Using solar and storage to meet 100% of the electricity requirements of a distribution circuit

A case study for LG&E Highland 1103 circuit

LG&E
a PPL company

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Summary

This study evaluates the solar generation and energy storage requirements and associated economics of serving the electricity requirements of the LG&E Highland 1103 distribution circuit with local resources on a standalone basis, without connection to the power grid. This circuit has approximately 1,600 residential customers and 240 commercial customers that use approximately 20,500 MWh annually with a summer peak hourly demand of 8.9 MW. While the electricity consumption on the Highland 1103 circuit accounts for less than 0.4% of Jefferson County's total electricity consumption, its size and load characteristics are typical of many of LG&E's circuits and includes a customer mix that uses natural gas in their homes and businesses.

After evaluating a wide range of alternatives, this study shows that:

- While the technical challenges of using just local solar generation and energy storage to reliably serve the real-time electricity needs of customers on this circuit can likely be met, doing so would require a large geographic space (almost as large as the circuit footprint) that would result in land being used for solar panels and battery storage on a scale that would likely not be acceptable to the local community.

- Despite assuming customers would continue to use natural gas for space and water heating, the quantity of solar generation capacity required to be built would need to be about eight times greater than the summer hourly peak to generate enough energy to charge the batteries to reliably serve nighttime load and address extended periods of dense clouds and short days that are common during winters in Louisville.

- The cost of electricity would likely be two to five times higher over the 30-year study period as compared to continuing to take electricity from the LG&E system.

This study is an attempt to quantify, at a high-level, some of the technological and economic challenges associated with serving a typical distribution circuit with 100% locally generated renewable energy. In addition to the findings in this study, a number of questions, issues, and challenges were identified that were not addressed but were captured and documented for future consideration and included as part of this report.

Background

There is growing national interest in using renewable generation technologies to displace fossil-fuel generation in order to reduce CO_2 emissions.[1,2] Many advocates claim this can technically and economically be accomplished using existing renewable technologies in combination with current developments in storage technology.[3] Furthermore, some are interested in accomplishing this transition to 100% renewable generation via the use of microgrids based solely on distributed solar generation and battery storage.[4] This focus on local generation and storage development is often premised on the idea of creating local jobs and eliminating the need for central station power generation and its associated transmission grid.[5,6]

To understand and identify some of the challenges and issues that would need to be addressed in pursuing a local 100% solar/storage solution, this study used actual 2017 load and solar irradiance data for a representative LG&E distribution circuit to develop a range of possible technology and cost cases and compared the results to a range of costs of continuing with traditional utility grid service. The circuit that was selected is Highland 1103, which is located in the heart of Louisville. Figure 1 shows the geographic location (red rectangle) and electrical lines associated with this circuit.

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[1] Bloomberg New Energy Outlook 2018 — https://www.bnef.com/core/new-energy-outlook

[2] Benefits of Renewable Energy Use, Union of Concerned Scientists — https://www.ucsusa.org/clean-energy/renewable-energy/public-benefits-of-renewable-power

