCMP. While DEP's 2015 IRP has not been approved by the Commission, it was filed after enactment of N.C. Sess. Law 2015-110 and does include the WCMP. For purposes of these comments, NCSEA is treating DEP's 2015 IRP as DEP's most recent IRP even though it has not been approved by the Commission at this time.

Regardless, DEP's CPCN Application seeks authorization for 746 MW of winter-rated capacity (560 MW + 186 MW), which is in excess of the 733 MW winter-rated need DEP asserts it included in the 2015 IRP.[7] Thus, measured against its own IRP, DEP's CPCN Application – particularly the inclusion of the 186 MW CT – seeks to overbuild capacity.[8]

Alternatives to DEP's Proposed 186 MW CT

The CPCN Application acknowledges that "[t]he landscape of the electric utility business is rapidly changing thanks to the emergence of new technologies that are quickly enabling alternatives to traditional generation resources." CPCN Application at p. 13. The Application also acknowledges, at least implicitly, that DEP has several years during which it can evaluate the rapidly changing landscape before committing, if need be, to a 186 MW CT.[9]

Indeed, DEP prefers to see implementation of an alternative to construction of a 186 MW CT by 2023. DEP states that it has a "goal of delaying or eliminating the need

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[7] The generating units DEP seeks to have certificated have an aggregate summer-rated capacity of 673 MW (496 MW + 177 MW), which is similarly in excess of the 663 MW summer-rated need expressly included in the 2015 IRP. CPCN Application, Revised Exhibit 3 (Partially Confidential) at pp. 2 of 6, 5 of 6.

[8] While an overbuild of 13 winter-rated MW could be argued to be negligible, an overbuild is an overbuild and this particular overbuild should further be contextualized against the following background facts: (1) DEP's 2015 IRP increases its target summer reserve margin from 14.5% to 17%; and (2) DEP's 2015 IRP indicates that its actual summer reserve margin will exceed the upwardly revised 17% target summer reserve margin by "3% or more" in several of the key years at issue in this proceeding. CPCN Application, Exhibit 1A at pp. 11-13. In short, a 13 MW overbuild in a 17+% reserve margin scenario would be an even larger overbuild if the target reserve margin were to remain at 14.5% or some percentage lower than 17%.

[9] *See,* footnote 2 above for record citations supporting this assertion.

for the contingent Asheville CT unit in 2023." *Id.* at 13. Moreover, to realize this goal, DEP has committed to

> *work aggressively* to transition to a cleaner and smarter energy future through community engagement, deliberate investment in [DER], and greater promotion of and access to DSM/EE programs in the DEP-Western Region which may delay or eliminate the need for the contingent Asheville CT unit.

Id. at p. 11 (emphasis added). As to the aggressive work, DEP acknowledges that the currently unripe need for the 186 MW CT "could be delayed or eliminated based on the success of programs to reduce energy use in the region."[10] As Duke has put it:

> Through existing programs and innovative solutions to be developed, we can work together to help delay the need for additional generation[,]

and

> [w]e are eager to continue working with the community to reduce power demand across the region through energy efficiency, demand response and renewable energy and technology[[11]] to avoid building another power unit on the Asheville site for as long as possible.

"Western Carolinas Modernization," pp. 3 of 5, 4 of 5, Duke Energy FAQ (November 2015) (accessed on 20 January 2016 at http://www.duke-energy.com/western-carolinas-modernization/#C0R9) (copy attached as **Exhibit D**).

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[10] **Exhibit A** at p. 2 of 4; *see Notice of Intent to File Application for CPCN for WCMP*, Commission Docket No. E-2, Sub 1089 (16 December 2015) (DEP's advance notice contains a substantially identical admission).

[11] As an example of the referenced "technology" that could avoid a future need for the 186 MW CT, DEP has indicated that the WCMP will include the installation of at least 5 MW of utility-scale electricity storage "consistent *with the goal of delaying or eliminating the need for the contingent Asheville CT unit in 2023.*" CPCN Application at p. 13 (¶23c) (emphasis added).

a. The Economic Argument for Pursuing Alternatives

In considering the economic viability of alternatives, the Commission should consider some of the implications of DEP's confidential cost information. First, **[BEGIN CONFIDENTIAL]** [redacted]

[END CONFIDENTIAL] If DSM/EE, renewables, and batteries, in an appropriate combination, could be incented and installed by 2023 at a lower total cost than the CT (reduced to 2023$) and in such a way as to support system reliability at peak in 2023 and

[12] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

beyond, then the Commission should encourage DEP to aggressively explore these alternatives.

Next, DEP's CPCN Application provides hints that its avoided cost rates could well begin increasing in one of the next few biennial proceedings. Natural gas prices are the most significant driver of the avoided cost energy rates, comprising approximately 70% of the overall combined payments made to a solar qualifying facility ("QF"). *Transcript of Testimony (Heard 7-9-2014 in Raleigh) Volume 4*, p. 116, Commission Docket No. E-100, Sub 140 (30 July 2014) (Duke Energy employee Glen Snider's testimony). The best information currently available indicates that gas prices are unlikely to decline between now and 2023 and, instead, are likely to stay roughly the same or increase. *See, e.g., Motion to Compel by NC WARN and the Climate Times*, Attachment, pp. 9-11, Commission Docket No. E-2, Sub 1089 (25 January 2016) (as set out in DEP's data response to NC WARN's Data Request 1-15, the January 2016 NYMEX Henry Hub market indications are that natural gas prices will rise from $2.53/MMBtu in 2016 to $3.84/MMBtu in 2025). Similarly, combustion turbine prices are a significant driver of the avoided cost capacity rates, comprising the remaining roughly 30% of the overall combined payments made to a solar QF. *Transcript of Testimony (Heard 7-9-2014 in Raleigh) Volume 4*, p. 116, Commission Docket No. E-100, Sub 140 (30 July 2014). **[BEGIN CONFIDENTIAL]** [redacted]

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[13] **[BEGIN CONFIDENTIAL]** [redacted] **[END CONFIDENTIAL]**

[redacted] [END CONFIDENTIAL] The foregoing is important to consider because an increase in avoided cost rates (1) is likely to make more DSM/EE measures pass cost-effectiveness tests and (2) will make an increased variety of renewables projects and battery projects viable.

In short, given the [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] likelihood that DSM/EE, renewables, and batteries will become increasingly economically viable in the next six years, DEP's assertion that "[t]he landscape of the electric utility business is rapidly changing thanks to the emergence of new technologies that are quickly enabling alternatives to traditional generation resources" should be regarded by this Commission as more than mere lip service to the prospects of cost-effective clean energy in the coming years.

b. Examples of Alternatives Worth Discussing (or Continuing to Discuss)

Alternatives to the 186 MW CT exist. DEP's CPCN Application mentions fairly specific plans for installation of utility-scale solar and utility-scale batteries in Asheville. NCSEA generally supports these plans. But it seems clear that these efforts, standing alone, are insufficient to avoid or eliminate a future need for a CT.

The CPCN Application makes less specific reference to additional renewables-focused and DSM/EE-focused alternatives. *See, e.g.,* CPCN Application at p. 11. NCSEA supports aggressive work to design and implement such alternatives. NCSEA believes numerous alternatives are worth exploring. Several measures, however, should be considered for near-term adoption and implementation:

- *Default New Residential Accounts into Time-of-Use Rates.* If new load, including new residential load, is projected to contribute to a future winter peak that will create a need for a 186 MW CT by 2023, DEP and the community should consider whether new residential load in the area (or perhaps all new residential accounts in the area including future new accounts for currently existing residential load) should be "defaulted" into a residential time-of-use ("TOU") rate instead of into a residential flat rate. The Asheville area could serve as a pilot for this approach over the next several years. As the Commission has recognized:

  > TOU rates provide appropriate price signals to consumers and can result in changes of energy use patterns from higher cost on-peak periods to lower cost off-peak periods. … TOU rates, therefore, are beneficial in reducing peak load and encouraging reduced usage when it would be most valuable. Changes by consumers are likely to be greater … as they learn to adapt their behavior in response to the pricing structure, purchase timers or other equipment that will help them to shift energy usage, and purchase more efficient appliances. … Virtually every customer in North Carolina,

> including residential … customers, may elect to receive service under TOU rates.

Report of the North Carolina Utilities Commission to the Governor et al. Regarding An Analysis of Rate Structures, Policies, and Measures to Promote Renewable Energy Generation and Demand Reduction in North Carolina, p. 19, Commission Docket No. E-100, Sub 116 (1 September 2008). While DEP's residential customers *may elect* to receive service under TOU rates, the truth is that relatively few do; instead, most stick with the flat rate they are defaulted into when they open their accounts.[14] To date, utility efforts to enroll customers in TOU rates has not proven effective. Duke Energy Carolinas, LLC, for example, recently filed a report on its pilot TOU rates indicating that "enrollment efforts resulted in slightly below average overall acquisition rate of 0.76% of the customer accounts receiving invitations to enroll[.]" *Duke Energy Carolinas Pilot TOU Rates Report to the North Carolina Utilities Commission*, p. 3, Commission Docket No. E-7, Sub 1026 (18 December 2015). However, the report's silver lining appears to be that once customers had enrolled in a TOU rate, "over 80% of survey respondents stat[ed] they would participate in the future." *Id.* Given the peak-clipping potential of widespread TOU rate enrollment in the Asheville area, the apparent impediments to securing enrollment where the default is a flat rate, and customers' apparent satisfaction with TOU rates once they are enrolled, DEP and the community should be encouraged to explore a pilot that would default new residential accounts in the area into a TOU rate (with the option for

[14] NCSEA reviewed the low participation in DEP's TOU rates in a 2013 filing and argued that this was at least in part attributable to a lack of marketing. *Post-Hearing Brief*, pp. 12-18, Commission Docket No. E-2, Sub 1023 (29 April 2013).

customers to opt-out into a flat rate). As illustrated by the graph below, recent research suggests that making a residential TOU rate the default can significantly increase sustained customer participation, making the peak-clipping benefits of a TOU rate schedule much more likely to be realized:

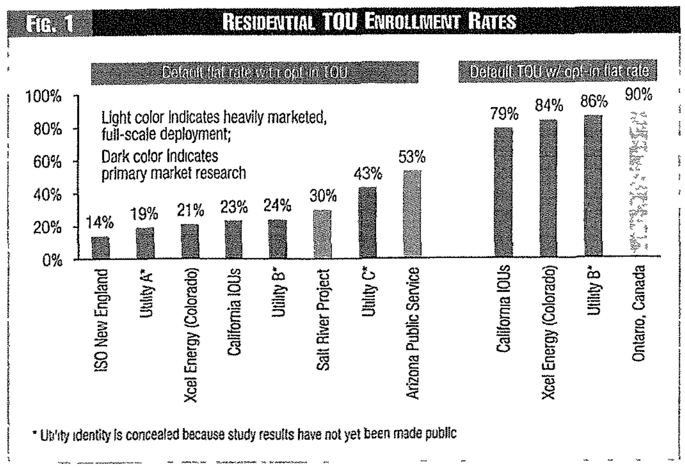

Exhibit E (a copy of an August 2014 *Public Utilities Fortnightly* article, "Smart by Default," from which this graph was excerpted).

