BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET No. E-100, SUB 158

In the Matter of:	)	
	)	
Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities – 2018	)	**DIRECT TESTIMONY OF BRENDAN KIRBY, P.E. ON BEHALF OF SOUTHERN ALLIANCE FOR CLEAN ENERGY**
	)	
	)	

TABLE OF CONTENTS

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, position and business address.

A. My name is Brendan J. Kirby P.E. I am an electric power systems consultant, and my business address is 12011 SW Pineapple Court, Palm City, Florida.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying on behalf of the Southern Alliance for Clean Energy.

Q. Please summarize your qualifications and work experience.

A. I am currently a private consultant with numerous clients including the Hawaii Public Utilities Commission, National Renewable Energy Laboratory (NREL), over fifteen utilities, the Energy Systems Integration Group (ESIG), Electric Power Research Institute (EPRI), the American Wind Energy Association (AWEA), Oak Ridge National Laboratory (ORNL), and others. I retired from the Oak Ridge National Laboratory's Power Systems Research Program.

I have 44 years of electric utility experience, and I have been working on electric power industry restructuring and ancillary services since 1994 and spot retail power markets since 1985.

I am a licensed Professional Engineer with a M.S degree in Electrical Engineering (Power Option) from Carnegie-Mellon University and a B.S. in Electrical Engineering from Lehigh University.

A copy of my curriculum vitae is included as Kirby Exhibit A.

Q. Can you please describe in greater detail your experience related to power system operations?

A. Yes. I will note at the outset that Duke Energy's Reply Comments filed previously in this proceeding mischaracterized my power systems qualifications and incorrectly referenced another affiant's qualifications in an effort to discount my extensive power systems experience.[1] To correct any misunderstanding, I have attached a full resume, including a list of relevant publications, to this testimony, and further provide a brief summary of my relevant experience here.

After graduating from Lehigh University with a Bachelor of Science in Electrical Engineering in 1975 I started my career at the Long Island Lighting Company. I moved to the Department of Energy's (DOE) Oak Ridge Reservation in 1977 after receiving a Master's Degree in Electrical Engineering (Power Option) from Carnegie Mellon University. My first fifteen years in Oak Ridge were spent with the operating contractor for DOE's 7,000 MW uranium enrichment complex performing operational and planning load flow, transient stability, short circuit and specialty analysis both individually and in joint studies with the Tennessee Valley Authority, Union Electric, Central Illinois Public Service, Illinois Power, and Kentucky Utilities. In 1985 I participated in taking the 3,040 MW Paducah Gaseous Diffusion Plant from a firm power contract

[1] *See* Duke Reply Comments at p. 87 ("Mr. Kirby—who has no power system operational experience…"). This statement references n. 248, which cites SACE Response to Duke Energy Request No. 1, Item 1-24, Docket No. E-100 Sub 158. This Data Response was prepared by Mr. Wilson in response to Duke's inquiry regarding his qualifications and therefore describes Mr. Wilson's qualifications, not my qualifications.

supply paradigm to real-time supply from the wholesale, inter-utility, spot energy market.

I spent my second fifteen years in Oak Ridge as a senior power systems researcher in the Power Systems Research Program at the Oak Ridge National Laboratory (ORNL) where I conducted research into:

- Electric power system reliability and security,
- Ancillary services – especially including the definition of, need for, measurement of, and supply of regulation and load following,
- Electric industry restructuring,
- Wind and solar generation integration,
- Distributed resources,
- Demand side response, and
- Energy storage.

Dr. Erik Hirst and I published our first ORNL report on ancillary services (including regulation) in March 1995, one year before the Federal Energy Regulatory Commission (FERC) issued its landmark Order 888 on electric industry restructuring and unbundling of ancillary services.[2] FERC discussed and referenced our ancillary services report and comments in Order 888 as "Oak Ridge".

Over the following ten years we published over fifteen ORNL reports and dozens of technical papers further refining ancillary services (including regulation) definitions, requirements, quantification metrics, and allocation

[2] B. Kirby, E. Hirst, and J. VanCoevering 1995, *Identification and Definition of Unbundled Electric Generation and Transmission Services*, ORNL/CON-415, Oak Ridge National Laboratory, Oak Ridge, TN, March.

methods. I extended this work to include the provision of spinning reserve and regulation through demand response. I worked with ALCOA to have their Warrick Indiana aluminum smelter load provide regulation to the Midwest Independent System Operator.

Working with colleagues at the National Renewable Energy Laboratory we extended this work to the ancillary services requirements of and provision by wind and solar resources.

Immediately following the August 14, 2003 northeast blackout, I was sent by FERC to conduct the system operator field interviews of PJM, American Electric Power, and the Michigan Electric Coordinated System that became part of the North American Electric Reliability Corporation (NERC) US/Canada Investigation Team Report. I was subsequently detailed to FERC from ORNL for a year to provide technical support as FERC increased their internal capabilities in preparation for the establishment of mandatory reliability standards.

During that year, among other tasks, I was the FERC representative on the initial NERC Reliability Readiness Audits of Control Areas and Reliability Coordinators covering about half of North America (including Duke, TVA, and Southern).

I started private consulting while still at the Oak Ridge National Laboratory but have been consulting full time since my retirement from ORNL in 2007. Clients have included over 15 utilities (including TVA, Southern, and NextEra) as well as (among others):

- The Hawaii Public Utilities Commission (where, among other things, I was appointed the Special Advisor for Demand Response),
- National Renewables Energy Laboratory (NREL),
- Edison Electric Institute (EEI),
- Electric Power Research Institute (EPRI),
- Voith Hydro,
- Wartsila,
- Caterpillar,
- The World Bank,
- Regulatory Assistance Project (RAP),
- American Wind Energy Association (AWEA),
- Canadian Wind Energy Association, and
- Energy Systems Integration Group (ESIG).

My research interests continue to include wind and solar power integration, ancillary services, demand side response, distributed resources, electric industry restructuring, bulk system reliability, energy storage, and advanced analysis techniques. I have published, at ORNL and after, over 180 papers, articles, and reports. I coauthored a pro bono amicus brief cited by the United States Supreme Court in its January 2016 ruling confirming FERC demand response authority. I have a patent for responsive loads providing real-power regulation and am the author of a NERC certified course on Introduction to Bulk Power Systems: Physics / Economics / Regulatory Policy. I served on the NERC Standards Committee and the NERC Integration of Variable Generation Task Force (IVGTF).

Q. Have you previously filed testimony as an expert witness in a regulatory proceeding?

A. Yes. I have testified in proceedings regarding wind and solar integration, bulk power system reliability, ancillary services, and demand response before Commissions in Georgia, California, Minnesota, Texas, Wyoming, and Hawaii, as well as before the Federal Energy Regulatory Commission.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate and respond to the Duke Energy Carolina ("DEC") and Duke Energy Progress ("DEP") (together "Duke Energy" or "the Companies") proposed solar integration charge and the *Stipulation of Partial Settlement Regarding Solar Integration Services Charge*, entered into by Duke Energy and Public Staff on May 21, 2019 ("Solar Integration Charge Stipulation"). My testimony responds to direct testimony, comments, and the stipulation filed by Duke Energy in this proceeding.

Q. Are you sponsoring any Exhibits?

A. Yes. I am sponsoring two expert reports: *Duke Energy Proposed Integration Charge*, included as Kirby Exhibit B, and *Proposed Solar Integration Re-Dispatch Charge*, included as Kirby Exhibit C. I am also sponsoring my curriculum vitae, which is included as Kirby Exhibit A.

Q. Please provide an overview of your testimony.

A. My testimony explains that Duke Energy's proposed solar integration charge is based on an analysis methodology that does not represent the physical balancing requirements or requirements imposed by NERC mandatory reliability standards.

The proposed solar integration charge was developed for Duke Energy by Astrapé Consulting and documented in a November 11, 2018 study titled "Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study" (*Ancillary Service Study* or the *Study*). The unreasonable assumptions and flawed methodology used in the Study will result in increasingly unrealistic estimates of required regulation reserves as solar penetration increases. The Commission should not approve a solar integration charge that is based on regulation requirements that Duke will not actually experience or costs that Duke will not actually incur.

My testimony will discuss several major errors in the *Ancillary Service Study's* assumptions, each of which results in the Study overestimating the Companies' regulatory requirements and artificially inflating solar integration cost projections:

(1) The $LOLE_{FLEX}$ reliability metric is unrelated to mandatory NERC reliability requirements and is inappropriate for this analysis.

(2) The production cost modeling assumption that DEP and DEC are islanded systems, disconnected from the Eastern Interconnection, is wrong.

(3) Linear scaling of expected short-term variability from new solar generators as solar penetration rises is physically incorrect.

All of these assumptions result in overstating the regulation requirements and related costs that DEP and DEC will experience as solar penetration increases.

My testimony will also explain my past concerns with the quality of data used in the *Study*, and will discuss my concerns regarding the terms of the Solar Integration Charge Stipulation entered into by Duke Energy and Public Staff, including the use of marginal rather than average costs when calculating the proposed integration services charge cap.

Finally, I discuss concerns with Dominion Energy's proposed Intermittent Generation Re-Dispatch Charge.

II. DUKE ENERGY RELIES ON THE *ANCILLARY SERVICE STUDY'S* FLAWED METHODOLOGY TO JUSTIFY EXPONENTIALLY INCREASING SOLAR INTEGRATION CHARGES

Q. Please explain the basic methodology underlying the *Ancillary Study Report*. Is this methodology sound?

A. The basic underlying analysis methodology of determining the cost of solar integration by comparing production cost modeling results with and without solar, while holding reliability constant, is well established and has been executed successfully by others. However, the analysis described in the *Ancillary Service Study* is fatally flawed because Astrapé:

(1) invented and applied a wholly inappropriate $LOLE_{FLEX}$ reliability metric;

(2) modeled DEC and DEP as isolated power systems rather than modeling them as they actually operate, as part of the Eastern Interconnection; and

(3) linearly scaled the short-term variability of new solar generation from existing data rather than being modeled to reflect actual aggregation benefits.

Q. What is the effect of this flawed approach at progressively higher solar penetration levels?

A. At high solar penetration levels, the *Ancillary Service Study* generated exponentially increasing integration costs based on the flawed underlying assumptions.[3] This conclusion, which suggests that integration charges must exponentially rise as solar penetration increases in order to cover accelerating integration costs, is inaccurate. This conclusion arises from the use of inappropriate reliability metrics, not due to exponentially increasing physical balancing requirements. If relied upon, this flawed methodology could be used to impose exponentially increasing integration charges upon solar developers when

[3] Testimony and Exhibits of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, Direct Testimony of Nick Wintermantel at p. 20 ("Looking to the high penetration scenarios, the Study results indicated an exponentially increasing cost of integrating incremental solar with the conventional fleet.") (hereinafter "Wintermantel Direct Testimony").

they are not justified.

A. Inappropriate Use of the $LOLE_{FLEX}$ Metric

Q. Is $LOLE_{FLEX}$ an appropriate metric for quantifying a solar integration charge?

A. No, the $LOLE_{FLEX}$ metric is not appropriate for quantifying a solar integration charge. Mr. Wintermantel states in his Direct Testimony that "[t]his LOLE metric is traditionally used for IRP purposes to determine target reserve margin and required installed capacity amounts."[4] He further states that:

> The "1 day in 10 year" planning standard is used to ensure a utility has enough capacity installed and available so that only one firm load shed event is forecasted to occur every 10 years. All simulations in the Study were targeted to this level of reliability by adjusting capacity as needed to be consistent with the "1 day in 10 year" planning standard . . .[5]

However, a metric based on a one-day-in-ten-year *planning* adequacy criteria is completely inappropriate for daily operations. Duke Energy's Reply Comments state: "$LOLE_{FLEX}$ essentially requires the system to maintain enough ramping capability to match 5-minute load ramps ***in all but one period every 10 years***"[6] This is not a rational daily operating requirement because it imposes a substantially more stringent requirement than what is actually needed to safely

---

[4] *Id.* at p. 15

[5] *Id.* at p. 16.

[6] Duke Energy Carolinas, LLC and Duke Energy Progress, LLC Reply Comments at p. 96 (hereinafter "Duke Energy Reply Comments") (emphasis added).

and reliably conduct daily operations. This requirement is unnecessary for a Balancing Area operating within the Eastern Interconnection and is not required by NERC mandatory reliability standards.

Q. If a one-day-in-ten years reliability criteria is appropriate for setting IRP generation capacity requirements why is it not an appropriate short-term balancing requirement?

A. The *Ancillary Service Study* explains that "plans must be in place to have adequate capacity such that firm load is expected to be shed one or fewer times in a 10-year period."[7] This is a reasonable long-term generation planning criteria since a shortfall in generation capacity can indeed result in the need to shed firm load in order to avoid a blackout. However, it is a completely inappropriate short-term balancing criteria under non-contingency conditions because a 5-minute imbalance will not result in the need to shed firm load or a blackout. That is why NERC does not require continuous perfect balancing from each BA.

Q. Does Duke admit that their proposed $\mathbf{LOLE_{FLEX}}$ standard is subjective?

A. Yes. The Reply Comments state: "the standard of 0.1 $LOLE_{FLEX}$ is admittedly subjective".[8]

[7] Duke Energy Reply Comments, DEP/DEC Exhibit 2, *Ancillary Service Study* at p. 10 (hereinafter "*Ancillary Service Study*").
[8] Duke Energy Reply Comments at p. 97.

Q. How did Mr. Wintermantel's Direct Testimony address the *Ancillary Service Study's* use of the $\mathrm{LOLE}_{\mathrm{FLEX}}$ metric?

A. Mr. Wintermantel acknowledges that the $\mathrm{LOLE}_{\mathrm{FLEX}}$ standard is not a generally used industry metric. He further admits that operational reliability is governed by NERC Balancing standards, which do not include the $\mathrm{LOLE}_{\mathrm{FLEX}}$ metric employed in the *Ancillary Service Study*.

Q. Is $\mathrm{LOLE}_{\mathrm{FLEX}}$ of 0.1 a generally utilized industry metric or standard for assessing reliability events caused by lack of flexibility?

A. No. Operational reliability is governed by the NERC Balancing Standards and is measured by different metrics.[9]

Q. Has NERC established mandatory balancing requirements that address short-term variability of loads and uncontrolled generators?

A. Yes. Power system balancing requirements to maintain reliability are established by NERC. These requirements are laid out in mandatory NERC reliability standard BAL-001-2 – Real Power Balancing Control Performance. BAL-001-2 establishes two reliability metrics that apply during normal (non-contingency) operations: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE Limit (BAAL). I discussed CPS1 and BAAL balancing requirements in my expert report. Duke Energy's Reply Comments never disputed the fact that the

[9] Wintermantel Direct Testimony at p. 17.

actual balancing requirements are based on the NERC BAAL and CPS1 metrics and not on the invented $LOLE_{FLEX}$ metric.

Q. Can you briefly state the difference between balancing requirements based on the Companies' self-imposed $LOLE_{FLEX}$ *Study* metric versus those based on the actual NERC CPS1 and BAAL requirements?

A. Yes. As Duke Energy's Reply Comments state: "$LOLE_{FLEX}$ essentially requires the system to maintain enough ramping capability to match 5-minute load ramps in all but one period every 10 years."[10]

Rather than requiring perfect balancing for all but one 5-minute interval in ten years NERC's CPS1 limits the *annual average* imbalances. Further, not all imbalances are bad. When interconnection frequency is below 60 Hz overgeneration helps raise frequency and helps reliability. Similarly, when interconnection frequency is above 60 Hz under generation helps lower frequency and also helps reliability. CPS1 gives credit for those imbalances that help restore interconnection frequency. While an annual average CPS1 score of 100% is required CPS1 scores range from 0% to 200%, so 100% is not perfect balancing. The Balancing Authority ACE Limit (BAAL) does not require perfect balancing either. BAAL only limits ACE deviations that exceed *30 consecutive minutes*. Further, like CPS1, BAAL only limits ACE deviations that hurt interconnection frequency. That is, over-generation is not limited when interconnection frequency

[10] Duke Energy Reply Comments at p. 96.

is below 60 Hz and under-generation is not limited when interconnection frequency is above 60 Hz. ACE limits are lax when frequency is close to 60 Hz and get progressively tighter as frequency deviates farther from 60 Hz.

Therefore, neither of the applicable reliability metrics that DEC and DEP must follow require the Companies to balance load as stringently as the self-imposed $LOLE_{FLEX}$ metric. In sum, the *Ancillary Service Study* inflates the balancing requirements far beyond what is actually necessary, and then passes on the cost of achieving this unnecessarily stringent and unrealistic standard onto QFs in the form of an inflated solar integration charge.

Q. Did the *Ancillary Service Study* mention NERC balancing requirements?

A. Yes. The *Ancillary Service Study* references two NERC reliability metrics: CPS1 and CPS2 saying: "Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and CPS2 standards is a critical component of a solar ancillary service cost impact study."[11]

CPS2 is no longer applicable, however. It was replaced in July 2016—well before the *Ancillary Service Study* was published—with the BAAL requirement, discussed above, when BAL-001-02 became the effective standard. CPS2 did not require perfect balancing either. CPS2 required the monthly average 10-minute imbalances to remain below 92 MW for DEC and below 17 MW for DEP *90% of the time*. That is, CPS2 allowed deviations for over 5,000

[11] *Ancillary Service Study* at p. 10.

10-minute intervals each year while $LOLE_{FLEX}$ considers more than 1 5-minute deviation in 10 years unacceptable. Therefore, even the outdated metric the *Ancillary Service Study* does mention does not require nearly as stringent of balancing requirement as $LOLE_{FLEX}$.

Q. Page 35 of Mr. Snider's May 21, 2019 Direct Testimony includes a Figure 5, meant to illustrate an increase in volatility with solar generation currently operating on the DEP power system relative to a no-solar scenario. Please respond to this figure.

A. I would like to make two important points regarding this figure. First, as discussed above, NERC mandatory reliability standards do not require instantaneous balancing of all deviations, so finding a single 2-minute interval with a 65 MW increase in deviation does not equate to a NERC requirement of an additional 65 MW of reserves.[12] Second, Figure 5 shows the results for March 10, 2019, the most variable day of the 10-day sample provided. The other nine days have single point excursions that range from 7 MW to 62 MW (averaging 35 MW) higher with solar than without.

In any case, Figure 5 does not demonstrate that the average deviation is 35 MW greater with solar than without. To the contrary, it shows that the single worst daily 2-minute deviation in this sample of ten days is, on average, a mere 35 MW greater with solar than without. And again, NERC does not require

[12] The *Ancillary Service Study* states that DEP will require 166 MW of additional reserves for the DEP Existing Plus Transition case. *Id.* at p. 49.

balancing each 2-minute deviation. Therefore, Figure 5 seems to prove that the *Ancillary Service Study* significantly overstates the added reserve requirements that increased solar penetration imposes on the Companies' balancing areas.

Q. Has Duke recently discussed efforts to integrate distributed energy resources to account for and mitigate increases in generation variability?

A. Yes, indeed Duke Energy recently represented to the NERC Operating Committee that it has successfully reduced impacts of solar generation short-term volatility.[13] Duke Energy's Adam Guinn made a presentation at the June 4-5, 2019 NERC Operating Committee meeting titled "Integration and Monitoring of Distributed Energy Resources in System Operations". In that presentation Mr. Guinn stated that DEP "tuned" its automatic generation system (AGC) in September 2018 in response to the changing generation resource mix, which is primarily driven by the increase in solar generation. AGC is the central generation control system that sends control signals to each Duke Energy generator every few seconds directing their provision of regulation. More specifically, Mr. Guinn stated that "Control bounds were ***relaxed*** to improve response performance".[14] Mr. Guinn listed a number of benefits that resulted from this relaxing of the AGC regulation control:

- Generators better respond to sustained system needs
- Dispatchable generators no longer chasing fleeting events
- Reduces impacts from Variable Energy Resource 1-min volatility

[13] Duke Energy Progress presentation to the NERC Operating Committee, June 4-5 2019, "Integration and Monitoring of Distributed Energy Resources in System Operations." Kirby Exhibit D.
[14] Duke Energy Progress presentation to the NERC Operating Committee, June 4-5 2019, "Integration and Monitoring of Distributed Energy Resources in System Operations", slide 9. Kirby Exhibit D.

- Improves fleet efficiency
- An ~20% reduction in BAAL exceedance minutes
- Negligible impacts to CPS1%[15]

The presentation to the Operating Committee shows Duke Energy's appropriate operational focus on the actual NERC balancing metrics BAAL and CPS1 rather than the fictitious $LOLE_{FLEX}$ metric. It also shows that DEP has reduced the impact of solar generation short-term volatility by no longer "chasing fleeting events." In other words, this presentation demonstrates that the assumptions used in the *Ancillary Service Study* deviate from Duke Energy's actual operations and that the *Study* fails to account for recent improvements in Duke's response performance. No doubt performance will continue to improve as greater experience with integrating solar generation is gained.[16]

Q. How did Duke Energy respond to your findings in its Reply Comments?

A. Duke Energy altogether failed to explain its reliance on the self-imposed $LOLE_{FLEX}$ requirement instead of NERC mandatory reliability standards. Instead, it questioned whether my recommendation to consider mandatory industry-wide balancing standards, instead of a fictitious, self-imposed standard, was "intended to be constructive and to improve the precision of the modeling or, in actuality, is a 'poison pill' designed to make the task unachievable."[17] My recommendation

[15] *Id.*
[16] M. Milligan, B. Kirby, T. Acker, M. Ahlstrom, B. Frew, M. Goggin, W. Lasher, M. Marquis, and D. Osborn, 2015, "Review and Status of Wind Integration and Transmission in the United States: Key Issues and Lessons Learned", NREL/TP-5D00-61911, March
[17] Duke Energy Reply Comments at p. 97.

that the Companies model their balancing requirements based on actual, up-to-date NERC standards is not a "poison pill"—it is a reasonable response to a modeling framework that is completely divorced from reality. My concern is compounded by the fact that the Companies appear unwilling to acknowledge that the *Ancillary Service Study's* sole reference to NERC requirements was to a standard that was already obsolete at the time the *Study* was published. While my recommendation that Astrapé adjust its modeling framework to more closely reflect actual balancing requirements may complicate the analysis somewhat, it is not, as Duke Energy suggested, "unachievable." Furthermore, my report suggests the methodology used in a 2016 Idaho Power study as a feasible way of modeling actual balancing requirement. I discuss this study in more detail later in my testimony.

B. Inappropriate Treatment of DEC and DEP as Islanded Power Systems

Q. Are DEP and DEC islanded power systems?

A. No. Treating DEC and DEP as islanded power systems in the *Ancillary Service Study* differs from how Duke actually plans and operates DEC and DEP as interconnected utilities.

Q. Is Duke's proposed solar integration charge based on the assumption that DEP and DEC are disconnected from the Eastern Interconnection?

A. Yes. The *Ancillary Service Study* states that "The utilities are modeled as islands for the Ancillary Service Study."[18]

Q. Why is it important that DEP and DEC be modeled as part of the Eastern Interconnection rather than as islanded power system?

A. Importantly, and fundamentally, NERC reliability requirements are based on operations within an interconnection; specifically, within the 720,000 MW Eastern Interconnection in Duke Energy's case. This is fundamentally important because with interconnected utility operations, small imbalances within one BA do not result in loss of load events under normal conditions. In fact, imbalances are occurring all the time under normal conditions. As Mr. Guinn noted in Duke Energy's presentation to the NERC Operating Committee, there is no need for dispatchable generators to chase "fleeting events."[19] As I discussed above, the NERC standards limit the magnitude and frequency of allowed imbalances, but they do not attempt to eliminate them or restrict them to one-event-in-ten-years.

Utilities interconnect precisely because interconnecting gives all participants tremendous reliability and economic benefits. Only under the most extreme circumstances would DEC or DEP temporarily withdraw from the Eastern Interconnection because doing so would reduce reliability and increase costs dramatically for rate payers with no offsetting benefits. Modeling DEC and DEP as islanded power systems makes no sense for the same reasons.

[18] *Ancillary Service Study* at p. 13.
[19] Duke Energy Progress presentation to the NERC Operating Committee, June 4-5 2019, "Integration and Monitoring of Distributed Energy Resources in System Operations", slide 9. Kirby Exhibit D.

Q. Has Duke explained why they base the proposed solar integration charge on an analysis that wrongly assumes that DEP and DEC are islanded power systems?

A. The stated reason for modeling DEC and DEP as islanded power systems in the *Ancillary Service Study* is that "it is aggressive to assume that neighbors will build flexible systems to assist DEC and DEP in their flexibility requirements."[20] Mr. Wintermantel elaborates in his Direct Testimony:

> "DEC and DEP systems were modeled as islands for this Study in order to capture the incremental impact of adding solar generation to each system. Each Company is responsible for meeting NERC requirements within its own BA. I have been advised by the Companies' system operators that while the Joint Dispatch Agreement between DEC and DEP does allow for excess energy transfers of non-firm energy, it does not support the firm capacity that would be required to provide the intra hour ancillary services needed to manage the variability in solar output.
>
> "Although DEC and DEP are interconnected with surrounding regions, additional ancillary services are necessary to integrate solar generation, and these services have a cost. Further, it is inappropriate for the Companies to assume that they are able to rely upon surrounding neighbors for this type of service. While the Companies could hypothetically contract for real-time regulation service from designated generating units in other BAs, this alternative would require securing firm transmission service as well as capacity and energy contracts from the neighboring generating facility owners—both of which would come at a cost. For these reasons, it is appropriate that the Study models the Companies as islands."[21]

These arguments completely misunderstand the benefits of interconnected utility

[20] *Ancillary Service Study* at p. 13.
[21] Wintermantel Direct Testimony at p. 27.

operations and the impacts on regulation requirements and reserves. Utilities started to interconnect over ninety years ago in order to increase reliability while reducing each utility's reserve requirements. This works because of the strong aggregation diversity benefits for load and generation short-term variability under both normal and contingency conditions. Interconnected power systems are more resilient, reliable, and economic than islanded power systems. All utilities participating in an interconnection benefit from reduced reserve requirements. The mandatory NERC reliability standards are based on interconnected operations. Determining reserve requirements for islanded versions of DEC and DEP is irrelevant to the way the power systems, including DEC and DEP, are actually designed, built, and operated.

Put simply, regulation requirements for utilities operating as an interconnection are lower than the regulation requirements for those same utilities operating as islands. This is not a question of obtaining regulating reserves from a neighbor over a firm transmission path. This is a reflection of the reduced requirement for regulation. The *Ancillary Service Study* fails to account for this reduced requirement and therefore overstates the regulation requirements the Companies are actually subject to.

Q. How did Duke Energy Respond to your concerns regarding the modeling DEC and DEP as islanded power systems?

A. Instead of meaningfully responding to the concerns raised in SACE's initial comments, Duke Energy repeatedly mischaracterizes the islanding concern and attempts to obfuscate the valid points raised by myself, the Public Staff, and NCSEA.

For example, in its Reply Comments Duke Energy repeatedly describes other parties' concerns with modeling DEC and DEP as islanded systems as "assuming that the Companies can rely on 'external market assistance'… to provide the load-following reserves required to reliably respond to the intra-hour intermittency and volatility of solar resources."[22] I did not suggest that the Companies obtain "external market assistance" from other utilities. My concern, which Duke Energy never addressed in its comments, is that modeling DEC and DEP as islands completely misses the benefits of interconnected operations—the reduced requirement for moment-to-moment balancing—which are reflected in the mandatory NERC reliability requirements. This is true even if DEC and DEP have no contractual transactions with each other or with any neighbor. In sum, modeling DEC and DEP as islands ignores the fact that the NERC reliability standards the utilities are subject to factor-in the benefits of interconnected operations. Pretending that this is not the case allows the Companies to once again inflate their balancing requirements to an unrealistic level, and pass on the costs necessary to meet these self-imposed requirements onto solar QFs.

