UPDATING DISTRIBUTION SYSTEM PLANNING RULES IN COLORADO AND NEVADA

Country/region	**Colorado and Nevada (United States)**
Type of E1st approach	B – In front / Investment 3 – Requiring E1st-proof assessments (Integrated distributed planning)
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end-uses targeted	All sectors connected to distribution grids
Implementing bodies	Colorado Public Utilities Commission (PUC) State of Nevada Public Utilities Commission (PUCN)
Decision makers involved	Regulators Utilities
Main objective(s)	Maximise the use of distributed energy resources, including energy efficiency and demand response, and anticipate their impact on grid needs
Implementation period	Starting now or about to start

Until recently, regulators in the United States were giving little scrutiny to how the electric distribution system — which carries electricity from the transmission system to individual consumers — was planned by utilities (MADRI, 2019). The integration of distributed energy resources into the electric power system by utilities, independent power producers and energy consumers has opened the need for more regulatory oversight. Their increase provides opportunities to accelerate the energy transition. Sound network planning is required to maximise benefits for the environment and for consumers. This case study looks at the distribution system planning rules currently under examination in Colorado, and to those just adopted in Nevada, in view of discussing how the E1st principle is being enacted through the use of appropriate integrated resource planning tools. Important considerations for planning include the alignment and consistency of the different utility plans, setting a proper planning timeframe, and ensuring sufficient regulatory and stakeholder oversight over the process, based on rules which allow for a dynamic forecast of distributed energy resources and for recognising the value of non-wires alternatives.

1. Background

An integrated resource plan is "a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period" (Wilson and Biewald, 2013). This process used in the power sector allows the

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combining of resources “to provide energy services at minimum cost, including environmental and social costs” (Swisher et al., 1997). Taking into account both supply-side and demand-side resources provides an “opportunity to achieve lower overall costs than might result from considering only supply-side options” (Wilson and Biewald, 2013). This approach is in line with the definition of the E1st principle (ENEFIRST, 2020).

Today, nearly 30 U.S. states require all or some of their utilities to file an integrated resource plan with the regulator, allowing for longer-term planning and for identifying options for meeting customers’ anticipated needs for electric services in a way that addresses multiple objectives (ENEFIRST, 2020). In some cases, energy efficiency is treated comparably to supply-side resources within the plan itself, while in other cases it is less integral to the process and “more heavily influenced by other political or economic considerations” (Lamont and Gerhard, 2013).

Until recently, regulators in the United States were giving little or no scrutiny to how the electric distribution system — which carries electricity from the transmission system to individual consumers — was planned by utilities (MADRI, 2019). Utilities were preparing distribution network development plans, but these plans were mostly kept internal and separate from the states’ integrated resource planning efforts.

The integration of increasing amounts of distributed energy resources into the electric power system by utilities, independent power producers and energy consumers has changed the game. Distributed energy resources cover both demand resources (energy efficiency and demand response), distributed supply (photovoltaic, micro CHP systems, etc.) and storage systems. Their development, but also their untapped potential to deliver on the energy transition while maximising benefits for the environment and for consumers, has opened the need for more regulatory oversight on distribution system planning (MADRI, 2019).

This case study looks at the distribution system planning rules currently under examination in Colorado, and those just adopted in Nevada, in view of discussing how the E1st principle is being enacted through the use of appropriate integrated resource planning tools.

2. How has the E1st principle (or similar concept) been implemented?

In Nevada, Senate Bill 146 was approved in June 2017, revising the rules of integrated resource planning. Utilities are now required to file three-year distribution plans with the Public Utilities Commission of Nevada (PUCN) as part of their triennial integrated resource plans (Nevada, 2017).

The Public Utility Commission of Colorado (PUC) has traditionally considered all distribution system investments to be in the “ordinary course of business.” Utilities have typically developed internal, five-year distribution plans, meaning that neither stakeholders nor the Commission have an opportunity to provide input to that plan (Colorado PUC, 2019). Senate Bill 19-236, signed in May 2019, directs the PUC to promulgate rules establishing the filing of Distribution System Plans by Colorado electric utilities (Colorado, 2019). Draft rules were due by March 2019. They have not been published at the time of writing.

