Microgrids Beyond the Hype: Utilities Need to See a Benefit

By John D. McDonald

TO MOVE MICROGRIDS from the potentially irritating "hype cycle" across the dreaded "trough of disillusionment" and up the slippery "slope of enlightenment" to reach the long-sought "plateau of productivity" might seem a daunting task, particularly given the obviously melodramatic language that often accompanies technology maturation and market acceptance. Nonetheless, the promise of microgrids for achieving energy assurance—essentially a measure of reliability—when coupled with other crucial value propositions, including environmental and economic goals, deserves review. While not all technology advancements survive beyond the hype cycle, every successful technology must endure a journey that begins in a giddy whirlpool of potential outcomes.

In the case of microgrids, many stakeholders are optimistic that the fundamental strengths of the technology and its myriad applications will prevail over what appear to be surmountable hurdles. But to move beyond the hype, the technology's drivers and opportunities should be spelled out alongside an honest review of the barriers to implementation.

My own related work focuses on interconnections, where technology, standards, and policies join grid to microgrid. To develop the proper context for interconnection-related issues, I will begin by defining microgrids in general terms and describing typical use cases. Then, I will turn to recent efforts by the state of Minnesota to explore microgrid drivers, opportunities, hurdles, and next steps. It is in that specific context that a description of ongoing changes to interconnection standards and policies will make the most sense. The discussion is relevant not only to Minnesota's interest in microgrids but to other states, utilities, microgrid sponsors, and readers of *IEEE Electrification Magazine*.

Definitions, Drivers, and Hurdles

Definitions can be a perilous exercise, but let us try one. Microgrids are often conceived as self-contained energy systems with the ability to operate independently of the grid, either as stand-alone systems or, if grid tied, by islanding—disconnecting from the grid while continuing to operate. Microgrids must possess their own generation source(s), typically under the category of distributed generation (DG), which could be fossil fuel-driven (likely diesel) generators and/or renewable resources such as wind turbines, solar photovoltaic (PV) cells, fuel cells, or other means. Microgrids include load management functionality to balance the supply/demand mix, perhaps aided by energy storage in chemical or thermal form.

Drivers are many, and they range from energy assurance, where that single benefit is sometimes deemed to outweigh high costs, to implementations based on a variety of specific goals that offer a positive business case. Likely sponsors range from utilities to large customers such as cities and towns and military installations, universities, schools, and hospitals (MUSH). The fact that a microgrid can serve a nonutility sponsor by providing a degree of self-sufficiency, of course, is often perceived to challenge utility interests by reducing volumetric sales, a traditional avenue for utility revenue. That is a policy issue that must be addressed as such. But technological challenges presented by microgrids must be overcome as well, particularly regarding their interconnection with the utility grid. In fact, amendments to fundamental interconnection standards are ongoing, and all stakeholders will gain by tracking progress in this vital area.

Although this article focuses on interconnection standards and policies, I will finish by discussing how regulatory reform to a more results-based approach can improve incentives for utilities to implement or accommodate microgrids. In fact, the path of least resistance to

Digital Object Identifier 10.1109/MELE.2013.2297181
Date of publication: 18 March 2014

accelerated adoption of microgrids will be the path that supports clear, attractive benefits for the affected utility. Certainly, the default position in a case where a microgrid is sought by an end user or a third-party developer is, at the very least, to not adversely impact the affected utility.

Typical Use Cases

It is worth reviewing typical use cases to provide context for Minnesota's exploration of microgrid opportunities. The U.S. Department of Defense (DoD) is a leading adopter of microgrids for stationary bases to meet its fundamental obligations to protect the American people, the homeland, and our allies, where our bases are located, overseas. The business case, which is so important to private enterprise, takes a backseat to mission criticality in this example.

In contrast, a variety of industrial facilities, such as ports, mines, refineries, airports, and campuses, require uninterruptible power to ensure the continuity of processes, the safety of patients and the public, and/or the protection of assets. Energy assurance and its costs in those cases are typically weighed in light of the cost of the consequences of power failure. On corporate campuses, especially in regions where the cost of grid-based electricity is high or very volatile, a self-contained system offering a mix of DG and load control creates an attractive business case. The same is true for isolated, off-grid communities where fossil fuel must be shipped in at great cost.