- *Default New Residential Accounts into Use of Smart Meters (With Data Access).* If new residential customers in the Asheville area are defaulted into a TOU rate, they should also be defaulted into use of a smart meter (with the option to opt-out). As Duke Energy Carolinas, LLC indicated in its recent report on pilot TOU rates, customers participating in the pilot TOU rates stated they "would like enhanced information and feedback on their performance." *Duke Energy Carolinas Pilot TOU Rates Report to the North Carolina Utilities Commission*, p. 3, Commission Docket No. E-7, Sub 1026 (18 December 2015). The presence of a smart meter is a condition precedent to providing customers with enhanced, granular usage data that enables the customers to more fully understand the cost/savings implications of reducing consumption or shifting consumption from peak to off-peak.[15]

[15] The Public Staff recently recognized that advanced metering infrastructure ("AMI") "or 'smart' meters, offer a number of benefits to consumers, including better information on their energy consumption, potentially helping them to reduce energy consumption and save money." *Public Staff Reply Comments*, p. 2, Docket No. E-100, Sub 141 (January 25, 2016). The Public Staff's statement is accurate but it is worth clarifying that, while smart meters offer the *potential* to help consumers use better information to reduce energy consumption and save money, the potential will not be realized if the Commission does not *enable the potential* by modernizing its rules regarding consumer access to data. In 2013, Duke Energy wrote that "the Companies would not object to a separate rulemaking proceeding to explore customer data access if the Commission deems it advisable." *Duke Energy Carolinas and Progress Energy Carolinas' Reply Comments*, p. 12, Docket No. E-100, Sub 137 (March 5, 2013). However, at that time, the Commission believed that there was not a significant enough saturation of smart meters to necessitate a rulemaking. *Order Requesting Additional Information and Declining to Initiate Rulemaking*, p. 11, Commission Docket No. E-100, Sub 137 (23 August 2013). Circumstances have changed. Since 2013, the utilities have significantly increased the deployment of smart meters. For example, the Public Staff recently noted that "DEC indicated that it has deployed AMI meters to approximately 19 percent of its customer base, a relatively high level of saturation … ." *Public Staff Reply Comments*, p. 3, Docket No. E-100, Sub 141 (January 25, 2016). NCSEA holds firm to the belief that smart meter saturation has reached a level, since the Commission's 2013 ruling, that changed circumstances exist; and that the changed circumstances necessitate reexamination of how best to enable consumer access to data. Increasing Asheville area residents' access to their usage and cost data – particularly the more granular data that smart meters can provide – will enable the community to better make use of TOU rates and smart meter technology and, ultimately, better enable them to reduce peak consumption in coming years.

- *Create a Smart Thermostat Demand Response Program.* DEP and the Asheville area community should explore creation of a program that would enable DEP to call on residential customers' smart appliances to help shave peak during times of critical need. Specifically, DEP and the community should explore a program that would subsidize customer installation of smart thermostats in exchange for (1) enrolling in a TOU rate (if not already enrolled) and (2) authorizing DEP to call on these thermostats – for example, to reduce the temperature setting by several degrees – during extreme winter peaks.[16] Alternatively, if DEP opts not to pursue such a program, it should at least develop the capability to provide its customers with electronic advance notice of impending peaks so that these customers (or their authorized agents) can use the electronic advance notice to drive non-utility community demand response initiatives using smart appliances.[17] As the Commission has recently stated:

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[16] While DEP has proposed the inclusion of smart thermostats in one of its energy efficiency programs, DEP has not yet proposed utilizing smart thermostats for demand-response. *See, DEP's Proposed Modifications to Home Energy Improvement Program*, Commission Docket No. E-2, Sub 936 (2 October 2015).

[17] In the last several years, NCSEA has encouraged the utilities to provide residential customers with advance notice of impending peaks. *See, e.g., Comments of NCSEA and EDF (Public),* pp. 15-16 n. 44, Commission Docket No. E-100, Sub 141 (9 January 2015); *Letter in Lieu of a Post-Hearing Brief*, pp. 7-10, Commission Docket No. E-2, Sub 1030 (17 October 2013); *Amended Post-Hearing Brief*, pp. 13-15, Commission Docket No. E-7, Sub 1031 (22 July 2013). During the 2015 Polar Vortex II, Duke Energy "asked for voluntary conservation ... [and found that,] while it's certainly hard to measure that exactly, we're very convinced that that was helpful across this peak, even though we can't measure it explicitly." *Staff Conference Transcript for March 2, 2015*, p. 16, Commission Docket No. M-1, Sub 7 (16 March 2015). NCSEA understands that advance notice to residential customers can have counterintuitive behavioral effects – for example, in the face of an impending winter peak, some customers may actually increase the ambient temperature in their homes in anticipation of a power outage. NCSEA also understands, though, that (1) in the aggregate, alerted customers have reduced load across a peak and (2) automating the process so that the customers' smart appliances can receive

> It may be that deployment of smart grid technology (SGT) will increase the opportunities for electric public utilities to provide advance notice of impending peak usage to their customers and to measure the response of individual customers to the notice. The Commission is interested in exploring that possibility.

Order Approving DSM/EE Rider and Requiring Filing of Proposed Customer Notice, p. 23, Commission Docket No. E-7, Sub 1031 (29 October 2013).

- *Utilize the Generation Component of Topping-Cycle Combined Heat and Power Systems to Support the Asheville Area Grid During Critical Peaks.* If new load, including new commercial/industrial load, is projected to contribute to a future winter peak that will ripen a need for a 186 MW CT by 2023, DEP and the Asheville area community should consider whether opportunities exist for new commercial/industrial customers to use combined heat and power ("CHP") systems to delay or eliminate the need for a 186 MW CT. If the Commission issues an order confirming that topping-cycle CHP constitutes an energy efficiency measure eligible for inclusion in a utility incentive program,[18] any incentive could be conditioned on the customer curtailing electric consumption during times of critical grid need, thereby making the electric generating unit, *e.g.*, a 15 MW natural gas-fueled CT, available to meet the Asheville area system needs during extreme winter peaks. Alternatively, if DEP seeks to rate-base topping-cycle CHP,[19] it similarly could explore situating the CHP in the

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the advance notice or alert can mitigate the counterintuitive behavioral effects and contribute to further net peak clipping within the community.

[18] *See, NCSEA's Requests for Declaratory Ruling and, if Appropriate, a Rulemaking*, Commission Docket No. E-100, Sub 113 (1 June 2015).

[19] DEP's 2015 IRP contains the following statement: "CHP incorporating a CT and heat recovery steam generator (HRSG) is more efficient than the conventional method of

Asheville area and structuring its contracts such that the electric generating component could be called on to meet Asheville area system need during extreme winter peaks.

- *Small-Scale Solar and Battery Incentive Programs.* Beyond utility-scale solar and utility-scale batteries, DEP and the community should explore the design and implementation of programs to encourage installation of small-scale solar and batteries, including programs designed to encourage increased use of these technologies in low income communities and communities of color. Such programs should incorporate use of appropriate incentives.

NCSEA believes the foregoing examples of alternatives illustrate that DEP's and the community's aggressive work to delay or eliminate a future need for a 186 MW CT holds great promise and could in fact serve as a model for the rest of the State.

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producing usable heat and power separately via a gas package boiler. Duke Energy is exploring and working with potential customers with good base thermal loads on a regulated Combined Heat and Power offer. The CHP asset will be included as part of Duke Energy's IRP as a placeholder for future projects as described below. The steam sales are credited back to the revenue requirement of the projects to reduce the total cost of this generation grid resource. Along with the potential to be a competitive cost generation resource, CHP can result in CO2 emission reductions, and present economic development opportunities for the state. Projections for CHP have been included in the following quantities in the 2015 IRP: 2019: 20 MW[;] 2021: 20 MW[.]" CPCN Application, Exhibit 1A at p. 11.

ARGUMENT

THE COMMISSION SHOULD NOT ISSUE A CPCN FOR A 186 MW CT BECAUSE THE PUBLIC CONVENIENCE AND NECESSITY DOES NOT REQUIRE A 186 MW CT AT THIS TIME.

As already mentioned above, the fundamental determination that the Commission must make in this proceeding is whether or not public convenience and necessity requires or will require the construction of the 186 MW CT. *See* N.C. Gen. Stat. § 62-110.1(a). In this case, as established by the record facts set out above, the public need for a 186 MW CT has not ripened such that the Commission can conclude, at this time, that the CT is required or will be required. Furthermore, based on the need set out in DEP's 2015 IRP, issuance of a CPCN for the CT will result in authorization of an overbuild of capacity. Finally, given the alternatives that exist (or will soon exist as a result of rapid technological advancements and DEP's aggressive work) and the availability of several years for evaluating these alternatives, the Commission should decline to issue a CPCN for the 186 MW CT at this time; instead, the Commission should encourage DEP to continue to aggressively pursue its goal of delaying or eliminating any need for the CT but make clear that, if DEP cannot achieve this goal, DEP may re-file to certificate the CT if a public need for the CT ripens.

NCSEA anticipates that DEP will make several counter-arguments and therefore NCSEA endeavors here to preemptively reply to three possible counter-arguments. First, DEP may argue that N.C. Sess. Law 2015-110 effectively mandates that a public need exists for double the capacity of the 379 winter-rated MW coal-fired units being retired in Asheville; in other words, DEP may argue that the Session Law mandates a public need for 758 winter-rated MW of natural gas-fueled generating units in Asheville. Any such argument would be based on a misreading of the session law. The session law does provide that a "new natural gas-fired generating facility … [having] no more than twice the generation capacity as the coal-fired generating units to be retired" is eligible for expedited Commission review, but this is as far as the session law goes; nowhere does the session law dictate that a public need actually exists for 758 winter-rated MW of capacity and nowhere does it direct the Commission *not* to conduct a "public need review" under N.C. Gen. Stat. § 62-110.1(a). *See, Order Granting Certificate of Public Convenience and Necessity Subject to Conditions*, Commission Docket No. E-2, Sub 960 (22 October 2009) (illustrating that the Commission conducts a traditional "public need review" even when operating within the purview of a legislatively-mandated expedited process).

Next, DEP may make two related but distinct arguments about the burden of proof. The first of these two related arguments is a general argument about burden of proof in proceedings like this. DEP may argue (and it could reasonably be inferred from DEP's requested relief that it already has argued) that it need not present evidence of a ripened public need for a facility to secure a CPCN. Specifically, DEP may argue that N.C. Gen. Stat. § 62-110.1(e1)[20] authorizes the Commission (1) to issue a CPCN where a public need is "contingent" or conditional (*i.e.*, unripe) and then (2) to monitor the public need and, where appropriate, revoke or modify the CPCN to ensure an unneeded facility is not built. Any such argument invites a turning of the certificating process on its head

[20] The statutory subsection provides: "Upon the request of the public utility or upon its own motion, the Commission may review the certificate to determine whether changes in the probable future growth of the use of electricity indicate that the public convenience and necessity require modification or revocation of the certificate. If the Commission finds that completion of the generating facility is no longer in the public interest, the Commission may modify or revoke the certificate."

and places an additional ongoing policing responsibility on the Commission. To prevent costly overbuilding, NCSEA believes the Commission should issue CPCNs to incumbent utilities only where a ripe (*i.e.*, non-contingent, non-conditional) public need has been adequately evidenced. Indeed, NCSEA believes the Commission has already recognized that N.C. Gen. Stat. § 62-110.1(a) requires this.[21] In short, to secure a CPCN, the applicant should bear the burden of proving that, based on the best information currently available, a ripe, non-contingent need for the proposed facility exists; put another way, the Commission should *not* issue a CPCN where the applicant essentially says, "Based on the best information currently available, maybe we'll need the facility, maybe we won't – issue us a CPCN and we'll let you know."[22]

Finally, DEP may make a similar burden of proof argument that hangs on the specific facts of this case. Though NCSEA believes the record, including DEP's admissions, would belie such an argument, DEP nonetheless might rely on this Commission's 2007 order issuing a CPCN for the 800 MW Cliffside unit to assert that DEP has made a sufficient showing of need for the 186 MW CT because, just as in the Cliffside case, DEP "cannot rely upon DSM and renewables to eliminate or delay its need

---

[21] In 2007, the Commission refused to issue a CPCN to Duke Energy Carolinas, LLC ("DEC") to build *two* 800 MW coal-fired units, holding in essence that DEC had presented evidence of a mere contingent need for the second 800 MW unit – based on unreasonable speculation that four cooperatives would sign wholesale contracts – instead of evidence of a ripe need. *See Order Granting Certificate of Public Convenience and Necessity with Conditions*, p. 15, Commission Docket No. E-7, Sub 790 (21 March 2007).