In the U.S., the Mid-Atlantic Distributed Resources Initiative (MADRI) was established in 2004 by a number of state regulators along with the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC) and PJM Interconnection. It sought to identify and remedy retail and wholesale market barriers to the deployment of distributed generation, demand response, energy efficiency and energy storage in the Mid-Atlantic region.[1]

MADRI (2019) has developed guidance for regulators designing integrated distribution planning for electric utilities. For the purpose of this case study, some of MADRI's recommendations are examined below. They have been grouped into three themes to examine how the efficiency first principle can be enacted: scope of planning, governance and assessment of options.

Theme 1: Scope of planning

Geographical coverage - MADRI (2019) notes that integrated distribution planning can be implemented by one utility at a time or through a joint proceeding involving all regulated utilities. Both approaches have pros and cons: the former allows for a "deeper dive," the latter could produce a "more consistent statewide approach" to planning. In Nevada, distribution planning has been integrated into the regular resource planning process (utility by utility approach). In Colorado, rules are yet to be approved.

Consistency - MADRI (2019) recommends considering whether to align the timing and frequency of integrated distribution planning filings with other related plans, such as integrated resource plan filings, energy assurance plans, energy master plans, etc. In Nevada, the distributed plan is filed together with the resource plan of the utility, and those documents shall be consistent. In Colorado, stakeholders have been consulted (Colorado PUC, 2019) on how distribution system plans filings be coordinated with other filings with the Public Utility Commission,[2] and on whether there is a preferred sequencing of planning and reporting.[3]

Time coverage - The length of the planning horizon, the timing of plan filings, and the frequency of plan updates are also parameters to be considered. Based on practices observed to date, MADRI recommends a five- to ten-year planning horizon at a minimum, as well as frequent updates to each utility's plan to provide for the rapid pace of change in the power sector (annual updates, or two or three years between filings if this is difficult to manage). In Nevada, distributed resources plans shall be submitted every third year as part of the utility's overall resource plan. These three-year plans should take into account a forecast of net distribution system load and distributed resources over a six-year period. The utility shall file an updated plan each year. In Colorado, stakeholders have been consulted about the frequency of planning, and on whether plans should address both short-term capital investments (1-3 years) and long-term capital plans (7-10 years) (Colorado PUC, 2019).

Theme 2: Governance

Approval by the regulator - The regulator must decide whether a utility filing should be informational or subject to a regulator's approval that binds the utility to the planned course of action (MADRI, 2019).[4] In Nevada, the regulator has to approve the plans and determine whether the plan is prudent. In Colorado,

[1] MADRI meetings were organised and facilitated by the Regulatory Assistance Project, funded through the U.S. DOE.
[2] Specifically, Electric Resource Plans (ERPs), Renewable Energy Standard (RES), annual generation and transmission facilities filings, Certificate of Public Convenience and Necessity filings, and transportation electrification applications.
[3] Whereby certain proceedings yield decisions that inform other proceedings, or proceedings occur in parallel.
[4] Even if a plan is approved, the regulator might still require the utility's actions be reasonable and prudent at the time each action is taken (MADRI, 2019).

stakeholders were consulted on what principles the regulator should consider in setting criteria to govern the review and approval of distribution system plans (Colorado PUC, 2019).

Role of stakeholders - MADRI (2019) notes that stakeholder participation increases transparency and creates more confidence in the process. It recommends that at a minimum, stakeholders should have the opportunity to review and comment on a filed integrated distribution planning. In Nevada, Strategen Consulting (2018) has published an analysis of NV Energy's Integrated Resource Plan as well as an Alternative Resource Portfolio.[5] In Colorado, stakeholders have been calling to set up an integrated distribution planning process. Stakeholders have been consulted on whether they should have the opportunity to provide input into forecasting assumptions and methodology (Colorado PUC, 2019).