On the utility side, a microgrid can provide the advantage of islanding to reduce load on a stressed circuit, defer capital investment in capacity (known as a "deferral opportunity"), or meet load growth through a line extension. Microgrids can provide a controllable means of managing DG, especially where intermittent renewable energy sources can lead to voltage instability and other operational issues.

Utilities in California and Maine are exploring the latter opportunities, while in Connecticut, nonutility actors, including municipalities, are considering microgrids to bolster system reliability in the wake of a series of devastating storms that culminated in 2012's Hurricane Sandy. In contrast, Minnesota has a history of viewing energy assurance as a fundamental aspect of economic productivity and stability and energy innovations as a means to achieve environmental and self-sufficiency goals.

The Land of 10,000 Lakes

Minnesota is the 12th largest state and straddles the continental craton, which has been etched by glaciers, leaving innumerable freshwater lakes, thus its nickname, "Land of 10,000 Lakes." Its population of roughly 5.5 million citizens is relatively highly educated and exhibit high voter turnout. More than half of the state's residents cluster around the Twin Cities of Minneapolis and Saint Paul, hubs of business, industry, transportation, education, government, and a thriving arts community. Its economy, historically based on agrarian pursuits and natural resource extraction, has evolved into a well-integrated mix of finished products and services. Thirty-three of the top 1,000 publicly traded companies in the United States by revenue were headquartered there in 2008. Minnesota borders Canada to the north, the Dakotas to the west, Wisconsin and Lake Superior to the east, and Iowa to the south.

> *The path of least resistance to accelerated adoption of microgrids will be the path that supports clear, attractive benefits for the affected utility.*

Whether those factors translate to the state's policy support for DG, renewable energy resources, and energy alternatives I will leave to the experts on Minnesota. Suffice it to say here that state policy makers determined last year to take a hard look at microgrids, which appeared to align with the state's energy, environmental, and economic policy goals, with an emphasis on energy assurance as a pillar of the local economy.

American Recovery and Reinvestment Act Grant for Microgrid Study

The Minnesota Department of Commerce's Division of Energy Resources sought and won a U.S. Department of Energy grant under the American Recovery and Reinvestment Act that funded many related smart grid projects in the 2008–2009 time frame. (The fact that Minnesota's Department of Commerce has a Division of Energy Resources reflects the fact that energy assurance is considered a mainstream, bread-and-butter issue to the economic health and welfare of the state.) Policy makers wanted to better understand the drivers, opportunities, and barriers associated with microgrid adoption and the effects on the gamut of stakeholders. To that end, the state contracted with a microgrid team led by Burr Energy LLC, to which I contributed my expertise on interconnection standards and policies. I was one of seven co-authors of the resulting study, "Minnesota Microgrids: Barriers, Opportunities, and Pathways Toward Energy Assurance," which was published by the Minnesota Department of Commerce in September 2013. The white paper was incorporated as an annex to the official Minnesota Energy Assurance Plan.

The six-point scope of the white paper (paraphrased for brevity) lays out the context here.

- Review regulations and policies affecting microgrid development, ownership, and operation.

- Identify applicable interconnection standards and practices, including interoperability and control of distributed resources.
- Explain how traditional contracting, risk assessment, and financing practices apply to microgrids and analyze Minnesota policies that affect microgrid development.
- Research and model potential electric loads available to microgrids in Minnesota, and segment those loads by user groups.
- Identify renewable resources in the state potentially accessible in microgrid applications and examine economic and operational factors for possible renewables-based microgrids.
- Recommend policy steps that would capture microgrid benefits for Minnesotans and assist in the safe, cost-effective implementation and integration into the utility system.

My charge, the focus of this article, can be articulated at slightly greater length. The importance of interconnection standards and policies in this context was viewed as a fundamental, pragmatic matter. So the team was tasked with identifying Minnesota's applicable interconnection standards and practices, including interoperability and control of distributed resources. The team was also directed to compare and contrast Minnesota's standards and practices with current federal and industry standards and articulate differences that might affect microgrid development and optimization in utility systems.