[22] NCSEA believes the better approach is to view N.C. Gen. Stat. § 62-110.1(e1) as the legislature's acknowledgment that even the best information evidencing a ripe need for a facility at the time a CPCN was issued can turn out, in hindsight, to have been imperfect and that where this is the case the Commission shall have authority to act in the public's best interest.

for [this] generating capacity … ." *Order Granting Certificate of Public Convenience and Necessity with Conditions* ("Cliffside Order"), p. 8, Commission Docket No. E-7, Sub 790 (21 March 2007). Any such argument would be based on a cursory and imprecise reading of the order. A precise reading of the Cliffside Order reveals that timing was a crucial factor in the Commission's decision to rule as it did. The Commission held that "Duke cannot rely upon either DSM measures or additional renewable generation *in the short term* to eliminate or delay construction of additional supply-side resources[,]" *id.* at 23 (emphasis added); the Commission held it could not

> conclude that cost effective DSM programs can eliminate or delay the need for new generation facilities *in [four years]. The main benefits of Duke's DSM efforts will be realized in the years beyond that time.* Similarly, the Commission cannot conclude that there are sufficient renewable resources to eliminate the need for construction of a more conventional generating plant *[in four years].*

Id. at p. 33 (emphasis added). Timing makes the present case distinguishable. DSM/EE and renewables could not have avoided the short-term need four years out for the 800 MW unit certificated by the Commission in the Cliffside Order; in this case, however, by DEP's own admission, DSM/EE, renewables, and batteries could well avoid the mid-term need seven years out for a CT in 2023 (and, in this case, there are in fact several years in which to develop these resources such that they can actually avoid a need for a CT).

CONCLUSION

The public convenience and necessity does *not* require issuance of a CPCN for the 186 MW CT. For this reason, NCSEA believes the Commission, exercising its best judgment, should decline to issue a CPCN for the 186 MW CT. In so ruling, the Commission should encourage DEP and the Asheville area community to work aggressively to develop and implement alternatives to the 186 MW CT and yet make clear that DEP is free to re-initiate the certificating process for a 186 MW CT in the future if, despite aggressive work, a public need for a CT ripens.

Respectfully submitted,

Michael D. Youth
Counsel for NCSEA
N.C. State Bar No. 29533
4800 Six Forks Rd., Suite 300
Raleigh, NC 27609

CERTIFICATE OF SERVICE

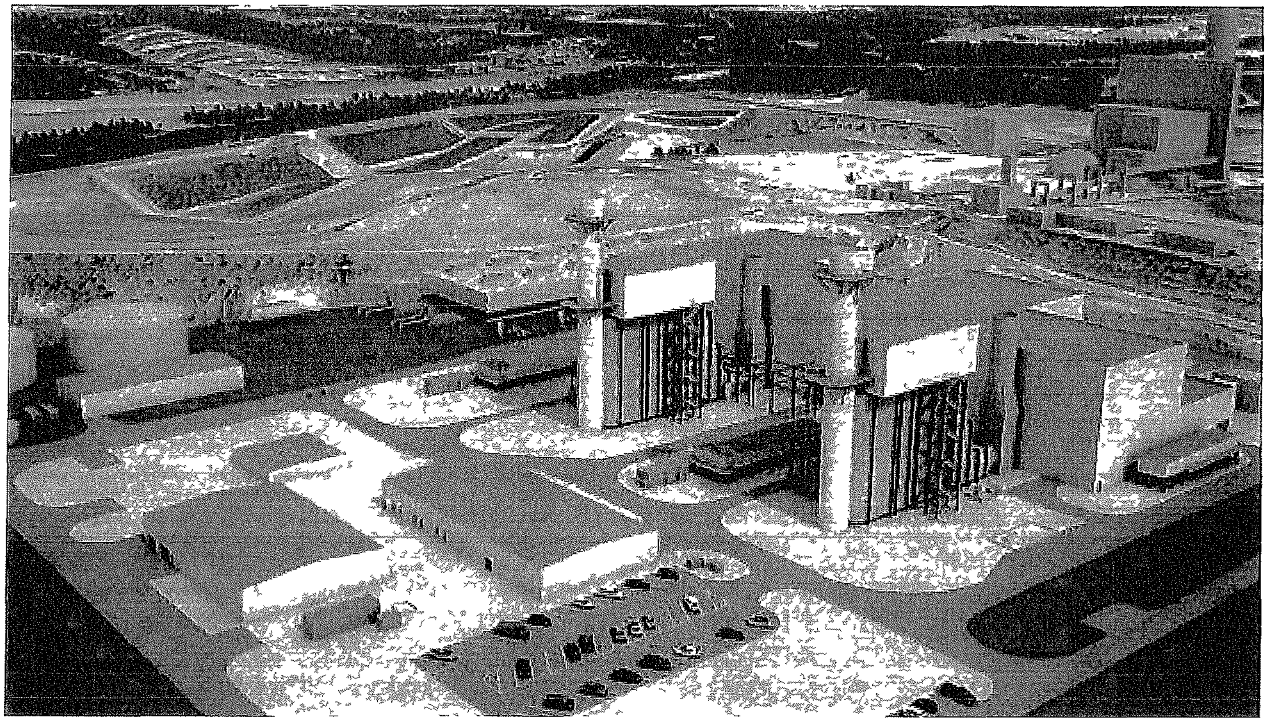
I hereby certify that all persons on the docket service list have been served true and accurate copies of the foregoing filing, together with any exhibits attached thereto, by hand delivery, first class mail deposited in the U.S. mail, postage pre-paid, or by email transmission with the party's consent.

This the 10th day of February, 2016.

Michael D. Youth
Counsel for NCSEA
N.C. State Bar No. 29533
4800 Six Forks Rd., Suite 300
Raleigh, NC 27609
(919) 832-7601 Ext. 118
michael@energync.org

NCSEA
EXHIBIT A

DUKE ENERGY



Duke Energy Progress seeks approval to construct $1.1 billion Western Carolinas Modernization Project to support region's energy future

24-Hour: 800.559.3853

January 15, 2016

Share This Story

- 15 megawatts of new solar generation and 5 megawatts of utility-scale storage is planned in Duke Energy Progress West region

ASHEVILLE, N.C. – Duke Energy today filed an application for a Certificate of Public Convenience and Necessity (CPCN) with the North Carolina Utilities Commission for the Western Carolinas Modernization Project.

The CPCN application seeks approval to construct two 280-megawatt combined cycle natural gas-fueled electric generating units to replace its coal plant in Asheville. The application also includes a contingent natural gas-fueled 186-megawatt simple cycle combustion turbine unit.

The simple cycle peaking unit could be delayed or eliminated based on the success of programs to reduce energy use in the region.

"Today marks an important milestone in the region's energy future" said Robert Sipes, Duke Energy's general manager of delivery operations for Western North Carolina. "As we committed last fall, we continue working with the community to create a smarter and cleaner energy future in meeting our customers' energy needs."

Duke Energy will file a future CPCN application to seek approval for a minimum of 15 megawatts of new solar generation over the next seven years after the Asheville Plant's coal units have been decommissioned and coal ash excavation is completed.

The company also plans to seek approval to install a minimum of 5 megawatts of utility-scale electricity storage over the next seven years. Duke Energy will continue to evaluate other investments in renewables and other technologies to cost-effectively meet the needs of its customers.

The company is continuing to work with the Asheville, Buncombe County and surrounding communities to explore and maximize programs and innovative energy solutions to reduce energy use in the fast-growing, nine-county Duke Energy Progress-West region, which serves more than 350,000 people.

Environmental and customer benefits

The natural gas-fired combined-cycle power plants are scheduled to begin serving customers by late 2019 and will have significantly lower environmental impacts than the existing coal plant.

- Sulfur dioxide will be reduced by an estimated 90 to 95 percent.
- Nitrogen oxide will be reduced by an estimated 35 percent.
- Mercury will be eliminated.
- Water withdrawals will be reduced by an estimated 97 percent.
- Water discharges will be reduced by an estimated 50 percent.
- Carbon dioxide emissions will be reduced by about 60 percent, on a per-megawatt-hour basis, due to the efficiency of the new gas units and the fact that natural gas burns more cleanly than coal.

(The percentages above are estimates and include both phases of the modernization project. Final percentages will be determined after the company receives environmental permits.)

The smaller combined cycle gas units have efficiency ratings similar to the original plan, which enables the units to be about 35 percent less expensive to operate than the existing coal units. These savings will be annually passed on to customers dollar-for-dollar via the company's annual fuel clause adjustment.

Upgrades to existing transmission equipment on the Asheville Plant site are also planned as part of this project.

Since 1970, peak power demand has more than tripled in Duke Energy Progress' Western Region. Ensuring power reliability was particularly difficult during the winters of 2014 and 2015, when peak demand was 30 percent higher than in 2013. Over the next decade, continued population and business growth is expected to increase overall power demand by more than 17 percent.

For more information about the company's plan see http://www.duke-energy.com/western-carolinas-modernization/.

About Duke Energy

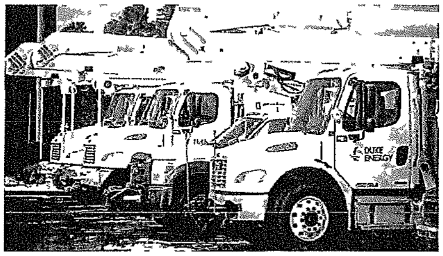
Duke Energy is the largest electric power holding company in the United States. Its regulated utility operations serve approximately 7.3 million electric customers located in six states in the Southeast and Midwest, representing a population of approximately 23 million people. It's Commercial Portfolio and International business segments own and operate diverse power generation assets in North America and Latin America, including a growing portfolio of renewable energy assets in the United States.

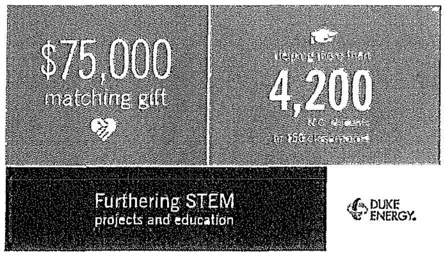
Headquartered in Charlotte, N.C., Duke Energy is a Fortune 250 company traded on the New York Stock Exchange under the symbol DUK. More information about the company is available at duke-energy.com.

Follow Duke Energy on Twitter, LinkedIn and Facebook.

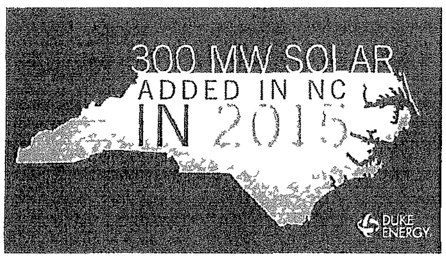
Related Stories

Duke Energy preparing for Jonas' triple threat





Duke Energy offers North Carolina teachers $75,000 for classroom STEM projects



North Carolina solar was hot in 2015; Duke Energy led the charge

Related Tags

North Carolina, Environment, Emissions, Solar

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NCSEA
EXHIBIT B

Duke Energy responds to community concerns; creates new plan for Western Carolinas Modernization Project

Nov 4, 2015

ASHEVILLE, N C - Duke Energy today announced it has created a new plan for its proposed infrastructure upgrade for the Western Carolinas in response to community feedback

Under the revised plan, the company will replace its coal plant in Asheville with two smaller gas units rather than one large one As a result, the proposed 45-mile Foothills Transmission Line and Campobello substation are no longer necessary

Western North Carolina is growing faster than most other areas in the Carolinas To successfully meet the region's growing power needs, the revamped project will require significantly more participation in energy efficiency, demand-side management, renewable energy and developing technologies from the company, communities and customers in the region

"I want to thank everyone who has been involved in this process for their input and patience, including those who sent us more than 9,000 comments regarding our proposed transmission line and overall project," said Lloyd Yates, Duke Energy's executive vice president for market solutions and president of the Carolinas region "We believe the process worked

"We have been committed to developing a plan to maintain the region's power reliability with the least possible impact on communities, property owners and the environment from the start of this effort, and we believe our revised plans accomplish those goals," said Yates

