What are the best ways to interconnect greater amounts of Distributed Energy Resources (DER) and compensate them for the values they provide to the grid without compromising fairness for all customers and reliability?

Definition of DERs:

Distributed Energy Resources (DERs) are distribution system-interconnected[1] generation or Energy Efficiency (EE) sources that provide grid services including energy, ancillary services, and capacity. These resources may be:

- Active (operating to control active power, reactive power, or voltage) or passive (operating without controlling active power, reactive power, or voltage);
- Behind or in-front of meter;
- Generators, load, energy storage, or a combination thereof; and/or
- Utility-, customer-, or third-party-owned.

Current Framework for DER Compensation in North Carolina:

- The Competitive Procurement for Renewable Energy (CPRE) program established under HB589 has created a competitive bidding process for projects interconnected to the existing grid infrastructure; generators receive energy payments that are aligned to the avoided cost (average cost of the next marginal unit of energy) of the utility.
- CPRE also enables solar plus storage projects and the first tranche has demonstrated that solar plus storage is a limited[2] but possibly growing cost-effective solution for the NC energy and capacity markets. More reductions in storage prices and fair compensation policies are necessary for this trend to grow and possibly to radically change the NC energy market place. The inclusion of energy storage to a project in the CPRE causes the offer to be placed behind other offers in the interconnection queue.
- CPRE attempts to balance the interest of utility customers and the solar developers by establishing a fair, independently-administered process for procuring clean renewable energy at economically beneficial terms for customers. CPRE Tranche 1 was successful in establishing a 600 MW competitive procurement process that will provide twenty years of renewable energy at pricing below Duke's Avoided Cost.
- The Integrated Resource Planning process relies on least-cost resources and not clean energy goals, placing it into direct conflict with EO 80. The state does not currently have distribution system planning rules.
- The CPRE Independent Administrator estimates that the first tranche of procurement will provide $375 million in savings for Duke customers in the Carolinas over the term of the contracts (when compared to the 20-year avoided cost). CPRE provides the System Operator with flexibility to help manage the balancing challenges that come with increasing levels of renewable generation.
- As required by the federal Public Utility Regulatory Policies Act, utilities provide a standard offer contract to small qualifying facilities (QFs). Federal statute requires this standard contract to be made available to QFs up to 100 kW, but North Carolina requires that this contract be available to systems up to 1 MW. This size limit will decrease to 100 kW once an aggregate capacity of 100 MW is reached for this program. The contract length is 10 years, and capacity credits are only provided when the utility's integrated resource plan indicates a need for that type of a resource. Negotiated contracts may have a term of up to 5 years. Prior to the enactment of H.B. 589, North Carolina required projects up to 5 MW to be eligible for a 15-year standard contract.

[1] Less than 69 kVa (FERC)

[2] Due to current regulations.