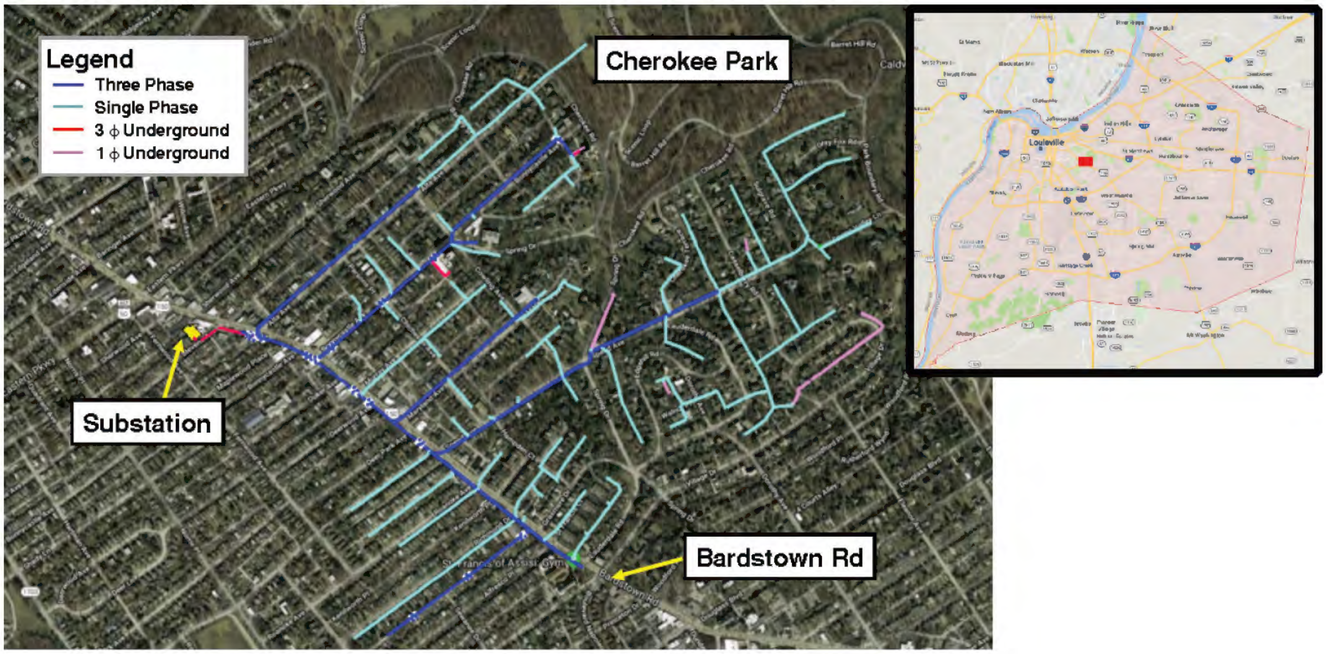
[3] How Energy Storage Can Pave the Way for Renewable Energy Adoption — http://climate.org/how-energy-storage-can-pave-the-way-for-renewable-energy-adoption/

[4] https://www.renewableenergyworld.com/articles/2017/08/100-percent-renewable-powered-microgrid-in-illinois-islands-from-the-grid-for-24-hours.html

[5] A Resolution for 100% Clean Energy for Metro Louisville Operations by 2030 and Community-wide by 2035.

[6] Distributed Generation of Electricity and its Environmental Impacts — https://www.epa.gov/energy/distributed-generation-electricity-and-its-environmental-impacts

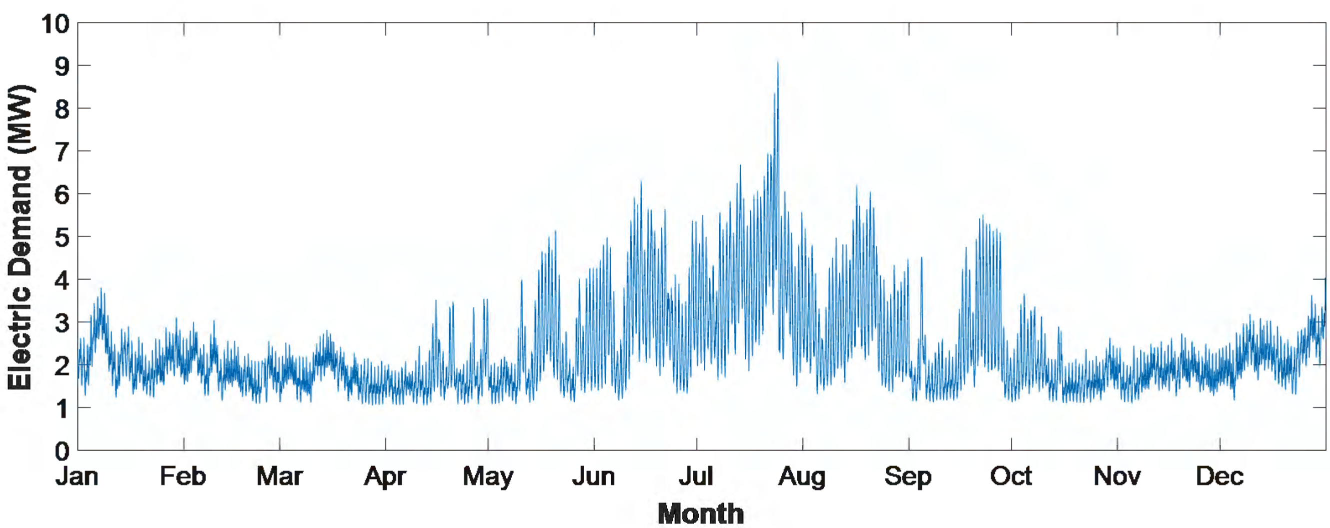
Figure 1: Google Earth Overview of Highland 1103 Circuit Distribution Infrastructure