The new plan does require a stepped-up effort to work with customers and interested groups to expand participation in programs to reduce peak power demand and grow renewable energy and associated technologies It also includes a two-phased approach to reconfigure the Asheville Power Plant site that will provide the same significant environmental benefits as the original modernization plan

"While the previous plan was more robust and scaled for the longer-term, the new plan balances the concerns raised by the community and the very real need for more electricity to serve this growing region," said Yates "We're eager to ramp up our efforts in working with the community to reduce power demand across the region through energy efficiency, demand response, renewable energy and other technologies to work collectively to avoid building additional generation in the area for as long as possible "

Reconfigured Asheville Power Plant site

The reconfigured plan for the Asheville Power Plant site includes

- Retiring the coal units as scheduled by 2020
- Building two highly efficient natural gas combined-cycle 280-megawatt units on the site, with the option for a simple-cycle 190-megawatt unit in 2023 or later, depending on the success of the company and community's efforts to reduce daily and peak power demand
- New units that will be designed to operate with a dual fuel source so oil can serve as emergency backup in the event of an interruption of the natural gas supply
- Plans for a utility-scale solar power plant on the site
- Rebuilding existing transmission lines and related substation upgrades using existing transmission rights-of-way to increase Duke Energy Progress' ability to continue importing enough power into the Asheville region to serve the region's growing power demand and meet federal power reliability standards

New plan features significant environmental and customer benefits

As with the original plan, the newly reconfigured natural gas units are estimated to have significantly lower environmental impacts than the existing coal plant

- Sulfur dioxide will be reduced by an estimated 90 to 95 percent
- Nitrogen oxide will be reduced by an estimated 35 percent
- Mercury will be eliminated
- Water withdrawals will be reduced by an estimated 97 percent
- Water discharges will be reduced by an estimated 50 percent
- Carbon dioxide emissions will be reduced by about 60 percent, on a per-megawatt-hour basis, due to the efficiency of the new gas units and the fact that natural gas burns more cleanly than coal

(The percentages above are conservative and include both phases of the modernization project Final percentages will be determined after the company receives environmental permits)

The smaller combined cycle gas units have efficiency ratings similar to the original plan, which enables the units to be about 35 percent less expensive to operate than the existing coal units These savings will be annually passed on to customers dollar-for-dollar via the company's annual fuel clause adjustment

The company will be working with major suppliers of key components for the plant to further refine the overall cost estimate, but it is expected to be essentially the same as the original plan of approximately $1 1 billion

"This region's economy is booming with 14 new hotels, two national craft breweries and more than $1 billion in new industrial investment in just the last five years," said Robert Sipes, Duke Energy's general manager of delivery operations for the Western Carolinas

"So our challenge now is to support that growth while working with the community to reduce the region's peak power and ongoing demand through much more participation in energy efficiency programs, demand response and renewable energy and related technologies," added Sipes. "A great example of such a collaborative effort is Asheville's newly adopted Clean Energy Policy Framework where we look forward to being an active participant working with others to find real solutions to reduce peak energy demand."

Since 1970, peak power demand has more than tripled in Duke Energy Progress' Western Region, which serves 160,000 customers in nine Western North Carolina counties. Ensuring power reliability was particularly difficult during the winters of 2014 and 2015, when peak demand was 30 percent higher than in 2013. Over the next decade, continued population and business growth is expected to increase overall power demand by more than 15 percent.

The company plans to file for a Certificate for Public Convenience and Necessity (CPCN) with the North Carolina Utilities Commission for the new gas units in January 2016.

For more information about the company's proposals see **http://www.duke-energy.com/western-carolinas-modernization/ (http://www.duke-energy.com/western-carolinas-modernization/)** .

About Duke Energy

Duke Energy is the largest electric power holding company in the United States with approximately $120 billion in total assets. Its regulated utility operations serve approximately 7.3 million electric customers located in six states in the Southeast and Midwest. Its Commercial Portfolio and International business segments own and operate diverse power generation assets in North America and Latin America, including a growing portfolio of renewable energy assets in the United States.

Headquartered in Charlotte, N.C., Duke Energy is a Fortune 250 company traded on the New York Stock Exchange under the symbol DUK. More information about the company is available at: **www.duke-energy.com (http://www.duke-energy.com)** .

Follow Duke Energy on **Twitter (https://twitter.com/dukeenergy)** , **LinkedIn (https://www.linkedin/company/duke-energy-corporation)** and **Facebook (http://www.facebook.com/dukeenergy)** .

Media Contact: Tom Williams
24-Hour: 800.559.3853 (#)

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NCSEA
EXHIBIT C

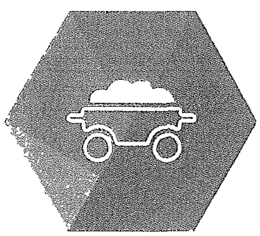
Western Carolinas Modernization Project

In the past four decades, customers' electricity use has more than doubled in and around the Asheville area. Peak power demand has more than tripled in Duke Energy Progress' Western region, which serves 160,000 customers in nine western North Carolina counties. And, demand is expected to grow by more than 15 percent in the next decade.

In May, we announced a comprehensive, longer-term solution to cost-effectively serve customers. In November 2015, a revised modernization plan for the region was announced to meet the region's power demand that is better fit for the community. The proposal balances public input, environmental impacts and our need to provide customers with safe, reliable and affordable electricity. Key components of this $1.1 billion investment are scheduled to be completed by 2020 and include:

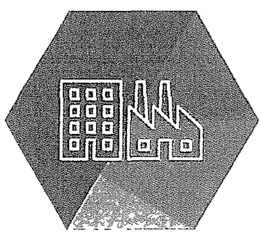
- Retiring coal units at the Asheville Plant and continuing ongoing coal ash excavation and ash basin closure operations
- Building two new natural gas-fired combined-cycle units totaling 560 megawatts and solar generation facilities at the Asheville Plant site
- Leveraging energy efficiency, demand side management, renewables and technology programs and initiatives to help meet peak demand
- Modernizing existing transmission and distribution lines, substations and equipment

RETIREMENT OF COAL UNITS

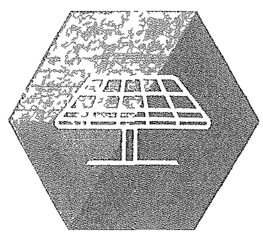


The Asheville Plant has served the region well since 1964 and will continue to serve customers until the new natural gas plant comes on line. Duke Energy expects to retire the two coal-fired units, totaling 376 megawatts, by 2020.

NATURAL GAS PLANTS AND SOLAR GENERATION

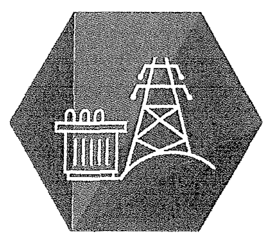


The two new natural gas-fired combined-cycle units will have a capacity of approximately 560 megawatts, which is enough electricity to serve nearly 448,000 homes. The units are scheduled to begin serving customers in late 2019. Duke Energy will work with the local gas distribution company to upgrade an existing gas pipeline to accommodate and serve our proposed combined cycle units with a firm fuel supply.



After coal ash excavation work is complete, Duke Energy plans to add a solar facility at the Asheville plant site. The modernization project will also include engaging the community with energy efficiency, demand side management, renewables and technology programs and initiatives to help manage peak demand.

TRANSMISSION AND DISTRIBUTION PROJECTS



Duke Energy plans to meet increased power demand and ensure long-term reliability by expanding and modernizing existing transmission and distribution equipment.

Reducing water usage

The new natural gas-fired combined-cycle plants will significantly reduce water withdrawal and remove all thermal impacts to Lake Julian. Compared to statistics of the Asheville coal plant in 2014, the new combined-cycle plants are estimated to reduce:

97%

Water withdrawal

Investing in our air

With the retirement of the coal plant and the investments in new, highly efficient technologies, the company expects to reduce annual emissions. Compared to statistics of the Asheville coal plant in 2014, the revised project is estimated to result in:

35% reduction of NO_X

95% reduction of SO_2

60% reduction of CO_2 per megawatt-hour

Note: The percentages above are conservative and include both phases of the modernization project. Final percentages will be determined after the company receives environmental permits.

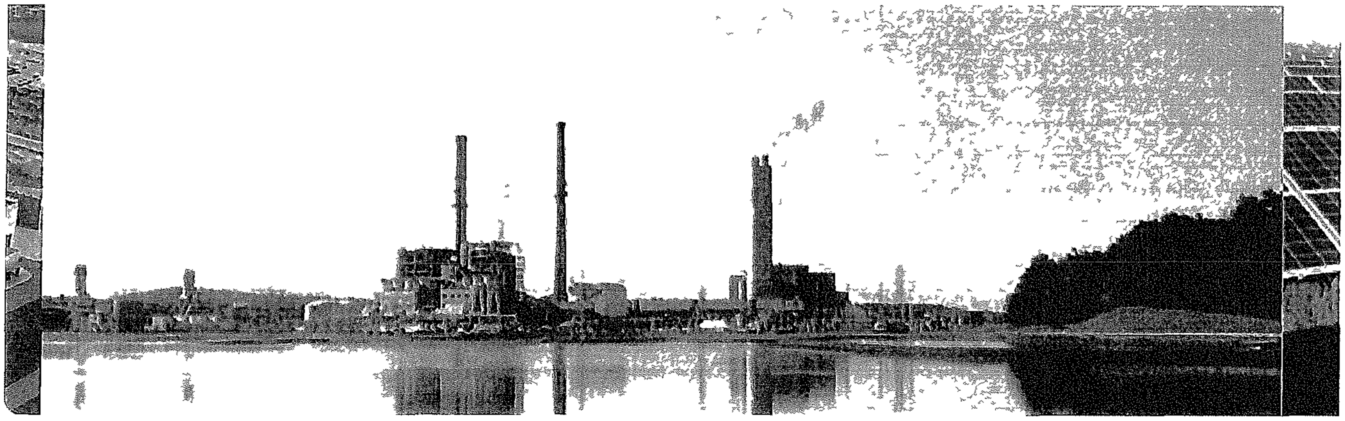
NCSEA
EXHIBIT D

ENERGY

North Carolina
change location

Sign up for Email Investors

Western Carolinas Modernization



Powering the Western Carolinas

More than 7.3 million customers in the Southeast and Midwest count on us for electricity 24/7, and we're committed to delivering it in a safe, reliable and affordable way. Over the next few years, we're upgrading our system in the Western Carolinas to meet growing power demand, ensuring reliability and reducing our environmental footprint.

Read the **news release (/news/releases/2015110402.asp)** and our **fact sheet (/pdfs/WCMP-FactSheet.pdf)** for more information.

For questions related to the Western Carolinas Modernization Project work, call 800.820.9359 (#) or email **WCModernization@duke-energy.com (mailto:WCTransmissionEnhancements@duke-energy.com)**.

Project Overview

In the past four decades, customers' peak electricity use in Duke Energy Progress' Western region, which serves 160,000 customers across nine counties, has more than tripled. Over the next decade, this demand is expected to grow by more than 15 percent.

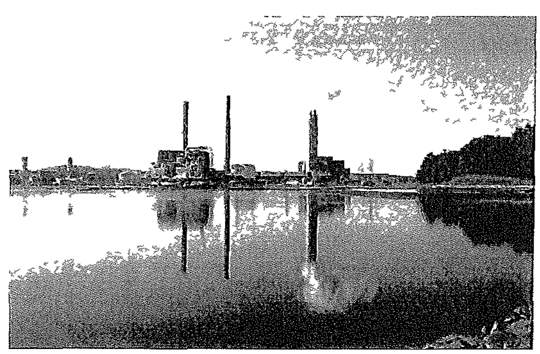
In May, we announced a comprehensive, longer-term solution to cost-effectively serve customers. In November 2015, a revised modernization plan for the region was announced to meet the region's power demand that is better fit for the community. The proposal balances public input, environmental impacts and our need to provide customers with safe, reliable and affordable electricity.