Theme 3: Assessment of options

Volkmann (2019) highlights the difference between the traditional distribution planning process and integrated distribution planning.

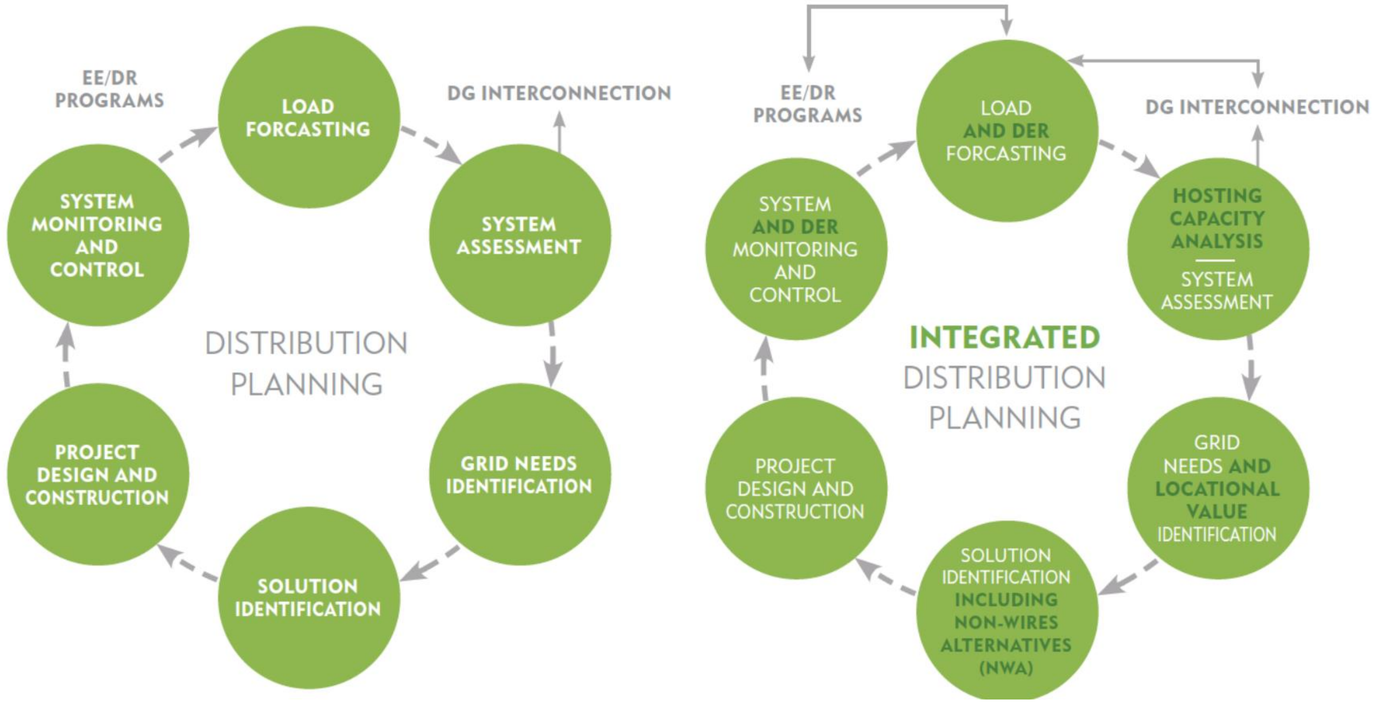

Figure 1 – Comparison between distribution planning and integrated distribution planning (Source: Volkmann, 2019)

Two parameters make a difference with regard to the implementation of the E1st principle:

Dynamic forecast of distributed energy resources - As explained by Lamont and Gerhard (2013), in traditional planning a certain amount of demand-side solutions are considered. This simply reduces the load forecast. The gap is filled by supply-side resources even if less costly demand-side savings are available.