LG&E operates 6,445 total miles of electric distribution lines making up 572 distribution circuits in and around Jefferson County serving approximately 411,000 electric customers.[7] Highland 1103 is a typical residential/small commercial circuit in that it has approximately 1600 residential customers and 240 small commercial customers, most of which also use natural gas, particularly for space and water heating. It is a 12.47kV circuit consisting of 9.26 total circuit miles (90% overhead, 10% underground and 30% 3 phase, 70% 1 and 2 phase).

Figure 2 displays the 5-minute load data on Highland 1103 for 2017 used in this study. It shows the summer peaking nature of the circuit as well as the lower winter electric demand due to natural gas space heating.

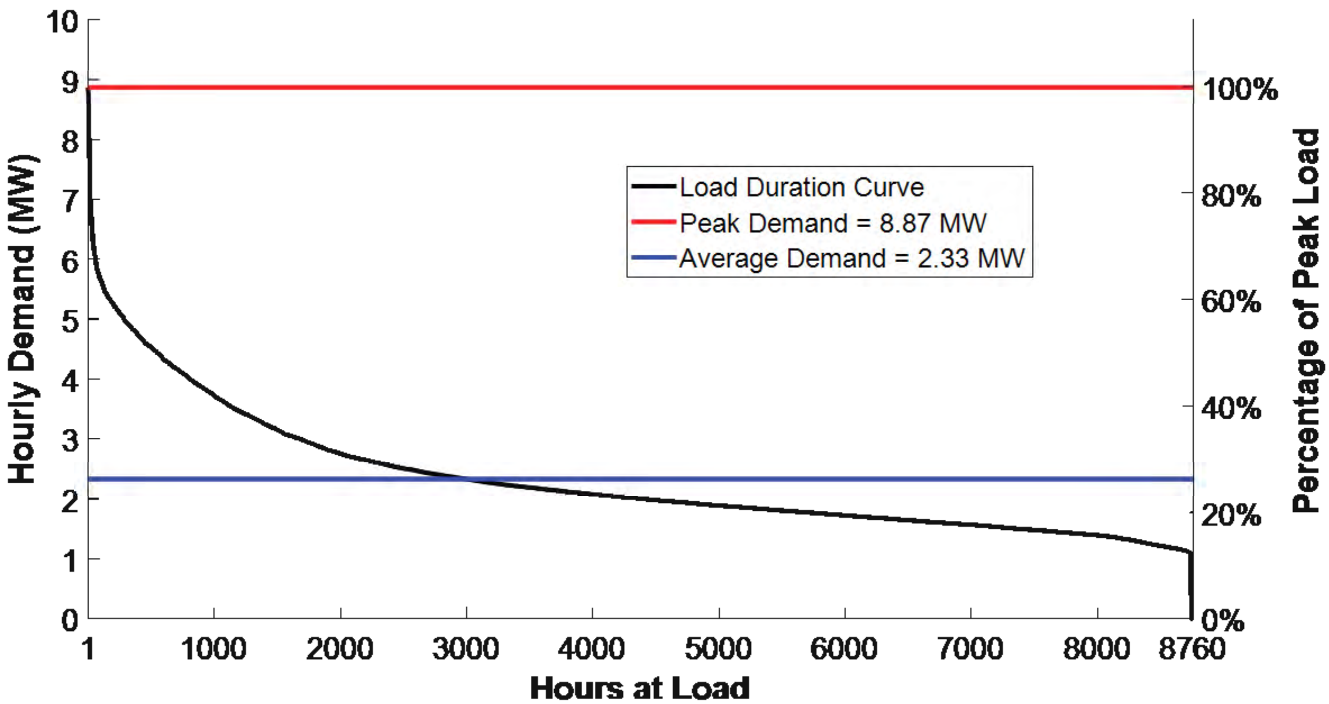
Figure 2: Five-Minute Electric Demand ("Load") for Highland 1103



[7] Data as of December 31, 2017. Includes pro-rata share of indirect or jointly owned assets.