[22] Duke Energy Reply Comments at pp. 86, 88 ("Mr. Kirby's presumption that the Companies can rely upon other members of the VACAR RSG to provide regulating reserves to meet intra-hour volatility is simply wrong."); *Id.* at p. 91 ("The parties criticizing the BA island assumption appear to believe that after solar is added to the system, the DEC and DEP BAs should be able to increase their reliance on intra-hour market assistance to alleviate reliability issues caused by solar QFs.")

Q. Are you suggesting that Duke Energy shirk its balancing responsibilities and "lean" on its neighbors by not treating DEC and DEP as islands?

A. No. Just as DEC and DEP are not shirking their contingency reserve obligations or leaning on their neighbors when they participate in the VACAR reserve sharing group neither are they leaning on their neighbors when they follow the NERC BAL-001 standard. By joining the VACAR reserve sharing group DEC, DEP, and every other VACAR member is able to significantly reduce the amount of contingency reserves they carry and still maintain reliability. This is a fundamental benefit of reserve sharing groups, that the total amount of reserves required to maintain the same level of reliability is greatly reduced because the multiple members are treated as a connected whole. If DEC and DEP were treated as islanded systems they would each have to carry enough contingency reserves to cover the loss of their own largest generator. Because they are not islands and are members of a reserve sharing group they can meet NERC standards and operate reliably with only a fraction of the contingency reserves required for islanded operations.

While obtaining contingency reserve aggregation benefits requires DEC and DEP to join the VACAR reserve sharing group they obtain regulation reserve reduction benefits by interconnecting with the Eastern Interconnection. Interconnected utility operation inherently provides regulation benefits to all of the interconnection participants.[23] DEC, DEP, and every other utility simply do not incur the same balancing requirements or costs as part of the Eastern Interconnection that they would incur if they were islands. The NERC reliability standards do not require perfect balancing to maintain reliability and everyone benefits. Aggregation reduces individual balancing requirements. No one is "leaning" on their neighbors or shirking their responsibilities. This is a major reason that utilities started interconnecting over ninety years ago.

The Commission should not allow Duke Energy to try to recover regulation reserve costs based on calculations of what would be required for islanded operations since DEC and DEP do not operate that way.

C. Unsupported Assumption that Solar Variability Scales Linearly

Q. Duke Energy linearly scaled existing solar plant minute-to-minute output data to represent new solar plants. Is that appropriate?

A. No. Of necessity, the *Ancillary Service Study* (and any planning study) modeled solar sites that do not yet exist and for which there is no actual data. Consequently, appropriate solar plant output data must be synthesized for the analysis. It is important that the synthesized data captures aspects of the actual solar plants that will be built. It is also important that the synthesized data represents data that is synchronized to the load data it is paired with to accurately represent net power system variability and uncertainty.

[23] Regulation Sharing Groups are recognized in the NERC standards, but they provide different and additional benefits to those being discussed here.

Linear scaling is reasonable for determining the average energy production from additional solar generation; double the number of solar plants and get about double the energy. It is inappropriate for estimating the minute to minute variability, however. Short-term variations of loads and variable renewable generators are typically uncorrelated among themselves and with each other. Consequently, regulation requirements are not arithmetically additive but instead increase with the root mean square: doubling the solar output increases short-term variability by a factor of about 1.4 (the square root of [1^2+1^2]), not 2 (1+1).

Solar plant short-term variability tends to be uncorrelated because solar plants cannot be physically placed on top of each other. They have significant geographic size. They also are typically not all placed side-by-side, giving them even greater geographic diversity. A cloud passing by will not shadow all plants at exactly the same time. Solar short-term variability tends to be uncorrelated for physical reasons.

Longer term trends for both load and solar generation (the daily load pattern, sun cycle, and the passage of weather fronts) result in coordinated load and generation patterns that impact many loads or generators similarly. The aggregate daily load pattern for two municipalities, for example, tend to be similar and the load patterns tend to add linearly. Conversely, short-term minute-to-minute variability for loads, solar plants, and wind turbines tend to be uncoordinated and short-term variability tends to add statistically rather than linearly.

Q. Can you provide an example of another instance where diversity benefits reduce regulation requirements and linear scaling would be inappropriate?

A. Yes, one might consider common household appliances like water heaters (and air conditioners and many other pieces of equipment), which individually have very high variability but collectively present a much smoother profile to the utility. Water heaters and air conditioners do not provide temperature control, for example, by smoothly dialing their output up and down like a light dimmer. Instead they cycle fully on and completely off every few minutes to hold water (or air) temperature within a desired narrow range. This cycling fully on and fully off presents as highly variable individual load to the utility.

If tank type electric water heaters were a brand-new technology a cautious utility might install one to gain experience. They would discover that the water heater cycled its 2.5 kW heating element and then fear that if a million customers installed water heaters the utility could be faced with a 2,500 MW load instantly coming on and off every few minutes. After all, “it is difficult to predict the volatility of future portfolios”[24].

Fortunately, we have a lot of operating history with electric water heaters and we know that they do not synchronize their short-term variability. We know that it is completely inappropriate to linearly scale water heater short term variability. We know that it is completely appropriate to recognize that the longer-term water heater energy use pattern is largely synchronized, with greater

[24] *Ancillary Service Study* at p. 30.

consumption in the morning and evening, but that short-term variability is not. Consequently a utility would not be allowed to charge residential customers for an additional 2,500 MW of regulation reserves that were not actually required "just in case."

Like water heater variability (and air conditioner variability, etc.), solar variability scales statistically, not linearly. With both water heaters and solar generators, the short-term variability of one individual entity is not synchronized with the variability of other individual entities: short-term variability is uncorrelated. Just as with water heaters, it is not appropriate to linearly scale the short-term variability of a few solar generators to represent the aggregate short-term variability of a larger fleet.

Q. Does the scientific literature recognize significantly reduced regulation requirements resulting from geographic diversity of solar plants?

A. Yes. A 2010 Lawrence Berkeley National Laboratory report provides a good example.[25] The report acknowledged that "[e]arly studies of PV grid impacts suggested that short-term variability could be a potential limiting factor in deploying PV."[26] However, after studying variability across multiple solar sites, the report concluded that "accounting for the potential for geographic diversity can significantly reduce the magnitude of extreme changes in aggregated PV

[25] Andrew Mills and Ryan Miser, 2010, Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power, Ernest Orlando Lawrence Berkeley National Laboratory, (Sept. 2010), https://emp.lbl.gov/publications/implications-wide-area-geographic.

[26] *Id.* at p. 2.

output, the resources required to accommodate that variability, and the potential costs of managing variability."[27] The report found that short-term variability of geographically dispersed solar plants is largely uncorrelated and that previous studies that linearly scaled reserve requirements were in error stating: "[a]s is well known for wind, however, accounting for the potential for geographic diversity can significantly reduce the magnitude of extreme deltas, the resources required to accommodate variability, and the potential increase in balancing reserve costs."[28]

Q. Is there evidence in the data supplied by Duke Energy that short-term solar variability does not scale linearly?

A. Yes. An examination of the historic solar output data for DEP and DEC shows this decline in relative variability.[29] For example, for the month of July 2018 DEP had a maximum solar output of 1,630 MW while DEC had a maximum solar output of 427 MW. The maximum coincident solar output for the combination of DEP and DEC was 2,041 MW, just 0.8% below the sum of the DEP plus DEC maximum solar outputs. As expected, maximum solar output is closely correlated for DEP and DEC. Aggregating DEP and DEC does not greatly reduce the maximum solar output of the aggregation. By contrast, the relative short-term intra-hour variability of the aggregation of DEP and DEC is significantly lower than the sum of the variability of the two BAs. The hourly average standard

[27] *Id.*
[28] *Id.* at p. 34.
[29] SACE Data Request No. 2 Item No. 2-30 asked for, and Duke provided, 5-minute aggregate solar and load data for DEP and DEC for April 2016 through August 2018.

deviation of the DEP intra-hour variability for July 2018 was 9.7 MW. The hourly average standard deviation of the DEC intra-hour variability for July 2018 was 3.6 MW. If short-term variability scaled linearly as the *Ancillary Service Study* claims, then the hourly average standard deviation of the short-term variability for the net Duke system would be expected to be 13.3 MW (9.7 + 3.6). Instead, the hourly average short-term variability had a standard deviation of only 10.3 MW, just 78% of what linear scaling predicts. The 10.3 MW is also exactly what would be expected for completely uncorrelated short-term variability aggregation for DEP and DEC [square root of (9.7^2, + 3.6^2)].

Examining the increase in short-term variability as the solar fleet grew from April 2016 through July 2018 shows a similar result with short-term variability increasing much more slowly than peak output.

Because historic data shows the expected trend of short-term variability increasing much more slowly than solar capacity as solar penetration increases, the assumption of linear scaling is unjustified.

Q. How did Duke Energy respond to your recommendation that short-term variability of new solar plants should be modelled as uncorrelated?

A. Despite the historical data mirroring the trends that would be expected for uncorrelated short-term variability aggregation for DEP and DEC, the *Ancillary Service Study's* linear scaling of variability assumes perfect correlation of the short-term variability of the new and old solar plants. In response to SACE's initial comments, which explained that solar plant short-term variability tends to be uncorrelated, Duke Energy's reply comments stated:

> "Mr. Kirby estimated the discount with the following subjective formula.
>
> $$1 \,/\, \sqrt{\frac{\textit{Existing Plus Transition Capacity}}{\textit{Capacity from Historical Dataset}}}$$ [294]
>
> "The formula is not appropriate as it is not based on the observed diversity benefit of increasing solar."[30]

First, the formula I employed is not "subjective"—it is the standard root mean square statistical formula for combining the variability of uncorrelated, randomly varying, entities such as the short-term variability of aggregations of loads, solar generators, and wind generators. Second, as discussed above, this formula models hourly average short-term variability for the Companies' system more precisely than the linear scaling modeling the *Ancillary Service Study* employs. Therefore, it is Astrapé's assumption that short-term variability scales linearly which is unreasonable and out of line with observed diversity benefits of increased solar.

Q. Why isn't the *Ancillary Service Study's* inclusion of solar generation with reduced variability sufficient to account for the aforementioned diversity benefits?

A. The *Ancillary Service Study* states that it did include a case in which "the raw historical data volatility was utilized along with a distribution that has 75% of the raw data volatility to serve as bookends in the study for the "+1,500" MW solar

[30] Duke Energy Reply Comments at p. 106.

scenarios."[31] But these scenarios are not "bookends": they both still vastly overstate the short-term variability for the growing solar fleet. It would be much more reasonable to assume that short term variability of new solar plants is uncorrelated with that of the existing solar plants and with each other. The resulting expected short-term variability per MW of installed solar generation from uncorrelated solar variability would then be:

- 100% for the actual measured solar fleet
- 74% of-the-actual-measured-MW-variability-/-MW-of-installed-solar-generation for the Existing solar generation
- 61% for the Existing + Transition
- 55% for the Existing + Transition + Tranche 1
- 43% for the Existing + Transition + Tranche 1 + 1500 MW

The *Ancillary Service Study* included Existing + Transition + Tranche 1 + 1500 MW cases with 100% and 75% short-term variability when a more realistic assumption is that short-term solar variability will decline to 43% due to aggregation benefits.

Q. The *Ancillary Services Study* included solar generation from thirteen locations throughout the DEC and DEP service territories. Why is that not sufficient?

A. Thirteen locations is not a lot of diversity for 7,630 MW of solar generation in the Existing + Tranche 1 + 1500 MW case. If the simulated solar plants were evenly spread among only thirteen locations that would result in each solar plant being 587 MW and occupying about 3000 acres or 4.6 square miles. It would be much

[31] *Ancillary Services Study* at p. 31.

more realistic to simulate 7,630 MW of solar generation spread over 150 distinct locations, each representing a 50 MW solar plant.

The study did not include even that much diversity, however. Twenty two percent of the DEP solar plants and 24% of the DEC solar plants were modeled at single sites.[32] 78% of the DEP solar and 85% of the DEC solar was modeled at just four sites each. What might appear to be a reasonable attempt at site diversity is, in fact, singularly lacking in diversity.

Even if a 587 MW solar plant covering 3,000 acres were built, it would have a significant reduction in short-term variability compared with existing solar plants simply from its own geographic size.

High quality solar integration studies model realistically sized solar plants that are sited with realistic geographic separation. The *Ancillary Service Study* fails to do so.

Q. How do the best integration studies model higher penetrations of wind and solar generation than currently exist?

A. The best studies have sub-hourly solar or wind data that is time-synchronized to actual load data. This is because weather drives wind, solar, and load. The best solar and wind integration studies use mesoscale atmospheric numeric modeling to generate five- or ten-minute wind and solar data, at specific locations for every

[32] *Id.* at pp. 22-23.

proposed wind and solar generator, for a number of historic years.[33] The solar and wind data is then synchronized with actual measured load data covering exactly the same historic time period. This assures that diversity benefits as well as coordinated behavior are appropriately modeled. The best studies utilize reliability metrics that approximate actual NERC reliability requirements.

Because the *Ancillary Service Study* did not follow the practices of good integration studies the Commission should not accept the study results as proposed by Duke and should not find the proposed integration charge reasonable.

III. THE IDAHO POWER STUDY PROVIDES A BETTER MODEL FOR CALCULATING INTEGRATION COSTS

Q. In your report, you refer to a 2016 Idaho Solar Integration Study as providing a "feasible approach" to modelling variable renewable generation integration in a realistic way. Please explain why.

A. The Idaho Power Study studied variable renewable generation integration (solar and wind). The Idaho Power Study is a better model because it (1) employed production cost modeling with reserve requirements adjusted to maintain pre-solar-and-wind reliability levels; and (2) targeted reserves sufficient to compensate for 99% of the 5-minute balancing deviations—in other words it allowed a cumulative 90 hours per year of deviations. This methodology, while

[33] *See, e.g.*, Eastern Wind Integration and Transmission Study, NREL/SR-5500-47078, February, 2011 and Western Wind and Solar Integration Study Phase 2, NREL/TP-5500-55588, September 2013

still more conservative than the actual NERC balancing requirements, allowed the Idaho Power Study to more realistically model variable renewable generation integration. I recommend that the Commission relies on a study that more closely resembles the Idaho Power Study in order to more accurately calculate any appropriate solar integration charge.

Q. Mr. Wintermantel compares Idaho Power's incremental operating reserve requirements with those calculated for DEC and DEP. Is this an accurate comparison?

A. No. Mr. Wintermantel included a Figure 7 in his Direct Testimony that shows the MW of required additional reserves plotted against the MW of solar generation. Based on this figure, which shows that at low levels of solar penetration (800 MW and 1,500 MW of solar) the incremental load following reserves required by the Idaho Study is comparable to the load following reserves required by Astrapé's *Ancillary Service Study*, Mr. Wintermantel concludes that the $LOLE_{FLEX}$ metric is "reasonable and appropriate."[34] This conclusion is not sound because Idaho Power's peak load is only 3,400 MW compared with 20,600 MW for DEC and 14,000 MW for DEP, and as discussed above, the *Ancillary Service Study* predicts exponentially increasing cost of integrating incremental solar with the conventional fleet.[35]

Furthermore, variable renewable penetration (wind plus solar) in the Idaho

[34] Wintermantel Direct Testimony at p. 31, ll. 1-11.
[35] *Id.* at p. 20.

Power study was 67% of peak load compared with 5% to 33% penetration for Duke. Had integration requirements been plotted based on solar penetration percentage it would be clear that Duke's proposed solar integration charge is significantly higher than Idaho Power's at comparable levels of renewable penetration. Figure 1 below compares Idaho Power's additional reserve solar generation requirements with Duke's based on penetration level, and illustrates that DEC and DEP's additional operating reserve far exceeds Idaho Power's even though Idaho Power is experiencing far higher rates of renewable penetration.

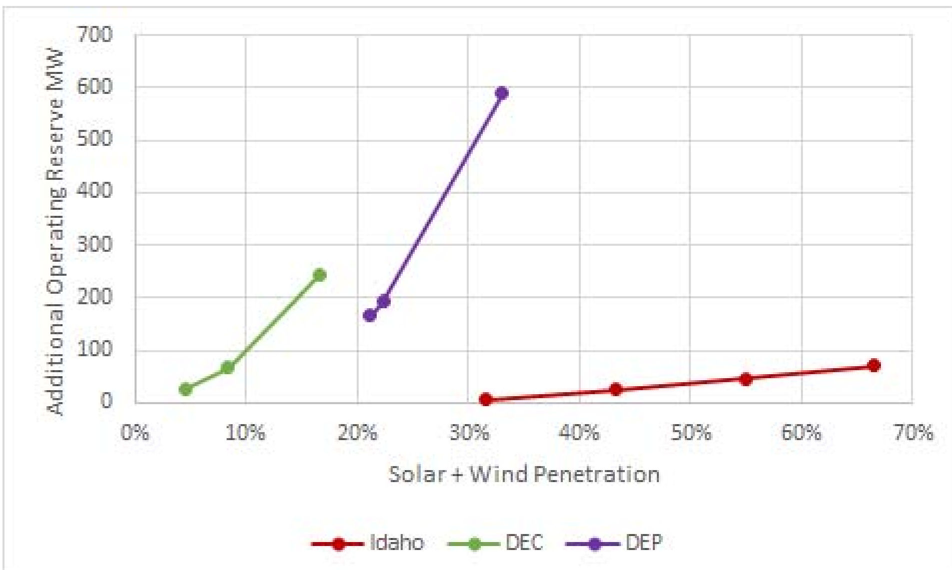


Figure 1: Idaho Power's additional reserve requirements compared to DEC and DEP's additional operating reserve

Figure 2, below, demonstrates that the integration costs calculated for DEC and DEP also dramatically exceed the integration costs calculated in the Idaho Power Study, even though Idaho Power is experiencing significantly greater renewables penetration.

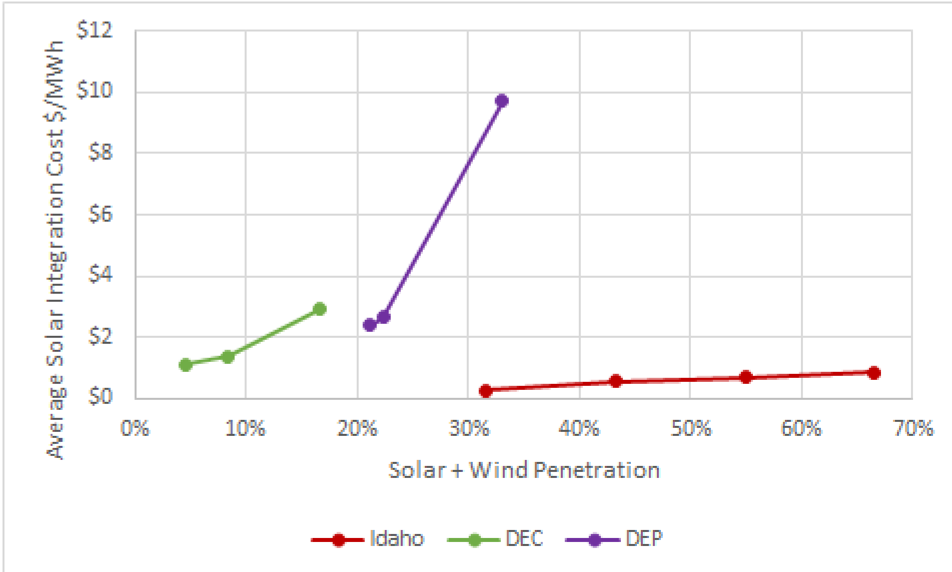


Figure 2: Idaho Power's calculated solar integration cost compared to DEC and DEP's calculated solar integration cost

These figures illustrate that reserve requirements and integration costs calculated in the *Ancillary Service Study* far exceed those calculated in the Idaho Power Study for much greater rates of solar and wind penetration. In other words, Mr. Wintermantel's statement that the Idaho Power Study validates the conclusions reached in the *Ancillary Service Study* is misleading and inaccurate.

Q. Why did Idaho Power find that it could relatively easily integrate 67% wind and solar generation penetration while the *Ancillary Service Study* concluded that the Companies will face significant integration costs at much lower levels of solar penetration?

A. A major difference in the integration analysis performed by Idaho Power and the *Ancillary Service Study* is the reliability metric. While the *Ancillary Service Study* used the fictitious 1-day-in-10-year $LOLE_{FLEX}$ short-term balancing requirement, Idaho Power targeted reserves (in both the base and renewables cases) sufficient to compensate for 99% of the 5-minute balancing deviations. That is, Idaho Power allowed a cumulative 90 hours per year of deviations rather than one-event-in-10-years. Idaho Power's modeling reliability metric is still very conservative but is much closer to the actual NERC reliability requirements and consequently results in a more realistic assessment of solar generation integration requirements.

Q. In Reply Comments, Duke Energy argued that the 99% confidence level used in the Idaho Power Study is no less stringent than the LOLE$_{\mathrm{FLEX}}$ 1-day-in-10-year balancing requirement used in the Astrapé *Ancillary Service Study*. Is this accurate?

A. No. The 99% confidence level used in the Idaho Power Study is less stringent than the LOLE$_{\mathrm{FLEX}}$ 1-day-in-10-year balancing requirement used in the *Ancillary Service Study*. The LOLE$_{\mathrm{FLEX}}$ reliability metric used in the *Ancillary Service Study* allows only a single 5-minute imbalance in ten years while Idaho Power's reliability metric allows 90 hours of imbalance per year. In other words, the LOLE$_{\mathrm{FLEX}}$ metric used in the *Ancillary Service Study* requires balancing that is over 10,000 times stricter than the 99% confidence level used in the Idaho Power study.

Duke Energy claims that the LOLE$_{\mathrm{FLEX}}$ balancing requirement is not as draconian as it seems because load deviations counteract solar deviations in some intervals and that DEP and DEC systems already have excess flexibility during some hours.[36] But these same points regarding flexibility and load deviation are inherent to any basic production cost modeling, including the Idaho Power Study, so they cannot be used as a means of distinguishing the balancing requirement in the two studies.

More importantly, the $LOLE_{FLEX}$ 1-day-in-10-year balancing requirement is completely unrelated to the mandatory NERC balancing requirements, which also apply to each BA's net load.

IV. DATA QUALITY ISSUES IN THE *ANCILLARY SERVICE STUDY*

Q. Please describe your concerns with potential solar output data quality issues adversely impacting Duke Energy's solar integration analysis as articulated in your Report.

A. In my Report, I discussed *possible* dropouts and data anomalies in the solar data underlying the *Ancillary Service Study*.[37] Because analysis of regulation requirements is much more sensitive to data dropouts than energy or capacity analysis, I devoted several pages of my report to analyzing the raw output data that Duke Energy supplied in response to data requests.

[36] Duke Energy Reply Comments at pp. 100-02.

[37] *See* SACE Initial Comments, Exhibit B at pp. 15-19.

Q. Have your concerns regarding the presence of potential solar output quality issues been addressed?

A. Yes. In Reply Comments, the Companies acknowledged that raw output data must be carefully scrubbed prior to regulation analysis and stated that Astrapé did scrub the output data it received from Duke Energy prior to regulation analysis.[38] This addressed my concerns about the potential for dropouts and data anomalies.

Q. Why did you previously believe that the data Duke provided to Astrapé had not been scrubbed?

A. Duke Energy characterized my assumption that the *Ancillary Service Study* relied on unscrubbed data as "unreasonable."[39] However, my belief that the data Duke Energy provided to Astrapé had not been scrubbed arose from misleading responses to SACE's data requests.

SACE Data Request 2 Item 2-27 explicitly asked for sub-hourly output data from *individual* solar plants covering the same time period that the Astrapé *Study* was based upon.[40] Duke Energy refused this data request, responding that the data was not accessible:

> Duke Response to SACE Docket No. E-100, Sub 158 Avoided Cost – 2018 SACE Data Request No. 2 Item No.

---

[38] Duke Energy Reply Comments at pp. 111-12.
[39] *Id.* at p. 11.
[40] SACE Data Request No. 2, Item No. 2-27, Docket No. E-100, Sub 158. ("Please provide actual, 1-minute generation output of all QF solar across DEP and DEC's territory for 2018 year to date, as well as 1-minute aggregate load data for each system. If possible break down DEP in east and west regions. Please provide data in aggregate, as well as plant data (if available).").

> 2-27: "[T]he Companies object to SACE's request to have the Companies prepare or gather data and analysis that is not reasonably available and/or does not exist and therefore would be unduly burdensome to create. The aggregate data consists of nearly 200 individual sites, each of which would have to be retrieved separately at one-minute granularity. … Please refer to the attachment provided in the Companies' response to SACE DR 2-30, which includes five-minute granularity aggregate data".[41]

Note that the Data Request asked for both aggregate data and individual plant data. Duke Energy substituted 5-minute aggregate solar output data for 1-minute aggregate solar output data (which was fine) but did not provide any individual solar plant data, stating that the individual plant data was "not reasonably available and/or does not exist". This omission is significant <u>because a lack of individual solar plant data makes it virtually impossible to scrub the solar data or conduct a valid regulation analysis.</u>

Based on Duke Energy's response, which stated that the individual solar plant data was "not reasonably available" or did not exist at all, it was reasonable to conclude that Duke Energy did not provide Astrapé with data from individual solar plants. Otherwise, Duke Energy's response would have misrepresented, or at least obscured, the true availability and existence of the data SACE requested. Since Astrapé could not have fully scrubbed the solar data without date from individual solar plants, I was reasonably concerned about the presence of data dropouts and anomalies in the data, and how they would have affected the

[41] *Id.*

Ancillary Service Study's conclusions.[42]

V. DUKE ENERGY AND THE PUBLIC STAFF'S STIPULATED INTEGRATION SERVICES CHARGE CAP

Q. Is the stipulated proposal to cap future increases to the integration services charge based upon Duke Energy's calculation of incremental ancillary service costs appropriate?

A. No. As explained previously, Duke Energy's integration cost calculations are already over inflated, especially for higher solar penetrations. Additionally, Duke Energy's proposed integration charge is based on average costs. Presumably future integration charge proposals will also be based on average, rather than marginal, costs. It makes no sense, then, to set a cap based on the inherently higher marginal costs when future rate adjustments will be based on average costs.

VI. DOMINION'S INTERMITTENT GENERATION RE-DISPATCH CHARGE

Q. Do you have concerns with Dominion's proposed re-dispatch charge?

A. Yes, a primary concern continues to be the lack of details that Dominion has provided concerning the re-dispatch charge calculations.

[42] In response to a similar data request in DEC and DEP's pending South Carolina Avoided Cost proceeding, the Companies responded by providing the one-minute generation output from individual plants. DEC and DEP Response to SACE and CCL First Data Request 1-19, Docket 1995-1192-E-1. It is unclear why the Companies considered this data reasonably available in the context of the South Carolina proceeding, but not in this proceeding.

I am also concerned that Dominion did not include analysis of the benefits that distributed solar provides to the power system in their development of the proposed re-dispatch charge.

Q. Mr. Petrie states that Dominion is now willing to eliminate the 80 MW solar penetration level from the analysis. Is this appropriate?

A. Yes, I was originally concerned that the proposed re-dispatch charge was based on analysis of inappropriate levels of solar penetration. Solar penetration is already 823 MW in the study region and is expected to be 965 MW in 2020 and 1,063 MW in 2021.[43] Inclusion of the 80MW Scenario in the re-dispatch calculation is inappropriate because the low-solar-penetration results dominate the calculated cost. Removal of the 80 MW solar penetration scenario alleviates this concern.

Q. Mr. Petrie states that Dominion is now willing to base its proposed re-dispatch cost calculation on the "all costs" category and not to average in the other categories. Does this alleviate your concerns?