The new plan for meeting the growing energy needs of the Western Carolinas allows time for innovation and additional technologies to be developed that can be used to address future energy needs. The Foothills Transmission Line and substation near Campobello, S.C. projects are no longer needed

Projects

Asheville Coal Plant Retirement

The 376-megawatt Asheville Plant has served the region well since 1964, and will continue to serve customers until the new natural gas plants come on line. We expect to retire the two coal units by early 2020



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- Overview
  - Coal Plant Retirement
  - Natural Gas Plant
  - Energy Efficiency and Demand Side Management
  - Ash Basin Closure
  - Solar Generation

Duke Energy Progress, LLC has notified the North Carolina Utilities Commission (NCUC) that it intends to file an application on or after January 15, 2016, for a Certificate of Public Convenience and Necessity (CPCN) to construct the two natural gas-fueled 280-MW (winter rating) combined-cycle units and a contingent 192-MW (winter rating) natural gas-fueled combustion turbine unit, each with fuel oil backup, at its existing Asheville plant site in Buncombe County

The Western Carolinas Modernization Project will enable the early retirement of the existing coal units at the Asheville site and will include new solar generation that will be subject to a future CPCN application The NCUC has scheduled a hearing for the purpose of receiving non-expert public witness testimony at 7 p m on Tuesday, January 26, 2016, at the Buncombe County Courthouse, 60 Court Plaza, Courtroom 1A, Asheville, NC 28801 The NCUC has further ordered that any person having an interest in this proceeding may file a petition to intervene stating such interest on or before Friday, February 12, 2016, and that the Public Staff shall investigate the application, when filed in this docket, and present its findings, conclusions and recommendations to the North Carolina Utilities Commission at its Regular Staff Conference to be held on Monday, February 22, 2016, at 10 a m in Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury St , Raleigh, NC

Project Timeline

Begin to seek project approvals permits and agreements, and start pipeline construction

2015

Begin construction of new natural gas plants

2017

Complete gas pipeline and new natural gas plants

2019

Retire Asheville Plant coal units and begin to install solar facility

2020

Frequently Asked Questions

Hide All

General Overview

What is Duke Energy planning in Western North Carolina and South Carolina?

Get news and updates on Duke Energy s merger, acquisition and divestiture activities Includes articles, videos and news releases

Following a comprehensive evaluation of the energy system, we've crafted a multi faceted plan to meet the current and growing energy needs of the region

The Western Carolinas Modernization Project includes

- Retiring the 376 megawatt (MW) Asheville coal units excavating the ash and closing the basin
- Building two 280 megawatt (winter rating) combined cycle power plants on the Asheville coal plant site to take advantage of historically low gas prices
- Working with the local gas distribution company to upgrade an existing intrastate gas pipeline that will serve the region beginning in 2019 and will provide a firm fuel supply to the new combined-cycle natural gas plant
- Building new transmission infrastructure and upgrading related area substation infrastructure
- Continuing to move ahead on coal ash excavation and ash basin closure at the Asheville power plant site

These investments provide economical and long term reliability for the region while reducing our environmental footprint

Why did Duke Energy revise the Western Carolinas Modernization plan?

Our unwavering commitment is to serve all of our customers with safe, reliable affordable power generated as cleanly and efficiently as possible And we want to do that in a way that's respectful of our customers and communities Public input was imperative in this process and we clearly heard that most everyone wanted us to explore all options/alternatives for meeting the growing energy needs of the region

The revised plan strikes that balance of addressing concerns from the public, minimizing environmental impact and meeting our schedule of being able to supply much needed generation to this growing area

What is the cost to customers?

The company will be working with major suppliers of key components for the plant to further refine the overall cost estimate, but we expect the costs to essentially be the same as the original plan of approximately $1 1 billion

Once the project is complete, we will seek to recover these costs from Duke Energy Progress (DEP) customers through the regulatory process

How do these projects contribute to the local tax base?

These projects represent a significant investment in the Western Carolinas region which, in turn, provides significant new regional tax base resulting from construction and ongoing operations of the facility

Duke Energy evaluates property tax on an annual basis and files an annual property tax report as part of that review The company will conduct the property tax assessment for both the soon to be retired coal plant and new natural gas plant over the next few years and submit a final filing closer to 2019 – 2020 Based on current Buncombe County tax rates, property taxes from the power plant are estimated to increase between 35 and 40 percent after the power plant site is modernized

Why the urgency?

We have a unique opportunity to work with PSNC as a contracted customer on an existing intrastate natural gas pipeline which will bring a firm fuel source to the region The timing of expanding the pipeline infrastructure to support Duke Energy's proposed gas generation in Asheville allows us to achieve project benefits as the timing is in sync with PSNC's project timeline

The advanced timing meets future demand which is expected to grow by more than 15 percent in the next decade The project enables us to meet current and future demand and supports industrial growth and future economic development Since 2010 the Asheville Chamber of Commerce reports approximately 3,000 new jobs and $1 billion in commercial/industrial investments have been realized in the Asheville area Further evidence of the rapid growth in this region is the 14 hotels that are currently under construction in Asheville

Additionally, the proposed projects would allow Duke Energy to avoid investing approximately $200 million in a 124-megawatt oil power plant and new coal ash equipment on the power plant site

What role can the public play in reducing the need for additional generation and/or transmission lines in the future?

Duke Energy is committed to serve the energy needs of our customers We're equally committed to helping our customers better manage and reduce their overall energy usage, especially during times of peak demand

An important aspect of the new plan is to work directly with our customers communities and other stakeholders to place a more emphasis on energy efficiency, demand response, and renewables and technology projects that will help slow peak load growth Through existing programs and innovative solutions to be developed, we can work together to help delay the need for additional generation

Transmission

Why are the Foothills Transmission Line and tie station near Campobello, S.C. no longer needed?

The Foothills Transmission Line and tie station near Campobello, S C are no longer required because the revised plan includes two 280-megawatt combined cycle power plants that will serve the region's current and future energy needs

Having multiple units provides the redundancy we need for reliability in the region The units will also be designed to run on oil as a backup in the event there are any disruptions of the natural gas supply Additionally, we will work with the community to increase participation in energy efficiency, demand-side management, technology and renewable programs and projects to help manage peak demand

What will Duke Energy do with the property it purchased for the substation in Campobello, S.C. now that the transmission line is no longer needed?

The company has property all across the Carolinas and its other service areas This property will simply be part of those landholdings The company no longer has any current plans for this property

Is the proposed Foothills Transmission line dead once and for all?

The Foothills transmission line project is no longer necessary However, the company builds and maintains its infrastructure to meet growing needs of customers and comply with regulatory and federal standards and requirements We have an obligation and responsibility to continue to enhance the reliability of the grid and overall system for all of our customers As communities grow, we must grow with it to power their daily lives Any future transmission lines and substations will be based on growth and regulatory needs at that time

Is the revised plan superior to the original? If so, why didn't you propose it first? If not, where is it deficient?

The initial plan was the best technical solution and more robust for the long term, but it wasn't the best practical solution After receiving feedback from the community throughout public input process, we revised the plan to strike the balance of addressing concerns from the public, minimizing environmental impact and meeting our schedule of being able to supply much needed generation to this growing area

We are eager to continue working with the community to reduce power demand across the region through energy efficiency, demand response and renewable energy and technology to avoid building another power unit on the Asheville site for as long as possible

Natural Gas Pipeline

What is Duke Energy's role in the construction of the new pipeline?

There is an existing natural gas pipeline in the region Duke Energy is working with the local gas distribution company (PSNC) to upgrade the pipeline to accommodate and serve the proposed natural gas-fired combined cycle power plant This upgrade will expand the critical infrastructure that will help support industrial growth and economic development in the Western Carolinas region, and provide a firm fuel supply to the proposed natural gas plant

Where will the pipeline be located?

The extension of the pipeline will run through an existing PSNC right-of-way area, which runs from Kings Mountain to Arden, North Carolina The extension will connect to the larger intrastate Transco gas pipeline which runs from the Gulf to New York For more information, please contact PSNC or visit their website **psncenergy com/pipeline (http //www psncenergy com/pipeline)**

When will the pipeline begin operating?

Based on the current schedule, the pipeline has an in-service date of early 2019

Where will the new pipeline infrastructure receive gas supply from?

PSNC will receive natural gas sourced from the Transco system

Who will approve the pipeline agreement between PSNC and Duke Energy Progress?

The local distribution company will file the agreement with the North Carolina Utilities Commission (NCUC) Duke Energy is simply a customer of this pipeline PSNC will also work with stakeholders and other agencies along the route to ensure the pipeline expansions have all the needed permits and approvals prior to construction and operation

New Generation

Why does Duke Energy need to build a new power plant?

As identified in the Duke Energy Progress 2014 Integrated Resource Plan (IRP), the company projects the need for new generating capacity by 2020 as a result of the following

- Load growth
- Retirement of aging and less efficient coal units, and
- The expiration of purchase power contracts

Building a highly efficient natural gas plant is part of the company's plan to meet future demand for reliable, affordable electricity Natural gas-fired combined-cycle power plants also offer economic and environmental advantages compared to other generation options

Why is Duke Energy replacing the coal units with larger capacity combined-cycle units?

The Western Carolinas region continues to experience residential, commercial and industrial growth The new combined-cycle units will help meet current and future energy demand for homes, schools and businesses in the region Currently peak demand increases approximately 25 megawatts per year These generation projects take years to license and build so it's always prudent to plan for future growth

Why are the new combine cycle units being designed for dual fuel, natural gas and ultra-low sulfur fuel oil?

Duke Energy will contract for firm (uninterruptible) natural gas supply in excess of the needs of the new combined cycle units As a result, it is anticipated that total fuel oil consumed will be reduced from current levels at the Asheville facility because some fuel oil currently consumed in the existing simple cycle units will be offset by firm natural gas The combined cycle units will be dual fuel capable to ensure electrical system reliability in the rare event of an interruption in the natural gas supply to the site

Who will need to approve the combined-cycle plant before construction begins?

The project requires approval from various local, state and federal governing bodies and regulatory agencies, including the North Carolina Department of Environment and Natural Resources and the North Carolina Utilities Commission

Where will the combined-cycle units be located?

The natural gas-fired combined-cycle power plant will be constructed on the existing Asheville Plant site It will have a footprint of approximately 25 acres

Where will the plant get its natural gas?

There is an existing pipeline in the Asheville region Duke Energy is working with the local distribution company to upgrade the pipeline to accommodate and serve the proposed natural gas plant

When will the new combined-cycle power plant be operational?

The natural gas plant will begin serving customers in late 2019 or early 2020

Retiring the coal plant and Ash Excavation

When will Duke Energy retire the coal units?

Based on the current schedule, the company will retire the coal units in early 2020, once the natural gas-fired combined-cycle power plant begins serving customers The coal units will continue to reliably serve the region until the natural gas plant is ready for operation

What happens to the units once retired?