[5] The development of this Alternative Portfolio would, according to WRA, "reduce future investments in natural gas and replace those resources with increased levels of energy efficiency, renewables, and battery storage." It could "save customers over $192 million, compared to the Low Carbon portfolio selected by NVE." Source: Strategen Consulting, 2018.

The graph above shows that integrated distribution planning requires distributed energy resources, including demand-side solutions, to be considered in a dynamic manner, meaning both as an input and an output of the model. Whenever there is an imbalance between demand and supply, both types of options shall be considered.

In Nevada, distributed resources plans shall be submitted every third year as part of the utility's overall resource plan. The regulator needs to determine that forecasts and analysis are prudently performed, and that the selection of new distributed resources is reasonable.

In Colorado, electric utilities currently take into account some forecasted distributed energy resources in their load forecasts, but the regulator notes that there may be a need to better account for the impacts of policies and goals (e.g., increasing electrification of heating and transport). Stakeholders are consulted on how utilities should incorporate load growth patterns and drivers outside of their historical experience (Colorado PUC, 2019).

The solutions/investments identified include non-wires alternatives - MADRI (2019) notes that integrated distribution planning needs to be comprehensive in terms of examining the entire grid and all the potential options for improving the grid from a reliability, resilience and cost effectiveness standpoint. Table 1 below presents the distributed resources considered in Nevada and Colorado.

Table 1 – Resources considered in distribution system planning in Nevada and Colorado

Nevada	Colorado
• Distributed generation systems • Energy efficiency • Energy storage • Electric vehicles • Demand response technologies	• Renewable electric generation • Energy efficiency measures • Energy storage systems connected to the distribution grid • Demand response measures • Microgrids
Proposed regulation of the Public Utilities Commission of Nevada. September 26, 2018.	*Colorado Senate Bill 19-236 (2019)*

In Nevada, the distributed resources plan evaluates the locational benefits and costs of distributed resources. This evaluation must be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits and any other savings the distributed resources provide to the electricity grid or costs to customers of the electric utility or utilities.

In Colorado, the legislation requires the regulator to develop a methodology for evaluating the costs and net benefits of using distributed energy resources as non-wires alternatives. The rules also determine a threshold for the size of a new distribution project (whether in dollars, meters or another factor), for when a utility must consider implementation or use of non-wires alternatives.[6] Stakeholders have been asked the following questions (Colorado PUC, 2019): How can distribution system planning integrate non-wires alternatives in a

[6] Potentially including energy efficiency measures under utility programmes for new electric service to any planned new neighborhoods or housing developments.

way that allows utility customers and distributed energy resources providers to provide incremental value to the utility system? What types of costs and benefits should be considered?

To conclude, important considerations for enacting the Efficiency First principle include the alignment and consistency of the different utility plans, setting the proper planning timeframe, and ensuring sufficient regulatory and stakeholder oversight over the process, based on rules which allow for a dynamic forecast of distributed energy resources and for recognising the value of non-wires alternatives in the assessment techniques.

3. Effects / impacts

In Nevada, the first distributed resources plan was submitted by the utility NV Energy in 2019. Stakeholder group Interstate Renewable Energy Council (IREC) has engaged in the regulatory proceeding to implement the new rules. According to IREC, these rules will "enable greater grid transparency and support the optimised, efficient and cost-effective deployment" of distributed energy resources.

Stakeholder negotiations led to the approval by the regulator of utility NVE's first distribution plan. IREC and NCARE (representing WRA, Natural Resources Defense Council, Sierra Club, Southwest Energy Efficiency Project and other groups) were involved (Baldwin, 2019).

In Colorado, the rules are not in place yet.

4. Changes over time, if any

Rules are recent (Nevada) or yet to be adopted (Colorado).