A. Mr. Petrie's statement partially alleviates my concerns. It is worrisome that Mr. Petrie states that "[t]he Company continues to believe that its initial approach to calculating the re-dispatch charge was appropriate". It is reasonable to perform analysis under different sets of assumptions in order to better understand what

[43] Virginia Electric and Power Company's Report of Its Integrated Resource Plan, p. 212 (May 1, 2018).

conditions contribute to specific results. It does not make sense to average results from different types of conditions such as “All Costs” and “No PJM Purchases/Sales”. Similarly, pumping costs and revenues should either be included or not. It is hard to imagine how it makes sense to average a “No Pumping Costs/Revenues” case with three other unrelated cases. Hopefully this analysis approach will not reappear in the future.

VII. CONCLUSIONS

Q. Can you summarize your recommendations for the Commission?

A. Yes. The analysis methodology presented in the November 2018 Duke Energy Carolinas and Duke Energy Progress Solar *Ancillary Service Study* is deeply flawed, and the resulting solar integration charges are unjustified. As a result of the deficiencies I discussed above, the solar integration costs developed in the *Ancillary Service Study* do not reflect actual increased reserve requirements or actual impacts on the operating costs that the Companies will likely experience as a result of increased solar generation. The analysis method and tools should be updated to reflect actual utility reliability requirements and operations. The solar data should be reanalyzed to reflect plant and system aggregation benefits. Errors in calculated reserve requirements will only get worse as expected solar penetrations increase. Reliance upon the $LOLE_{FLEX}$ reliability metric, islanded analysis methodology, and linear scaling of solar generation short-term variability should not be allowed in this or future integration studies.

Q. Does this conclude your testimony?

A. Yes.

Kirby Exhibit A

Curriculum Vitae

Brendan Kirby

(865) 250-0753 KIRBYBJ@IEEE.ORG WWW.CONSULTKIRBY.COM

Professional Experience:

2008-Present: **Consulting**, Consulting privately with numerous clients including the Florida Power and Light, NextEra, Hawaii PUC, National Renewable Energy Laboratory, ESIG, AWEA, Oak Ridge National Laboratory, EPRI, and others. He served on the NERC Standards Committee. He has 44 years of electric utility experience and has published over 180 papers, articles, and reports on ancillary services, wind integration, restructuring, the use of responsive load as a bulk system reliability resource, and power system reliability. He coauthored a pro bono amicus brief cited by the Supreme Court in their January 2016 ruling confirming FERC demand response authority. He has a patent for responsive loads providing real-power regulation and is the author of a NERC certified course on Introduction to Bulk Power Systems: Physics / Economics / Regulatory Policy.

1994-2008: **Sr. Researcher,** Power Systems Research Program, Oak Ridge National Laboratory. Research interests included electric industry restructuring, unbundling of ancillary services, wind integration, distributed resources, demand side response, energy storage, renewable resources, advanced analysis techniques, and power system security. In addition to the research topics listed above activities included: NYISO Environmental Advisory Council, assignment to FERC Technical Staff to support reliability efforts including NERC/FERC reliability readiness audits, Technical Advisory Committee for the 2006 Minnesota Wind Integration Study, DOE Investigation Team for the 2003 Blackout, the IEEE SCC 21 Distributed Generation Interconnection Standard working group, DOE National Transmission Grid Study, staff to the DOE Task Force on Electric System Reliability, and NERC IOS Working Group. Conducted research projects concerning restructuring for the NRC, DOE, EEI, numerous utilities, state regulators, and EPRI.

Consulting, Consulted privately with utilities, renewable generators, AWEA, ISO/RTOs, IPPs, loads, interest groups, regulators, manufacturers and others on power system reliability, ancillary services, responsive load, wind integration, electric utility restructuring and other issues. Testified as an expert witness in FERC and state litigation.

1991 to 1994: **Power Analysis Department Head,** Technical Analysis and Operations Division. Primary responsibility was to support the Department of Energy in the management of 7000 MW of uranium enrichment capacity. The most significant feature of this load was that 2000 MW were procured on the spot energy market from multiple suppliers requiring rapid response to changing market conditions. Support included technical support for power contract negotiations, development of the real-time energy management strategy, managing the development of a computer based operator assistant to aid in making real-time power purchase decisions. Conducted computer based simulations of the loads and the interconnected network which supplies them. Simulations included large scale load flows, short circuit studies, and transient stability studies. They also included extensive specialized modeling for analysis of electrical, mechanical, and thermal performance under balanced and unbalanced conditions. Responsible for maintaining close ties with technical personnel from the various utilities which supplied power to the diffusion complex to exchange data and perform joint studies.

Provided consultation services on a large range of power system concerns including: cogeneration opportunities, power supply for the Lawrence Livermore National Laboratory Mirror Fusion Test Facility, capacity at EURODIF, power supply for the Strategic Petroleum Reserve, power supply for large pulsed fusion loads, and wheeling.

1985 to 1991: **Electric Power Planning Section Head,** Enrichment Technical Operations Division with substantially the same responsibilities as stated above.

1977 to 1985: **Technical Computing Specialist,** Electrical Engineering and Small Computing Section, Computing and Telecommunications Division. Time was evenly divided between power system studies as described above and minicomputer work. The minicomputer work supported laboratory data collection and experiment control.

1975 to 1976: **Engineer,** Electrical Engineering Department, Long Island Lighting Company, Hicksville, New York. Responsible for electrostatic and magnetic field strength modeling as well as sound level testing and analysis.

Education:

1977 - M.S.E.E., power option, Carnegie-Mellon University, Pittsburgh, Pa.
Worked under a Department of Transportation contract studying more efficient means of energy use in rail systems.

1975 - B.S.E.E., Lehigh University, Bethlehem, Pa., cum laude, Eta Kappa Nu, the Electrical Engineering Honorary, and Phi Eta Sigma, the freshman Honorary.

Professional Affiliations and Awards:

- Licensed professional engineer
- Patent 7,536,240: Real Power Regulation For The Utility Power Grid Via Responsive Load
- 1985, 1986, 1987, 1990, and 1992 Awards for power system related work
- Life Senior Member of the IEEE
- Former DOE Q clearance

<u>Publications</u>:

B. Hobbs, B. Kirby, K. Lutz, J. Mccalley, B. Parsons, 2016, *In the United States Court of Appeals, For the District of Columbia Circuit: State Of West Virginia, Et Al., Petitioners, V. U.S. Environmental Protection Agency, Et Al., Respondents.: – On Petitions For Review Of Final Action By The United States Environmental Protection Agency – Final Brief Of Amici Curiae Grid Experts*, April 22

M. Milligan, B. Frew, B. Kirby, M. Schuerger, K. Clark, D. Lew, P. Denholm, B. Zavadil, M. O'Malley, B. Tsuchida, 2015, *Alternatives No More: Wind and Solar Power Are Mainstays of a Clean, Reliable, Affordable Grid*, Power and Energy Magazine, IEEE (Volume:13 , Issue: 6), Nov-Dec

D. Hilt, B. Kirby, K. Lutz, H. Michaels, B. Parsons, 2015, *Federal Energy Regulatory Commission, Petitioner v. Electric Power Supply Association, et. al.: Brief of Grid Engineers and Experts as Amici Curiae in Support of Neither Party*, United States Supreme Court, July

M. Milligan, B. Kirby, T. Acker, M. Ahlstrom, B. Frew, M. Goggin, W. Lasher, M. Marquis, and D. Osborn, 2015, *Review and Status of Wind Integration and Transmission in the United States: Key Issues and Lessons Learned*, NREL/TP-5D00-61911, March

B. Kirby, 2014, *Potential New Ancillary Services: Developments of Interest to Generators*, PowerGen 2014, December

B. Kirby, 2014, *Selling Power System Flexibility: Ancillary Service and Real-Time Energy Market Challenges for Storage*, ASME 2014 Dynamic Systems and Control Conference, October

S. Nolan, D. Burke, H. Wajahat Qazi, D, Flynn, M. O'Malley, J. Kiviluoma, B. Kirby, M. Hummon, M. Milligan, 2014, *Synergies between Wind and Solar Generation and Demand Response*, IEA 25

B. Kirby, E. Ela, and M. Milligan, 2014, Chapter 7, Analyzing the Impact of Variable Energy Resources on Power System Reserves. In L. Jones, (Ed.), *Renewable Energy Integration: Practical Management of Variability, Uncertainty, and Flexibility in Power Grids*, London: Elsevier

V. Koritarov, T. Veselka, J. Gasper, B. Bethke, A. Botterud, J. wang, M. Mahalik, Z. Zhou, C. Milosat, J. Feltes, Y. Kazachkov, T. Guo, G. Liu, B. Trouille, P. Donalek, K. King, E. Ela, B. Kirby, I. Krad, V. Gevorgian, 2014, *Modeling and Analysis of Value of Advanced Pumped Storage Hydropower in the United States*, ANL/DIS-14/7, June

Ela, E.; Gevorgian, V.; Tuohy, A.; Kirby, B.; Milligan, M.; O'Malley, M., 2014, *Market Designs for the Primary Frequency Response Ancillary Service—Part I: Motivation and Design*, Power Systems, IEEE Transactions on , vol.29, no.1, pp.421,431, January

Ela, E.; Gevorgian, V.; Tuohy, A.; Kirby, B.; Milligan, M.; O'Malley, M., 2014, *Market Designs for the Primary Frequency Response Ancillary Service—Part II: Case Studies*, Power Systems, IEEE

Transactions on , vol.29, no.1, pp.432,440, January

B. Kirby, 2013, *The Value of Flexible Generation*, PowerGen 2013, November

P. Denholm, J. Jorgenson, M. Hummon, D. Palchak, B. Kirby, O. Ma, M. O'Malley, 2013, *The Impact of Wind and Solar on the Value of Energy Storage*, NREL/TP-6A20-60568, November

D. Bhatnagar, A. B. Currier, J. Hernandez, O. Ma, B. Kirby, 2013, *Market and Policy Barriers for Energy Storage Deployment*, SAND2013-7606, September

M. Hummon, P. Denholm, J. Jorgenson, D. Palchak, B. Kirby, O. Ma, 2013, *Fundamental Drivers of the Cost and Price of Operating Reserves*, NREL/TP-6A20-58491, July

O. Ma, N. Alkadi, P. Cappers, P. Denholm, J. Dudley, S. Goli, M. Hummon, S. Kiliccote, J. MacDonald, N. Matson, D. Olsen, C. Rose, M. Sohn, M. Starke, B. Kirby, M. O'Malley, 2013, *Demand Response for Ancillary Services*, IEEE Transactions on Smart Grid

E. Ela, B. Kirby, A. Botterud, C. Milostan, I. Krad, V. Koritarov, 2013, *The Role of Pumped Storage Hydro Resources in Electricity Markets and System Operation*, NREL/CP-5500-58655, HydroVision, May

P. Denholm, J. Jorgenson, M. Hummon, T. Jenkin, D. Palchak, B. Kirby, O. Ma, M. O'Malley, 2013, *The Value of Energy Storage for Grid Applications*, NREL/TP-6A20-58465, May

M. Milligan, K. Clark, J. King, B. Kirby, T. Guo, G. Liu, 2013, *Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection*, NREL/TP-5500-57115, March

B. Kirby, D. Brooks, 2013, *Joint TVA EPRI Evaluation of Steel Arc Furnace Regulation Impacts and Potential Innovative Mitigation Solutions: Phase I*, EPRI, Palo Alto, CA: 2013. 3002000181, January

B. Kirby, 2012, *Co-Optimizing Energy and Ancillary Services from Energy Limited Hydro and Pumped Storage Plants*, EPRI, HydroVision, July

Ela, E.; Kirby, B.; Navid, N.; Smith, J. C., 2012, *Effective Ancillary Services Market Designs on High Wind Power Penetration Systems*, Proceedings of the 2012 IEEE Power and Energy Society General Meeting, July

L. Schwartz, K. Porter, C. Mudd, S. Fink, J. Rogers, L. Bird, L. Schwartz, M. Hogan, D. Lamont, B. Kirby, 2012, *Meeting Renewable Energy Targets in the West at Least Cost: The Integration Challenge*, Western Governors' Association, June

J. King, B. Kirby, M Milligan, S Beuning, 2012, *Operating Reserve Reductions From a Proposed Energy Imbalance Market With Wind and Solar Generation in the Western Interconnection*, NREL/TP-5500-54660, May

M. Milligan, B. Hodge, B. Kirby, C. Clark, 2012, *Integration Costs: Are They Unique to Wind and Solar Energy?*, NREL/TP-5500-54905, May

E. Ela, M. Milligan, B. Kirby, A. Tuohy, D. Brooks, 2012, *Alternative Approaches for Incentivizing the Frequency Responsive Reserve Ancillary Service*, NREL Report No. NREL/TP-5500-54393, March

J. C. Smith, B. Kirby, K. Porter, R. Zavadil, 2012, *China Renewable Energy Scale-up Program Phase II Preparation: Integration Study Task Descriptions*, World Bank, February

B. Kirby, M.J. O'Malley, O. Ma, P. Cappers, D. Corbus, S. Kiliccote, O. Onar, M. Starke, and D. Steinberg, *Load participation in Ancillary Services: Workshop Report*, Department of Energy, USA, 2011

M. Lauby, M. Ahlstrom, D. Brooks, S. Beuning, J. Caspary, W. Grant, B. Kirby, M. Milligan, M. O'Malley, M. Patel, R. Piwko, P. Pourbeik, D. Shirmohammadi, J. C. Smith, 2011, *Balancing Act*, IEEE Power and Energy Magazine, November/December

J. King, B. Kirby, M. Milligan, S. Beuning, 2011, *Flexibility Reserve Reductions from an Energy Imbalance Market with High Levels of Wind Energy in the Western Interconnection*, NREL/TP-5500-52330, November

M. Milligan, E. Ela, B. Hodge, D. Lew, B. Kirby, C. Clark, J. DeCesaro, K. Lynn, 2011, *Integration of Variable Generation, Cost-Causation, and Integration Costs*, Electricity Journal, November

M. Milligan, J. King, B. Kirby, S. Beuning, 2011, *Impact of Alternative Dispatch Intervals on Operating Reserve Requirements for Variable Generation*, NREL Report No. CP-5500-52506. Aarhus, Denmark, October

M. Milligan, B. Kirby, J. King, S. Beuning, 2011, *Operating Reserve Implication of Alternative Implementations of an Energy Imbalance Service on Wind Integration in the Western Interconnection*, NREL Report No. CP-5500-51343

D. Brooks, A. Tuohy, S. Deb, S. Jampani, B. Kirby, J. King, 2011, *DOE: Integrating Midwest Wind Energy into Southeast Electricity Markets*, EPRI DE-EE0001377, October

E. Ela, M. Milligan, B. Kirby, 2011, *Operating Reserves and Variable Generation*, NREL/TP-5500-51978, August

M. Milligan, E. Ela, B. Hodge, B. Kirby, D. Lew, C. Clark, J. DeCesaro, and K. Lynn, 2011, *Cost-Causation and Integration Cost Analysis for Variable Generation*, NREL/TP-5500-51860, June

J. C. Smith, S. Beuning, H. Durrwachter, E. Ela, D. Hawkins, B. Kirby, W. Lasher, J. Lowell, K. Porter, K. Schuyler, P. Sotkiewicz, 2010, *The Wind at Our Backs: The Impact of Variable Renewable Energy on U.S. Electricity Markets*, IEEE Power and Energy Magazine, pp. 63-71

B. Kirby, M. Milligan, E. Ela, 2010, *Providing Minute-to-Minute Regulation from Wind Plants*, 9th International Workshop on Large-Scale Integration of Wind Power, October

M. Milligan, B. Kirby, J. King, S. Beuning, 2010, *Benefit of Regional Energy Balancing Service on Wind Integration in the Western Interconnection of the United States,* 9th International Workshop on Large-Scale Integration of Wind Power, October

M. Milligan, et al, *Operating Reserves and Wind Power Integration: An International Comparison*, 9th International Workshop on Large-Scale Integration of Wind Power, October

M. Milligan and B. Kirby, 2010, *Market Characteristics for Efficient Integration of Variable Generation in the Western Interconnection*, NREL/TP-550-48192, August

M. Milligan, B. Kirby, J. King, S. Beuning, 2010, *Potential Reductions in Variability with Alternative Approaches to Balancing Area Cooperation with High Penetrations of Variable Generation*, NREL/MP-550-48427, August

J. Smith, S. Beuning, H. Durrwachter, E. Ela, D. Hawkins, B. Kirby, W. Lasher, J. Lowell, K. Porter, K. Schuyler, P. Sotkiewicz, 2010, *Impact of Variable Renewable Energy on US Electricity Markets*, IEEE PES, July

E. Ela, B. Kirby, E. Lannoye, M. Milligan, D. Flynn, B. Zavadil, M. O'Malley, 2010, *Evolution of Operating Reserve Determination in Wind Power Integration Studies*, IEEE PES, July

B. Kirby and M. Milligan, 2010, *Utilizing Load Response for Wind and Solar Integration and Power System Reliability*, WindPower 2010

M. Milligan, B. Kirby, and S. Beuning, 2010, *Combining Balancing Areas' Variability: Impacts on Wind Integration in the Western Interconnection*, WindPower 2010

P. Denholm, E. Ela, B. Kirby, and M. Milligan, 2010, *The Role of Energy Storage with Renewable Electricity Generation*, NREL/TP-6A2-47187, January

L. Kirsch and B. Kirby, 2009, *Screening Demand Response as a Distribution Resource: Case Studies*. EPRI Reports #1017900, December

L. Kirsch and B. Kirby, 2009, *Screening Demand Response as a Transmission Resource*. EPRI Reports #1017896, December

M. Milligan, K. Porter, E. DeMeo, P. Denholm, H. Holttinen, B. Kirby, N. Miller, A. Mills,

M. O'Malley, M. Schuerger, and L., 2009, *Wind Power Myths Debunked*, IEEE Power and Energy, November/December

B. Kirby, M. Milligan, 2009, *Capacity Requirements to Support Inter-Balancing Area Wind Delivery*, NREL/TP-550-46274, July

M. Milligan, B. Kirby, R. Gramlich, M. Goggin, 2009, *Impact of Electric Industry Structure on High Wind Penetration Potential*, NREL/TP-550-46273, July 2009

M. Milligan, B. Kirby, 2009, *Calculating Wind Integration Costs: Separating Wind Energy Value from Integration Cost Impacts*, NREL/TP-550-46275, July

B. Kirby, M. Starke, S. Adhikari, 2009, *NYISO Industrial Load Response Opportunities: Resource and Market Assessment*, New York State Energy Research and Development Authority, Oak Ridge National Laboratory, June

NERC, 2009, *Accommodating High Levels of Variable Generation*, North American Electric Reliability Corporation, http://www.nerc.com/files/IVGTF_Report_041609.pdf, April

D. Todd, M. Caulfield, B. Helms of ALCOA, M. Starke, B. Kirby, J. Kueck of ORNL, 2009, *Providing Reliability Services through Demand Response: A Preliminary Evaluation of the Demand Response Capabilities of Alcoa Inc.*, ORNL/TM 2008/233, Oak Ridge National Laboratory, January

L. Kirsch and B. Kirby, *Utilization of Energy Efficiency and Demand Response as Resources for Transmission and Distribution Planning*, EPRI Reports #1016360

L. Kirsch and B. Kirby, *Integration of Energy Efficiency and Demand Response Into Distribution Planning Processes*. EPRI Reports #1015985

L. Kirsch and B. Kirby, *Integration of Energy Efficiency and Demand Response Into Transmission Planning Processes*. EPRI Reports #1016093

B. Kirby, J. Kueck, T. Laughner, K. Morris, 2008, *Spinning Reserve from Hotel Load Response*, Electricity Journal, Dec., 2008, Vol. 21, Issue 10

B. Kirby, J. Kueck, T. Laughner, K. Morris, 2008, *Spinning Reserve from Hotel Load Response: Initial Progress*, ORNL/TM 2008/217, Oak Ridge National Laboratory, October

B. Kirby, M. Milligan, 2008, *An Examination of Capacity and Ramping Impacts of Wind Energy on Power Systems*, Electricity Journal, Aug./Sept. 2008, Vol. 21, Issue 7

H. Holttinen, M. Milligan, B. Kirby, T. Acker, V. Neimane, T. Molinski, 2008, *Using Standard Deviation as a Measure of Increased Operational Reserve Requirement for Wind Power*, Wind Engineering, Volume 32, No. 4

B. Kirby, M. Milligan, 2008, *The Impact of Balancing Area Size, Obligation Sharing, and Energy Markets on Mitigating Ramping Requirements in Systems with Wind Energy*, Wind Engineering Volume 32, No. 4

M. Milligan, B. Kirby, 2008, *The Impact of Balancing Area Size and Ramping Requirements on Wind Integration*, Wind Engineering Volume 32, No. 4

B. Kirby, M. Milligan, 2008, *Examination of Capacity and Ramping Impacts of Wind Energy on Power Systems*, NREL/TP-500-42872, July

E. Ela and B. Kirby, 2008, *ERCOT Event on February 26, 2008: Lessons Learned*, NREL/TP-500-43373, July

M. Milligan, B. Kirby, 2008, *Analysis of Sub-Hourly Ramping Impacts of Wind Energy and Balancing Area Size*, WindPower 2008, NREL/CP-500-43434, June

K. Dragoon, B. Kirby, M. Milligan, 2008, *Do Wind Forecasts Make Good Generation Schedules?*, WindPower 2008, NREL/CP-500-43507, June

B. Kirby, M. Milligan, 2008, *Facilitating Wind Development: The Importance of Electric Industry Structure*, The Electricity Journal, Volume 21, Issue 3, April, *and* National Renewable Energy Lab, NREL/TP-500-43251, May

R. Zavadil, N. Miller, A. Ellis, E. Muljadi, E. Camm, and, B. Kirby, 2007, *Queuing Up*, IEEE Power & Energy Magazine, Volume 5, Number 6, November/December

B. Kirby, K. Porter, 2007, *Increasing Renewable Resources: How ISOs and RTOs are Helping Meet This Public Policy Objective*, ISO/RTO Council, October

D. Brooks, B. Kirby, A. Del Rosso, 2007, *Utilization of Energy Efficiency and Demand Response as Resources for Transmission and Distribution Planning: Current Utility Practices and Recommendations for Increasing Opportunities as T&D Alternatives*. EPRI, Palo Alto, CA

B. Kirby, J. Kueck, H. Leake, M. Muhlheim, 2007, *Nuclear Generating Stations and Transmission Grid Reliability*, North American Power Symposium, September

B. Kirby, 2007, *Ancillary Services: Technical and Commercial Insights*, Wärtsilä North America Inc., June

M. Milligan, B. Kirby, 2007, *The Impact of Balancing Areas Size, Obligation Sharing, and Ramping Capability on Wind Integration*, American Wind Energy Association, WindPower 2007, June

Y. Wan, M. Milligan, B. Kirby, 2007, *Impact of Energy Imbalance Tariff on Wind Energy*, American Wind Energy Association, WindPower 2007, June

B. Kirby, 2007, *Load Response Fundamentally Matches Power System Reliability Requirements*, IEEE Power Engineering Society General Meeting, June

G. Heffner, C. Goldman, B. Kirby, M. Kintner-Meyer, 2007, *Loads Providing Ancillary Services: Review of International Experience*, ORNL/TM 2007/060, Oak Ridge National Laboratory, May

J. Eto, J. Nelson-Hoffman, C. Torres, S. Hirth, B. Yinger, J. Kueck, B. Kirby, C. Bernier, R. Wright, A. Barat, C. Energy, D. Watson, 2007, *Demand Response Spinning Reserve Demonstration*, LBNL-62761, Ernest Orlando Lawrence Berkeley National Laboratory, May

B. Kirby, 2007, *Evaluating Transmission Costs and Wind Benefits in Texas: Examining the ERCOT CREZ Transmission Study*, The Wind Coalition and Electric Transmission Texas, LLC, Texas PUC Docket NO. 33672, April

B. Kirby, 2006, *Demand Response For Power System Reliability: FAQ*, ORNL/TM 2006/565, Oak Ridge National Laboratory, December

J. Kueck, B. Kirby, T. Rizy, F. Li, N. Fall, 2006, *Economics of Reactive Power Supply from Distributed Energy Resources*, Electricity Journal, December

B. Kirby, 2006, *The Role of Demand Resources In Regional Transmission Expansion Planning and Reliable Operations*, ORNL/TM 2006/512, Oak Ridge National Laboratory, July

B. Kirby, M. Milligan, E. Wan, 2006, *Cost-Causation-Based Tariffs for Wind Ancillary Service Impacts*, American Wind Energy Association, WindPower 2006, June

M. Milligan, H. Shiu, B. Kirby, K. Jackson, 2006, *A Multi-year Analysis of Renewable Energy Impacts in California: Results from the Renewable Portfolio Standards Integration Cost Analysis*, American Wind Energy Association, WindPower 2006, June

H. Shiu, M. Milligan, B. Kirby, K. Jackson, 2005, *California Renewables Portfolio Standard Renewable Generation Integration Cost Analysis: Multi-Year Analysis Results And Recommendations*, The California Energy Commission, December

B. Kirby, M. Milligan, 2005, *A Method and Case Study for Estimating The Ramping Capability of a Control Area or Balancing Authority and Implications for Moderate or High Wind Penetration*, American Wind Energy Association, WindPower 2005, May

B. Kirby, 2004, *Frequency Regulation Basics and Trends*, ORNL/TM 2004/291, Oak Ridge National Laboratory, December

J. Kueck, B. Kirby, L. Tolbert, T. Rizy, 2004, *Voltage Regulation: Tapping Distributed Energy*

Resources, Public Utilities Fortnightly, September

B. Kirby, M. Milligan, Y. Makarov, J. Lovekin, K. Jackson, H. Shiu, 2004, *California RPS Integration Cost Analysis-Phase III: Recommendations for Implementation*, California Energy Commission, July

J. Kueck, B. Kirby, 2004, *Measurement Practices for Reliability and Power Quality*, ORNL/TM-2004/91, Oak Ridge National Laboratory, June

J. Kueck, B. Kirby, 2004, *Demand Response Research Plan to Reflect the Needs of the California Independent System Operator*, ORNL/TM 2004/2, Oak Ridge National Laboratory, January

B. Kirby, E. Hirst, 2003, *Allocating the Costs of Contingency Reserves,* The Electricity Journal, Volume 16, Issue 10, pg 39-47, December

B. Kirby, M. Milligan, Y. Makarov, D. Hawkins, K. Jackson, H. Shiu, 2003, *California RPS Integration Cost Analysis-Phase I: One Year Analysis of Existing Resources*, California Energy Commission, December

B. Kirby, J. Kueck, 2003, *Spinning Reserve from Pump Load: A Technical Findings Report to the California Department of Water Resources*, ORNL/TM 2003/99, Oak Ridge National Laboratory, November

E. Hirst, B. Kirby, 2003, *Water Heaters to the Rescue: Demand Bidding in Electric Reserve Markets*, Public Utilities Fortnightly, September

R. Cowart, J. Raab, C. Goldman, R. Weston, J. Schlegel, R. Sedano, J. Lazar, B. Kirby, E. Hirst, 2003, *Dimensions of Demand Response: Capturing Customer Based Resources in New England's Power Systems and Markets. Report and Recommendations of the New England Demand Response Initiative*, New England Demand Response Initiative, July

B. Parsons, M. Milligan, R. Zavadil, D. Brooks, B. Kirby, K. Dragoon, J. Caldwell, 2003, *Grid Impacts of Wind Power: A Summary of Recent Studies in the United States*, EWEC Wind Energy Journal, June

E. Hirst, B. Kirby, 2003, *Allocating Costs of Ancillary Services: Contingency Reserves and Regulation*, ORNL/TM 2003/152, Oak Ridge National Laboratory, Oak Ridge TN, June

J. D. Kueck, B. J. Kirby, 2003, *The Distribution System of the Future*, The Electricity Journal, June

B. Kirby, E. Hirst, 2003, *Technical Issues Related To Retail-Load Provision of Ancillary Services*, New England Demand Response Initiative, May