The reference to standards regarding "optimization in utility systems" in this element of the scope (as well as a similar reference in the final point listed previously) underscores that Minnesota is exploring microgrids for the benefit of its citizenry, with a clear intent to work with utilities. Minnesota public policy regarding microgrids reflects a commitment to make this innovation workable and even beneficial from a utility standpoint. This wisely recognizes utilities' prerogatives as well as the practical issues surrounding interconnections between microgrids and utility grids. Identifying mutual benefits makes sense because Minnesota's current regulatory approach, which is based on cost-of-service rate making and volumetric pricing, initially puts investor-owned utilities and microgrids "squarely at odds," as the white paper put it. As Minnesota clearly recognizes, utilities' concerns about microgrids' potential impact on their business model as well as impacts on operational matters based on interconnection issues are well founded and need to be addressed.

Utility Concerns on Microgrid Control, Safety

The interconnection of a utility grid with DG systems is governed by a finite number of industry standards issued by the usual suspects, including the IEEE, Underwriters Laboratories, the International Electrotechnical Commission, and the Federal Energy Regulatory Commission (FERC). All applicable standards are intended to address utilities' concerns, for the simple reason that utilities operate the grid to which microgrids would interconnect and they have significant, regulated public responsibilities. Those concerns can be summarized in four categories:

1) Anti-islanding features are needed to prevent the unintentional flow of current from grid-connected DG onto a circuit that otherwise should not be energized, as in an outage.
2) Distribution systems do not all have protection equipment to safely prevent short circuits from DG running in synchronous, parallel interconnection to the utility grid.
3) Synchronized generators that fluctuate to follow microgrid loads or intermittent renewable energy sources can cause voltage instability, forcing the utility to install expensive capacitor banks and voltage regulators to maintain voltage stability.
4) Utility grid operators often have little or no visibility into customer-owned DG, resulting in suboptimal operations for both parties.

Recent developments in interconnection technologies and new approaches to microgrid control have provided cost-effective solutions to many utility concerns. And new methods of testing and simulation can rapidly prove the safety of microgrid-related technologies and practices. (The white paper's appendices offer case studies in support of this statement.) That said, it certainly behooves utilities to have an active testing program to assess how new technology affects their systems, a precaution that can benefit their customers. However, cultural factors must be addressed as well. Power systems engineers' experience has bred mistrust of new systems until exhaustive field testing has concluded that they are effective and safe. Given utilities' public obligations and the danger of high-voltage power, caution is justified. And, as we shall see, in Minnesota as elsewhere, current policies may give utilities the upper hand in facilitating or inhibiting microgrid development. Thus, the onus is on microgrid sponsors to demonstrate the safety, reliability, and cost-effectiveness of their system to the utility—if utility cooperation is to be expected.

Applicable Standards and New Amendments

For microgrid development in Minnesota, the most important standard is IEEE 1547, *Standard for Interconnecting Distributed Resources with Electric Power Systems*. IEEE 1547, approved in 2003, aims to provide a uniform set of criteria and requirements for interconnecting the grid with DG. Its requirements relate to the testing, operations, maintenance, and safety of the grid-to-DG interconnection. IEEE members have approved eight complementary standards, including IEEE 1547.4 and IEEE 1547.8, which may be affected by a currently active amendment process.

In recognition of the measured pace that characterizes standards development and the speed with which microgrid technology is advancing, IEEE P1547a-Amendment 1 was introduced to speed up high priority changes to IEEE 1547. This amendment updates practices regarding voltage regulation and responses to abnormal voltage and frequency conditions on the grid. As of this writing, the amendment has cleared the balloting process and is subject to a comments period. If approved, as expected, the changes in this amendment will go into effect in early 2014, followed by a comprehensive overhaul of IEEE 1547 to resolve the additional issues that surfaced during work on IEEE P1547a-Amendment 1.

Two specific changes in IEEE 1547 address microgrids. DG systems henceforth may participate in voltage regulation via changes in real and reactive power supplies, allowing utilities to integrate DG as grid-supporting resources. (Before this change, DG was not allowed to actively regulate voltage at the point of common coupling.) This change permits the microgrid sponsor to regulate voltage and save energy in cases where the utility does not practice conservation voltage reduction.