- Net Metering is the current compensation mechanism for behind-the-meter solar in North Carolina, but there are only ~4,000 solar PV systems below a certain capacity operating in North Carolina today. Net metering provides retail rate compensation for behind-the-meter systems up to 1 MW. Net excess generation may be carried forward, but is granted to the utility at the beginning of the summer billing season. H.B. 589 called for a study of the costs and benefits of net metering and for the state's investor-owned utilities to file new net metering rates after this study is completed. A Commission proceeding has not yet been opened to implement these changes. Virtual net metering and meter aggregation are currently not allowed in North Carolina.
- H.B. 589 legalized solar leasing in North Carolina, but requires lessors to meet certain requirements and be registered with the Utilities Commission. Although leasing rules were approved by the Commission in early 2018, only two companies have registered to be solar lessors. Third-party power purchase agreements are currently not permitted in North Carolina.
- H.B. 589 established a solar rebate program, providing rebates to 20 MW of capacity each year (5 MW is reserved for residential applications and 2.5 MW is reserved for non-profits). The rebate amounts are as follows: Residential – 60 cents/Watt up to $6,000; Non-Residential – 50 cents/Watt up to $50,000; and Non-Profit – 75 cents/Watt up to $75,000. The rebate program was fully subscribed within days of opening in January 2019. The rebate program expires at the end of 2022.
- H.B. 589 required Duke Energy to establish a community solar pilot program for up to 40 MW of capacity. Each community solar project may be up to 5 MW in size. The statute requires that participating customers be compensated at the avoided cost rate. Duke Energy's community solar pilot program was approved in April 2019.
- North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (REPS), established by Senate Bill 3 in August 2007, requires all investor-owned utilities in the state to supply 12.5% of 2020 retail electricity sales (in North Carolina) from eligible energy resources by 2021. Up to 25% of the requirement may be met through energy efficiency technologies; after 2021, up to 40% of the standard may be met through energy efficiency. Municipal utilities and electric cooperatives must meet a target of 10% renewables by 2018 and are permitted to use demand side management or energy efficiency to satisfy the standard without limitation. Commission Rule R8-67(b) requires each electric power supplier to annually file its plan for complying with North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (see G.S. 62-133.8). These REPS Compliance Plans are included in each utility's Integrate Resource Plan filing; there is currently an open docket (Docket No. E-100 Sub 157) to review the utilities most recent filings re: compliance with SB3. All filings by utilities in NC for DSM programs- which primarily take the form of rebates for targeted EE measures in specific sectors (some deemed and some prescriptive) and do include demand response offerings for consumers- as well as the fees charged to rate payers for the same and the resulting programs available to consumers and businesses, relate to compliance with the requirements in SB3. C&I customers can also choose to participate in "curtailable rates" which can have a similar impact to DR programs but are not provided to customers as part of compliance with SB3. Demand Reduction (DR) capability (at the generator) for the 2019 Summer Peaks, based on the 2018 IRP, are:

  DEC Summer 2019: 992 MW
  DEP Summer 2019: 923 MW

Additional Clarifying Questions

1. *Briefly describe the nature of this policy tension/question – what is happening?*
   a. Injecting more DERs onto the grid is in tension with the need to modernize the grid to enable more DERs.
   b. Increasing penetration of DERs is in tension with (the lack of) both access to the data on where these resources are most valuable and the mechanisms for utilities to purchase these services.

2. *<u>To what extent does this policy tension exist in NC, if so, why is it relevant to the state?</u>*
    a. The tension around grid modernization exists because our policy and market frameworks did not contemplate customer-owned or third-party resources at the time of their creation, and general statutes require the incumbent utilities to prioritize lowest cost sources.
    b. Because NC is part of a regulated monopoly territory, third-party data access has not been required for the incumbent utilities to fulfill obligations to ratepayers.
3. *<u>What policy or regulatory action might be required to address the tradeoffs you see?</u>*
    a. See the section below on guiding principles and types of solutions, as well as the table of DERs.
4. *<u>How are people in other places responding to this tension? What are the most innovative and promising solutions? Do they seem feasible in NC?</u>*
    a. The states that have made the most progress on DER integration have adopted policies that require considerations in system planning other than (only) lowest cost (examples are included in the table of DERs)
5. *<u>Are there ways you think NC should consider responding to this tension? What entity would need to take the action you've identified?</u>*
    a. See the section below on guiding principles and types of solutions, as well as the table of DERs.

Guiding Principles for DER Compensation in North Carolina:

- Interconnecting greater amounts of DERs, specifically renewable fuel-based generation and Demand Side Management (DSM) will increase deployment of clean energy and reduce greenhouse gas emissions.
- The Integrated Resource Planning process relies on least-cost resources and not clean energy goals, placing it into direct conflict with EO 80. The addition of carbon costs into the economic evaluation would improve the likelihood of renewables being dispatched and integrated into utility plans.
- Maximizing DER penetration will require increased investment in the distribution system and expanded Integrated System Planning. Such planning will be the best tool to ensure cost and compensation allocation is fair and that grid upgrades which are necessary to manage greater interconnection of distributed capacity also provide the same or greater reliability than current state.
- A change from the current NC energy regulation and legislation which currently emphasizes least cost over other considerations such as GHG emissions reductions will be necessary to achieve a cleaner, lower carbon grid.
- Compensation for DER services[3] in addition to compensating energy is likely to lead to:
    - Wider and higher participation/interconnection of renewables by enabling investors to stack revenue streams;
    - More targeted locations for these resources; and
    - Increased technological and financial innovation.
- Compensation structures should be a means to develop price signals which encourage DERS to provide valuable grid services through:
    - **Locational Planning and Transparency:** More, public and granular visibility of load, supply, and distribution constraints (e.g, hosting capacity, thermal and voltage limits) on the grid is needed in order for DERs to be able to provide locational value. Visibility into system constraints down to the distribution level are necessary in order to determine where the assets can provide the most benefit for the grid. This information is a critical component to