E. Hirst, B. Kirby, 2003, *Opportunities for Demand Participation in New England Contingency-*

Reserve Markets, New England Demand Response Initiative, May

J. Kueck, R. Staunton, B. Kirby, 2003, *Microgrids and Demand Response: How Software Controls Can Bridge The Gap Between Wholesale Market Prices and Consumer Behavior,* Public Utility Fortnightly, May 15

B. Kirby, 2003, *Spinning Reserve From Responsive Loads,* ORNL/TM 2003/19, Oak Ridge National Laboratory, Oak Ridge TN, March

J. D. Kueck, R.H. Staunton, S. D. Labinov, B.J. Kirby, 2003, *Microgrid Energy Management System*, ORNL/TM 2002/242, Oak Ridge National Laboratory, Oak Ridge TN, January

B. Kirby, J. Dyer, C. Martinez, R. Shoureshi, R. Dagle, 2002,*Frequency Control Concerns In The North American Electric Power System,* ORNL/TM 2003/41, Oak Ridge National Laboratory, Oak Ridge TN, December

B. Kirby, M. Ally, 2002, *Spinning Reserves from Controllable Packaged Through the Wall Air Conditioner (PTAC) Units,* ORNL/TM 2002/286, Oak Ridge National Laboratory, Oak Ridge TN, November

B. Kirby, R. Staunton, 2002, *Technical Potential For Peak Load Management Programs in New Jersey*, Oak Ridge National Laboratory, Oak Ridge TN, November

R. Lee, S. Hadley, C. Liu and B. Kirby, 2002, *Electricity Transmission Congestion in The U.S.,* Oak Ridge National Laboratory, Oak Ridge TN, June

B. Kirby, J. Van Dyke, C. Martinez and A. Rodriguez, 2002, *Congestion Management Requirements, Methods and Performance Indices*, ORNL/TM-2002, Oak Ridge National Laboratory, Oak Ridge TN, June

B. Kirby and E. Hirst, 2002, *Reliability Management and Oversight,* U.S. Department of Energy National Transmission Grid Study, May

E. Hirst and B. Kirby, 2002, *Transmission Planning and the Need for New Capacity,* U.S. Department of Energy National Transmission Grid Study, May

J. Kueck, B. Kirby and L. Markel, 2002, *Best Practices For Distribution – Phase 2 Report – A Toolkit of Noteworthy Reliability Measurement Practices,* Oak Ridge National Laboratory, Oak Ridge TN, March

B. Kirby and J. Kueck, 2002, *Re Electricity Costs: How Savvy Building Owners Can Save*, Strategic Planning for Energy and the Environment, Vol. 21, No. 3

W. P. Poore, T. K. Stovall, B. J. Kirby, D. T. Rizy, J. D. Kueck, and J. P. Stovall, 2002, *Connecting*

Distributed Energy Resources to the Grid: Their Benefits to the DER Owner/customer, the Utility, and Society, ORNL/TM-2001/290, Oak Ridge National Laboratory, Oak Ridge TN, February

J. Eto, C. Goldman, G. Heffner, B. Kirby, J. Kueck, M. Kintner-Meyer, J. Dagle, T. Mount, W. Schultze, R. Thomas, R. Zimmerman, 2002, *Innovative Developments in Load as a Reliability Resource*, IEEE Power Engineering Society, February

R. Staunton, J Kueck, B. Kirby, J. Eto 2001, *Demand response: An Overview of Enabling Technologies*, Public Utilities Fortnightly, November

B. Kirby 2001, *Restructured Electricity Markets Offer Increased Complexities and Opportunities for Cogeneration*, Cogeneration and Competitive Power Journal, fall

E. Hirst and B. Kirby 2001, *Key Transmission Planning Issues*, The Electricity Journal, October

C. R. Hudson, B. J. Kirby, J. D. Kueck, R. H. Staunton 2001, *Industrial Use of Distributed Generation in Real-Time Energy and Ancillary Service Markets*, ORNL/TM-2001/136, Oak Ridge National Laboratory, Oak Ridge TN, September

E. Hirst and B. Kirby 2001, *Transmission Planning: Weighing Effects on Congestion Costs*, Public Utility Fortnightly, July

J. D. Kueck, B. J. Kirby, J. Eto, R. H. Staunton, C. Marnay, C. A. Martinez, C. Goldman 2001, *Load as a Reliability Resource in Restructured Electricity Markets*, ORNL/TM-2001/97, Oak Ridge National Laboratory, Oak Ridge TN, June

E. Hirst and B. Kirby 2001, *Transmission Planning for a Restructuring U.S. Electricity Industry*, Edison Electric Institute, Washington, DC, June

R. Hudson, B. Kirby, Y. Wan 2001, *Regulation Requirements for Wind Generation Facilities*, American Wind Energy Association, June

B. Kirby and E. Hirst 2001, *Real-Time Performance Metrics for Generators Providing the Regulation Ancillary Service*, The Electricity Journal, April

E. Hirst and B. Kirby 2001, *Metering, Communications and Computing for Price-Responsive Demand Programs*, April

B. Kirby and E. Hirst 2001, *Using Five-Minute Data to Allocate Load-Following and Regulation Requirements Among Individual Customers*, ORNL/TM-2001-13, Oak Ridge National Laboratory, Oak Ridge TN, January

J. Eto, C. Marnay, C. Goldman, J. Kueck, B. Kirby, J. Dagle, F. Alverado, T. Mount, S. Oren, C. Martinez, 2001, *An R&D Agenda to Enhance Electricity System Reliability by Increasing Customer*

Participation in Emerging Competitive Markets, DE-AC03-76SF00098. Power Engineering Society Winter Meeting, 2001. IEEE, Volume: 1, January

E. Hirst and B. Kirby 2001, *Measuring Generator Performance in Providing Regulation and Load-Following Ancillary Services*, ORNL/TM-2000-383, Oak Ridge National Laboratory, Oak Ridge TN, January

E. Hirst, B. Kirby, 2001, *Real-Time Balancing Operations and Markets: Key to Competitive Wholesale Electricity Markets*, January

E. Hirst and B. Kirby 2000, *Retail-Load Participation in Competitive Wholesale Electricity Markets*, Edison Electric Institute, Washington, DC, and Project for Sustainable FERC Energy Policy, Alexandria, VA, Dec

J. Cadogan, M. Milligan, Y. Wan, and B. Kirby 2000, *Short Term Output Variations in Wind Farms - Implications for Ancillary Services in the United States*, October

B. Kirby and J. Kueck 2000, *How Buildings Can Prosper By Interacting With Restructured Electricity Markets*, ACEEE, August

B. Kirby and E. Hirst 2000, *Pricing Ancillary Services so Customers Pay for What They Use*, EPRI, July

E. Hirst and B. Kirby 2000, *Time-Averaging Period for the Regulation Ancillary Service*, IEEE Power Engineering Review, July

M. Gallaher, S. Johnston, and B. Kirby 2000, *Changing Measurement and Standards Needs in a Deregulated Electric Utility Industry,* National Institute of Standards & Technology, May

B. Kirby 2000, *Restructured Electricity Markets Offer Increased Complexity and Increased Opportunities*, Association of Energy Engineers, Globalcon 2000, April

B. Kirby and E. Hirst 2000, *Bulk-Power Reliability and Commercial Implications of Distributed Resources*, NARUC, April

B. Kirby and T. Key 2000, *Technical Evaluation of Operational and Ownership Issues of Distributed Generation,* Office of Ratepayer Advocates, California Public Utility Commission, Rulemaking 99-10-025, April

E. Hirst and B. Kirby 2000, *Bulk-Power Basics: Reliability and Commerce*, The Regulatory Assistance Project, Gerdiner, ME, March

B. Kirby and J. Kueck 2000, *Review of the Structure of Bulk Power Markets,* ORNL/TM-2000/41, Oak Ridge National Laboratory, Oak Ridge TN, January

B. Kirby and E. Hirst 2000, *Customer-Specific Metrics for The Regulation and Load-Following Ancillary Services*, ORNL/CON-474, Oak Ridge National Laboratory, Oak Ridge TN, January.

E. Hirst and B. Kirby 2000, *Ancillary Services: A Call for Fair Prices*, Public Utilities Fortnightly, January

M. Milligan, D. Lew, B. Hodge, B. Kirby, E. Ela, Y. Wan, D. Corbus 2000, *Operational Analysis and Methods for Wind Integration Studies*, IEEE Transactions on Sustainable Energy

B. Kirby and N. Lenssen 1999, *Shifting the Balance of Power: Grid Interconnection of Distributed Generation*, E Source, The Distributed Energy Series, Boulder, Colorado, October

B. Parsons, Y. Wan, B. Kirby, 1999, *Wind Farm Power Fluctuations, Ancillary Services, And System Operating Impact Analysis Activities In The United States*, National Renewable Energy Laboratory, Golden CO, July

E. Hirst, B. Kirby and S. Hadley 1999, *Generation and Transmission Adequacy in a Restructuring U.S. Electricity Industry*, Edison Electric Institute, Washington, DC, June

B. Ernst, Y. Wan and B. Kirby 1999, *Short-term Power Fluctuation of Wind Turbines: Looking at Data from the German 250 Mw Measurement Program from the Ancillary Services Viewpoint*, American Wind Energy Association Windpower ‘99 Conference, Washington, DC, June

B. Kirby and E. Hirst 1999, *Load as a resource in Providing Ancillary Services*, American Power Conference, Chicago, Illinois, April

B. Kirby and E. Hirst 1999, *Maintaining System Black Start in Competitive Bulk-Power Markets*, American Power Conference, Chicago, Illinois, April

E. Hirst and B. Kirby 1999, *What is System Control*, American Power Conference, Chicago, Illinois, April

E. Hirst and B. Kirby 1999, *Technical and Market Issues for Operating Reserves*, The Electricity Journal, March

B. Kirby and E. Hirst 1999, *New Blackstart Standards Needed for Competitive Markets*, IEEE Power Engineering Review, Vol. 19, No. 2, pp9, February

E. Hirst and B. Kirby 1999, *Does Block Scheduling Waste Money?*, Electrical World, January/February

E. Hirst and B. Kirby 1998, *Operating Reserves and Bulk-Power Reliability*, Energy International Journal, Vol. 23, No. 11, pp. 949-959

B. Kirby and E. Hirst, 1998, *Generator Response to Intrahour Load Fluctuations,* IEEE Transactions on Power Systems, Vol 13 #4, PE-627-PWRS-0-12-1997, November

E. Hirst and B. Kirby, 1998, *Defining Intra- and Interhour Load Swings,* IEEE Transactions on Power Systems, Vol 13 #4, PE-628-PWRS-0-12-1997, November

E. Hirst and B. Kirby, 1998, *The Functions, Metrics, Costs, and Prices for Three Ancillary Services*, Edison Electric Institute, Economics Department, October

B. J. Kirby, J. D. Kueck, A. B. Poole 1998, *Evaluation of the Reliability of the Offsite Power Supply as a Contributor to Risk of Nuclear Plants*, ORNL/NRC/LTR/98-12, Oak Ridge National Laboratory, Oak Ridge TN, August.

E. Hirst and B. Kirby 1998, *Ancillary Services: The Forgotten Issue,* Electric Perspectives, July-August

B. Kirby, E. Hirst 1998, *Voltage Control In A Changing US Electricity Industry,* Utilities Policy, Vol 7, No. 2, June

E. Hirst and B. Kirby 1998, *Simulating the Operation of Markets for Bulk-Power Ancillary Services*, The Energy Journal, Vol. 19, No. 3

E. Hirst and B. Kirby 1998, *Creating Markets for Ancillary Services*, Pricing Energy in a Competitive Market, EPRI, June

E. Hirst and B. Kirby 1998, *Maintaining Reliability in a Restructured Industry*, Public Power, May-June

B. Kirby and E. Hirst 1998, *Characteristics of Concern in Supplying, Consuming, and Measuring Ancillary Services,* The Future of Power Delivery in the 21st Century, The Electric Power Research Institute, Palo Alto, California, May

E. Hirst and B. Kirby 1998, *Ancillary Services: The Neglected Feature of Bulk-Power Markets*, The Electricity Journal, April.

E. Hirst and B. Kirby 1998, *Unbundling Generation and Transmission Services for Competitive Electricity Markets*, ORNL/CON-454, Oak Ridge National Laboratory, Oak Ridge TN, January.

E. Hirst and B. Kirby 1998, *Unbundling Generation and Transmission Services for Competitive Electricity Markets: Examining Ancillary Services,* The National Regulatory Research Institute, January.

B. Kirby and E. Hirst 1997, *Ancillary-Service Details: Voltage Control*, ORNL/CON-453, Oak

Ridge National Laboratory, Oak Ridge TN, December.

E. Hirst and B. Kirby 1997, *Cutting Electricity Costs for Industrial Plants in a Real-Time World*, Public Utilities Fortnightly, December.

E. Hirst and B. Kirby 1997, *Ancillary-Service Details: Operating Reserves*, ORNL/CON-452, Oak Ridge National Laboratory, Oak Ridge TN, November.

E. Hirst and B. Kirby 1997. *Ancillary Services: The Neglected Feature of Bulk-Power Markets*, Electricity Journal

E. Hirst and B. Kirby 1997, *Creating Competitive Markets for Ancillary Services*, ORNL/CON-448, Oak Ridge National Laboratory, Oak Ridge TN, October.

B. Kirby, E. Hirst, B. Parsons, K. Porter, and J. Codagan, 1997, *Electric Industry Restructuring, Ancillary Services, and the Potential Impact on Wind*, American Wind Energy Association, June

E. Hirst and B. Kirby, 1997, *Dynamic Scheduling Can Enable Competitive Markets,* Public Utility Fortnightly, April, 15

E. Hirst and B. Kirby, 1997, *Ancillary-Service Details: Dynamic Scheduling*, ORNL/CON-438, Oak Ridge National Laboratory, Oak Ridge TN, January

E. Hirst and B. Kirby 1996, *Costs for Electric-Power Ancillary Services*, Electricity Journal, Volume 9, Number 10, December.

E. Hirst and B. Kirby 1996, *Ancillary-Service Details: Regulation, Load Following, and Generator Response*, ORNL/CON-433, Oak Ridge National Laboratory, Oak Ridge, TN, September.

B. Kirby and E. Hirst 1996, *Unanswered Questions Ancillary Services*, Electric Perspectives, July-August

B. Kirby and E. Hirst 1996, *Unbundling Electricity: Ancillary Services*, IEEE Power Engineering Review, June

B. Kirby and E. Hirst 1996, *Ancillary Services and the use of FACTS Devices*, The Future of Power Delivery Conference, EPRI, April

B. Kirby and E. Hirst 1996, *Ancillary-Services Costs for Twelve U.S. Electric Utilities,* ORNL/CON-427, Oak Ridge National Laboratory, Oak Ridge, TN, March.

E. Hirst and B. Kirby 1996, *Electric-Power Ancillary Services*, ORNL/CON-426, Oak Ridge National Laboratory, Oak Ridge, TN, February

E. Hirst and B. Kirby 1996, *Ancillary Services*, American Power Conference, Chicago, Illinois, February

B. Kirby and E. Hirst 1996, *Supplemental Comments on Ancillary Services*, Testimony before the U.S.A. Federal Energy Regulatory Commission, Washington, DC, January

E. Hirst and B Kirby 1995, *Devil in the Details!*, the Electricity Journal, Vol. 8, Num. 10, December

E. Hirst and B. Kirby 1995, *Testimony Before The U.S.A. Federal Energy Regulatory Commission, Ancillary Services,* Federal Energy Regulatory Commission, Washington, DC, June

B. Kirby, E. Hirst, and J. VanCoevering 1995, *Unbundling Electric Generation and Transmission Services*, Energy, Vol. 20, No. 12, pp. 1191-1203, Elsevier Science Ltd.

P. Barnes, W. Dykas, B. Kirby, S. Purucker, and J. Lawler 1995, *The Integration of Renewable Energy Sources into Electric Power Transmission Systems*, ORNL-6827, Oak Ridge National Laboratory, Oak Ridge, TN, June

W. P. Dykas, B. J. Kirby and J. P. Stovall 1995, *Superconducting Magnetic Energy Storage (SMES), Utility Application Study of Municipal Light & Power, Anchorage, Alaska*, Draft, ORNL-6877, Oak Ridge National Laboratory, Oak Ridge, TN, June

B. Kirby, E. Hirst, and J. VanCoevering 1995, *Identification and Definition of Unbundled Electric Generation and Transmission Services*, ORNL/CON-415, Oak Ridge National Laboratory, Oak Ridge, TN, March.

Kirby Exhibit B

Duke Energy Proposed Solar Integration Charge

Brendan Kirby, P.E. – February 2019

The proposed solar integration charge was developed for Duke Energy by Astrapé Consulting and documented in a November 11, 2018 study titled "Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study" (*Ancillary Service Study*). Unfortunately, the study methodology, as implemented, is fundamentally flawed and the resulting solar integration charges are unsubstantiated, unjustified, and simply wrong.

The basic analysis methodology of comparing production cost simulations with and without solar, while adjusting reserves in order to maintain reliability, is well established and has been executed successfully by others. However, Duke's analysis is flawed because the *Ancillary Service Study*:

- Modeled DEC and DEP as isolated power systems, not their actual coordinated operation within the Eastern Interconnection;
- Applied an inappropriate loss-of-load, one-in-ten-years, long-term system adequacy metric, not normally used for operations, rather than basing reserve requirements on the mandatory North American Electric Reliability Corporation (NERC) reliability standards to which Duke actually operates;
- May not have removed data dropouts and other data anomalies, greatly overstating solar variability;
- Improperly scaled solar plant intra-hour output variability data in a way that fails to accurately reflect geographic diversity benefits;
- Incorrectly modeled contingency reserve requirements and use;
- Failed to identify under what specific operating conditions reliability was challenged; and
- Failed to identify the specific added reserve requirements or changes in operating practices needed to cost effectively maintain reliability.

As a result of these deficiencies, the solar integration costs developed in the *Ancillary Service Study* do not reflect actual increased reserve requirements or actual impacts on the operating costs that Duke will likely experience as a result of increased solar generation. The analysis method and tools should be updated to reflect actual utility reliability requirements and operations. The solar data should be reanalyzed to reflect plant and system aggregation benefits. Simulated reserve shortfalls should be analyzed to determine the most cost-effective methods to adjust operations and/or add reserves to maintain reliability as solar generation increases.

Inappropriate Modeling of DEC and DEP as Isolated Power Systems

The *Ancillary Service Study* report states that "The utilities are modeled as islands for the Ancillary Service Study".[1] Note that treating DEC and DEP as islanded power systems in the *Ancillary Service Study* differs from how Duke actually plans and operates DEC and DEP as interconnected utilities. The stated reason for modeling DEC and DEP as islanded power systems in the *Ancillary Service Study* is that "it is aggressive to assume that neighbors will build flexible systems to assist DEC and DEP in their flexibility requirements". This completely misunderstands the benefits of interconnected utility operations and the impacts on reliability reserves. Utilities started to interconnect over ninety years ago in order to increase reliability while reducing each utility's reserve requirements. This works because of the strong aggregation diversity benefits for load and generation variability under both normal and contingency conditions. Interconnected power systems are more resilient, reliable, and economic than islanded power systems. All utilities participating in an interconnection benefit from reduced reserve requirements. Additionally, DEC and DEP are members of the VACAR Reserve Sharing Group[2] (which explicitly shares contingency reserve obligations and reserves. Further, Duke acknowledges that "DEC and DEP were jointly dispatched for avoided energy cost modeling".[3] The NERC reliability standards are also based on interconnected operations. Determining reserve requirements for islanded versions of DEC and DEP is irrelevant to the way the power systems, including DEC and DEP, are actually designed, built, and operated.

Inappropriate Reliability Metrics and Requirements

The *Ancillary Service Study* attempts to compare total production costs with and without solar generation in order to determine the cost of integrating additional solar generation (after compensating for the change in solar versus conventional energy value itself). In order to make a fair comparison, it is necessary to hold reliability constant in the no-solar and solar generation cases so that calculated integration costs are not reduced (or increased) as the result of a drop (or increase) in reliability. Reliability is held constant by adding reserves to the solar cases until reliability matches the non-solar base case. This basic methodology of using security constrained unit commitment and economic dispatch modeling is well established and has been used in numerous renewables integration studies including the National Renewable Energy Laboratory (NREL) Eastern Wind Integration and Transmission Study and the Western Wind and Solar

[1] Ancillary Service Study at 13.
[2] DEC and DEP Response to SACE Data Request No. 2, Question No. 25.
[3] DEC and DEP Response to SACE Data Request No. 2, Question No. 3.

Integration Studies.[4] The methodology has also been used by utilities to develop renewables integration charges.[5,6]

The assessment methodology reported on in the *Ancillary Services Study* correctly recognizes that it is the continuous balancing of generation and load that requires reserves and drives system reliability. However, rather than basing the DEC and DEP balancing requirements on mandatory NERC standards, the study introduces a completely arbitrary pair of misnamed loss-of-load-expectation (LOLE) metrics which attempt to identify instances of insufficient generation capacity or flexibility. These metrics are misnamed because there would be no loss of load expected during the identified imbalances for DEC or DEP as they actually operate in the Eastern Interconnection. In interconnected operations, small imbalances in one BA manifest themselves as deviations from scheduled interchange flows, not loss of load; load shedding is not required. It is only the aggregation of imbalances from all the BAs in the interconnection that influence frequency and potentially impact reliability. Under normal operating conditions, imbalances in one BA tend to counteract imbalances in another BA such that the total interconnection imbalance is much less than the sum of the absolute values of the individual BA imbalances. Interconnection greatly increases reliability while dramatically reducing individual BA balancing requirements. Consequently, NERC reliability standards do not require the level of reserves or balancing operations necessary to meet the 0.1 LOLE for 5-minute balancing that is the basis of the *Ancillary Service Study* and the proposed solar integration charges. These issues are explained in further detail below.

DEC and DEP Ancillary Service Study *Balancing Metrics and Requirements*

The *Ancillary Service Study* established two LOLE metrics: $LOLE_{CAP}$ and $LOLE_{FLEX}$. As described below, the two LOLE metrics used in the study are not appropriate standards and result in inaccurate and improper conclusions.

The production cost modeling looked at each power system (DEC and DEP) as isolated islands and simulated the generation/load balance every five minutes. $LOLE_{CAP}$ looked for instances when there was insufficient generation capacity to cover total load. $LOLE_{FLEX}$ looked for instances

---

[4] EnerNex, *Eastern Wind Integration and Transmission* Study, National Renewable Energy Laboratory, NREL/SR-5500-47078, Feb. 2011; GE Energy, *Western Wind and Solar Integration Study*, National Renewable Energy Laboratory, May 2010;D. Lew et al, *The Western Wind and Solar Integration Study Phase 2*, National Renewable Energy Laboratory, NREL/TP-5500-55588, Sept. 2013.

[5] See e.g. Solar Integration Study Report, Idaho Power, April 2016, http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTEGRATION%20STUDY%20REPORT.PDF.

[6] Commission and utility interest in variable renewables integration charges appears to be declining, making it difficult to find examples of well-designed integration charges. Analysts are recognizing that all generators have characteristics that impose costs on the power system. “Base load” generators, for example, are typically inflexible with high minimum loads, long startup times, and slow ramp rates. These limitations impose costs when lower-cost generation is available at low net-load times but cannot be used because the base load generators must run. Commissions are reluctant to impose integration charges on base load generators and instead allow security constrained unit commitment and economic dispatch optimization, as well as electricity markets, to optimize the utilization of the generation fleet.

when there was insufficient generation ramping capability to follow the net system load. The study imposed a 0.1 LOLE requirement which allowed one 5-minute imbalance event every ten years.

> "Reliability targets for capacity shortfalls have been defined by the industry for decades. The most common standard is "one day in 10 years" LOLE, or 0.1 LOLE." "To meet this standard, plans must be in place to have adequate capacity such that firm load is expected to be shed one or fewer times in a 10-year period."[7]

While it is true that a LOLE of 0.1 is an appropriate and accepted standard for long-term planning of reserve capacity, it is completely inappropriate, unnecessary, not required by NERC standards, and excessively expensive when applied to actual operations. The *Ancillary Service Study* acknowledges that "[r]eliability targets for operational reliability are covered by NERC Balancing Standards" and are not dictated by an arbitrary LOLE of one event in ten years. The Study further states that "[t]he Control Performance Standards (CPS) dictate the responsibilities for balancing areas (BA) to maintain frequency targets by matching generation and load".[8] Most importantly, with interconnected operations a small imbalance in one BA will not result in a LOLE event, which is why NERC does not require continuous perfect balancing from each BA.

The *Ancillary Service Study* acknowledges that actual NERC reliability and balancing requirements were not modeled, and the 0.1 LOLE was substituted, presumably because the modeling capability was insufficient to represent actual balancing capabilities and requirements:

> "Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and CPS2 standards is a critical component of a solar ancillary service cost impact study. However, ***<u>simulating violations of these standards is challenging</u>***. While the ***<u>simulations performed in SERVM do not measure CPS violations directly</u>***, the operational reliability metrics produced by the model are correlated with the ability to balance load and generation. In SERVM, instead of replicating the second-to-second Area Control Error (ACE) deviations, net load and generation are balanced every 5 minutes. The committed resources are dispatched every 5 minutes to meet the unexpected movement in net load. In other words, the net load with uncertainty is frozen every 5 minutes and generators are tested to see if they are able to meet both load and minimum ancillary service requirements. ***<u>Any periods in which generation is not able to meet load and minimum ancillary service requirements are recorded as reliability violations</u>***." … "So, while there are operational reliability standards provided by NERC that provide some guidance in planning for flexibility needs, ***<u>there is not a standard for loss of load due to flexibility shortfalls as measured by SERVM</u>***. Absent a standard, this study assumes that maintaining a constant operational reliability as solar penetration increases is an appropriate objective. ***<u>Simulations of the DEC and DEP</u>***

[7] Ancillary Service Study at 10.
[8] <u>Id.</u>

> ***systems with current loads and resources were calibrated to produce*** $\boldsymbol{LOLE_{FLEX}}$ ***of 0.1 events per year***."[9]

The 0.1 $LOLE_{FLEX}$ requirement is unrelated to NERC reliability standards and is not a reasonable analysis proxy for the actual balancing or reliability requirements. As the *Ancillary Service Study* acknowledges, SERVM cannot accurately measure NERC reliability violations. The Study invented a $LOLE_{FLEX}$ standard that is an unreasonable proxy for actual balancing and reliability requirements.

NERC Mandatory Reliability Balancing Requirements

As the *Ancillary Service Study* acknowledges, actual power system reliability and reserve requirements are established by NERC. These requirements are laid out in mandatory NERC reliability standards which are approved by the Federal Energy Regulatory Commission (FERC) and the Canadian provincial governments. Two NERC standards are particularly relevant[10]:

- BAL-001-2 – Real Power Balancing Control Performance
- BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event

These standards establish reliability and reserve requirements for Balancing Authorities (BAs) such as DEC and DEP. Importantly, and fundamentally, the reliability requirements are based on operations within an interconnection; specifically, within the 720,000 MW Eastern Interconnection in Duke's case.[11] This is fundamentally important because with interconnected utility operations, small imbalances within one BA do not result in Loss of Load events under normal conditions. In fact, imbalances are occurring all the time under normal conditions. The NERC standards limit the magnitude and frequency of allowed imbalances, but they do not attempt to eliminate them or restrict them to one-event-in-ten-years.

Obsolete CPS2 Requirement

The *Ancillary Service Study*[12] references two NERC reliability metrics: CPS1 and CPS2. CPS2 is no longer applicable, however. It was replaced in July 2016 with the BAAL requirement, discussed below, when BAL-001-02 became the effective standard. CPS2, however, was a much laxer balancing requirement than the *Ancillary Service Study* 0.1 $LOLE_{FLEX}$ requirement. CPS2 measured balancing over 10-minute intervals and required compliance only 90% of the time.