Figure 3 displays average hourly electric demand in 2017 on Highland 1103 from highest to lowest in what is known as a load duration curve. The load duration curve shows that in 2017 the highest hourly load was 8.9 MW, the lowest hourly load was 1.04 MW, and the average hourly load was 2.3 MW. This circuit's load duration curve is typical for a summer peaking system with very high loads occurring in less than 500 hours of the year.

Figure 3: Load Duration Curve for Highland 1103

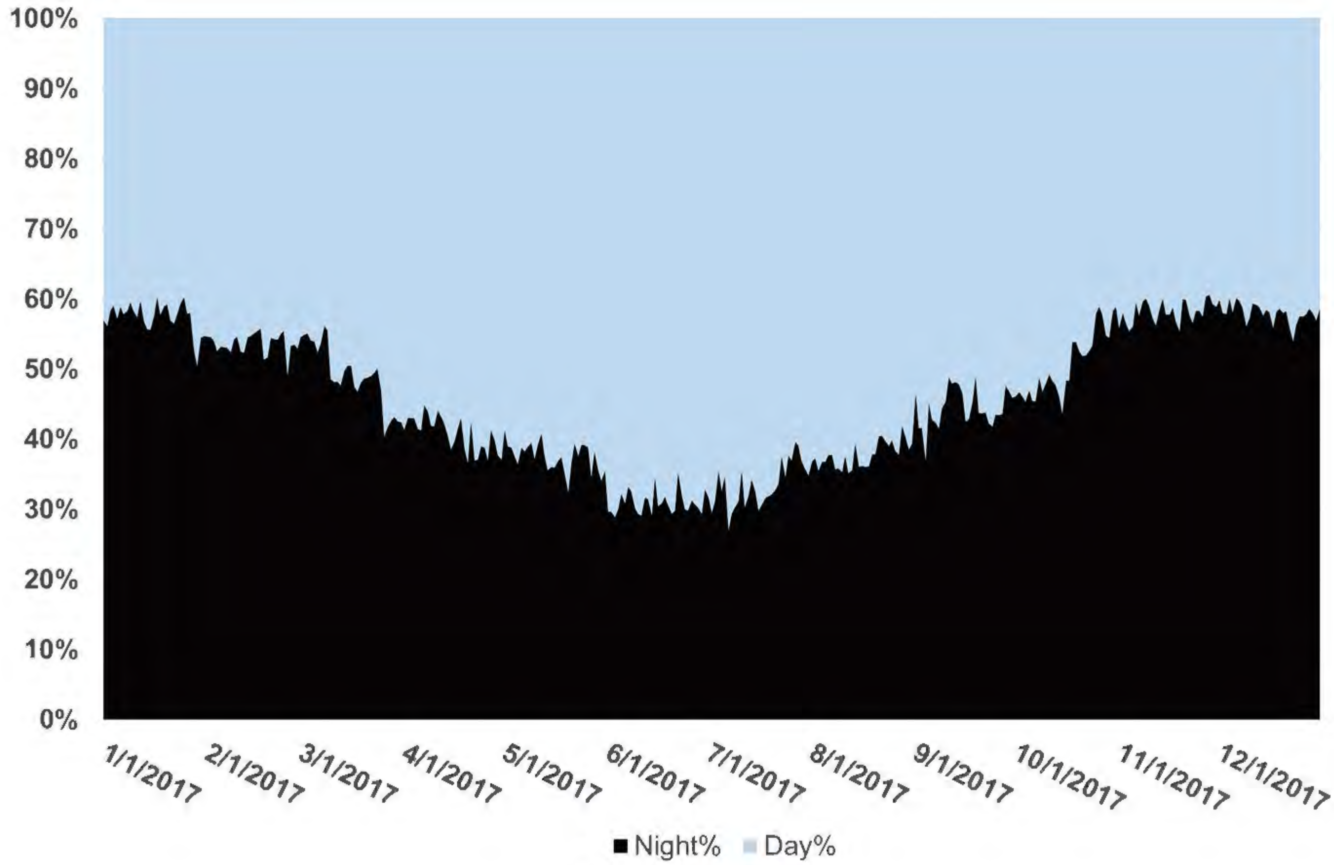


In 2017, base load generation (typically coal and combined cycle natural gas) satisfied the majority of the load shown in the load duration curve, and peaking generation capacity (simple cycle natural gas) served the peaks that only occur for a handful of hours in the year. If this circuit were to be served by 100% local solar generation then solar capacity would be needed to serve the peak hour and an additional amount of solar generation would be required to charge the energy storage required to meet customers' energy needs when the sun is down and on cloudy days. Therefore, much of the solar generation capability will be underutilized for a substantial portion of the year.