[3] e.g. energy, spinning and non-spinning reserves, frequency regulation and response, capacity avoidance/deferral, dispatchability, reactive power support, voltage regulation, avoiding T&D investment, etc.

grid planning and enabling more DERs on the grid. Southern California Edison (SCE) is one utility that provides a helpful level of distribution-level information.[4] See comparison of Duke Energy's[5] and SCE's grid maps in Appendix A.

- **Fair Compensation and Cost Allocation:** For example, studies should address how behind-the-meter customer generators (e.g. net-metered customers) should pay or be compensated for full additional or avoided local costs (i.e., reserve requirements, addition or avoided T&D investment) instead of spreading incurred or avoided costs to non-solar customers. This practice can be part of standard analysis of interconnection costs and benefits.
  - Upgrades to the electrical grid[6] are necessary to accommodate more DERs and the burden of cost should be studied in order to fairly allocate them.
- **Time-Based Pricing:** Particularly for DSM resources, hourly compensation is a dominant form of compensation in the restructured markets such as PJM, ERCOT, MISO and ISO-NE. Hourly, locational, marginal prices are the most accurate form of short-term variable costs including energy, capacity and ancillary services and are the most effective signals to these resources about when they are most valuable.
- **Long-Term Contracts:** Particularly for generators, long-term "off-take" contracts with a combination of fixed and variable prices (see time-based pricing, above) are necessary for new investments in clean energy generation. Conversely, absence of long-term contracts advantages incumbent technologies and suppliers. Energy sellers and some buyers prefer long-term price stability because it decreases the risks for each and cost of capital for sellers to make these investments.

- Renewable programs targeted specifically for government, non-profit and low-income customers, who might benefit from increased use of solar but for whom financial barriers to ownership are much higher, must be attainable. Though the HB589 leasing provision is a good start at offering a zero up-front solar cost to customers, North Carolinians could do a better job at consumer education around leasing options and there are very few currently eligible lessors.[7]
- Overwhelming demand for the first years of the NC solar rebate program shows the current rebate program needs to be redesigned and rebate reduced to reach more applicants and to align to the lower solar prices in today's market.

Types of solutions the Clean Energy Plan (CEP) can and should address are:

- Tariffs that are not compensation offers for DERs, but price signals to loads, e.g. more robust Time Of Use (TOU) riders and/or Real Time Pricing. These tools let owners or operators of DSM measures maximize their return on investment by targeting the most valuable loads to curtail.
- Compensation tariffs for DERs such as Net Metering or a Value of DERs tariff.

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[4] https://ltmdrpep.sce.com/drpep/#

[5] https://www.oasis.oati.com/duk/index.html

[6] Physical or virtual changes to the distribution system that enable more variable load or greater utilization of DERs such as smart meters, improved communication infrastructure, data transparency and accessibility, voltage regulators or line and substation capacitors

[7] The bill allows customers to lease PV systems, and Duke Energy is also permitted to lease PV systems. Leased systems are limited to 100% of contracted demand, 20 kW for residential systems, and 1 MW for nonresidential systems. Costs associated with marketing, installing, and owning leases may not be recovered from nonparticipating utility customers, and the Commission will not have jurisdiction over the financial terms of leases. Third-party lessors must hold a certificate issued by the Commission.