[9] Id. (emphasis added).
[10] Additional standards, such as BAL-003-1 — Frequency Response and Frequency Bias Setting, amplify and support the balancing requirements.
[11] NERC 2018 Summer Reliability Assessment.
[12] "Understanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and **CPS2** standards is a critical component of a solar ancillary service cost impact study." Ancillary Service Study at 10 (emphasis added).

CPS2[13]: Monthly-$AVG_{10\text{-minute}}(ACE)<L_{10}$ Where L_{10} = 92 MW for DEC and 17 MW for DEP[14]

So, rather than allowing only one 5-minute event every ten years, CPS2 allowed ACE to remain high or low for 5,256 10-minute intervals per year and bounded average ACE to 92 MW for DEC and 17 MW for DEP for the remaining 90% of the time.

Applicable NERC Balancing Requirements

BAL-001-2 – Real Power Balancing Control Performance establishes two reliability metrics that apply during normal (non-contingency) operations: Control Performance Standard 1 (CPS1) and the Balancing Authority ACE Limit (BAAL). NERC balancing requirements under contingency conditions are discussed further below.

CPS1 Reliability and Balancing Requirement

CPS1 limits the ***annual average*** 1-minute area control error deviations. ACE deviations result from difference between a BA's total instantaneous generation (plus scheduled imports) and total instantaneous load (plus scheduled exports) (plus the BA's instantaneous frequency support obligation).[15] While 100% compliance is required, this metric may be a bit deceptive. The CPS1 metric runs between 0% and 200%, meaning continuous perfect balancing would result in a CPS1 score of 200%, not 100%. Therefore, 100% compliance does not mean compliance during every minute. The CPS1 requirement is reflected in the following formula:

$$AVG_{Period}\left[\left(\frac{ACE_i}{-10B_i}\right)_1 * \Delta F_1\right] \leq \epsilon_1^2$$ [16]

This formula is simpler than it at first appears. It says that the annual average of the instantaneous ACE values, times the instantaneous ΔF [frequency deviation from the scheduled frequency (usually 60 Hz)], must be less than 0.000324.[17] It is the multiplication of ACE times ΔF that makes balancing operations easier (and analysis harder). During times when frequency is exactly equal to 60 Hz then there is no CPS1 limit on ACE. When frequency is exactly equal to 60 Hz then ΔF is zero, which is multiplied by ACE and the result remains zero no matter how large ACE is. Physically this means that the BA can be far out of balance with no penalty when frequency is exactly 60 Hz. This makes sense for reliability because, if frequency is exactly equal

---

[13] "BAL-001-1 — Real Power Balancing Control Performance", NERC.

[14] "BAL-003-1 Frequency Bias Setting and L10 Values for 2017", NERC, March 28, 2017.

[15] Because BA load cannot be measured directly NERC it is determined indirectly by measuring the BA's generation and interconnection flows (imports and exports). NERC defines ACE as "The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias[.]" Reliability Standards for the Bulk Electric Systems of North America, NERC (updated July 3, 2018).

[16] NERC Standard BAL-001-1 — Real Power Balancing Control Performance.

[17] ϵ_1 for the Eastern Interconnection is 0.018 Hz (Reliability Standards for the Bulk Electric Systems of North America, updated July 3, 2018) ϵ_1^2 is 0.000324.

to 60 Hz (ΔF is zero) the overall interconnection is not experiencing an overall imbalance and an individual BA's imbalance is not a reliability threat.

Further, not all imbalances are bad. If frequency is below 60 Hz (ΔF is negative) and the BA is over-generating (excess solar, for example) then the BA's imbalance is supporting reliability by reducing the interconnection's overall imbalance and helping to push frequency back up to 60 Hz. CPS1 calculation credits the BA for that help. The excess generation is a reliability benefit and there is no requirement to reduce ACE. Conversely, if frequency is above 60 Hz (ΔF is positive) and the BA is under-generating (excess load or solar is suddenly reduced, for example) the BA is again helping overall power system reliability by reducing the interconnection's overall imbalance and helping to push frequency back down to 60 Hz, and CPS1 again credits the BA.

Frequency in the Eastern Interconnection varies constantly over a small range. It is above 60 Hz (ΔF is positive) about half the time and below 60 Hz (ΔF is negative) about half the time as shown in figure 1.1 from the November 2018 NERC report *2018 Frequency Response Annual Analysis*:

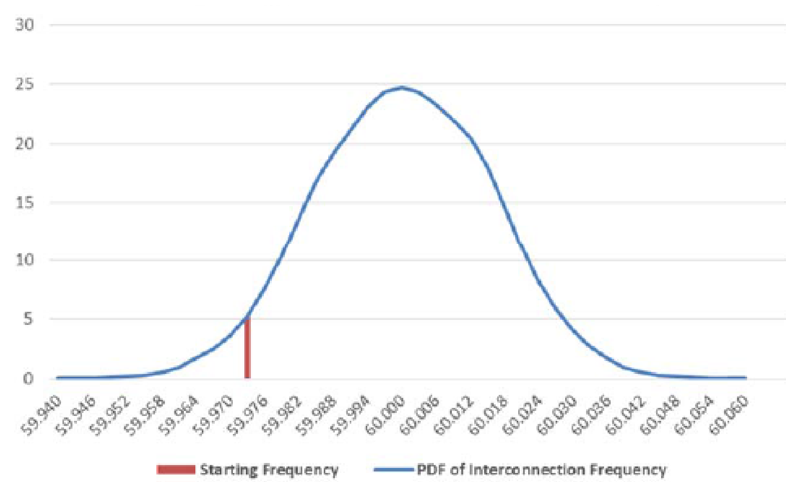


Figure 1.1: Eastern Interconnection 2014–2017 Probability Density Function of Frequency

Given that short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the 720,000 MW Eastern Interconnection, CPS1 does not require correction of imbalances about half of the time. This significantly reduces the balancing reserves that Duke must have available and reduces the times Duke must exercise those reserves.

BAAL Reliability and Balancing Requirement

Like CPS1, the Balancing Authority ACE Limit (BAAL) does not require perfect compliance. In fact, BAAL only limits ACE deviations that exceed *30 consecutive minutes*. Further, like CPS1, BAAL only limits ACE deviations that hurt interconnection frequency. That is, over-generation is not limited when interconnection frequency is below 60 Hz and under-generation is not limited when interconnection frequency is above 60 Hz. BAAL limits are specific to each BA and depend on the actual interconnection system frequency at each time interval. As shown in Figure 2 below, ACE limits are lax when frequency is close to 60 Hz and get progressively tighter as frequency deviates farther from 60 Hz.

Again, given that short-term, unexpected solar variability within the Duke service territories is unlikely to be related to frequency variations in the very large Eastern Interconnection, BAAL does not require correction of imbalances about half of the time.

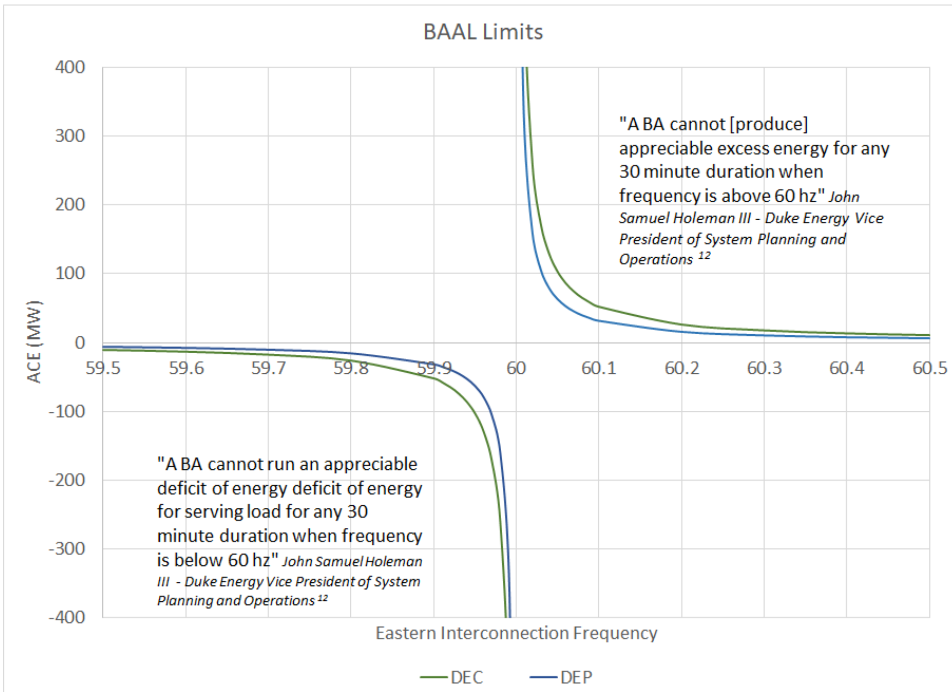


Figure 2 BAAL does not require perfect balancing

BAL-002 – Disturbance Control Standard (DCS)

NERC reliability standards recognize that large conventional generators occasionally fail unexpectedly and that the normal generation and load balance cannot be maintained by the host BA during such an event. The "BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event" standard provides the requirements to restore the generation and load balance after a reportable contingency.[19] BAL-002 contains three balancing related requirements. The first requirement is to restore the generation and load balance within the Contingency Recovery Period (15 minutes) by using the Contingency Reserves. The second requirement is to have Contingency Reserves equal to or greater than the most severe single contingency available at all times. The third requirement is to restore the Contingency Reserves within 105 minutes of the start of the contingency.

[18] Direct Testimony of John Samuel Holeman III, Duke Energy Vice President of System Planning and Operations, Testimony in Biennial Determination of Avoided Cost Rates for Electric Utility Purchases From Qualifying Facilities – 2016 Docket No. E-100, Sub 148.

[19] "BAL-002-2 – Disturbance Control Standard – Contingency Reserve for Recovery from a Balancing Contingency Event", NERC.

There are three DCS issues that are important for the *Ancillary Service* analysis. The first is that NERC recognizes contingencies—the sudden, unexpected failure of large generators, for example—as distinct events, and NERC changes the balancing requirements during such events. The second is that NERC recognizes Contingency Reserves as specific resources that can be used during contingencies. The third is that NERC requires BAs to continuously maintain specific amounts of Contingency Reserves, even during normal conditions.

The *Ancillary Service Study* chose to specifically model conventional generation contingencies by randomly removing generators during the study runs:

> "SERVM will randomly draw a Time-to-Fail value from the distribution provided for both full outages and partial outages. The unit will run for that amount of time before failing. … When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration." (page 40)

While this, at first, sounds like a modeling improvement, it is actually a needless complication for solar integration modeling that is inaccurate when done incorrectly. The problem is that Contingency Reserves are not released to help balance the power system when, and only when, the model randomly inserts a contingency. Nor are reserves restored within 105 minutes of the contingency. Further, there is no indication that the model respects the requirement to maintain contingency reserves during "normal" times. Failure to release Contingency Reserves during a contingency results in overstating the balancing problem: the model reports imbalances when none would actually occur. Failure to hold Contingency Reserves during normal, non-contingency, times results in the model using Contingency Reserves to compensate for non-contingency imbalances. This understates the normal-conditions balancing reserve requirements.

A solution that many modelers employ is to simply carry the Contingency Reserves (differentiated into spinning and non-spinning based on the Regional Reliability Council requirements) continuously and to not try to model the specific contingency events. Contingency Reserves are designed to compensate for Contingencies when they actually occur, so reliability is maintained without the need to explicitly model the random and infrequent contingency events. This more closely matches actual operating restrictions.

Solar generation plants are typically small compared with large fossil and nuclear generators and consequently do not add to contingency reserve requirements. That is, solar plants do not increase the size of the most severe single contingency, which sets the size of the contingency reserves the BA must have available. Contingency reserves must, however, be maintained in both the base-case and solar-case production cost modeling runs. It is the holding of the Contingency Reserves that is important for the production cost modeling, not the infrequent actual deployment, which is the same under base-case and solar-case conditions.

Use of Curtailed Solar Generation for Contingency Reserves

Curtailed solar (and wind) generators can be ideal *suppliers* of contingency (and other) reserves. Modern solar plants can control their output faster and more accurately than conventional generators. If they are equipped with automatic generation control (AGC) they can provide that response to the system operator during contingencies. Solar plants normally operate at their full available output, and have no reserve capacity to offer, because they have zero marginal production cost and are therefore more economic than fuel burning generators. If, however, a solar generator is curtailed for some reason it will have available generation capacity that could be called upon to support power system reliability. Any solar generator that is *supplying* contingency reserves should be compensated for provision of that service.

Interconnection Frequency Does Complicate Modeling – How to Solve That

The *Ancillary Service Study* is correct when it states that "[u]nderstanding how the increase in solar generation will affect the ability of a BA to meet the CPS1 and CPS2[20] standards is a critical component of a solar ancillary service cost impact study. However, **simulating violations of these standards is challenging**." (page 10, emphasis added). The Study is only partly correct when it states that "[w]hile the simulations performed in SERVM do not measure CPS violations directly, the operational reliability metrics produced by the model are correlated with the ability to balance load and generation."[21] It is correct to state that the modeling does not measure CPS violations. It is not correct to imply that the analysis effort and the LOLE reliability metric are in any way suitable substitutes for the NERC CPS1, BAAL, or DCS reliability requirements.

The difficulty in directly modeling NERC balancing requirements is because CPS1 and BAAL both require balancing *only* when ACE drives the interconnected power system frequency further away from 60 Hz: each metric uses (ACE x ΔF) in assessing instantaneous balancing performance.[22] The NERC reliability metrics *credit* generation/load imbalances when they are helping to restore the overall interconnection system frequency to 60 Hz. To do the analysis exactly, the model would have to know the power system frequency at each time step in order to directly model the NERC requirements. That would require knowing the generation and load balance for the entire Eastern Interconnection for each time step, which is currently an infeasible modeling effort.

Instead, a feasible approach is to require more realistic balancing. A recent Idaho Power study[23] of variable renewable generation integration (solar and wind) studied solar penetration levels of

---

[20] Again, the correct NERC reliability requirements are CPS1, BAAL, and DCS, but the concept that it is mandatory NERC reliability standards that govern balancing requirements is correct.
[21] Ancillary Service Study 10-11.
[22] Excess generation is bad only when frequency is above 60 Hz and excess load is bad only when frequency is below 60 Hz.
[23] Solar Integration Study Report, Idaho Power, April 2016, http://www.puc.idaho.gov/fileroom/cases/elec/IPC/IPCE1611/20160506SOLAR%20INTEGRATION%20STUDY%20REPORT.PDF.

47% of peak load and wind-plus-solar penetrations of 67% of peak load. For reference, the Duke *Ancillary Service Study* only studied solar penetrations ranging from 5% to 33% of peak load.[24] The Idaho Power study also employed production cost modeling with reserve requirements adjusted to maintain pre-solar-and-wind reliability levels. Idaho Power targeted reserves (in both the base and renewables cases) sufficient to compensate for 99% of the 5-minute balancing deviations. That is, Idaho Power allowed a cumulative 90 hours per year of deviations rather than one-event-in-10-years:

> "The target to capture 99 percent of deviations for this study is considered appropriate in ensuring generators have sufficient reserve requirements for all but approximately 90 hours per year. Importantly, the targeted 99 percent is the criterion held for both simulations performed for this study: the base case simulation of load combined with wind, and the test case simulation of load combined with wind and solar. This ensures both simulations are designed to bring about an equivalent level of system reliability, rendering the selected reliability level relatively immaterial from the perspective of comparing production cost differences between paired simulations."[25]

Inappropriate or Questionably Synthesized Solar Data

Of necessity, the *Ancillary Service Study* (and any planning study) modeled solar sites that do not yet exist and for which there is no actual data. Consequently, appropriate solar plant output data must be synthesized for the analysis. It is important that the synthesized data captures aspects of the actual solar plants that will be built. It is also important that the synthesized data represents data that is synchronized to the load data it is paired with to accurately represent net power system variability and uncertainty.

The Study states "[t]o develop data to be used in the SERVM simulations, Astrapé used 1 year of historical five-minute data for solar resources and load." (page 26). This is a reasonable start. The study also notes:

> "Knowing that solar capacity is only going to increase in both service territories, it is difficult to predict the volatility of future portfolios. In both DEC and DEP, the majority of the historical data is made up of smaller-sized units while new solar resources are expected to be larger. So, while it is expected there will be additional diversity among the solar fleet, *the fact that larger units are coming on may dampen the diversity benefit*. For this study, <u>*the raw historical data volatility was utilized along with a distribution that has 75% of the raw data volatility to serve as bookends in the study for the "+1,500" MW solar scenarios*</u>."[26]

---

[24] Existing, transition, Tranche 1, and plus 1500 MW of solar generation for DEP and DEC.
[25] Ancillary Service Study at 8.
[26] <u>Id.</u> at 30-31 (emphasis added).

This is completely unreasonable. Linearly scaling (doubling variability when the solar resource capacity doubles) is not realistic. The relative intra-hour variability of an aggregation of solar plants (or loads or wind generators) *declines* as the aggregation grows. This is because the short-term variations at one solar plant are not coupled to the short-term variations at other solar plants. The geographic separation of the solar plants prevents cloud shadow edges from crossing multiple solar generators simultaneously.[27]

An examination of the historic solar output data for DEP and DEC shows this decline in relative variability.[28] For example, for the month of July 2018 DEP had a maximum solar output of 1,630 MW while DEC had a maximum solar output of 427 MW.[29] The maximum coincident solar output for the combination of DEP and DEC was 2,041 MW, just 0.8% below the sum of the DEP plus DEC maximum solar outputs. As expected, maximum solar output is closely correlated for DEP and DEC. Aggregating DEP and DEC does not greatly reduce the maximum solar output of the aggregation. By contrast, the relative short-term intra-hour variability of the aggregation of DEP and DEC is significantly lower than the sum of the variability of the two BAs. The hourly average standard deviation of the DEP intra-hour variability for July 2018 was 9.7 MW.[30] The hourly average standard deviation of the DEC intra-hour variability for July 2018 was 3.6 MW. If short-term variability scaled linearly as the *Ancillary Service Study* claims, then the hourly average standard deviation of the short-term variability for the net Duke system would be expected to be 13.3 MW. Instead, the hourly average short-term variability had a standard deviation of only 10.3 MW, just 78% of what linear scaling predicts. The 10.3 MW is also exactly what would be expected for completely uncorrelated short-term variability aggregation for DEP and DEC.

Examining all the historic data Duke provided also shows the strong aggregation benefits of reduced relative variability as the solar aggregation grows. Figure 3 shows that solar generation increased significantly in both DEP and DEC between April 2016 and July 2018. Figure 4 shows that short-term intra-hour variability increased as well. Figure 5, however, shows that short-term variability *declines* relative to the maximum solar generation, both as solar penetration increases through time and when comparing the net Duke system with DEP and DEC individually. That is, variability does not scale linearly with solar generation fleet size but instead exhibits strong aggregation benefits.

With the historic data showing the expected trend of short-term variability declining as solar penetration increases, the assumption of linear scaling is clearly unjustified.

---

[27] A. Mills and R. Wiser, Implications of Wide-Area Geographic Diversity for Short-Term Variability of Solar Power, Ernest Orlando Lawrence Berkeley National Laboratory, September 2010.

[28] SACE Data Request No. 2 Item No. 2-30 asked for, and Duke provided, 5-minute aggregate solar and load data for DEP and DEC for April 2016 through August 2018.

[29] Maximum solar output is used as a proxy for solar capacity because Duke did not provide data about which solar plants are included in the aggregate solar output data.

[30] The appendix discusses why the use of standard deviation for quantifying short-term variability is both appropriate and more useful for comparisons than a probability distribution.

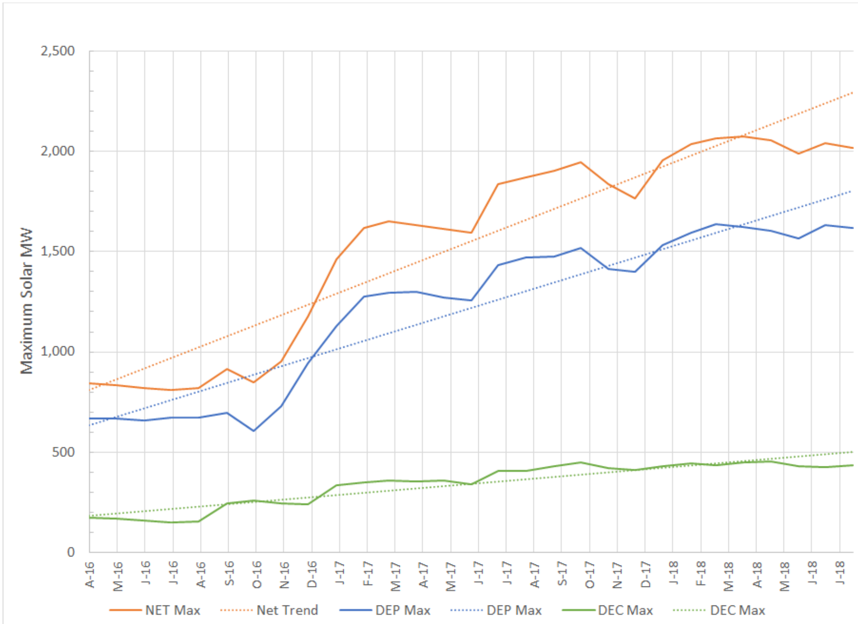


Figure 3 Solar generation increased significantly in DEP and DEC between April 2016 and July 2018

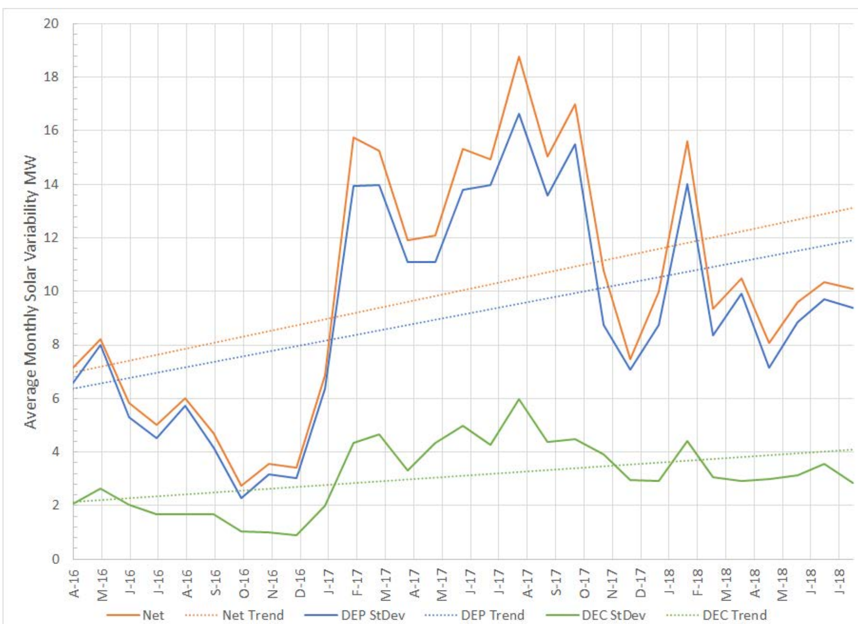


Figure 4 Short-term variability also increased in DEP and DEC between April 2016 and July 2018

Figure 5 Variability relative to maximum solar declines as solar penetration increases.

Concerns with the *Ancillary Service Study* analysis get worse. The study says that it spread the simulated solar plants over 13 locations throughout the DEC and DEP service territories. Thirteen locations is not a lot of diversity for 7,630 MW of solar generation in the Existing + Tranche 1 + 1500 MW case. That would result in thirteen 586 MW solar plants that cover 3,000 acres (4.6 square miles) each. Further, Tables 5 and 6 show that 22% of the DEP solar plants and 24% of the DEC solar plants are at single sites (site C4 for DEP and site B3 for DEC). That represents a 791 MW solar plant in DEP and an 800 MW solar plant in DEC: 4,000 acres or 6.3 square miles of solar cells in one location. 78% of the DEP solar and 85% of the DEC solar was modeled at just four sites each. This creates a significant lack of diversity in the analysis. But even if an 800 MW solar plant covering 4,000 acres were built, it would have a significant reduction in short-term variability compared with existing solar plants simply from its own geographic size. All of this is in spite of the fact that Schedule PP only applies to solar plants with a capacity of 1 MW_{AC} or less, and that much of the solar generation in Duke's North Carolina BAs is approximately 5 MW, corresponding to the previous Schedule PP standard offer contract.

Analysis of the historic solar generation shows that it is much more reasonable to assume that the short-term (5-minute) variability and uncertainty of new solar generation plants will be uncorrelated with the short-term variability and uncertainty of the existing solar generation plants, and with each other. Further, the *Ancillary Service Study* report states: "[t]o develop data to be used in the SERVM simulations, Astrapé used 1 year of historical five-minute data for solar resources and load"[31]and "the five-minute data used to develop intra-hour load volatility was developed from actual data ranging from October 2016 - September 2017[.]"[32] Assuming that

[31] Ancillary Service Study at 26.
[32] Id. at 27.

"the 1 year of historical five-minute data for solar resources" was also October 2016 through September 2017, then the DEC maximum solar increased from 244 MW to 431 MW during the historic calibration year while the DEP solar fleet increased from 697 MW to 1,476 MW. Total Duke solar generation thus increased from 941 MW to 1,907 MW, averaging 1,424 MW during the historic year that was apparently used to calibrate solar variability. This is significantly smaller than the 679 MW of "Existing" solar generation for DEC and 1,923 MW for DEP (2,602 MW total) listed in Table 3 of the *Ancillary Service Study* report.

The *Ancillary Service Study* analyzed total solar penetrations ranging from 2,602 MW for the "Existing" fleet to 7,630 MW for the "Existing+Transition+Tranche 1+1500". That is a range of 1.8 to 5.4 times the size of the solar fleet that was actually analyzed for short-term variability impacts. This results in short-term variability and uncertainty expectations of:

- 100% for the actual measured solar fleet
- 74% for the Existing solar generation
- 61% for the Existing + Transition
- 55% for the Existing + Transition + Tranche 1
- 43% for the Existing + Transition + Tranche 1 + 1500 MW

This large increase in solar penetration creates significant diversity benefits.

Concerns with Dropouts and Data Anomalies

There are additional concerns with the *Ancillary Service Study* analysis of solar variability. While analysis of a generator's energy output is relatively insensitive to bad data, analysis of short-term variability is inherently sensitive to data dropouts and data anomalies. The *Ancillary Service Study* $\text{LOLE}_{\text{FLEX}}$ 1-in-10-year limit is especially sensitive. If metering data incorrectly showed that a 1,000 MW generator's (or generation fleet's) output dropped to zero for one 5-minute interval every month, that would have essentially no impact on the energy output assessment. The assessed output would only be understated by 0.01%. The assessment of variability, on the other hand, would show 12 massive 1,000 MW jumps in output every year, 120 times the single event allowed by $\text{LOLE}_{\text{FLEX}}$ in ten years. Data dropouts will dominate any analysis of variability and the resulting reserve requirements.

Duke warned that the 5-minute historic solar data they provided in response to SACE Data Request No. 2 Item No. 2-30 was not perfect: "[p]lease note that this data is sourced from the historian software (OSI PI), so there are some periods where data drop-outs occurred, particularly for DEP." Figure 6 shows an example where the DEP solar fleet data dropped by 1,400 MW for 15 minutes while the DEC solar and DEP load data were unaffected. This type of event is reasonably easy to identify, and it is easy to determine if the event was real. If there had been a 1,400 MW instantaneous drop in generation output it would have been a significant event not only for DEP but for the Eastern Interconnection.