Once the units are retired, they will be decommissioned This is a comprehensive and methodical process that takes several years and involves site characterization studies and engineering analyses to determine the best site-specific decisions The long-term vision for retired units across our system is to return them to ground-level We will salvage what equipment we can and repurpose at other sites, conduct any environmental abatement needed, sell any scrap material we can, safely dismantle and remove the powerhouse, stack and any auxiliary structures no longer needed and then restore the site This approach is best suited to ensure continued safety, security and environmental compliance at the site both for the company and the community

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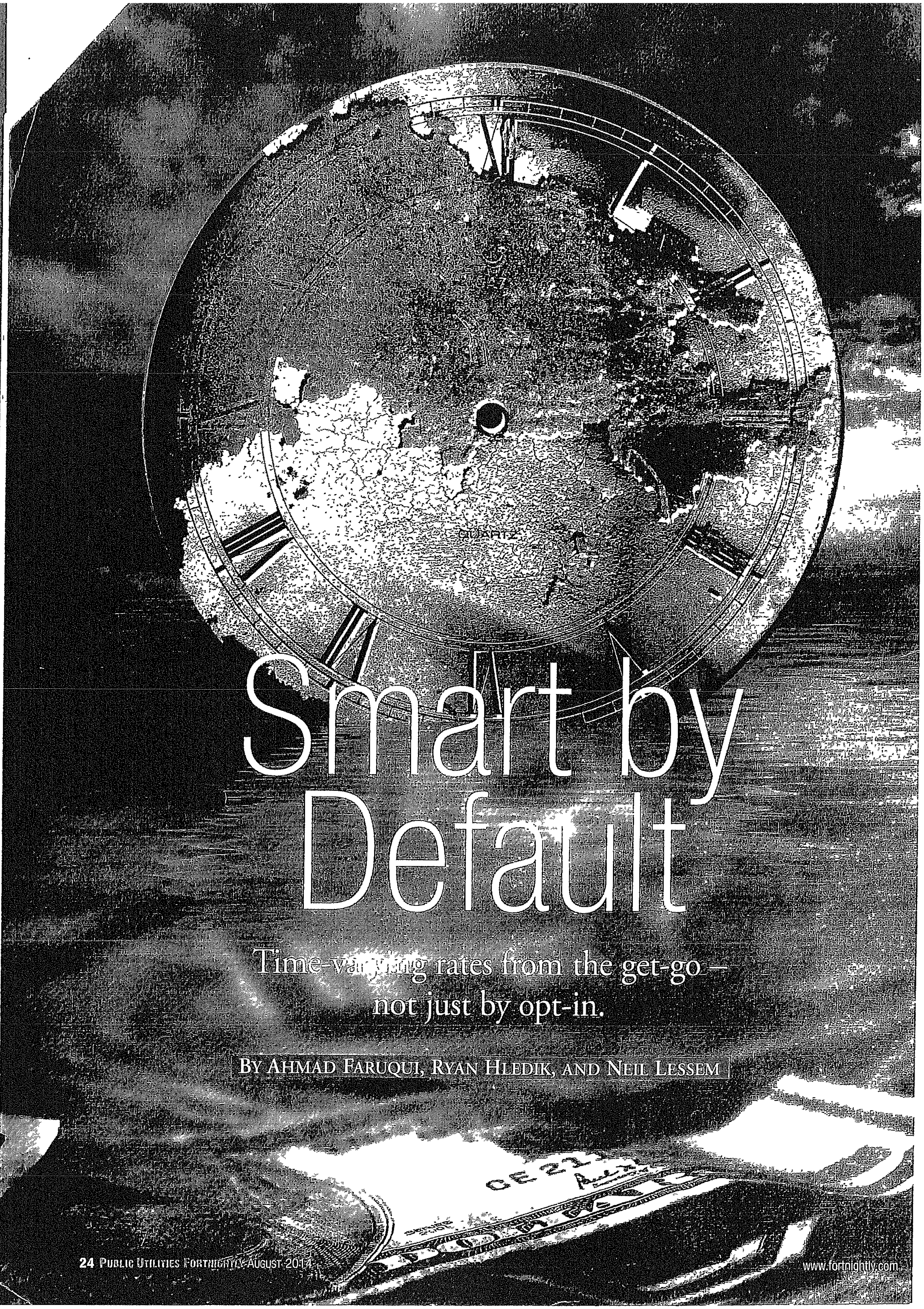


Smart by Default

Time-varying rates from the get-go – not just by opt-in.

By Ahmad Faruqui, Ryan Hledik, and Neil Lessem

About a third of U.S. households are now receiving electric service through smart meters but only two percent are buying the energy portion of their electric bill on a time-varying rate, or TVR. As we look at the future, it is clear that the number of customers with smart meters will continue to grow while the number of customers on TVRs will continue to stagnate. (TVRs come in several forms. For definitions of some of the more commonly used TVRs – , CPP, PTR, TOU, and VPP – see sidebar, "Common Forms of Time-Varying Rates," p. 26.)

It is possible that nearly all U.S. households will be on smart meters sometime during the next decade. But how many will buy electricity through a TVR? Unfortunately, if the current regulatory logjam persists, that percentage is not likely to enter double digits any time soon.[1]

In other words, while the economic case for TVRs is well-known,[2] it is the politics which is murky. And whether these rates should replace the default flat rates that are ubiquitous today by becoming the default tariff is the subject of vigorous debate in California and Massachusetts, as both states have opened proceedings on the topic. It will probably also enter the debate in New York at some point.[3]

Default rates will reach far more customers than opt-in.

This article lays out a simple way to overcome the barriers to TVR adoption: offer TVR on a default basis.[4] If all of a utility's customers were transitioned to a TVR with the option to switch to a different, non-time-varying rate design, enrollment in the TVR would be three to five times higher than if it were offered on an opt-in basis. As a result, major cross-subsidies that are embedded in today's flat rates[5] would be eliminated, utilization of generation resources would be improved, the total cost of supplying and delivering electricity would be reduced, and a customer's freedom to choose from a diverse array of rate offerings would still be preserved.

Some regions of the world are already transitioning to default TVR. All four million households in the province of Ontario, Canada have been defaulted to a time-of-use (TOU) rate, with the option to choose a different rate offered by retail supplier. TOU pricing is the default residential rate across Italy and this involves some 25 million customers.[6] In Maryland and Delaware, BGE and Pepco Holdings (PHI) are currently transitioning all of their

1. The logjam is based on myths and misperceptions. For a discussion of these myths, see Ahmad Faruqui and Jennifer Palmer, "Dynamic Pricing and its Discontents," *Regulation*, Fall 2011. http://object.cato.org/sites/cato.org/files/serials/files/regulation/2011/9/regv34n3-5.pdf
2. Ahmad Faruqui, Ryan Hledik, and John Tsoukalis, "The Power of Dynamic Pricing," *The Electricity Journal*, April 2009, Vol. 22, Issue 3.
3. The proceedings in California were initiated two years ago: R.12-06-013. It is expected to run through next year. A welter of rate designs has been suggested by the dozen-plus participants in the case. Implementation of the new rates cannot begin prior to 2018 because of the provisions of a state law, AB 327. The Massachusetts DPU has issued an Order containing a straw proposal that would make TOU with CPP the default tariff and also offer PTR with flat rates: D.P.U. 14-04-B. A final Order is expected before year-end. Implementation may be eight years away because a companion proceeding focusing on grid modernization may take some five years to adjudicate. The newest proceeding is taking place in New York, under the rubric of Reforming the Energy Vision: 14-M-0101.
4. For the purposes of this discussion we ignore the meta-issue of whether a default is needed at all. In markets with retail competition, it is possible to have no default at all, just a menu of alternatives. However, even in such cases a default may be beneficial since it may affect the options offered on the menu. In restructured markets such as those in Massachusetts. Texas, Australia, New Zealand, Ontario (Canada) and the United Kingdom, retail competition has failed to offer any sort of TVR. Retailers typically anchor their offerings to customers on the existing default flat rate and offer slight tweaks such as fixed prices for various contract lengths. Retailers may stick "close" to the existing default tariff because it is difficult for consumers to make decisions between very different alternatives. Thus it may be difficult to choose between a TOU rate and flat rate, but easier to choose between a flat rate and a slightly cheaper flat rate. A variety of experiments outside of the electricity sector illustrate this problem (see Dan Ariely, . Predictably Irrational, the Hidden Forces That Shape Our Decisions, 2008). In Ontario, Canada, when the TOU rate became the default, a number of retailers offered flat rates that included very expensive hedges against price uncertainty and risk. Less than 10% of customers signed up for these flat rates and the percentage has been falling. Now as retailers and customers start to anchor to the TOU rate, we see the emergence of "Retail 2.0" with a number of retailers starting to experiment with dynamic rates that offer bigger peak-off to peak price ratios than the current standard offering.
5. For ease of exposition we use the term flat rates to encompass all non- time varying rates. This would include increasing and decreasing block rates.

6. Walter Graterri and Simone Maggiore, "Impact of a Mandatory Time-of-Use Tariff on the Residential Customers in Italy," November 14, 2012. http://www.ieadsm.org/Files/Content/14.Espoo_IEA_DSM_Espoo2012_SimoneMaggiore_RSE.pdf

Ahmad Faruqui, **Ryan Hledik**, and **Neil Lessem** are economists with The Brattle Group, based in San Francisco. They would like to thank their colleague Sanem Sergici for her thoughtful comments on earlier drafts of this paper. Many other reviewers also read previous drafts. The views expressed in the paper are not necessarily those of Brattle. Comments can be directed to ahmad.faruqui@brattle.com.

Some Common Forms of Time-Varying Rates

Critical Peak Pricing (CPP). Charges customers a higher rate in a small percentage of critical peak periods, in return for lower prices throughout the rest of the year.

Peak Time Rebates (PTR). Offers customers a rebate for conserving during these same critical peak periods. Rates remain constant otherwise.

Time of Use (TOU). Offers a lower rate during certain hours of the day when energy is cheaper to produce and a higher rate during peak periods when it is most expensive. These rates and hours are established in advance.

Variable Peak Pricing (VPP). Similar to TOU, except the peak rates vary with market conditions.

For more background on various time-varying rate designs, consult Ahmad Faruqui, Ryan Hledik and Jennifer Palmer, "Time-Varying and Dynamic Rate Design," The Regulatory Assistance Project, July 2012. ***–AF, RH, and NL***

customers to a default peak time rebate (PTR), while the Massachusetts Department of Public Utilities has proposed rolling out default TOU rates over the next several years. In California, the Sacramento Municipal Utility District (SMUD) has committed to rolling out a default residential TOU by 2018. San Diego Gas & Electric (SDG&E) currently offers a default PTR program and has proposed rolling out a default residential TOU rate by 2018. The California Public Utilities Commission's (CPUC) Energy Division has issued a report with a similar recommendation for default TOU.[7] Despite these examples, there is a significant gap between the regions with the metering capability to offer default TVR, and those that have elected to do so.

Our focus in this article is specifically on transitioning the energy portion of a customer's rate to a time-varying design. Fixed costs (e.g. metering and billing costs) are better collected through a fixed monthly charge. Capacity costs (e.g. generation, transmission, and distribution costs) may be better collected through a demand charge if the necessary metering infrastructure is in place. The advantages of redesigning residential rates to include these charges will be the focus of a future article.

Dispelling Myths

Contrary to some views that continue to be widely cited in the media, TVR is not expensive or unfair. That double honor belongs to flat rate pricing. We have estimated that each year American consumers are paying $7 billion more for electricity on flat rate pricing than they would be paying on TVR. Flat rates also create inequities in the form of cross-subsidies in the amount of $3 billion per year.[8] Yet flat rates are the mandatory or default rate in most parts of the U.S.

There is a strongly held perception that consumers won't understand TVR. The reality is quite the opposite. The average person has encountered TVRs routinely in the normal business of life, such as when making a phone call, buying an airline ticket, booking a hotel room, renting a car, going to a San Francisco Giant's game, attending a symphony performance, going to the movies, riding the subway, or simply buying produce at the local farmer's market. And recently, TVR even has been encountered when driving on the Fast Track lane of certain freeways, crossing bridges such as the San Francisco-Oakland Bay Bridge, driving into central London on weekdays and simply while parking a car in a metered space. TVRs are ubiquitous in everyday life.

TVRs ensure the efficient utilization of capacity by minimizing peak loads and improving load factors. By so doing, average costs are lowered for everyone and congestion is better managed so that supply is available for high valued uses and rationed for less valued uses.

When it comes to electricity, we find that TVRs are pervasive in wholesale markets and in retail markets for large commercial and industrial customers. But they are virtually invisible when we review retail markets for residential and small business customers. Consequently, the annual load factor is under 60% for most utilities, with the top 1 percent of the hours accounting for 8 to 18 percent of the annual peak load. Residential load factors are even lower. Peaking generation capacity sits idle for thousands of hours a year. But it has to be paid for, and that puts upward pressure on costs and rates for all customers.