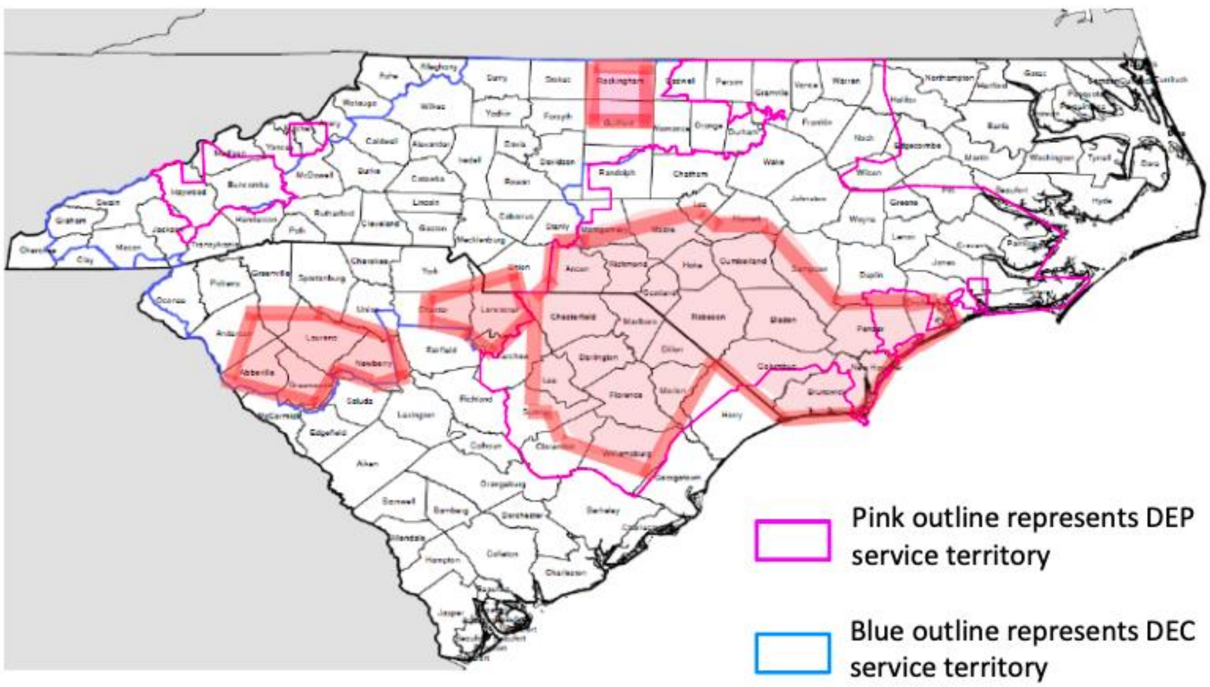
- RFPs should be used where possible and most effective as the effects of competition always benefit rate payers; these procurement actions can be broad (e.g. state-wide calls for services/products, resources, or resource types) or targeted to a specific distribution substation.
- Improved interconnection processes:
  - Fast-tracking of interconnection for systems paired with energy storage.
  - Enforcement of required response time in the Interconnection Standard.
  - Interconnection standards as well as process improvements (e.g. utilities could potentially waive certain interconnection standards that are applied too broadly and use a different protocol for distribution system safety for grid tie inverters that provide ancillary services such as VARs).
  - Utilities providing interconnection capacity by feeder or area so developers can target those feeders or areas.
- Compensation for generators or load that responds to dispatch signals or prices (e.g. storage-paired resources).
- Inclusion of non-wires alternatives (NWAs) in the planning of T&D upgrades (e.g. distribution deferral through energy storage) procured typically through an RFP or a tariff designed to compensate NWA.
- Distribution planning and Integrated System Planning expansion and improvement: the group recognizes that distribution planning can take many forms and may also carry costs or benefits not yet born or avoided by rate payers.
- Grid upgrades: Physical or virtual changes to the distribution system that enable more variable load or greater utilization of DERs such as smart meters, improved communication infrastructure, data transparency and accessibility, voltage regulators or line and substation capacitors

Appendix A

Duke's Map for developers[8]