Bad data is more difficult to detect if only part of the solar fleet is impacted but the only data available is for the entire aggregation. Figure 7 shows an event from March 2017 when the output for numerous DEP solar plants was erroneously reported at zero for one 5-minute interval. This event too is relatively easy to detect and eliminate from the analysis because of its 1,100 MW size. Had the data been bad for only one or two plants, the bad-data-event would not be detectable from the aggregate solar fleet data alone, and the event would be incorrectly included in the assessment of solar variability.

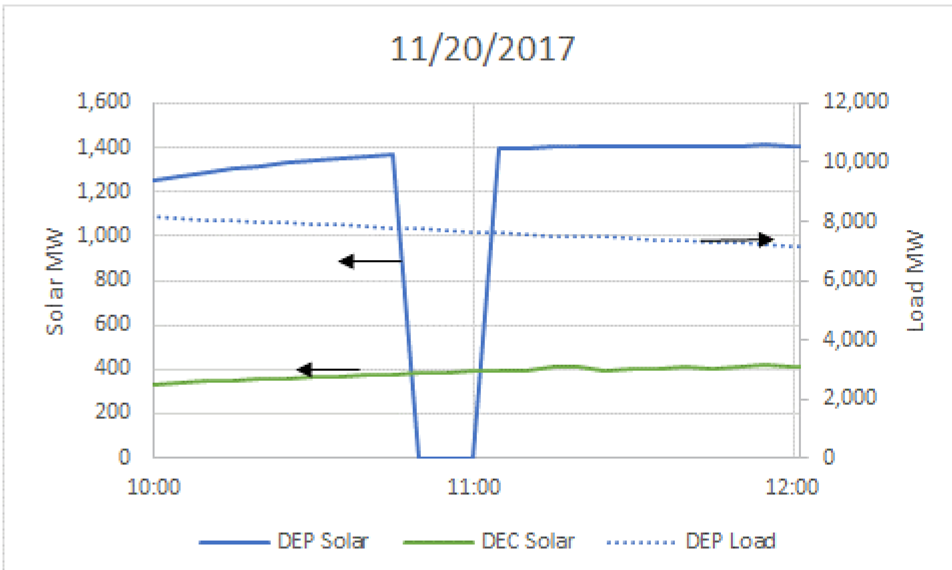


Figure 6 Solar fleet output data suffers from data dropouts.

Figure 8 shows that improbable spikes occasionally appear in the data.

Figure 9 shows a September 2016 event where DEC solar output suddenly increased by nearly 100 MW in one 5-minute interval. While not completely impossible, this sudden increase is unlikely to be real. An evaluation of the data from each solar generator included in the aggregation would clarify if the event was real.

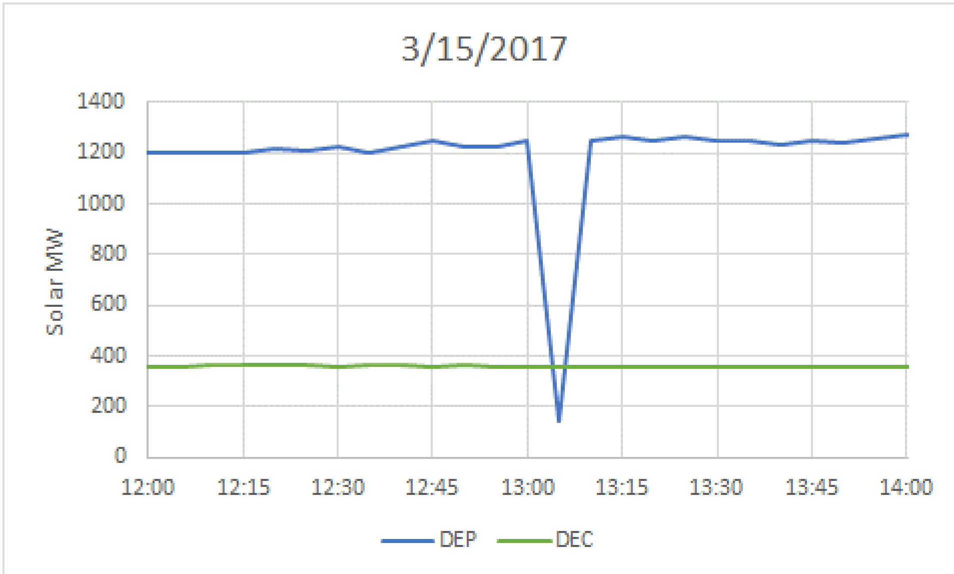


Figure 7 Data dropouts are harder to detect if they impact only art of the aggregation.

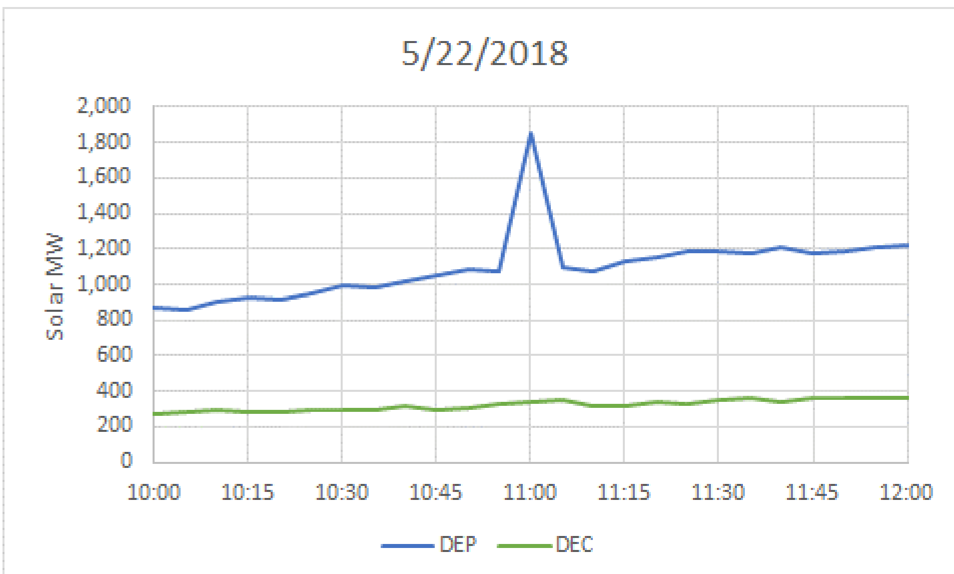


Figure 8 Solar output data occasionally shows unlikely spikes.

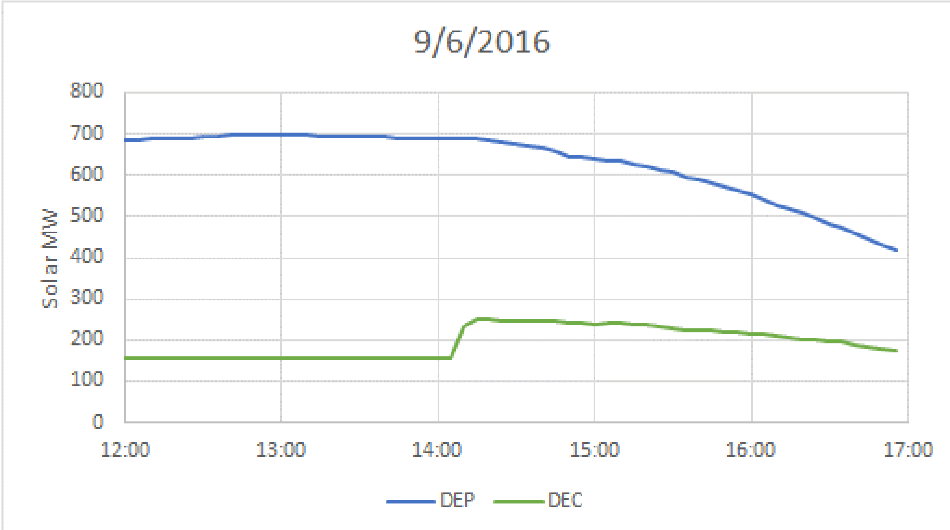


Figure 9 Data anomalies are not limited to dropouts and spikes.

Figure 10 shows hourly variability versus solar output for the data Duke provided. The 1,400 MW 15-minute drop in DEP solar output is immediately obvious.

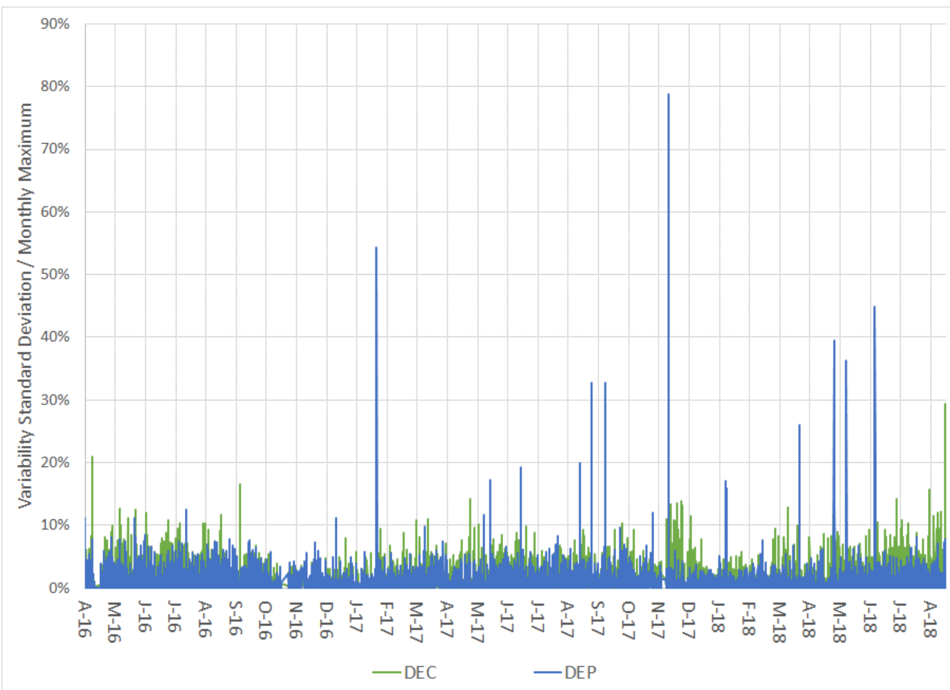


Figure 10 Spikes in hourly solar variability indicate likely data anomalies worth investigating.

Figure 11 shows the hourly variability versus solar output after the readily identifiable data anomalies have been removed. Note that the vertical axis scale is reduced from a maximum of 90% to only 14%.

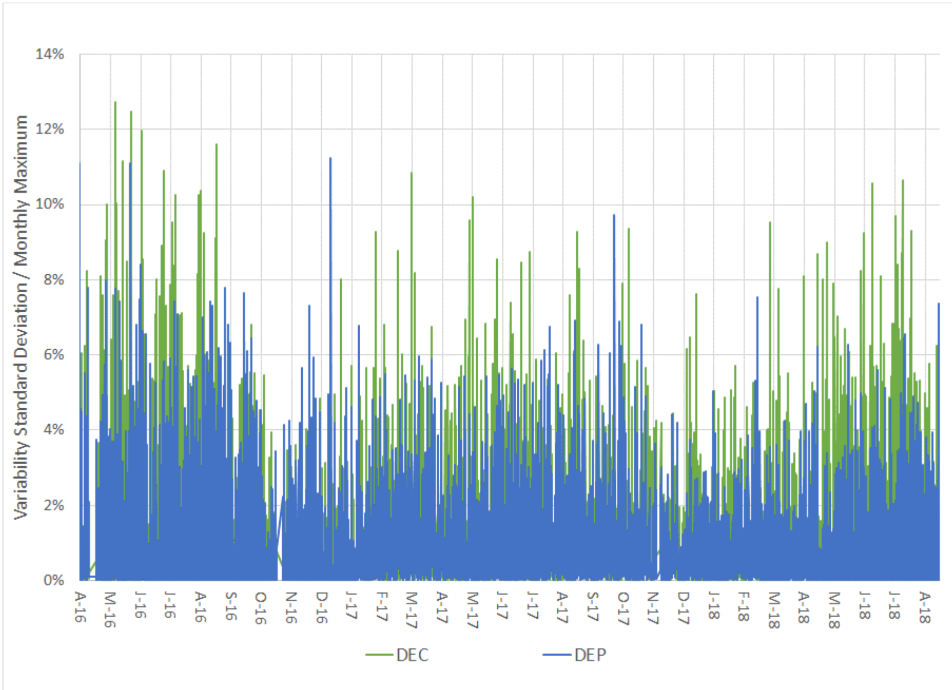


Figure 11 Solar variability is reduced after removal of data anomalies.

Over the 30 months covered by the historic 5-minute solar output data Duke provided, there were 93 events for DEP and 403 events for DEC that are almost certainly bad data that can be identified from the aggregate solar data. These events represented only 0.15% of the DEP data and 0.39% of the DEC data, but they dominate any assessment of short-term intra-hour solar variability if they are left in the analysis. Even with approximately 500 bad data events eliminated from the analysis, the short-term solar volatility is still likely overstated, perhaps significantly, because data dropouts from individual solar generators cannot unambiguously be identified from the aggregate solar data alone. It is unclear if and how solar output data dropouts were eliminated from the *Ancillary Service Study* analysis of short-term solar generator output volatility.

Unclear How Reserves Were Increased

The basic *Ancillary Service Study* methodology compares production cost simulations that include additional solar generation with base cases that have no solar. "The number of yearly simulation cases equals 36 weather years * 5 load forecast errors * 20 unit outage iterations * 6 solar profiles = 21,600 total iterations for each level of solar penetration simulated."[33]

The study methodology increased load following reserves in the with-solar cases in order to maintain the same level of reliability (as measured with the inappropriate $LOLE_{FLEX}$ metric): "To

[33] Ancillary Service Study at 44.

reduce $LOLE_{FLEX}$, additional load following is added as an input into the model."[34] The study noted the increased amount of reserves required and the resulting increased production cost to determine the proposed solar integration charge.

The *Ancillary Service Study* report does not detail how reserves were added to maintain reliability. For example, were reserve requirements increased for all 8,760 hours of the year? Were reserve requirements increased only during daylight hours? The report only states that "[i]n order to reduce $LOLE_{FLEX}$ back down to 0.1 events per year, additional ancillary services (load following up reserves) are simulated in the model so the system can handle the larger net load volatilities."[35]

A better approach would be to determine under what conditions increased solar generation stressed power system response and to then select appropriate mitigation measures. For example, it may be that increased reserves are only needed during the morning or evening solar ramps. Alternatively, there may be specific load conditions (either very high or very low loads) that are problematic. Specific weather conditions or conventional generation configurations may prove troublesome. Added reserves may only very rarely be needed, rather than being required almost every day. This is especially true with the very tight "one day in 10 years" LOLE criteria used for the study, in which a single event in 87,600 hours is all that is allowed. The answers that would result from a more robust analysis could dramatically impact the types of reserve resources that can be used to maintain reliability at least cost.

Next Steps – What Should Be Done?

The analysis methodology should be modified, and the modeling tools upgraded if necessary:

- Production cost modeling should be based on actual NERC reliability and balancing requirements and operating practices.
- Data anomalies for individual solar generators and for the solar generation fleet aggregation should be eliminated from the analysis of short-term intra-hour variability.
- Reductions in short-term intra-hour variability for the aggregate solar generation fleet from the variability identified in the historic data should be reflected in the analysis of each level of solar penetration studied.
- Actual balancing requirements that are expected to result from increased solar penetration should be identified.
- Least-cost methods to meet any additional balancing requirements should then be determined.

Once these steps are taken, it will be possible to begin to determine if any solar integration charge is warranted.

[34] Id. at 45.
[35] Id.

Duke should also consider utilizing a Technical Review Committee (TRC), composed of outside experts on variable renewables integration. TRC's have been successfully used by many utilities to help guide their integration studies and to utilize the latest and best integration study practices.[36] The Energy Systems Integration Group has published guidelines for TRC involvement in renewables integration studies.[37]

Improvements to Production Cost Modeling Methodology

Each BA should be modeled as part of the interconnected power system, not as an isolated island. Balancing and reliability requirements based on the mandatory NERC reliability standard BAL-001-02 and metrics based on CPS1 and BAAL should be used, not the arbitrary, made-up, and unrelated "1 day in 10-year" metric of $LOLE_{FLEX}$ and $LOLE_{CAP}$. A balancing requirement of 99% or 90 hours per year is still conservative but more closely matches the actual requirements imposed by CPS1 and BAAL in the interconnected power system.

Eliminate the explicit modeling of conventional generation failure contingencies. NERC reliability standard BAL-002 and Regional Reliability Council requirements dictate the amount of spinning and non-spinning contingency reserves that must be carried continuously to respond to sudden, unexpected generation and transmission failures, regardless of the frequency of those failures. Simply model the reserve requirements, and do not attempt to artificially simulate the events themselves. This will be more accurate and will reduce the number of required production cost modeling runs by a factor of 20.

If explicit contingency modeling is still included, then: 1) release the contingency reserves to respond to each event and 2) change the balancing requirements during the event to match the DCS requirements (rebalancing in 15 minutes and reserve restoration within 105 minutes).

Any curtailed solar generators should be allowed to provide reserves, including contingency reserves. The economic benefit of solar generators providing reserves should be credited to those generators.

Improvements to Solar Variability Modeling

The historic data used to assess the variability of the existing solar generation fleet should be carefully scrubbed to eliminate data anomalies. This will require the analysis of the output of every solar plant individually.

Intra-hour solar variability should be modeled more accurately. Aggregation benefits should be accounted for. Large amounts of additional solar generation should not be assumed to be placed at only four sites within each BA. Even if the massive 800 MW solar plants that were

---

[36] For example: Idaho Power, Portland General Electric, Arizona Public Service, BC Hydro, Public Service Colorado, Pan Canadian Wind Integration Study, ISO-New England, Pacificorp, Public Service of New Mexico, SMUD, the Western Wind and Solar Integration Study, Eastern Wind Integration and Transmission Study.

[37] Energy Systems Integration Group, Principles for TRC Involvement in Wind Integration Studies, https://www.esig.energy/resources/principles-trc-involvement-wind-integration-studies/.

modeled in the *Ancillary Service Study* were built, their own square-mile geographic size would reduce the single plant intra-hour variability significantly. Intra-hour variability should be reduced from the measured variability of the existing solar fleet to:

- 100% for the actual measured solar fleet
- 74% for the Existing solar generation
- 61% for the Existing + Transition
- 55% for the Existing + Transition + Tranche 1
- 43% for the Existing + Transition + Tranche 1 + 1500 MW

Identify Actual Balancing Requirements or Changes in Operating Practices

Once the production cost modeling methodology has been aligned with actual NERC reliability standards, and the expected solar variability has been represented accurately, the power systems can be studied to determine what additional balancing requirements additional solar generation may impose. Those balancing requirements should be analyzed to determine:

- Balancing shortfall event frequency, duration, direction, and MW amount
- Balancing shortfall event timing (early morning, midday, evening, week days, weekends, …)
- Power system conditions during balancing shortfall events (morning/evening load ramps, morning/evening solar ramps, extreme high/low loads, during times of conventional generation maintenance outages, high/low hydro conditions, …)
- Solar and weather conditions during balancing shortfall events

Only after the additional balancing characteristics are understood can cost effective mitigation methods be determined.

Additionally, changes in operating practices may help integrate greater amounts of solar generation more cost effectively than simply adding reserves. Changing the characteristics of which units are committed in order to increase response flexibility (lower minimum loads, faster response speeds, etc.) may be warranted. Production cost modeling, if done correctly, can effectively capture the costs of increasing flexibility and the benefits of reduced reserves.

Determine Cost Effective Methods to Maintain Reliability

Once any additional balancing requirements are understood, cost effective methods for obtaining that balancing capability can be determined. Standard utility practice is to differentiate reserve requirements based on response speed, duration, and frequency. The same criteria should be applied to additional balancing requirements for solar generation penetration. For example, fast-start combustion turbines are often used to meet non-spinning reserve requirements for infrequent events where the cost of continuously standing ready is more important than the cost of infrequent response events. Similarly, demand response is often cost effective for relatively infrequent events, especially if the events are expected to correlate with load capability.

Once additional balancing requirements are understood and quantified, the cost of meeting those requirements with the conventional generation fleet can be determined. Once the cost of meeting the additional balancing requirements with conventional generation is understood, alternative technologies, such as demand response or storage, can be examined. Finally, once the additional balancing requirements are quantified and costed, those requirements can be made public to see if third parties can supply the needed response at a lower cost than has been assumed in the studies.

Conclusions: The *Ancillary Service Study* is Fundamentally Flawed, and the Resulting Solar Integration Charge is Unsubstantiated

The analysis methodology presented in the November 2018 Duke Energy Carolinas and Duke Energy Progress Solar Ancillary Service Study report is deeply flawed, and the resulting solar integration charge is unjustified. The methodology is not based on actual utility operating practices or on mandatory NERC reliability requirements. Actual balancing and reliability requirements were not considered. Solar generation intra-hour variability was dramatically overstated because geographic diversity was not accurately considered. Balancing requirements themselves were not studied, and balancing resources were not matched to requirements.

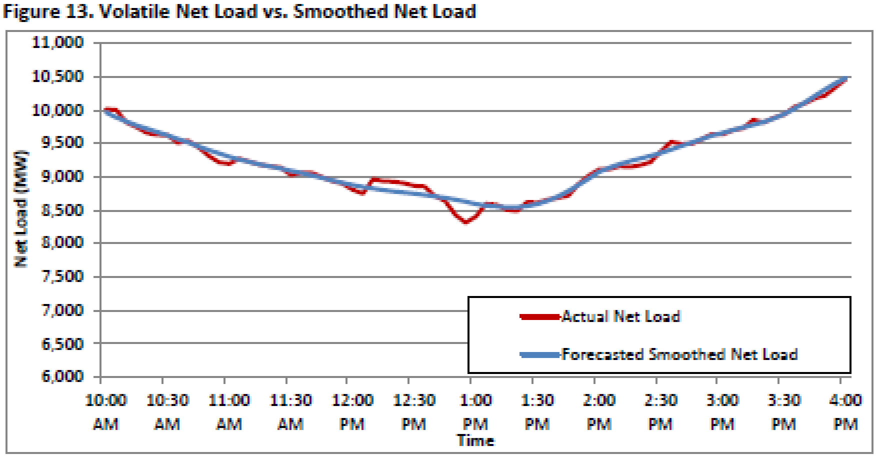
Appendix A

Quantifying Short-Term Variability

The *Ancillary Service Study* report identifies increases in the short-term variability and uncertainty in the net-load (load plus solar generation) caused by increasing amounts of solar generation as the cause for increased balancing reserves and therefore increased operating costs. The study quantifies short-term variability by comparing the actual 5-minute net-load with the longer-term trend of net-load:

> Within each hour, load and solar can move unexpectedly due to both natural variation and forecast error. SERVM attempts to replicate this uncertainty, and the conventional resources must be dispatched to meet the changing net load patterns. SERVM replicates this by taking the smooth hour to hour load and solar profiles and developing volatility around them based on historical volatility. **An example of the volatile net load pattern compared to a smooth intra-hour ramp is shown in Figure 13.** The model commits to the smooth blue line over this 6-hour period but is forced to meet the red line on a 5-minute basis with the units already online or with units that have quick start capability. As intermittent resources increase, the volatility around the smooth, expected blue line increases requiring the system to be more flexible on a minute to minute basis. The solution to resolve the system's inability to meet load on a minute to minute basis is to increase operating reserves or add more flexibility to the system which both result in additional costs.[38]

Figure 13. Volatile Net Load vs. Smoothed Net Load



[38] Ancillary Service Study at 26 (emphasis added).

Eric Hirst and I introduced this method of quantifying the short-term variability from the raw net-load signal in 1996 when ancillary services were first being defined by FERC.[39] Recognizing that short-term volatility does not typically scale linearly for loads and almost all utility resources, we developed a method for allocating the total-utility regulation volatility burden among individuals in 2000 when we introduced the vector allocation method.[40] The analysis method recognizes the importance of the level of correlation of the short-term variability of multiple resources (loads, generators, storage devices) with each other and the net-system-load in determining the utility aggregate load and generation balancing response. It has been applied to solar and wind generation many times since.[41] Figure A1, used in both reports Oak Ridge National Laboratory reports, shows the decomposition of the total net system load into base energy, the morning ramp, and the short-term fluctuations.

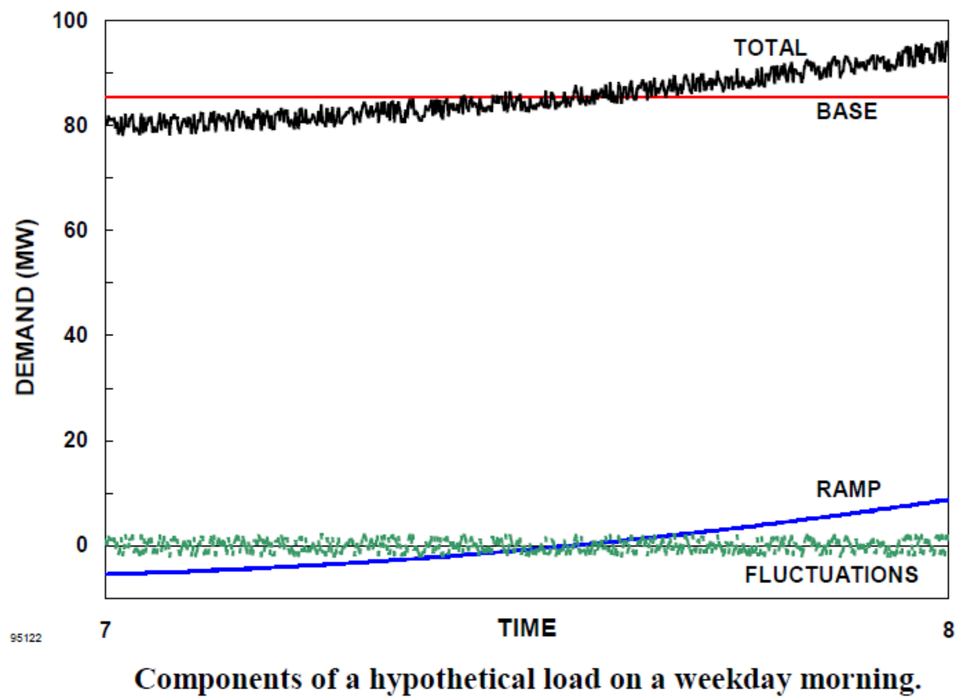


Figure A1 Separation of short-term volatility from base energy and ramping.

[39] E. Hirst and B. Kirby 1996, *Ancillary-Service Details: Regulation, Load Following, and Generator Response, ORNL/CON-433*, Oak Ridge National Laboratory, Oak Ridge, TN, September.
[40] B. Kirby and E. Hirst 2000, *Customer-Specific Metrics for The Regulation and Load-Following Ancillary Services, ORNL/CON-474*, Oak Ridge National Laboratory, Oak Ridge TN, January.
[41] For example: Kirby, Milligan, Mararov, Hawkins, Jackson, Shui, California Renewable Portfolio Standard, 2003 – ERCOT Wind Regulation Study – Holtinnen, Milligan, Kirby, Acker, Neimans, Molinski, Using Standard Deviation as a Measure of Increased Operational Reserve Requirement for Wind Power. Wind Engineering Journal 2008 – Milligan, Ela, Hodge, Kirby, Lew, Clark, DeCesar,o Lynn, Cost-causation and wind
integration analysis. 2011 – Milligan, King, Kirby, Beuning. Impact of Alternative Dispatch Intervals on Operating
Reserve Requirements for Variable Generation. Ackermann Conference 2011 – Kirby, Milligan, Wan, Cost-causation-based tariffs for wind ancillary service impacts

The *Ancillary Service Study* uses the method of separating short-term variability from the longer-term trend to analyze regulation requirements for load, solar generation, and net-load. The study quantifies the short-term variability in probability distribution tables like Table 9 from the *Ancillary Service Study* report.

