Comments of Paul Centolella
On
NextGrid Draft Final Report

First, I want to express my appreciation to the Illinois Commission for initiating NextGrid and to the ICC Staff, the University of Illinois, and the Working Group Leaders. The process created a greater understanding of grid modernization and of the opportunities to create a more affordable, reliable, resilient, secure, and environmentally sustainable energy future. The Draft Final Report reflects the hard work of the Lead Facilitators, Working Group Leaders, and NextGrid participants. It describes some broadly, although not necessarily universally, shared views. And, it identifies, defines, and clarifies key issues. Despite the high overall quality of the Draft Final Report, there are a few points that should be clarified for future readers. My comments are limited to addressing such points, including clarifications related to the presentations I provided in Working Groups 5 and 7.

The introductory discussion of Grid Modernization and Illinois Efforts states that, "As these resources are integrated into the distribution grid, the need for independent distribution system operators (DSOs) that provide distribution network services along analogous lines as ISOs providing bulk grid services, becomes evident."[1] The view that a DSO should be independent was not a view adopted in Working Group reports. WG5, "emphasized thinking about retail markets from a functional perspective rather than a role-based or entity-based perspective."[2] WG5 also identified possible economies of scope in that, "markets would necessarily exchange information with distribution system operations to ensure that the market outcomes respect the grid engineering constraints."[3] WG1 reached a conclusion that, "…utilities, as regulated entities that own and operate the grid, are seen as the appropriate system managers…."[4] The need for an independent, as opposed to a utility, DSO is not self-evident. I am not aware of any State that has required or indicated a preference for the formation of an independent DSO.

The Overview of the Final Report summary for Chapter 3 states that, "While higher levels of RR&S are attainable, the associated high costs and the practicality of such solutions fail to meet any cost effectiveness tests. Indeed, surveys by utilities indicate the lack of willingness to pay by customers for such costly fixes."[5] There is nothing in Chapter 3 or in the WG 3 presentations that appears to support a conclusion that a higher than current level of reliability, resilience, and security is impractical, not cost-effective, or inconsistent with customers' willingness to pay. This statement is in the Overview seems inconsistent with the identification of opportunities to improve reliability, resilience, and security throughout Chapter 3.

The Overview of the Final Report summary for Chapter 5 states, "WG5 discussions did not include the consideration of the legislative/regulatory policies required to remove existing roadblocks to

[1] Draft Final Report at 4.
[2] Draft Final Report at 145.
[3] Draft Final Report at 155.
[4] Draft Final Report at 25.
[5] Draft Final Report at 15.

the establishment of the regional markets discussed extensively in the WG5 sessions."[6] The characterization of WG5 as focused on establishing "regional markets" is potentially misleading. WG5 addressed time- and location-specific transactional markets that could settle at locations within an Illinois distribution utility and services markets that potentially could be extensions of existing ComEd and Ameren Customer Marketplaces. However, the WG did not discuss establishing such markets on a broader RTO- or region-wide basis. There is no specific mention of "regional markets" in Chapter 5. While the WG recognized that there would be an interface between bulk power markets and any future distribution level transactive energy markets, such an interface does not imply that distribution level markets would have to be regional in scope.

The Overview of the Final Report summary for Chapter 7 includes the following two sentence description of the WG's discussion on rate design: "Some participants stressed the economics basis for efficient rate design and cost-based signals as essential components of a well-functioning system. Others asserted that the pillar for cost allocation and rate design requires a new marginal cost study, which has not been performed by a large Illinois utility since the 1990s." With respect to the first sentence, a more accurate summary would be: "Some participants stressed that basic economic principles require a combination of market-based or dynamic price signals that communicate time- and location-specific marginal costs, accompanied by the recovery of the remaining residual utility revenue requirements in rates that have a minimal impact on usage patterns." This separation of dynamic time- and location-specific price signals from the recovery of residual costs, with recovery of remaining costs in fixed charges, was the focus of my presentation and of much of the WG's discussion on rate design. The second sentence on marginal cost studies conflates the rate design discussion, occurring largely on July 30, with a question on marginal cost of service studies, which followed a presentation on June 19 reviewing types of class cost of service studies used to allocate embedded costs. The rate design discussion focused on directly tracking dynamic time- and location-specific short-run marginal costs and not on using studies to allocate costs. Tracking time- and location-specific short-run marginal costs does not require a new marginal cost of service study comparable to the cost of service studies utilities did in the 1990s.[7] Since class cost allocation was not one of the larger topics of discussion in the WG, the second sentence quoted above could be dropped from Report Overview.