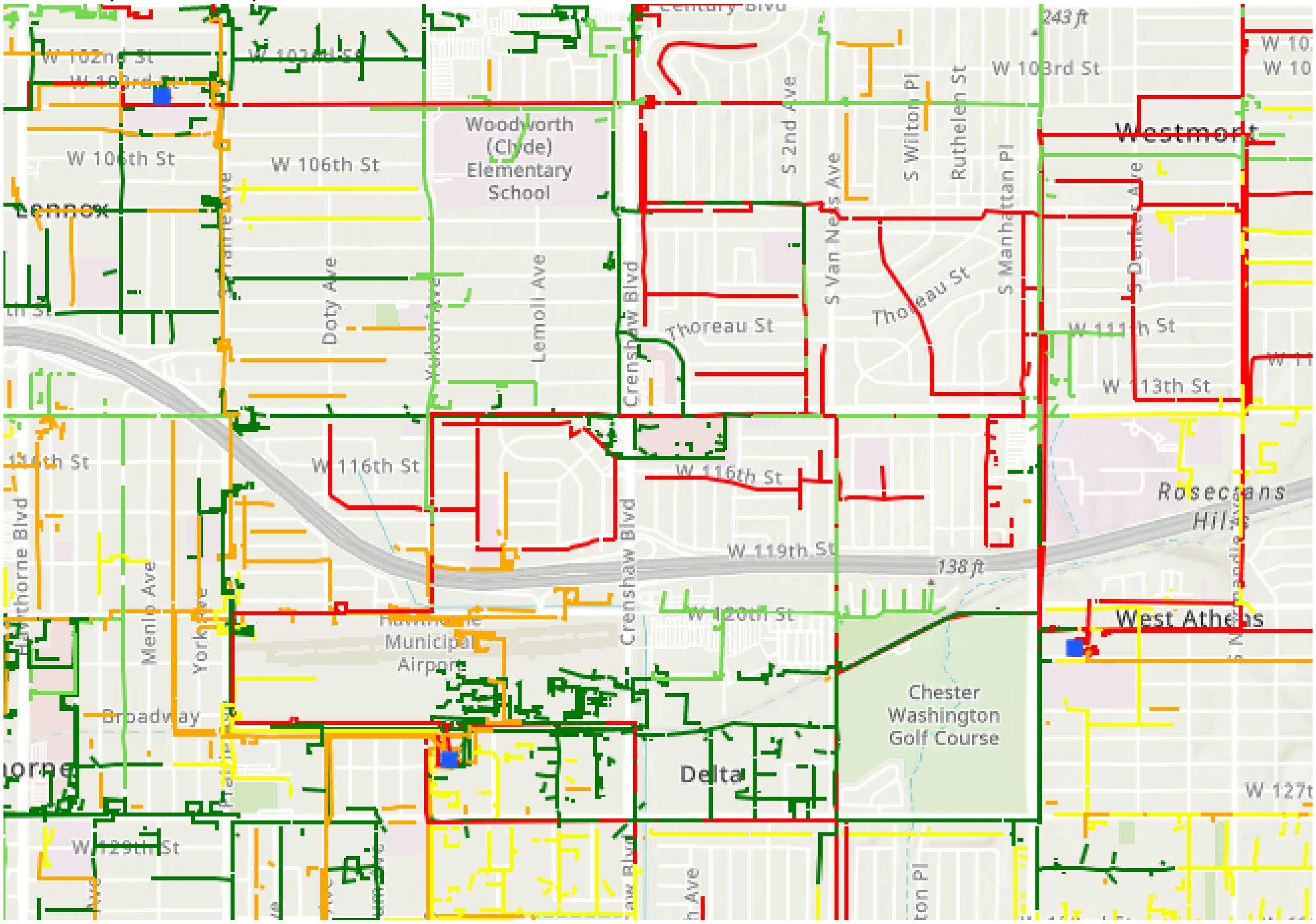
Attachment 1

DEC and DEP Constrained Areas



[8] https://www.oasis.oati.com/duk/index.html

SCE’s map for developers[9]



[9] https://ltmdrpep.sce.com/drpep/#