Table 9. DEP West Load Volatility

Normalized Divergence (%)	Probability (%)
-3	0.020
-2.8	0.000
-2.6	0.003
-2.4	0.001
-2.2	0.008
-2	0.010
-1.8	0.010
-1.6	0.010
-1.4	0.020
-1.2	0.084
-1	0.242
-0.8	0.704
-0.6	2.269
-0.4	10.299
-0.2	37.095
0	35.792
0.2	9.899
0.4	2.107
0.6	0.796
0.8	0.337
1	0.167
1.2	0.079
1.4	0.028
1.6	0.006
1.8	0.002
2	0.008
2.2	0.001
2.4	0.000
2.6	0.002
2.8	0.005
3	0.000

Using probability distribution tables to quantify short-term variability makes comparing various conditions difficult. Table 9 took 62 numbers to quantify the short-term variability of the DEP West load for the historic calibration year. The report uses even larger tables to quantify solar variability versus solar output.

A well-established alternative to using probability distribution tables to quantify short-term variability is to use the standard deviation of the short-term variability.[42] This has been done for

[42] For example: B. Kirby, E. Ela, and M. Milligan, 2014, Chapter 7, Analyzing the Impact of Variable Energy Resources on Power System Reserves. In L. Jones, (Ed.), *Renewable Energy Integration: Practical Management of Variability, Uncertainty, and Flexibility in Power Grids, London*: Elsevier – M. Hummon, P. Denholm, J. Jorgenson, D. Palchak, B. Kirby, O. Ma, 2013, *Fundamental Drivers of the Cost and Price of Operating Reserves*, NREL/TP-6A20-58491, July – M. Milligan, K. Clark, J. King, B. Kirby, T. Guo, G. Liu, 2013, *Examination of Potential Benefits of an Energy Imbalance Market in the Western Interconnection*, NREL/TP-5500-57115, March

qualifying short-term variability of solar, wind, and load in numerous studies. The standard deviation provides a single number for each measurement of variability, allowing easier comparison of changes in variability from case to case or through time. Standard deviation can be meaningfully quantified for intervals as short as an hour, allowing identification of the timing of periods of high variability. This is useful for identifying under what conditions additional reserves are required (solar conditions such as high or low solar output, power system conditions such as very high or low system load or the morning or evening ramp, times of conventional generation outages, etc.). It is also useful for identifying dropouts and other anomalies with the solar data.

Figure A2 provides an example of the usefulness of the standard deviation metric as compared to probability distribution table. The figure shows the maximum and average monthly solar output for all of Duke from April 2016 through July of 2018 on the left axis. It also shows how the short-term variability changes from month to month as measured by the standard deviation of the short-term variability on the right axis. This type of graphical comparison is not possible utilizing a probability distribution for each monthly data point.

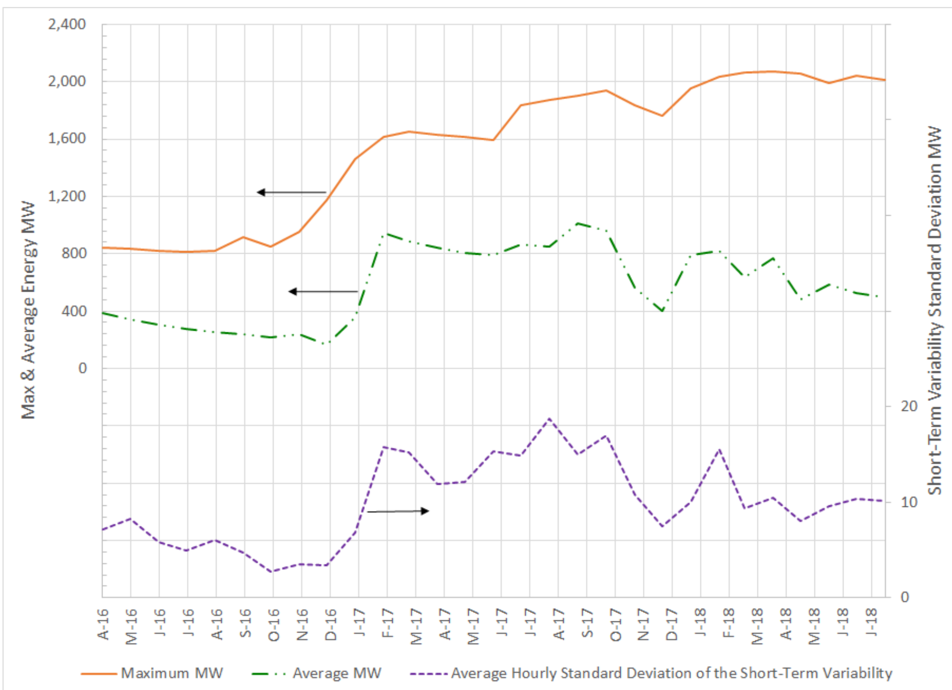


Figure A2 Monthly peak solar production, average hourly energy, and short-term variability for the combination of DEP and DEC.

Appendix B

Qualifications of Brendan Kirby, P.E.

Brendan Kirby is a private consultant with numerous clients including the Hawaii Public Utilities Commission, National Renewable Energy Laboratory (NREL), the Utility Variable-Generation Integration Group (UVIG), the Electric Power Research Institute (EPRI), the American Wind Energy Association (AWEA), Oak Ridge National Laboratory, and others. He retired from the Oak Ridge National Laboratory's Power Systems Research Program. Mr. Kirby has 44 years of electric utility experience, and he has been working on restructuring and ancillary services since 1994 and spot retail power markets since 1985.

Mr. Kirby's interests include electric industry restructuring, bulk system reliability, energy storage, wind power integration, ancillary services, demand side response, renewable resources, distributed resources, and advanced analysis techniques. He has published over 180 papers, articles, and reports. He coauthored a pro bono amicus brief cited by the Supreme Court in their January 2016 ruling confirming FERC demand response authority. He has a patent for responsive loads providing real-power regulation and is the author of a NERC certified course on Introduction to Bulk Power Systems: Physics / Economics / Regulatory Policy. He served on the NERC Standards Committee and the Integration of Variable Generation Task Force. He has participated in the NERC/FERC reliability readiness reviews of balancing authorities and reliability coordinators, performed field investigations for the US/Canada Investigation Team for the 2003 Blackout, and has appeared as an expert witness in FERC and state litigation. He has conducted research projects concerning restructuring for the NRC, DOE, NREL, EEI, AWEA, UWIG, numerous utilities, state regulators, and EPRI.

Mr. Kirby is a licensed Professional Engineer with a M.S degree in Electrical Engineering (Power Option) from Carnegie-Mellon University and a B.S. in Electrical Engineering from Lehigh University.

Kirby Exhibit C

Dominion Proposed Solar Integration Re-Dispatch Charge

Brendan Kirby, P.E. – February 2019

Dominion Energy North Carolina has proposed a solar integration re-dispatch charge of \$1.78/MWH. Though Dominion has provided little information concerning how the proposed re-dispatch charge was calculated, there are significant concerns, both with the calculation itself and with the underlying concept.

Re-Dispatch Charge Based on Analysis of Inappropriate Solar Penetration Levels

Dominion's re-dispatch charge is based on production cost analysis that "was performed at three different levels of solar penetration (up to 4,000 MW) to provide a range of results."[1] Dominion references the 2018 Integrated Resource Plan (2018 IRP) for further details on the re-dispatch cost analysis, but that document also only states that the analysis was performed at three solar penetration levels. The "Solar Integration Cost – Generation (Re-dispatch) 2018 IRP" PowerPoint presentation states that "penetration levels of 80 MW, 2000 MW, and 4000 MW were chosen for the study".[2]

Solar penetration is already 823 MW in the study region and is expected to be 965 MW in 2020 and 1,063 MW in 2021.[3] Inclusion of the 80 MW Scenario in the re-dispatch calculation is inappropriate because the low-solar-penetration results dominate the calculated cost. The proposed \$1.78/MWH re-dispatch cost adder is an *average* of the results from all of the production cost runs from all three solar penetration levels. Table 1 shows that Dominion's calculated re-dispatch costs drop significantly as solar penetration increases with the 2000 MW Scenario re-dispatch cost being less than a quarter of the 80 MW Scenario re-dispatch cost.

Table 1 Dominion re-dispatch cost calculation drops with increased solar penetration[4]

Final Answer Calculations

	MW Scenario		
Assumption Combo	**80**	**2000**	**4000**
All Costs	\$2.26	\$0.88	\$0.56
No PJM Purchases/Sales	\$5.58	\$1.32	\$0.79
No Pumping Costs/Revenues	\$2.01	\$0.51	\$0.42
Generator Costs Only (Fuel/VOM/Emissions)	\$5.41	\$1.01	\$0.65
Scenario Average	**\$3.82**	**\$0.93**	**\$0.60**

[1] Biennial Determination of Avoided Cost Rates for Electric Utility Purchases from Qualifying Facilities 13, Docket No. E-100, Sub 158, (Nov. 1, 2018).
[2] Dominion Response to NCSEA Data Request No. 1, Question No. 20 at (a) (AV).ppt, slide 5.
[3] Virginia Electric and Power Company's Report of Its Integrated Resource Plan 212, May 1, 2018..
[4] Dominion Response to NCSEA Data Request No. 1 Question No. 20 at (b) (AV) CONF_COC_1_6.xlsx, sheet "MWh MatrixedResults".

Average of all Scenarios $1.78

The 80 MW Scenario results should not be included in any assessment of current or future solar penetrations. The 2000 MW Scenario is closer to current and near-term expected solar penetration.

Re-dispatch Charge an Average of "Assumption Combo[s]"

Table 1 also shows that the proposed $1.78/MWH solar re-dispatch charge is not only an average of results calculated for three solar penetration levels, it is also an average of results from four "Assumption Combo[s]". These "Assumption Combo[s]" are not described, or even mentioned, in either the 2018 IRP or in the Avoided Cost filing. They are listed (but not described) in an Attachment to Dominion's response to NCSEA Set 1-20(b). The re-dispatch results from the four "Assumption Combo[s]" differ significantly, with the maximum being 1.9 to 2.7 times as high as the minimum, depending on the MW Scenario. Rather than explaining what the assumptions are or which set of assumptions is appropriate, Dominion simply took an average of the results from all of the "Assumption Combo[s]".

It is reasonable to perform analysis under different sets of assumptions in order to better understand what conditions contribute to specific results. It does not make sense, however, to average results from different types of conditions such as "All Costs" and "No PJM Purchases/Sales". Similarly, pumping costs and revenues should either be included or not. It is hard to imagine how it makes sense to average a "No Pumping Costs/Revenues" case with three other unrelated cases.

In the absence of further explanation of what is included in each set of assumptions, the "All Costs" "Assumption Combo" appears most appropriate.

Re-dispatch Charge a Strange Average of Averages

The calculation of re-dispatch charges for each "Assumption Combo" at each of the three MW Scenario solar penetration levels is also itself an average of results with various weightings and averagings. Table 2 lists the eight sets of results that were averaged to create each of the "Assumption Combo" results that were then averaged again for each MW Scenario and averaged yet again to calculate the final $1.78/MWH solar integration re-dispatch cost.

Table 2 Each calculated solar integration re-dispatch cost result is itself an average of averages.

Simple Average of All Studied Units
Levelized Simple Average of All Studied Units
Weighted Average of All Studied Units
Levelized Weighted Average of All Studied Units
Simple Average of Studied Units excluding outliers
Levelized Simple Average of Studied Units excluding outliers

Weighted Average of Studied Units excluding outliers
Levelized Weighted Average of Studied Units excluding outliers

None of the categories listed in Table 2 were described, or even mentioned, in either the 2018 IRP or in the Avoided Cost filing. They are listed (but not described) in the Dominion's Response to NCSEA Question 1, No. 20 (b) (AV) CONF_COC_1_6.xlsx Excel workbook.

The use of different weightings, levelizations, and outlier exclusions is often appropriate. Comparing results with different exclusions and weightings can also be useful. The type of analysis, and the quality of the data, typically dictate what weighting, exclusions, and levelizing are appropriate for a given purpose. In this case it is important because results differ by 112% to 135%. It is not appropriate to average a weighted average analysis result with a levelized cost analysis result. Similarly, either outliers are excluded or they are left in the analysis. It makes no sense to average results from an analysis that excludes outliers with the results from an analysis that includes outliers. Using a weighted average and excluding outliers appears to be most appropriate.

Kirby Exhibit D

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Integration and Monitoring of Distributed Energy Resources in System Operations

Adam Guinn, PE, REES
Duke Energy Progress
June 4-5, 2019

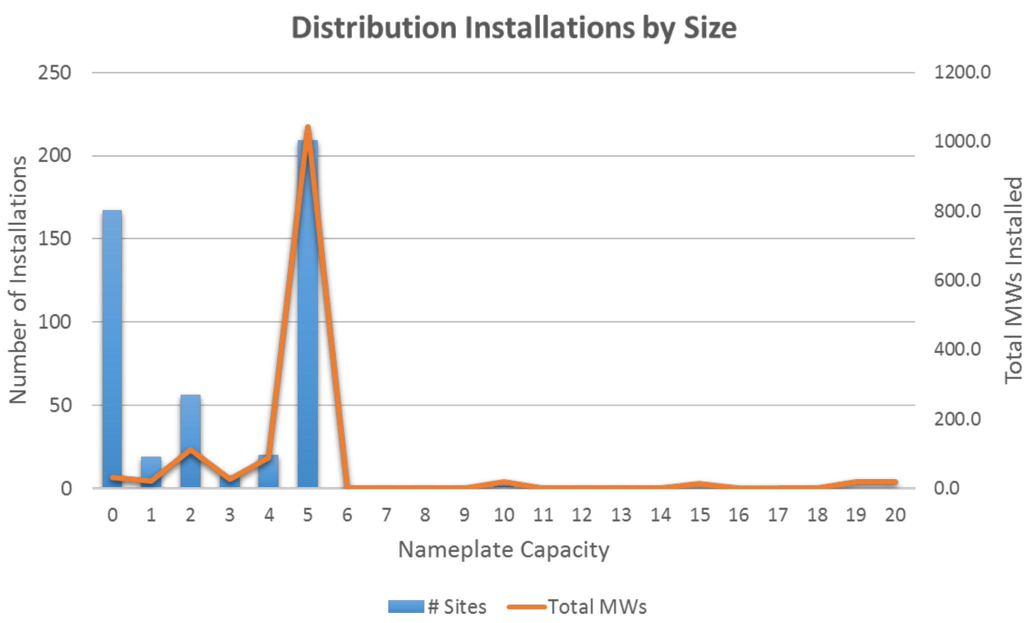
RELIABILITY | ACCOUNTABILITY

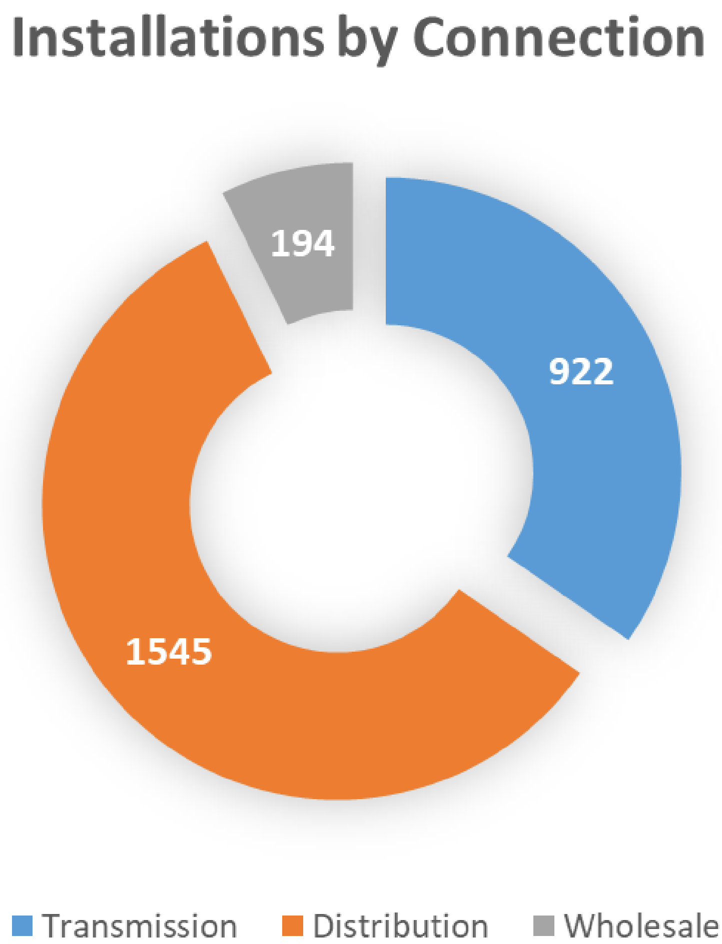



Kirby Exhibit D

The Landscape

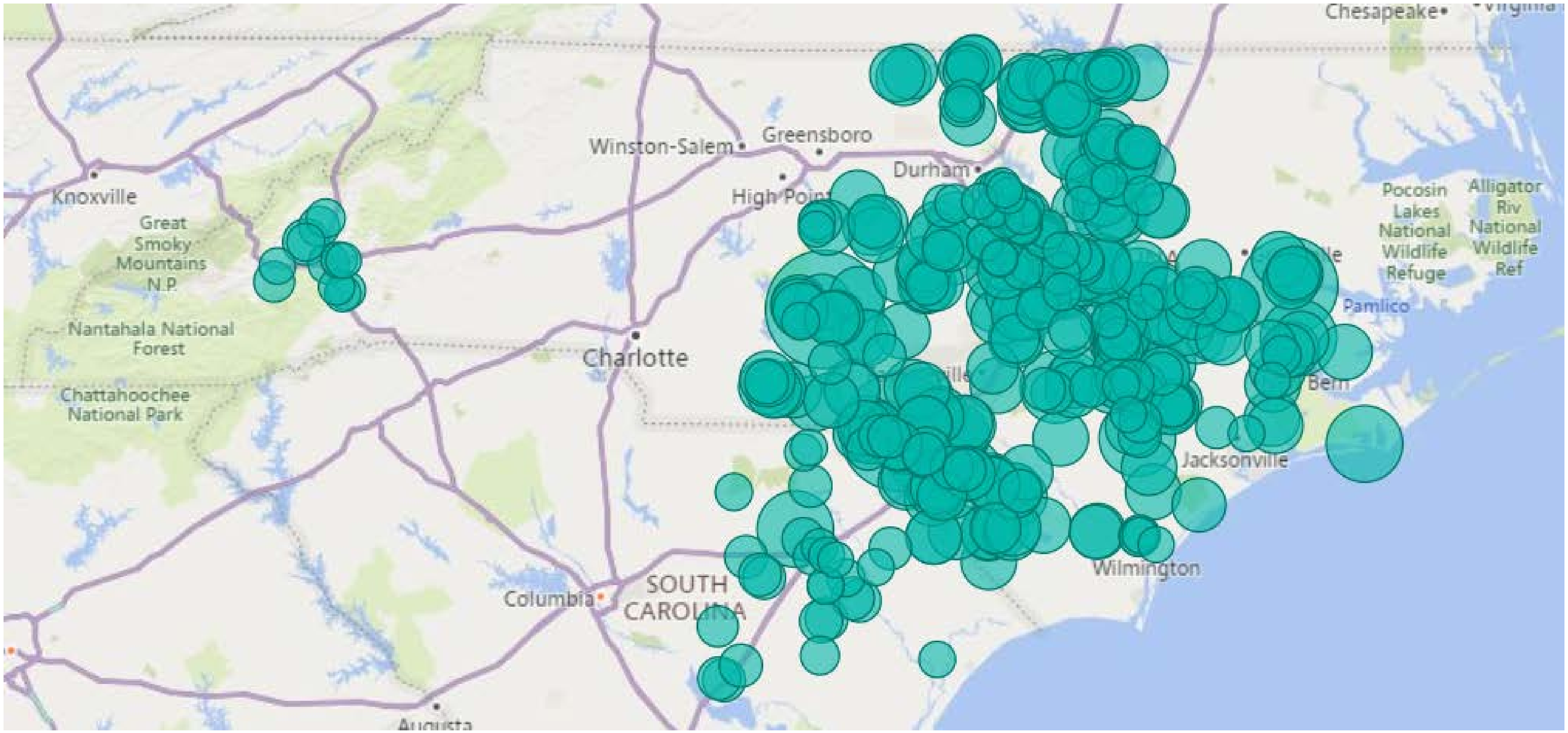
- DER penetration is primarily solar
  - Transmission-Connected: Sites ranging in size from 25 to 88 MW
  - Distribution-Connected: Sites range in size as follows:





Kirby Exhibit D

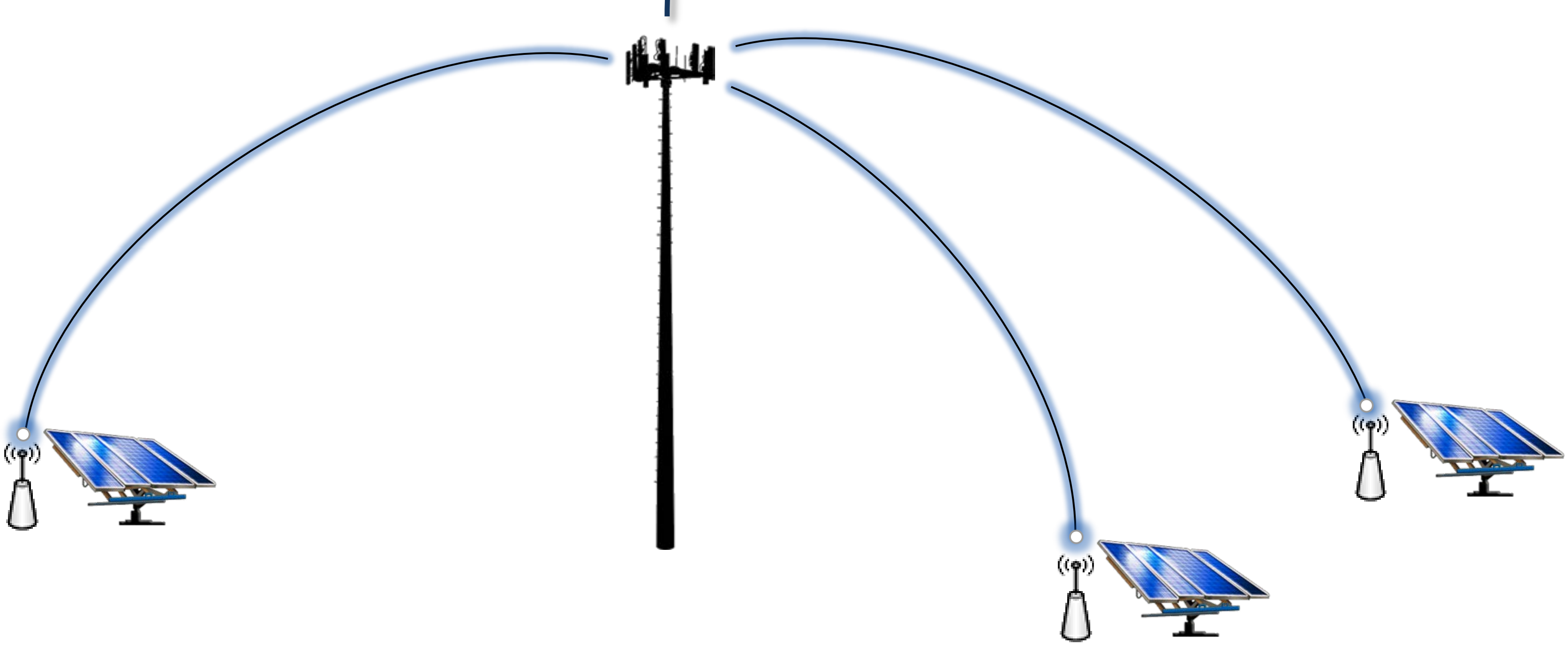
Geographical Overview of Sites



~97% of these are telemetered within the EMS in Real-Time

Distribution Data Acquisition

EMS at the ECC:
- *Modeled*
- *Aggregated*
- *Forecasted*
- *Appreciated*



BA Operational Areas Impacted

Generation Commitment and Dispatch

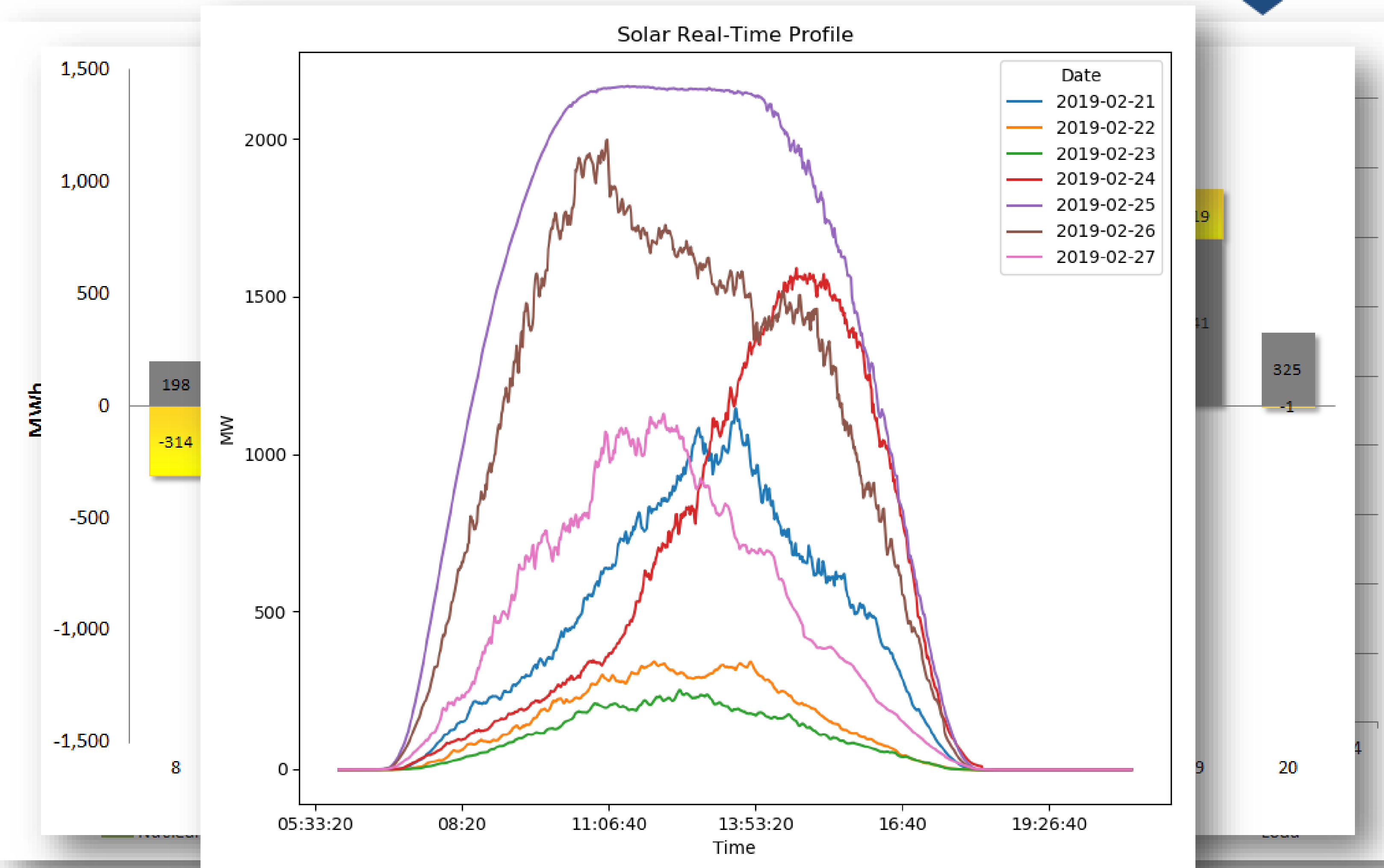
- Net Demand Ramping
- Intermittency
- Excess Energy (Lowest Reliability Operating Limit)
- Inertial Response
- Compliance considerations