Whereas IEEE 1547 defined recommended practices for DG system behavior in response to abnormal frequency conditions—i.e., spelling out when a DG system must stay connected and when it must disconnect—amendments were fast tracked because of evolving concerns. A rapid increase in the penetration of PV rooftop systems in pockets around the country presented utilities with the possibility that perhaps hundreds of DG systems might disconnect at the same time due to a dip in frequency on the grid. If an unscheduled outage at a major power plant caused the underfrequency, then a sudden loss of DG power could exacerbate the situation.

These amendments will enable microgrids to better meet utility interconnection concerns to operate more efficiently and, thus, encourage their development. The first amendment provides for microgrid integration with distribution control systems and allows a microgrid to serve grid-support functions, a direct answer to specific utility concerns. The second amendment allows a microgrid to remain grid-connected, which will preclude the introduction of unneeded backup generation for the utility. If an interconnected microgrid is feeding power onto the grid, the ride-through (second) amendment contributes to avoiding a bad-to-worse scenario.

Anti-islanding, a crucial safety function of protective systems, will remain as a provision of the amended 1547 standard.

Further work on standards will be needed. Standard information models for microgrid control point functionality are in the early stages of development. The vision of a distribution system comprising multiple, interactive microgrids in support of reliability for both distribution and transmission systems is getting closer to reality. These standards will take time, largely because technologies and applications are still maturing. Sophisticated smart grid applications in this context will require uniform standards as the need for interoperability increases.

Islanding and Anti-Islanding

One important clarification is in order here. The terms islanding and anti-islanding can be confusing.

IEEE 1547's anti-islanding tenets were written to prevent unintentional islanding of grid-connected generation. Separate provisions provide standards for intentional islanding. Pending changes in the standard should clarify how the two effects differ or relate.

Anti-islanding, a crucial safety function of protective systems, will remain as a provision of the amended 1547 standard. Grid-tied, standards-compliant DG systems typically are grid activated, meaning that they automatically shut down when an outage occurs, preventing unintentional islanding.

An amended IEEE 1547 will likely provide specific provisions to enable intentional islanding in cases where a microgrid or other islandable DG source is designed to function both connected to and disconnected from the grid. For instance, IEEE 1547 originally encouraged highly sensitive trip-off settings. The downside of that approach is that a minor fault could lead to DG deactivation. Given the high penetration of DG, such hair-trigger settings for anti-islanding can lead to problems. Also, those settings represent a nuisance for systems designed to isolate themselves and initiate backup generation upon sensing a system fault. The proposed amendments to IEEE 1547 are focused on allowing a wider ride-through tolerance so that DG and microgrids can continue generation despite fluctuations in grid frequency.

In other words, the main difference between anti-islanding and intentional islanding is that once a system is intentionally islanded, anti-islanding requirements no longer apply. The islanded DG system is disconnected from the grid and, therefore, is no longer a safety concern. IEEE 1547.4 will contain recommended practices for intentional islanding, and the forthcoming 1547.8 standard addresses the functionality of small generators such as microgrids, which are designed to intentionally island.

In summary, islanding and anti-islanding features are designed to work in tandem in an amended IEEE 1547. Furthermore, systems that comply with the amended version of IEEE 1547 will allow for the stable interconnection of islandable microgrids while maintaining the safety of anti-islanding features.

Interconnection Costs

Many if not most states, including-Minnesota, have adopted regulations regarding (synchronous) interconnection based on IEEE 1547 and FERC's small generator interconnection procedures (SGIP), adopted in May 2005 under FERC Order 2006.

Several states that are concerned about the potential impacts of faults and unintentional islanding require the affected utility to study the impacts. This leaves the door open for utilities to delay a proposed microgrid via lengthy, expensive studies. Subsequently, the microgrid developer might be required to pay for added protection measures on the grid to the tune of thousands of dollars per kilowatt of capacity. Such a cost in Minnesota, where retail electricity rates are relatively low, could easily sink a project. Knowing that such charges could be imposed and are largely unquantifiable at the outset can deter developers from even proposing a microgrid project. These potential deterrents have led FERC and some states to simplify the impact study process and make it more transparent.