To further understand some of the challenges of just using local solar generation and energy storage, it is important to understand how much of Highland 1103 circuit's load occurs during daylight hours and nighttime hours. As shown in Figure 4, despite customers on this circuit predominately using natural gas for space heating, over 50 percent of their electricity is used during the night in winter months. Their usage at night decreases to around 35 percent to 40 percent in summer months as longer days and daytime air conditioning load increases the share of electricity used when the sun is up. Regardless of the season, the customers on this circuit use a substantial amount of energy when the sun is down, energy that must be stored in batteries.[8]

[8] The day/night energy profile of this circuit is comparable to the profile of the entire LG&E and KU system. See Figure 8 in PPL Corporation Climate Assessment at https://www.pplweb.com/wp-content/uploads/2017/12/Climate-Assessment-Report.pdf

Figure 4: Proportion of Energy Consumed during Daylight and Nighttime Hours for Highland 1103



Evaluation Methodology

This case study uses actual five-minute load for 2017 from Highland 1103 and actual five-minute solar irradiance data measured from a NOAA weather station located in Versailles, KY. While the solar irradiance data is from a site that is about 50 miles from Highland 1103, it is representative of regional solar conditions that are adequate for this high-level case study. In general, it should be noted that this is a high-level conceptual study and is not meant to represent a final or optimal engineering or economic design. To design and size the equipment for an actual "off-the-grid" project would require additional analysis and engineering associated with issues such as, but not limited to, load diversity over time, motor starting/stall currents, fault current sources, protection, and over/under voltage risks. Table 1 shows the major assumptions used in preparing this case study.

Table 1: Major Assumptions for Case Study

	Assumption	Low Range	High Range
Utility-scale solar	$/kW installed[9]	810 (installed in 2030)	951 (installed in 2020)
	Annual capacity factor	~17% on average	
	Land requirement — acres / MW	3.2 Acres/MW (DC), 3.84 Acres/MW (AC)	
	Useful life of panels	25 years	30 years
	Useful life of inverters	10 years	20 years
Roof-mounted solar	$/kW installed[9]	1,493 (2030 Dollars)	2,306 (2020 Dollars)
	Average system size (per roof)	5 kW	15 kW
	Annual capacity factor	~17% on average	
	Space requirement — sq. ft./kW	~60 ft^2/kW (DC), 72 ft^2/kW (AC)	
	Useful life of panels	25 years	30 years
	Useful life of inverters	10 years	20 years
Utility scale Li-ion storage	$/kWh installed[9]	327 (installed in 2030)	435 (installed in 2020)
	Peak energy delivery — kW	1,000 kW	
	Energy storage — kWh	4,000 kWh	
	Battery size	0.015 Acres/MWh[10]	
	Useful life	10 years	15 years
In home Li-ion storage	$/kWh installed[9]	476 (installed in 2030)	634 (installed in 2020)
	Peak energy delivery — kW	5 kW (RS)	15 kW (GS)
	Energy storage — kWh	13.5 kWh (RS)	40.5 kWh (GS)
	Battery size	~9.5 ft2 per 13.5 kWh[11]	
	Useful life	10 years	15 years
Average retail rate in 2017 — cents/kWh	Residential	10.90 cents/kWh	
	Commercial	9.28 cents/kWh	
Distribution-only rate in 2018 — cent/kWh	Residential	25% of average retail rate	
	Commercial	26% of average retail rate	
Future retail rate escalation		2%	5%
Cost of Capital		4.40% (100% Debt Financing)	7.58% (Utility Cost of Capital)

When considering utility scale energy storage applications, it is important to be aware of its size and proximity to other structures. Employing the large number of batteries that would be necessary for these cases will require a keen attention to location, spacing, and fire mitigation strategies.[12] Figure 5 shows a typical utility-scale lithium-ion battery site with a 30 MW, 120 MWh (4 hours at peak discharge rate) energy storage system consisting of twenty-four 40-foot containers and a dedicated switchgear/control room, which is much smaller than the system needed for this circuit.