As mentioned earlier, the cost of not having TVR's is in the $10 billion a year range. So what can be done to change this expensive reality? Several fears have to be overcome. The first fear is that that consumers won't respond to dynamic pricing. However, scores of pilot programs carried out over the past decade

7. Robert Benjamin, Michele Kito, Rajan Mutialu, Gabe Petlin, Paul Phillips, Junaid Rahman, "Energy Division Staff Proposal on Residential Rate Reform," prepared by California Public Utilities Commission Energy Division Staff, January 3, 2014. http://www.cpuc.ca.gov/NR/rdonlyres/66CCE840-F464-42F5-8B6A-D9F0FC649F67/0/Integrated_ResidentialRateReform.pdf
8. These estimates were derived by scaling up estimates that were developed for California in the following report: Faruqui, Ahmad, Ryan Hledik and Bernie Neenan, "Rethinking Rate Design: A Survey of Leading Issues Facing California's Utilities and Regulators," Demand Response Research Center, Lawrence Berkeley National Laboratory, August 7, 2007.

show conclusively that consumers respond to price.[9] The second fear is that consumer response won't persist. Some pilots have run across multiple years and response has persisted in most pilots. For example, pilots in California and Oklahoma ran for two years and a pilot in Maryland ran for four years. All showed persistence. Full-scale TVR programs are in place in Arizona and France and also show persistence. The third fear is that low-income customers will be harmed. The contrary has been shown to be the case. In one study, nearly 80% of low-income customers were found to be paying more under flat rates.[10] After shifting load away from peak hours, the study found that they will save even more with TVR.

Making the Case

While most would be hard pressed to disagree about the benefits and efficacy of TVRs, many disagree on how they should be offered to consumers. To this end, we seek to clarify some of the rhetoric and confusion underlying this discourse. Our main points of contention are:

- "Default" is different than "mandatory,"
- A default rate is always present, and
- The aggregate impacts of a default TVR offering will always be greater than the impacts of default flat rate with opt-in TVR, even if the average impact per participant is lower.

The term "default" should be distinguished from the term "mandatory," which has been associated in some people's minds with the failed mandatory deployments of time-of-use rates in the 1980s and 1990s. Those rates were poorly designed and even more poorly marketed. In a mandatory rate offering, there is no choice. Customers are automatically enrolled in the rate, with no alternative.

In contrast, with default pricing customers are enrolled in a rate with the option to switch to other rate choices if they choose to do so. A default offering – importantly – allows for customer choice. In a competitive market, the term mandatory carries no meaning and is indeterminate. Customers can pick the default service if that is to their liking. Or they can shop around and go with a service offered by a competitive retailer. They have a choice. Nothing is being mandated for them. Likewise in markets without retail choice, if a menu of rate offerings exists, no one rate is mandatory.

The offering of new services on a default basis is commonly observed in other industries. In *Nudge: Improving Decisions About Health, Wealth, and Happiness,* University of Chicago Professors Richard Thaler and Cass Sunstein point to the benefits of automatic enrollment in retirement savings plans. Despite the "free money" that is offered through employer matching of 401k contributions, researchers find that when the plans require customers to proactively opt-in, many are delaying their enrollment or neglecting to do so altogether out of negligence or apathy, and later regretting it. With automatic enrollment participation is significantly higher and there is little difference in drop-out rates between default and opt-in enrollment offerings, suggesting that many new participants are finding that they benefit from the plan under default deployment.[11]

Other examples of default offerings in everyday life include default power saving settings on smart phones and laptop computers, and automatic renewal of magazine subscriptions. In countries such as Austria, Belgium, France, and Hungary, citizens are automatically enrolled in organ donor programs. These programs maintain enrollment levels of 98 to 99 percent, whereas countries with opt-in enrollment, such as Germany, the United Kingdom, and the Netherlands, have seen participation well below 30 percent.[12] There is no shortage of precedent for default offerings.

"Default" is different than "mandatory." It still allows for customer choice.

The terms "opt-in" and "opt-out" are often used to describe how a TVR is deployed. The term "opt-in" obscures the fact that the there is a de-facto default rate in place, and that the default is almost always the flat rate. To create awareness of this issue, we refer in this article to default flat rates with opt-in TVR, and default TVRs with opt-in flat rates.

By and large the current system in the United States is devoid of customer choice, with customers facing either mandatory flat rates or default flat rates without a substantially different and attractive alternative. Even in those states with a long history of retail competition, the market has failed to provide residential customers with a meaningful time-varying rate option. The objectives of economic efficiency and equity have not been well served by such a rate offering. By changing the default rate from a flat rate to a time-varying rate, creative forces would be unleashed in the competitive market and the objectives of economic efficiency, equity and choice would all be enhanced.

Ideally, customers should have a menu of pricing options that allows them to choose where they want to be in the risk-reward trade-off that accompanies increasingly dynamic rates. Customers

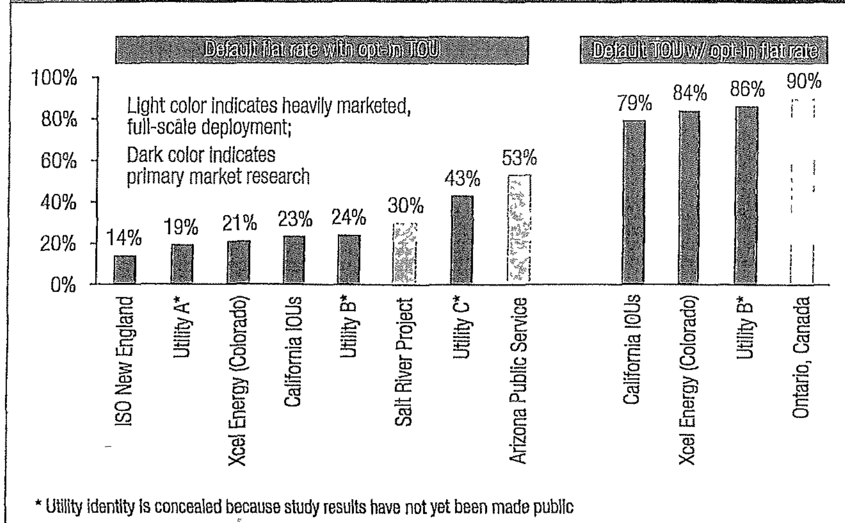
9. Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal,* August/September 2013.

10. Lisa Wood and Ahmad Faruqui, "Dynamic Pricing and Low Income Customers," *Public Utilities Fortnightly,* November 2010. http://www.fortnightly.com/fortnightly/2010/11/dynamic-pricing-and-low-income-customers

11. Thaler, R. & C. Sunstein (2008): "Nudge: improving decisions about health, wealth, and happiness", Yale University Press, New Haven.

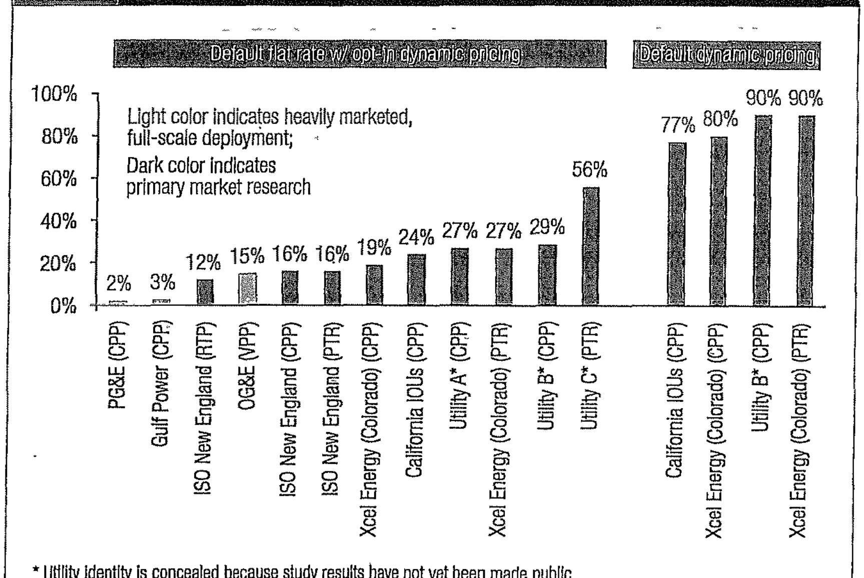
12. Johnson, E.J. & D Goldstein (2003): "Do Defaults Save Lives?" Science, vol. 310, pp.1338-1339.

FIG. 1 RESIDENTIAL TOU ENROLLMENT RATES



* Utility identity is concealed because study results have not yet been made public

FIG. 2 RESIDENTIAL DYNAMIC PRICING ENROLLMENT RATES



* Utility identity is concealed because study results have not yet been made public
Pepco and BGE have deployed a default residential PTR. Results forthcoming.

who want to avoid this uncertainty or risk can choose to pay an "insurance premium" built into flat rates. Within this menu, the default rate should be the time-varying rate. The design of the default rate matters for customer choice because many customers will stick with the default rate regardless of what it is.

Comparing Enrollment Levels

The contrast in TVR enrollment levels under a default flat rate versus default TVR offerings can be observed in a survey of full scale deployments and market research studies conducted across the U.S. and abroad. With respect to full scale deployments, our survey focused specifically on rate offerings that have been heavily marketed to customers and have achieved significant levels of enrollment. The enrollment estimates are based on data reported by utilities and competitive retail suppliers to FERC and other entities. Alternatively, the primary market research studies rely on a survey-based approach designed to gauge customer interest in TVR. It is important to note that after the surveys were collected by the market researchers, adjustments were made to account for the natural tendency of respondents to overstate their interest. Thus, they should provide a reasonable prediction of enrollment rates. The survey respondents were randomly selected from each utility customer base and confirmed to be representative of the entire class of customers. Samples were large enough to ensure statistical validity of the findings.

Figure 1 shows residential TOU enrollment levels for default flat rates (with the option to opt in to TOU) and default TOU rates (with the option to opt in to flat rates). Under default flat rates the average TOU enrollment level is 28 percent, while when TOUs are the default, the average enrollment rate rises to 85 percent.[13] Default TOU rate offerings are likely to lead to enrollment levels that are 3 to 5 times higher than opt-in TOU offerings.

Arizona Public Service and Salt River Project (SRP), both located in Arizona, have achieved high opt-in TOU enrollment through heavy marketing of the TOU rates as well as through large users' ability to avoid the higher priced tiers of their inclining block rate by switching to the TOU.[14] In Ontario, Canada, many of the customers not participating in the default TOU rate had already switched to a competitive retail provider before the TOU rate was deployed. After some initial issues with the rollout of the default rate in Ontario, the transition has been effective and system wide load reductions have been observed.[15] Similarly,

13. In all cases, for uniformity in making comparisons across utilities, enrollment is expressed as a percentage of the entire residential customer population.
14. In California, inclining block rates are mandatory and large users cannot bypass them.
15. Ahmad Faruqui et al., "Impact Evaluation of Ontario's Time-of-Use Rates: First Year Analysis," prepared for the Ontario Power Authority, November 26, 2013. http://brattle.com/system/publications/pdfs/000/004/967/original/Impact_Evaluation_of_Ontario's_Time-of-Use_Rates-First_Year_Analysis_Faruqui_et_al_Nov_26_2013.pdf?1386626350

TOU has been deployed on a default basis across Italy.

Figure 2 shows residential enrollment levels in dynamic pricing rates under default flat rate and default TVR deployments. The dynamic pricing enrollment levels are similar to those of the TOU offerings, with average dynamic pricing enrollment of 20 percent under default flat rates and 84 percent when dynamic prices are the default. Dynamic pricing options considered include CPP, PTR, VPP and Real Time Pricing (RTP).

Oklahoma Gas & Electric (OG&E) has achieved the highest level of full scale opt-in enrollment, with 15 percent of its residential customer base enrolled in its VPP rate and a target of 20 percent enrollment by 2016. This has been achieved through proactive marketing and outreach, and by offering a free smart thermostat to customers who enroll in the rate. The first residential default dynamic pricing deployments have just begun in Maryland and Delaware, where BGE and PHI are enrolling all of their residential customers in peak time rebates. Information is not yet available as to the number of customers who have opted out of these rates. SDGE and SMUD are proposing default deployments in the year 2018.