Changes in California's regulations promise to provide a path forward in such circumstances. The California Public Utility Commission revised its "Rule 21" interconnection policies to set time limits for interconnection studies and mechanisms to resolve disputes between utilities and microgrid developers. California also established that interconnected DG on a distribution line segment can equal 100% of the segment's minimum load. The previous policy limited the interconnected DG to 15% of the peak load on the segment in question. Both limits remain in place, but projects that do not meet the 15% of peak bar criterion remain eligible to proceed if they meet the 100% of the minimum load criterion.

While California's revision of its regulations was driven by high penetration of DG, largely rooftop solar PV, it has implications for Minnesota. A large microgrid on a single distribution segment could generate electricity at a level equal to scores of rooftop PV arrays. Standards that accommodate DG systems in which smart inverters provide voltage support can also apply to a microgrid acting as a DG source, a controllable load, or both. The best practices established by California and FERC illustrate how policies can make interconnection studies more transparent and certain.

FERC policies are relevant to Minnesota's case in that they cover DG projects up to 20 MW in size and how they interconnect with interstate transmission systems, which is important if a Minnesota microgrid wishes to sell wholesale power into the Midwest Independent System Operator market. FERC has issued a notice of proposed rule making that it seeks to amend its SGIP and small generator interconnection agreement (SGIA) policies to, in FERC's words, "ensure the time and cost to process small generator interconnect requests will be just and reasonable and not unduly discriminatory."

Enter: Results-Based Regulation

I have discussed the gamut of utility reactions to microgrid proposals, from an enlightened grasp of the opportunity for grid benefits and shared capital investment to the use of impact studies to derail a proposal. We have reviewed the strengths and weaknesses of existing and evolving standards and policies to address the uncertainties that produce such a wide range of utility stances. Looming over these crucial details is each state's approach to traditional utility business models in the smart grid era.

A more flexible, results-based regulatory scheme that accommodates and rewards utility actions that demonstrably benefit their customers has been proposed by my colleague, David Malkin, and his co-author, Paul Centolella, in their recent article, "Results-Based Regulation: A More Dynamic Approach to Grid Modernization" (*Public Utilities Fortnightly*, February 2014). The simplest notion in this realm, of course, is well-known as decoupling—creating a model for utility revenue that is independent of the utility's volumetric electricity sales. Malkin and Centolella's article provides a rationale for that thinking and advances it.

"Results-based regulation is designed to support investments that deliver long-term value to customers, reward utilities for exceptional performance, and remain affordable by encouraging operational efficiencies and sharing the cost savings with customers," Malkin and Centolella write.

As one example in which results-based regulation would reward utilities for providing that long-term value to customers, Malkin and Centolella cite the fact that "distribution utilities are increasingly expected—and, in many cases, required—to perform fundamentally new functions," including resiliency in the face of extreme weather, the integration of distributed and variable, renewable generation, and cyber security. The limits of more typical cost-of-service regulation often fail to consider "the value of uninterrupted electric service to different customers," Malkin and Centolella write.

If a state such as Minnesota wishes to encourage microgrid development, regulatory policy will need to evolve along with standards not simply to enable microgrid adoption but to reward the cooperating utility for making possible a customer benefit that cuts into its revenue base. Thus, policy and standards should work in tandem.

Minnesota Standards Policy

Interconnection requirements in the state of Minnesota were issued on 28 September 2004 (Docket No. E-999/CI-01-1023). A subset of those regulations governs small, grid-tied DG. The IEEE's consideration of IEEE 1547a amendment and more likely changes to come to existing IEEE 1547 standards—plus FERC's proposed revisions to its SGIP and SGIA—should lead Minnesota to review its own existing interconnection standards and tariffs. This should be an ongoing process for years to come, given the speed of change in standards, best practices, and technology in this space. If Minnesota continues to see value in microgrid adoption, it needs to institute a regular standards review process and swiftly adopt new, approved standards. On the utility side, some of Minnesota's utilities have staff that serve on the IEEE Standards Committee and, thus, are well aware of pending changes in these areas. Other utilities have dedicated distribution technology teams charged with reviewing standards and best practices, which will have to monitor and adapt to related changes.