[9] Source: NREL's 2018 ATB (https://atb.nrel.gov/).

[10] Includes spacing required per fire codes, inverter footprint, and associated electrical infrastructure. Assumed 2400 ft2 for 1 MW, 4 MWh block.

[11] Residential and small commercial energy storage is typically wall-mount. 9.5 ft2 indicates wall space required. Actual footprint is dependent on local fire and building codes.

[12] "Big Battery Boom Hits Another Roadblock: Fire-Fearing Cities" https://www.bloomberg.com/news/articles/2018-05-18/the-big-battery-boom-hits-another-roadblock-fire-fearing-cities

Figure 5: Typical 30 MW, 120 MWh Lithium-Ion Energy Storage Site[13]

For all cases analyzed in this study, it is assumed that LG&E's distribution system costs will be included since the system is being relied upon to deliver solar energy to end-users and charge batteries. Other than escalation uncertainty, these costs are the same across all cases and do not drive differences. Also, this case study does not address potential stranded generation and transmission system costs that would be associated with a larger system-wide study.

The study assessed the cost of investments based on i) LG&E's cost of capital and ii) the cost of 100% debt financing. As identified in the "Potential Issues" section below, there are a number of possible ways that behind-the-meter rooftop and storage investments might be financed if owned by the property owner as well as some legislative and regulatory changes that could impact how utility system solar and storage might be owned and financed. This case study is focused on the scope and scale of the technology investments required to be 100% renewables and off-the-grid, not on the financial engineering of specific cases.

This study looks only at the 5-minute load profile from 2017. It does not address how future changes in load or load shape might impact system sizing and cost. For example, weather patterns could alter hourly and daily load shape and energy and widespread charging of electric vehicles would impact both the amount of electricity consumed as well as the daily load shape. Similarly, no assumption is made regarding future rate design or direct load control that might attempt to alter the load shape and the quantity of energy consumed. Lastly, no material change is assumed in natural gas utilization in the homes and businesses on this circuit that would impact electrical load.

Alternative Technology Solutions

Through initial modeling using the Highland 1103 circuit's 5-minute load and corresponding weather measured in 2017, it was determined that 75 MW (AC) of photovoltaic solar accompanied by 300 MWh of energy storage would be required to satisfy 100% of all electric demand in 2017 on this distribution circuit. This study assumes no equipment failures and zero generation capacity margin (for potential load changes), both of which would need to be considered for an actual sizing study. Figure 6 and Figure 7 show estimated solar production overlaid with electrical demand for representative winter and summer weeks. These figures show the variability in solar production day to day as well as by season and illustrate the need for such large solar and energy storage systems for this distribution circuit. A large solar and battery system is required in order to remain off grid during the winter, when there are fewer daylight hours, skies are more frequently overcast, the sun doesn't shine as brightly in the sky, and the majority of electricity demand occurs during the night. During the summertime, however, generation from this same system will exceed the neighborhood's electricity needs. When solar generation exceeds electric demand, the excess energy will be stored in batteries to be used to meet electricity requirements when solar generation is inadequate.

[13] Source: San Diego Gas & Electric.

Figure 6: Representative Week in January 2017 Showing Solar Generation and Electric Demand