5. Barriers and success factors

Volkmann (2019) lists some of the tools which should be deployed to allow integrated distribution planning. These notably include:

- Advanced Forecasting and System Modelling, which models the growth of distributed energy resource and includes a more detailed system modelling of loads and the impacts on the distribution system.
- Hosting Capacity Analysis, which helps determine how much additional distributed energy resources each distribution circuit can accommodate without requiring upgrades.
- Disclosure of Grid Needs and Locational Value, which helps identify and communicate about opportunities for distributed energy resources and locations where their deployment can provide grid benefits.
- New solution acquisition, which allows the acquisition or sourcing of distributed energy resources from customers and third parties to provide grid services using pricing, programmes or procurement.

On this last point, it is important to note that integrated distribution planning will not ensure the deployment of energy efficiency and demand response solutions on its own. As noted by Lamont and Gerhard (2013), energy efficiency is often less costly but "practical and financial considerations" are governing the speed at which energy efficiency resources can be deployed. These include market acceptance constraints, upstream capacity for product development and know how, and allowing for the adaptation of the utility business model.

Energy efficiency policies and goals should help address these barriers and value the benefits of demand-side solutions, which should be properly recognised in cost-benefit analyses conducted by the regulators.

6. Replicability and scalability potential

As noted by the European Commission (2016) in its impact assessment for the revamp of electricity market rules, the regulatory framework in the EU has so far not incentivised distribution network operators to actively manage the electricity flows in their networks, nor to provide incentives to customers connected to distribution grids to use the network more efficiently. Distribution System Operators (DSO) were not provided "proper incentives for investing in innovative solutions which promote energy efficiency or demand-response." The framework also failed to "recognise the use of flexibility as an alternative to grid expansion." There have also been "fears over the impact that the deployment of distributed resources could have at system-level" (Prettico et al., 2019).

The new EU rules on electricity markets[7] should allow an increased mobilisation of distributed resources. ENEFIRST (2020) describes the relevant legal provisions:

- Distribution network development plans shall be published and submitted to the National Regulatory Authorities every two years (Article 32; EU, 2019, 2019/944).
- These plans shall identify the needed medium- and long-term flexibility services. They shall include the use of demand response, energy efficiency, energy storage facilities or other resources as an alternative to system expansion (Article 32; EU, 2019, 2019/944).
- National Regulatory Authorities may introduce performance targets in order to incentivise DSOs to raise efficiencies, including through energy efficiency, flexibility and the development of smart grids and intelligent metering systems, in their networks (Article 18; EU, 2019, 2019/943).
- Regulatory frameworks shall incentivise DSOs to procure flexibility services, including congestion management, and ensure that they procure energy efficiency, demand response and distributed generation and storage "when such services cost effectively" supplant the need to upgrade capacity (Article 32; EU, 2019, 2019/944).

Some European DSOs are already implementing such a practise, as shown in the example **Error! Reference source not found.** (***Error! Reference source not found.***). The practise is still recent, and both DSOs and regulators will need to ensure that they have the right capacity to develop and review the distribution network

[7] European Union (2019). Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast); and European Union (2019). Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast).

development plans. The benefits of the exercise are numerous, starting with an increase in the transparency over investments in distribution networks.

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ABOUT ENEFIRST

ENEFIRST is a 3-year project funded under the Horizon2020 programme, which gathers a consortium of partners from across sectors and regions: IEECP, BPIE, Fraunhofer ISI, CEU, RAP, IREES, TU Wien.

From definition to implementation, ENEFIRST aims at making the “Efficiency First” (E1st) principle more concrete and operational, better understand its relevance for decision processes related to energy demand and supply, its broader impacts across sectors and markets, focusing on the building sector and related energy systems in EU Member States.

> ***E1st gives priority to demand-side resources whenever they are more cost-effective from a societal perspective than investments in energy infrastructure in meeting policy objectives. It is a decision principle that is applied systematically at any level to energy-related investment planning and enabled by an “equal opportunity” policy design***.

ENEFIRST combines policy analysis and quantitative assessments of E1st impacts to develop policy guidelines and recommendations, following a process with continuous exchanges with stakeholders.

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