The Backlash Argument

While theory suggests that default TVR deployment would simultaneously promote equity and efficiency in rate design, concerns persist among many stakeholders in the ratemaking process that it may fail in practice. The concern rests on the supposition that default deployment could trigger a customer backlash. Furthermore, it has been argued that default TVR deployment would yield a lower amount of demand response than opt-in TVR pricing, since customers who are forced onto the default TVR tariff will choose simply not to respond.

It is probably true that the average reduction in peak demand per participating customer is likely to be smaller with a default TVR offering, compared with an opt-in offering. But as shown below, we find that the significant increase in customer participation brought out by default deployment with an opt-out right should more than offset that tendency.

First, consider that in the public debate about TVRs, there are three competing hypotheses about how customers will respond to default TVR rates versus opt-in TVR rates:

H1 (No Better, No Worse): A default TVR deployment will enroll many more customers than an opt-in deployment but they won't respond to the TVR. Thus, the aggregate impact on peak demand under opt-out TVR deployment will *equal* the aggregate impact under opt-in TVR deployment,

H2 (Backlash Case): A default TVR deployment will trigger a negative customer backlash since customers will object to being defaulted onto a TVR. Thus, the aggregate impact under opt-out TVR deployment will be *less* than the aggregate impact under opt-in deployment, and

H3 (Net Improvement Case): A default TVR deployment will reach far more customers than an opt-in deployment and they will respond to the TVR incentives. Thus, the aggregate impact under opt-out TVR deployment will *exceed* the aggregate impact under opt-in TVR deployment.

To resolve the debate, we put these three hypotheses to test using evidence from a number of recent studies, including both pilots and full-scale rollouts. To begin, imagine that there are three types of customers: (A) the big responders, who are heavily interested in TVR, (B) marginal responders, who are somewhat interested in TVR, and (C) those who not interested in TVR and possibly hostile to it, including those who may influence the response rates of the other two groups.

Group A consists of customers who are probably the most interested and informed in TVR and will achieve the highest impacts. Group B consists of two types of customers: first, those who are bored by electricity rates and will stick with the default regardless of what it is; and, second, those who are uninformed and will learn more about the TVR with increased exposure to it. Some of these customers will opt into flat rates under default TVR and some will opt in to TVRs under default flat rates given information and time.

TVRs are not expensive or unfair. That double honor belongs to flat rate pricing.

Empirical evidence from SMUD and Ontario, Canada shows the number of B group customers choosing to opt-in to a flat rate from a default time-varying rate to be low. The same is generally true for customers opting in to TVRs under a default flat rate with the exception of Arizona Public Service, Oklahoma Gas & Electric, and the Salt River Project, all of whom have invested heavily in educating and informing their consumers. Group C consists of customers who will benefit the most from flat rates, or who are determined to stick with the status quo regardless of the financial ramifications.

To test our three hypotheses, we build an equation for each one, indicating in each case the total impact on demand response, as derived from the combined component impacts of each of our customer groups:

H1: $A * Impact_A + B * Impact_B = A * Impact_A$

(*i.e.*, $Impact_B$ is zero)

H2: $(1-\theta) * A * Impact_A + B * Impact_B < A * Impact_A$

where θ is the proportion of Group A customers who drop out under default TVR (*i.e.*, the impacts from those Group A customers who drop out under default TVR (θ) outweighs the benefits from the addition of Group B customers)

H3: $A * Impact_A + B * Impact_B > A * Impact_A$

Let's begin with Hypothesis 2, the "Backlash" theory. This idea says that under default TVR there will be such a large customer backlash to being defaulted onto TVR that some of the Group A customers (the big responders) who would have opted-in to TVR will now opt-out. The Group B customers are unaffected since by our definition they are the customers that remain on TVR when it is the default. As discussed earlier, this hypothesis is not borne out empirically; there has been no major customer backlash against default TVR deployment and TVR enrollment has been considerably higher under a default TVR offering than under a default flat rate offering. Based on this observation, we reject hypothesis 2.

Now let's test the other two theories our hypotheses H1 and H3. Here we can see in Figure 3 in pictorial form that a default TVR with a flat-rate opt-out will outperform a default flat rate with a TVR opt-in. Group A customers (the big responders) will participate in TVR in either case, while group B customers (the marginal responders) will contribute to peak demand reduction in the default case. Thus, under hypotheses 1 and 3 a default TVR strategy will (weakly) dominate the default flat rate strategy in terms of enrollment and ultimately in terms of aggregate DR impact.[16] This assertion is shown in Figure 3.

The overall demand response savings will always be greater under default TVR than a default flat rate, provided that the number of Group B customers is non-zero and their impact is positive.[17] We conducted an extensive international survey of TVR enrollment rates and load impacts to test whether hypothesis 1 or hypothesis 3 holds empirically.

FIG. 3 INDIFFERENT CUSTOMERS? AT LEAST SOME WILL ALWAYS RESPOND

Participation in TVR under different default options

Default flat rate with opt-in TVR | Default TVR with opt-in flat rate

Under default flat rates, a relatively small number of high impact customers in group A participate in TVR.

Under default TVR, a large number of lower impact group B customers participate in TVR in addition to the high impact group A customers.

Quantifying Net Improvement

Now let's move from a comparative analysis to a quantitative one. How great are the potential benefits of a default TVR deployment, versus flat rates with a TVR opt-in? To find the answer, we must discover how much each of our three different groups of customers will participate in TVR pricing and contribute to demand response, according to whether TVR pricing is deployed by default, or only by affirmative option.

To develop estimates of likely TVR enrollment levels under default flat rate offerings versus default TVR rate offerings, we relied on the previously discussed survey of market research studies and full scale rate offerings. The average TOU enrollment level under a default flat rate was 28 percent across these studies. When TOU was offered as the default rate, average enrollment was much higher, at 85 percent. Using these estimates, Group A comprises 28 percent of the population (since all participate in opt-in TOU under default flat rates). The participation rate under default TOU is the sum of Group A and Group B. Subtracting Group A's share of the population from the default TOU participation rate, yields a Group B population share of 57 percent.[18]

To estimate the average customer's peak load reduction under default flat rates, we relied on *Arcturus*, The Brattle Group's comprehensive database of more than 200 residential TVR pricing tests that have been conducted by utilities around the globe over the past 10 to 15 years.[19] These pilots took place in a rate design environment where flat rates were the default option. Customers, in most cases chosen randomly, still have to affirm their intent to participate in the TVR rates. Based on the average results across all of the TOU pilots, we estimate that the peak impact from TOU across all participants would be roughly six percent under an opt-in TOU offering. Therefore, since only Group A participates in TOU under an opt-in TOU rate offering, Group A's peak reductions are six percent.

TVRs minimize peak loads. Average costs are lowered for everyone.

As noted earlier, all the TVR pilots described above took place against a backdrop of default flat rate offerings. However, we need an estimate of customer response for a default TVR offering. To obtain this estimate, we have relied on a recent pilot by SMUD which featured both opt-in and default TVR offerings.[20] The SMUD experiment showed that randomly

16. In game theory, a strategy strictly dominates another strategy if it is always better than the second strategy. If it is sometimes better and always no worse than the other strategy, then it weakly dominates.

17. Since customers are extremely unlikely to increase peak consumption in reaction to a higher price, we can assume that impacts from Group B will never be negative.

18. For simplicity we exclude attrition over time.

19. Ahmad Faruqui and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," *The Electricity Journal*, August/September 2013.

20. SMUD Smart Pricing Option Pilot, Interim Load Impact Evaluation. Available at. https://www smartgrid.gov/sites/default/files/MASTER_SMUD%20CBS%20Interim%20Evaluation_Final_SUBMITTED%20TO%20TAG%2020131023 pdf (see p.153).

selected customers who were defaulted onto TOU collectively achieved greater savings than if they had been opted into a TOU rate, rendering Hypothesis 1 false. Using data from the SMUD experiment, we were able to calculate an approximately 3:1 ratio between Group A and Group B, regarding the impacts on demand response under TOU pricing.

Applying the SMUD ratio of 3:1 to Group A's impact of six percent for TOU rates (obtained from the Arcturus database), we calculate an average peak impact for Group B's TOU participants of two percent. To get what the default would be, we just multiply Group A's enrollment rate share by their impact and likewise for Group B.

FIG. 4 THE DEMAND RESPONSE IMPACTS

Peak reduction under opt-in TVR and default TVR for Smart Light & Power Company

	TOU		CPP	
	Opt-in TVR	Default TVR	Opt-in TVR	Default TVR
Enrollment rate	28%	85%	20%	84%
Average peak reduction per participant	6%	3%	18%	9%
Aggregate peak reduction (MW)	34	57	72	149

Thus:

$$\text{Impact}_{A+B} = \text{Impact}_A * \left(\frac{\text{Share}_A}{\text{Share}_{A+B}}\right) + \text{Impact}_B * \left(\frac{\text{Share}_B}{\text{Share}_{A+B}}\right).$$

Filling in the values we are able to infer the average default TOU impact:

$$\text{Impact}_{A+B} = 6 \text{ percent} * \left(\frac{28\%}{85\%}\right) + 2 \text{ percent} * \left(\frac{57\%}{85\%}\right)$$

$=3.4\%$.

Using the same algebra for CPP, we calculate a Group A to Group B impact ratio of just less than 3:1 using data from the SMUD pilot. Combined with an enrollment rate of 20 percent and peak impact of 18 percent under default flat rates (from the Arcturus database) and an enrollment rate of 84 percent under default CPP, we can infer a default CPP impact of 8.9 percent.[21]

All of these results validate Hypothesis 3 and negate Hypothesis 1 since the Group B customers have positive impacts. This means that TVRs set as the default benefitted from having all of the high impacts from the Group A (opt-in) customers, plus the smaller impacts from the Group B (uninformed but somewhat interested) customers, which are multiplied over a much larger customer base and resulted in substantially higher overall benefits (20-28 percent of the population were Group A customers while 57 to 64 percent were Group B). The consistently large differences in TVR enrollments between default flat and default TVR rates suggest that most electricity customers would fall into the B group. In the aggregate, despite the fact that the average per-participant impact was smaller with a default TVR offering, the significant increase in participation would lead to system peak reductions that are roughly *twice* as high as those of the opt-in TVR deployment.

These findings are illustrated in Figure 4 for Smart Light & Power Company, a hypothetical utility with one million residential customers and a coincident residential peak demand of 2,000 MW. In this case, the peak demand reduction increases from 34 MW to 57 MW when deployment is switched from opt-in TOU to default TOU. Similarly the peak demand for CPP increases from 72 MW to 149 MW when deployment switches from opt-in to default TVR.

The remaining unknown in our analysis is the impact of the C group – those customers who could potentially react negatively to a default TVR. It will be essential to accompany the transition to a default TVR with a strong customer outreach and education program. The program should provide customers with digestible information about their new rate and the bill savings opportunities it provides. It should also make them aware of the fact that they have a choice, and can enroll in a different rate if that is their preference. The rate transition will also need to be managed carefully, to avoid sudden, dramatic changes in customer bills. There are a number of options – such as gradual changes to the rate design, or a phased bill protection scheme – that would make this possible. Where default TVR rates have been deployed, these strategies have helped to pre-emptively address the concerns of customers in the C group.

Advice to Regulators

By and large, the status quo is dominated by a flat rate, with its attendant economic inefficiency and unfairness. Switching the default from flat rates to TVR will bring about significant economic gains and reduce cross-subsidies between consumers. Furthermore, a default TVR, unlike a mandatory rate, will preserve customer choice.

Regulators should reassess the choices that are embedded in the status quo since they are not always the best choices for society as its moves forward to embrace a new energy future. In the past, the status quo has been regarded as sacrosanct. It is time to discard this view, since new technologies and pricing designs are now available to meet the needs of a new generation of customers that has a strong interest in saving money, saving energy, and protecting the environment.

21. Both the CPP and TOU rates were offered concurrently with in-home energy information displays (IHDS).