The final draft of Chapter 7 drops portions of the summaries of presentations and related discussions contained in the WG Leader's draft. In some cases, this results in key omissions:

- In Chapter 7's discussion of utility cost recovery risk, the final draft presents the view of a subset of WG participants, while dropping an important caveat. The draft includes a paragraph that concludes,"… with the enactment of the Energy Infrastructure Modernization Act (EIMA) and FEJA, the utilities enjoy virtually risk-free cost recovery."[8] However, it excludes a key limitation in the WG Leader's draft, that, "The Illinois formula rate statute (EIMA) provides that, 'The performance-based formula rate approved by

[6] Draft Final Report at 17.
[7] My presentation to the WG indicated that embedded cost allocation terminology such as "long run marginal costs" should not be conflated with the term economic "marginal cost" in rate design. Paul Centolella, *Economics of Modern Rate Design: Efficient Pricing & Equitable Rates,* Working Group 7 Meeting of July 30, 2018, at p. 5.
[8] Draft Final Report at 189.

the Commission shall do the following: (1) Provide for the recovery of the utility's actual costs of delivery services that are prudently incurred and reasonable in amount consistent with Commission practice and law. ….' "[9]

- In introducing, Time-Varying Rates, the draft includes a statement that it, "relates primarily to the energy supply portion of customers' rates rather than the delivery service portion," but excludes the discussion in the WG Leader's draft of, "including marginal losses in distribution rates to better reflect the delivered cost of energy as an interim or transitional step prior to moving to a DLMP market."[10] A DLMP market is a possible future market design in which prices can vary between different points within a utility's distribution system. My WG 7 presentation suggested marginal losses and scarcity created by any constraints in the distribution system could be reflected in time- and location-specific distribution charges prior to development of any DLMP market.

- The draft includes references to the recovery of residual revenue requirements. However, it does not include the further explanations, that: 1) residual revenue requirements are the result of a utilities being unable to recover the cost of monopoly transmission and distribution services at marginal cost rates; 2) such residual costs ideally would be recovered in fixed monthly charges that have little or no impact on relative demand; and 3) to recover residual costs, regulators have options to set different charges for different customers to reflect equity and, for low income customers, income elasticity considerations.[11]

Chapter 7 summarizes the brief discussion in WG 7 of low participation in Ameren and ComEd Real-Time Pricing rates.[12] A more complete discussion appears in Chapter 4, which notes that, "Since their inception in 2007, participants in the ComEd and Ameren Illinois residential hourly pricing programs have seen average energy cost savings of 22 % and 16 %, respectively, compared to the payments for the same usage on volumetric flat rates, not including any amounts saved by reduced usage in response to price signals." Chapter 4 also includes a detailed discussion of factors contributing to low participation and ideas for enhancing participation in hourly pricing.[13] The Chapter 4 discussion should be cross-referenced in Chapter 7.

Chapter 1 includes a detailed discussion of the value of DER to the distribution system, which parallels the discussion of the time-, location-, and product-specific value of DER in WG 7.[14] The discussion from Chapter 1 could be cross-referenced in Chapter 7.

[9] WG Leader's Draft citing: 16 ILCS §108.5 (c).
[10] WG Leader's Draft at 33.
[11] WG Leader's Draft at 30. Supplementing the discussion of equity considerations in rate design in WG 7, Chapter 4 includes a detailed of protections for low income customers (Draft Final Report at 137 – 140), which could be cross-referenced in Chapter 7.
[12] Draft Final Report at 197.
[13] Draft Final Report at 121 – 123.
[14] Draft Final Report at 45 – 48.