Generator Impacts

- O&M Cost from ramp demand
- Increased cycling of resources

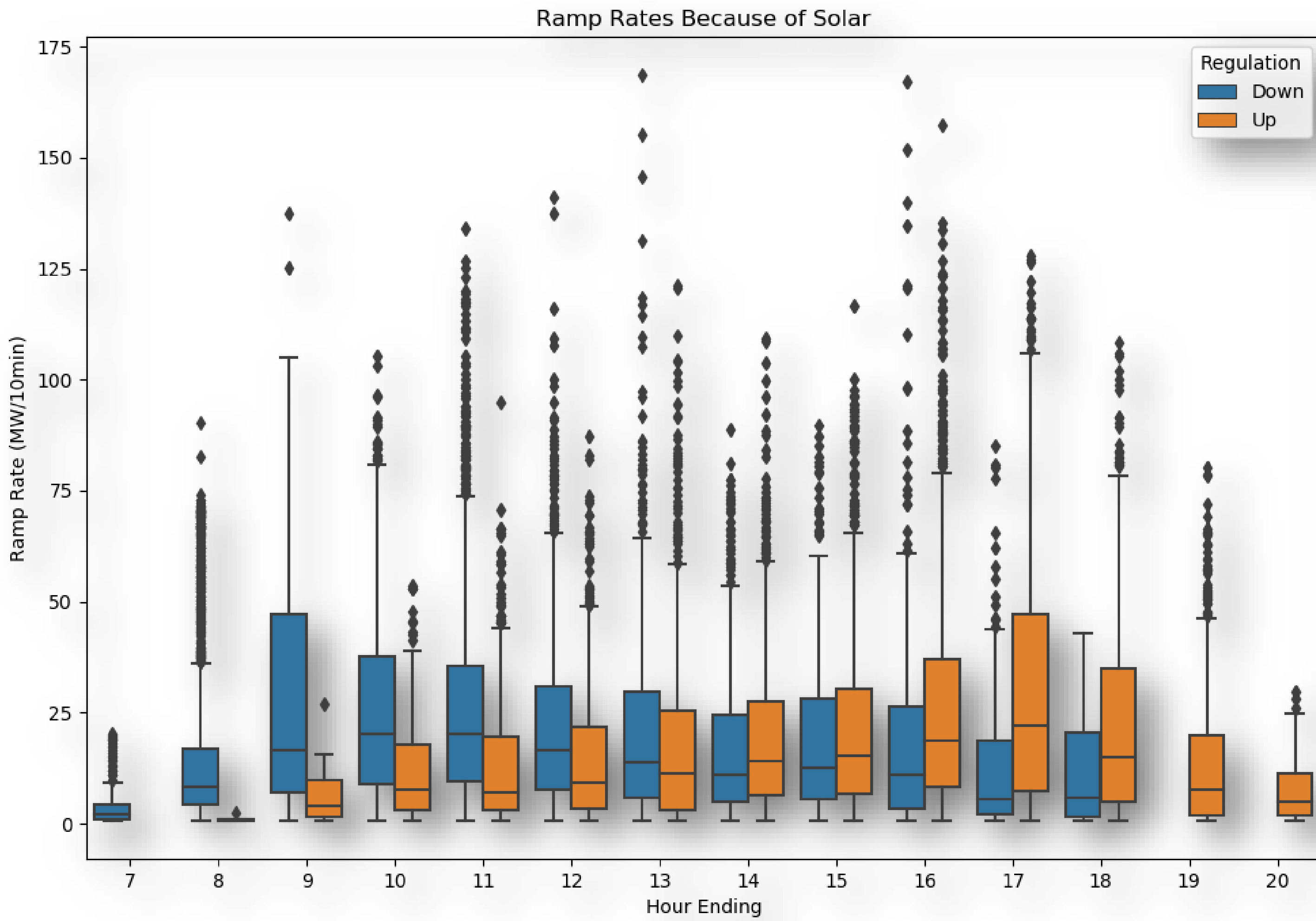
Under-Frequency Load Shed (UFLS)

Generation Commitment and Dispatch



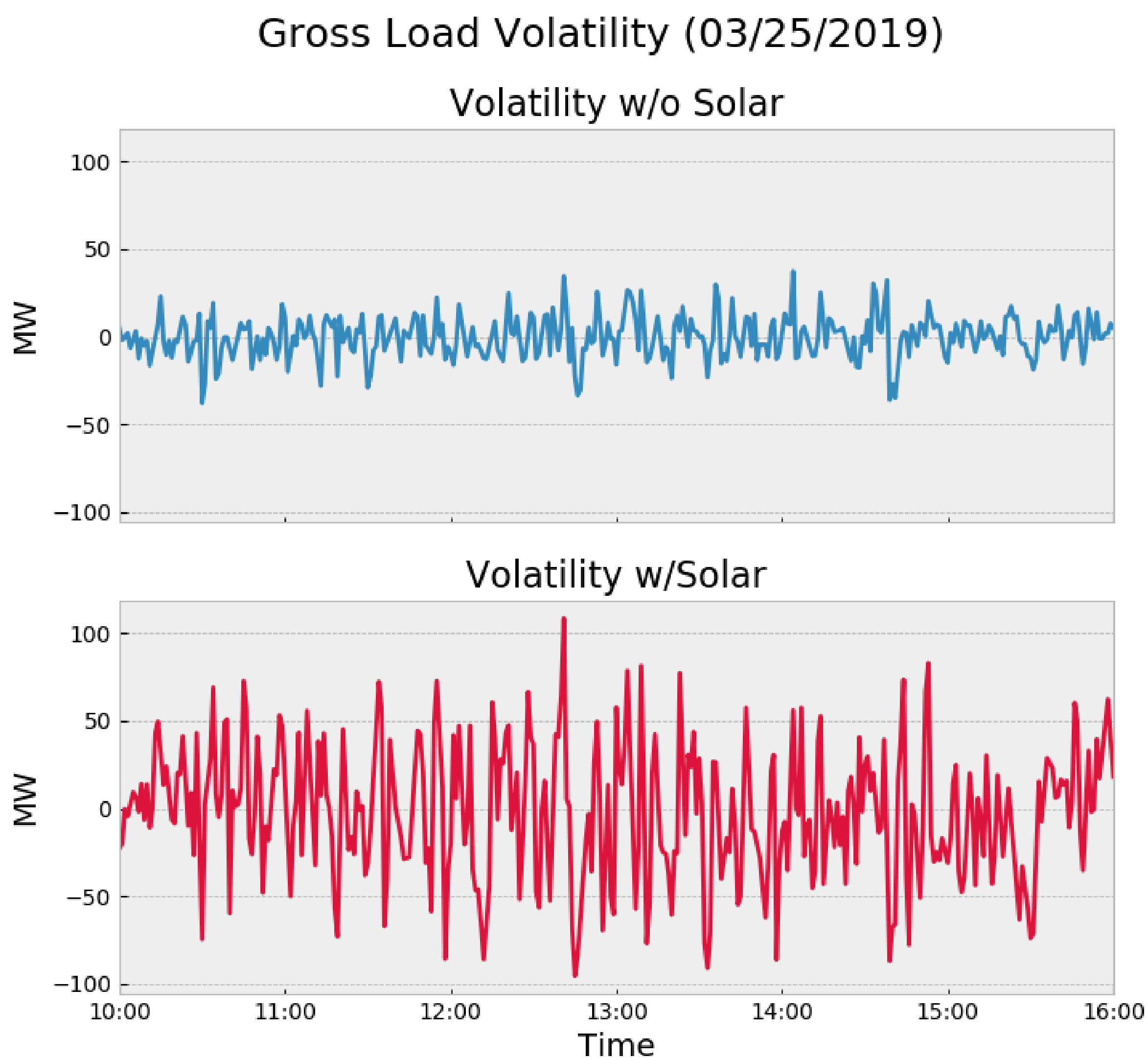
Kirby Exhibit D

10-Minute Average Sustained Ramps



Kirby Exhibit D

1-Minute Ramp Volatility



Area-Level AGC Tuning

DEP Performed Area-Level AGC Tuning in September 2018

Tuning was driven by changes in resource mix

Control bounds were relaxed to improve response performance

Generators better respond to sustained system needs

- Dispatchable generators no longer chasing fleeting events
- Reduces impacts from Variable Energy Resource 1-min volatility
- Improves fleet efficiency

Compliance benefits

- An ~20% reduction in BAAL exceedance minutes
- Negligible impacts to CPS1%

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Kirby Exhibit D

Operational Areas Impacted

Transmission

- Real-Time Network Analysis
  - State Estimation
  - Power Flow
  - Contingency Analysis
- Power Flow Studies
  - Outage Coordination
  - Planning

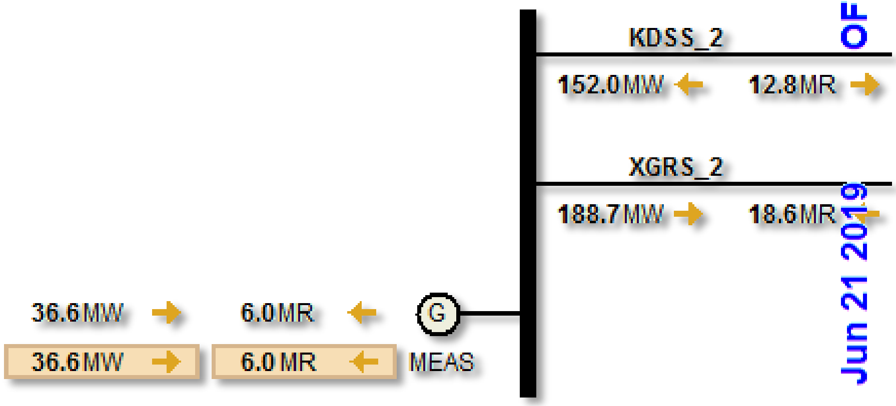
Coordination

- Tighter integration between T&D
- Tighter coordination with Planning

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

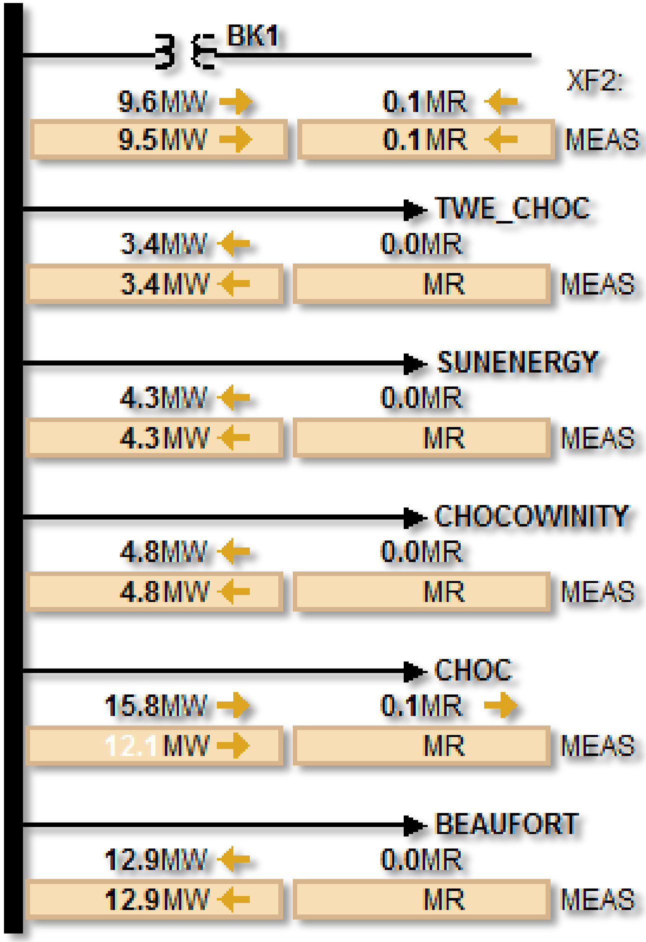
Transmission Site Modeling

- Modeled as actual generators in the network and generation applications
- Dedicated stations tapped from Transmission facilities
- Receive Real-Time telemetry with 4-Second scan rate data for all sites
- Sites receive a voltage schedule
- Can be regulated down like other Transmission resources



Distribution Site Modeling

- Modeling everything ≥250 kW as negative loads in the network model
- Tapped from Distribution feeders (existing or express)
- Receive Real-Time telemetry with 30-Second scan rate data for most sites
- All modeled resources are aggregated as a single value and included in the system load
- Helps State Estimator performance for site output



Data Requirements

Real-time power flow analysis requirements

- Generation and load values
- Net Interchange data
- Some generator bus voltages
- Topology

This data comes from the state estimation process that uses

- Real-Time measurements
- Some Statistics and
- Modeling assumptions

To support accurate state estimation and power flow results these inputs need to be as accurate as possible

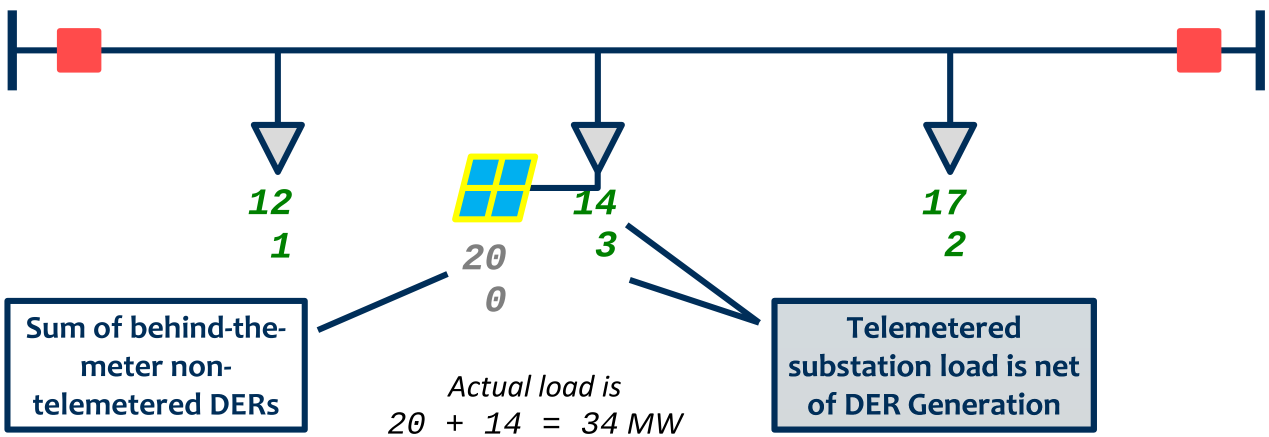
All because we asked ourselves "I wonder what happens if…?"

State Estimation Challenges

Just because a substation is not feeding power into the transmission network, does not mean it is not impactful

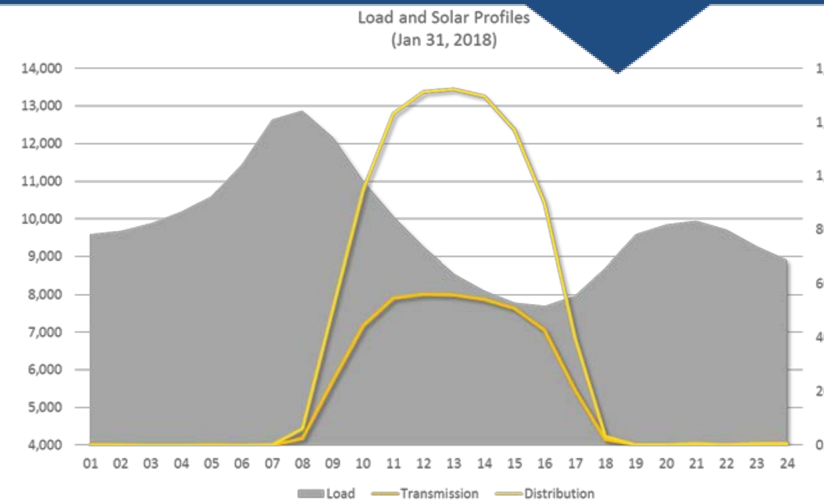
If the load and DER are not separated

- State Estimation will limit the amount they can change based on statistics
- Scaling an injection as gross load will result in an incorrect P/Q result



NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

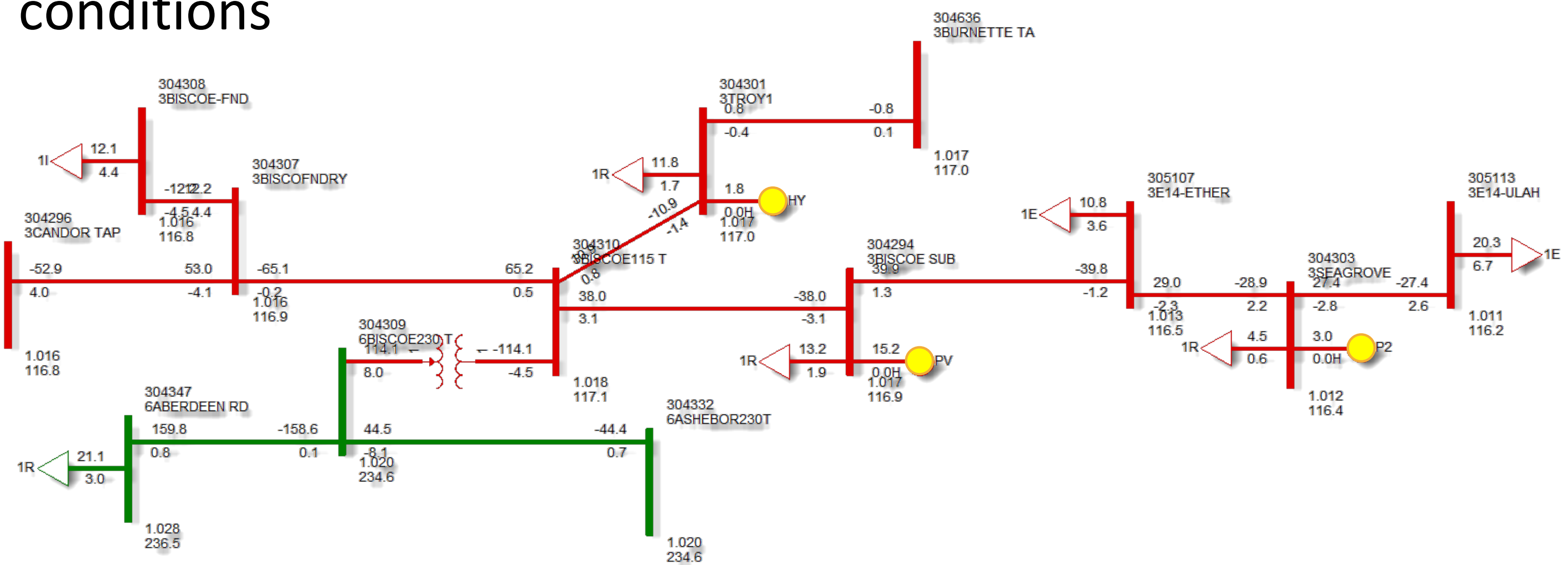
St[redacted]



- Solar injection profiles are not coincident with load profiles
  - Affects the statistical results in state estimation
  - Requires segregation of generation from load
- Separation of generation from load improves
  - State estimation statistics, and thus power flow and contingency analysis accuracy
  - Control and granularity of power flow studies as load and generation can be altered independently

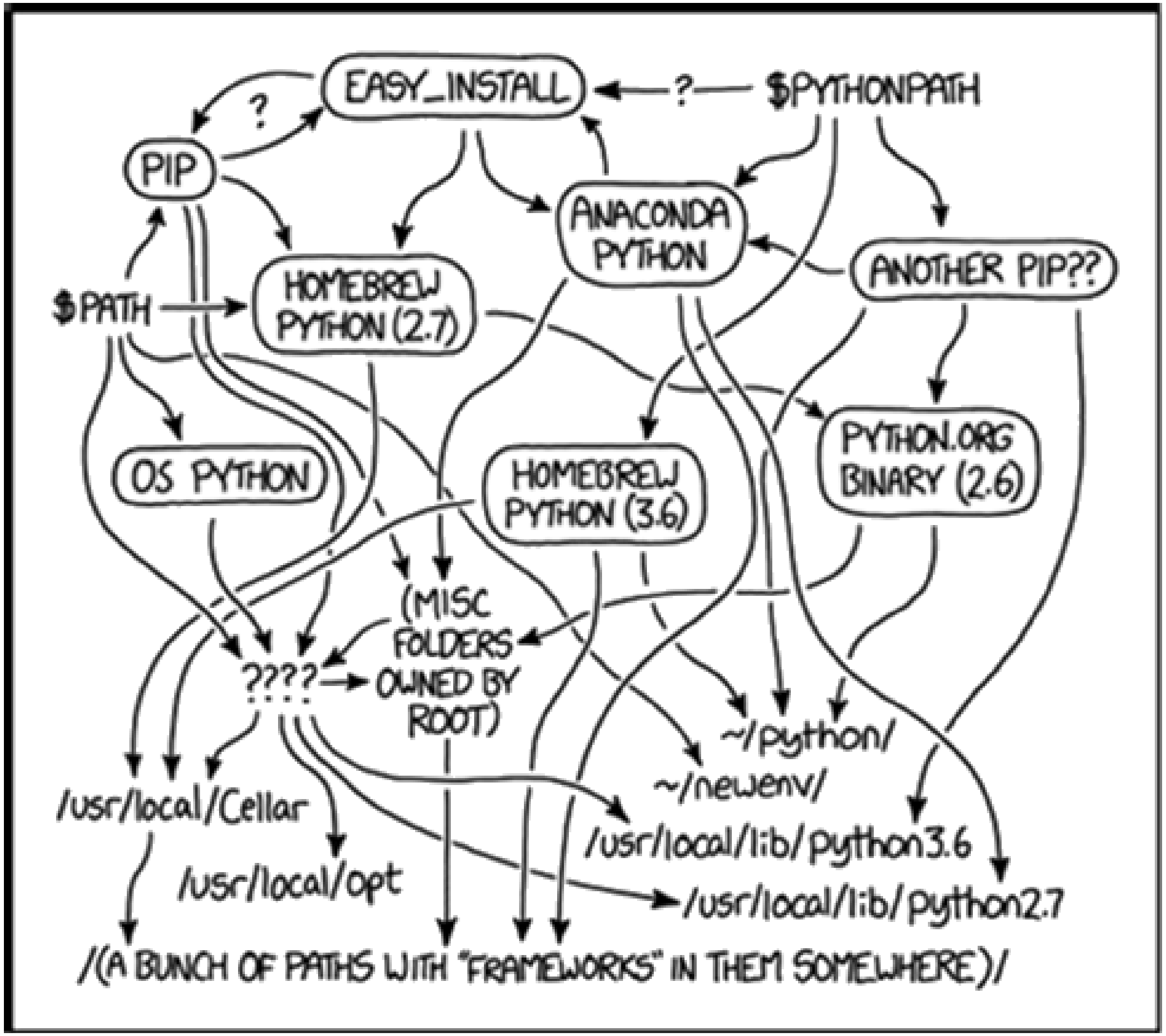
Transmission Power Flow Studies

- The resources are distributed in the model as they are in reality
- Injections from these resources drive local area power flows
- Failure to study them this way will result in unexpected loading conditions



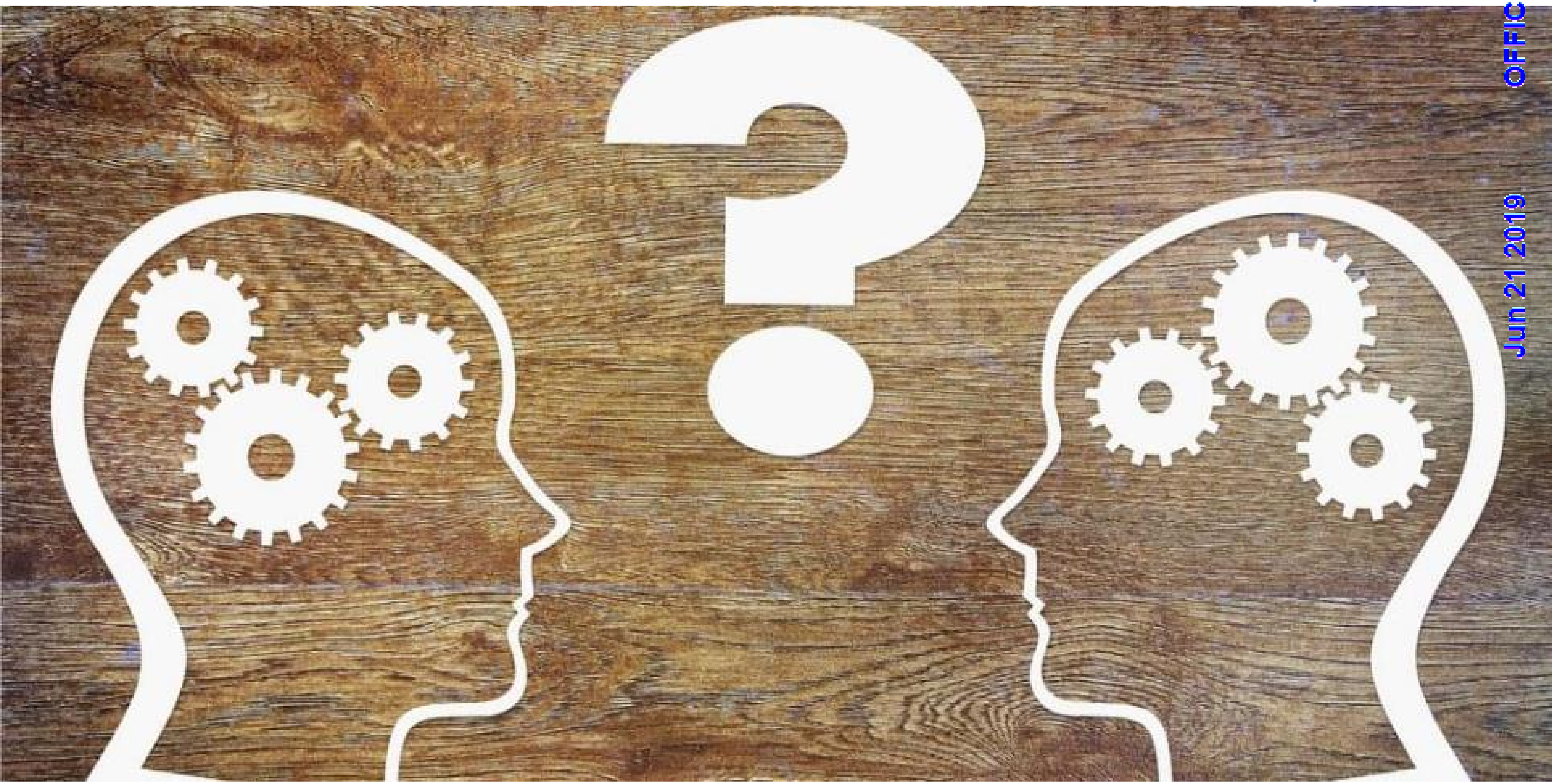
Kirby Exhibit D

Our Design



Kirby Exhibit D

Questions



CERTIFICATE OF SERVICE

I certify that a copy of the foregoing *Direct Testimony and Exhibits of Brendan Kirby*, as filed today in Docket No. E-100, Sub 158, was served on all parties of record by electronic mail or by deposit in the U.S. Mail, first-class, postage prepaid.

This 21st day of June, 2019.

/s/ Maia Hutt
N.C. State Bar No. 53764
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, NC 27516
Telephone: (919) 967-1450
mhutt@selcnc.org

Attorney for SACE