One immediate change Minnesota needs to make in its own regulations is to change its restrictive definition for DG capacity. The state's interconnection requirements set thresholds and size limits on DG and microgrids, with thresholds at 40 and 100 kW and a system capacity at 10 MW, half the size of FERC's 20-MW limit for small generator treatment. That's lower than most other states, several of which have no limits at all. The current rules force larger microgrid proposals to forge unique agreements with a utility at greater cost and uncertainty.

Next Steps

Should the state of Minnesota decide that encouraging microgrid development aligns well with its policies regarding energy assurance as a pillar of economic stability and growth, it has regulatory and legislative paths to achieve its aims. Currently, its interconnection standards and tariffs are outdated. They do not accommodate grid-integrated microgrids with a combination of generation, storage, and load-management functionality, and they set outmoded thresholds and limits for size. An ongoing review and revision of the state's interconnection policies will help it keep pace with evolving standards. As technology changes often outpace IEEE balloting and FERC rule-making processes, Minnesota can look to other states whose standards and practices better reflect prevalent industry norms as a guide.

Of course, interconnection standards and tariffs are but one set of concerns and opportunities for action in Minnesota and elsewhere. Minnesota's microgrid road map includes many steps best taken simultaneously. One important step, among others, is to establish a working microgrid with stakeholders that include the state, a local utility, and a microgrid developer; make it a pilot project not a demonstration project—the technology has been demonstrated; use the microgrid and its interconnection to satisfy utility safety concerns and create a business case that demonstrates value to the utility as well as its shareholders and customers; and make sure that interconnection policy, standards, and practices are kept current to enable the technology's potential.

We may be climbing that slippery "slope of enlightenment," but the "plateau of productivity" beckons from the horizon, clearly visible. Many, including myself, believe that we can get there from here.

For Further Reading

D. Malkin and P. Centolella. (2013). Results-based regulation: A modern approach to modernizing the grid. GE Digital Energy/Analysis Group. [Online]. Available: http://www.analysisgroup.com/uploadedFiles/Publishing/Articles/Centolella_GE_Whitepaper_Electricity_Regulation.pdf

K. Fox, S. Stanfield, L. Varnado, T. Culley, M. Sheehan, and M. Coddington, "Updating small generator interconnection procedures for new market conditions," NREL Technical Report, NREL/TP-5500-56790, National Renewable Energy Laboratory, Dec. 2012.

M. A. Hyams, A. Awai, T. Bourgeois, K. Cataldo, S. A. Hammer, T. Kelly, S. Kraham, J. Mitchell, L. Nurani, W. Pentland, L. Perfetto, and J. Van Nostrand, "Microgrids: An assessment of the value, opportunities, and barriers to deployment in New York State," Final Report, prepared for the New York State Energy Research and Development Authority (NYSERDA), Rep. 10-35, Sept. 2010.

M. T. Burr, M. J. Zimmer, B. Meloy, J. Bertrand, W. Levesque, G. Warner, and J. D. McDonald. (2013). Minnesota microgrids: Barriers, opportunities and pathways toward energy assurance, Minnesota Department of Commerce. [Online]. Available: http://mn.gov/commerce/energy/images/MN-Microgrid-WP-FINAL-amended.pdf

(2013). Model interconnection procedures, Interstate Renewable Energy Council. [Online]. Available: http://www.irecusa.org/wp-content/uploads/2013-IREC-Interconnection-Model-Procedures.pdf

P. Sheaffer. (2011, Sept.). Interconnection of distributed generation to utility systems: Recommendations for technical requirements, procedures and agreements, and emerging issues, Regulatory Assistance Project (RAP). [Online]. Available: www.raponline.org/document/download/id/4572

Biography

John D. McDonald (johndougmcd@gmail.com) is the chair of the Board of the Smart Grid Interoperability Panel (SGIP) 2.0, Inc., and the Smart Grid Consumer Collaborative (SGCC). He is a Fellow of the IEEE.