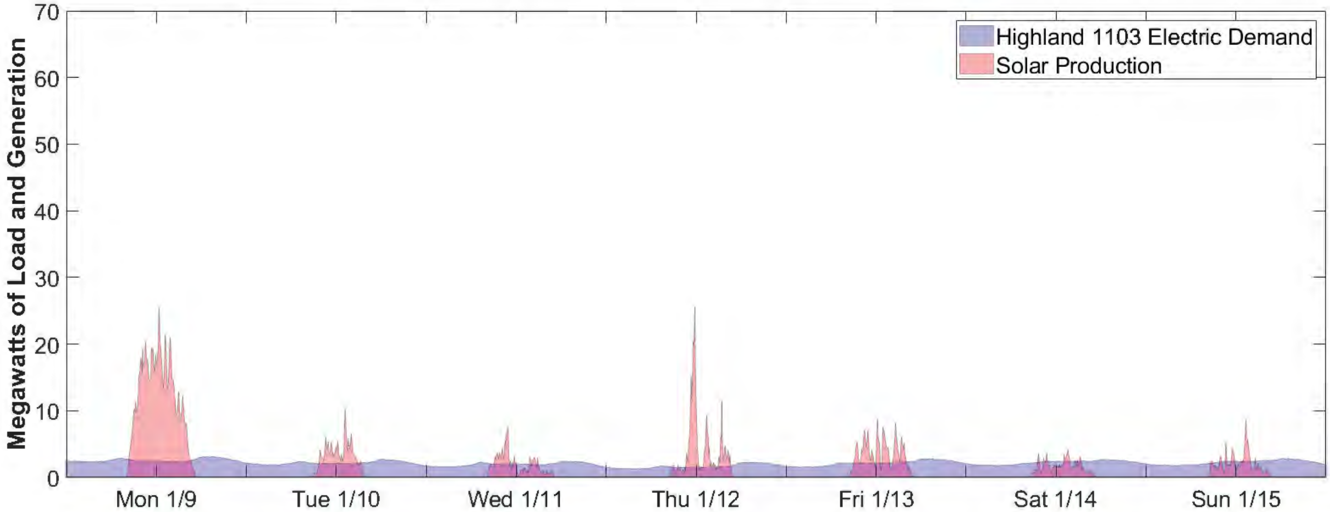
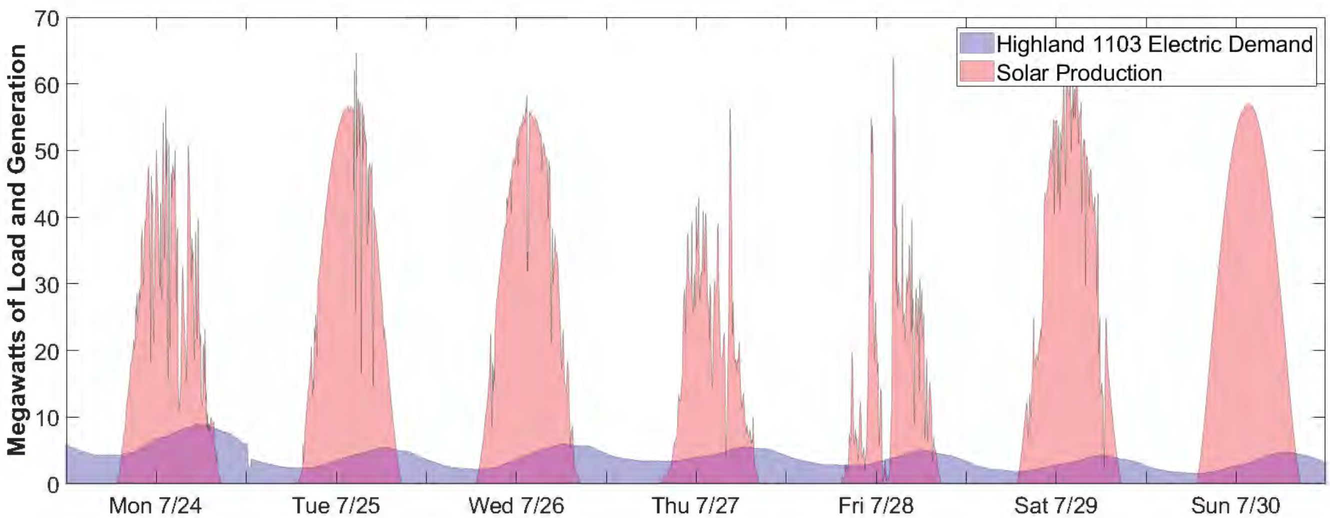


Figure 7: Representative Week in July 2017 Showing Solar Generation and Electric Demand



The study assumed each residential customer on the Highland 1103 circuit could install up to 5 kW of solar and up to 13.5 kWh of battery storage at their homes; non-residential customers were assumed to install up to 15 kW of solar and up to 40.5 kWh of battery storage. The range of results for the quantity of solar and storage technology is shown in Table 2. Note that the quantity of the required utility-scale battery storage is approximately two times the size of the typical storage facility shown in Figure 5.

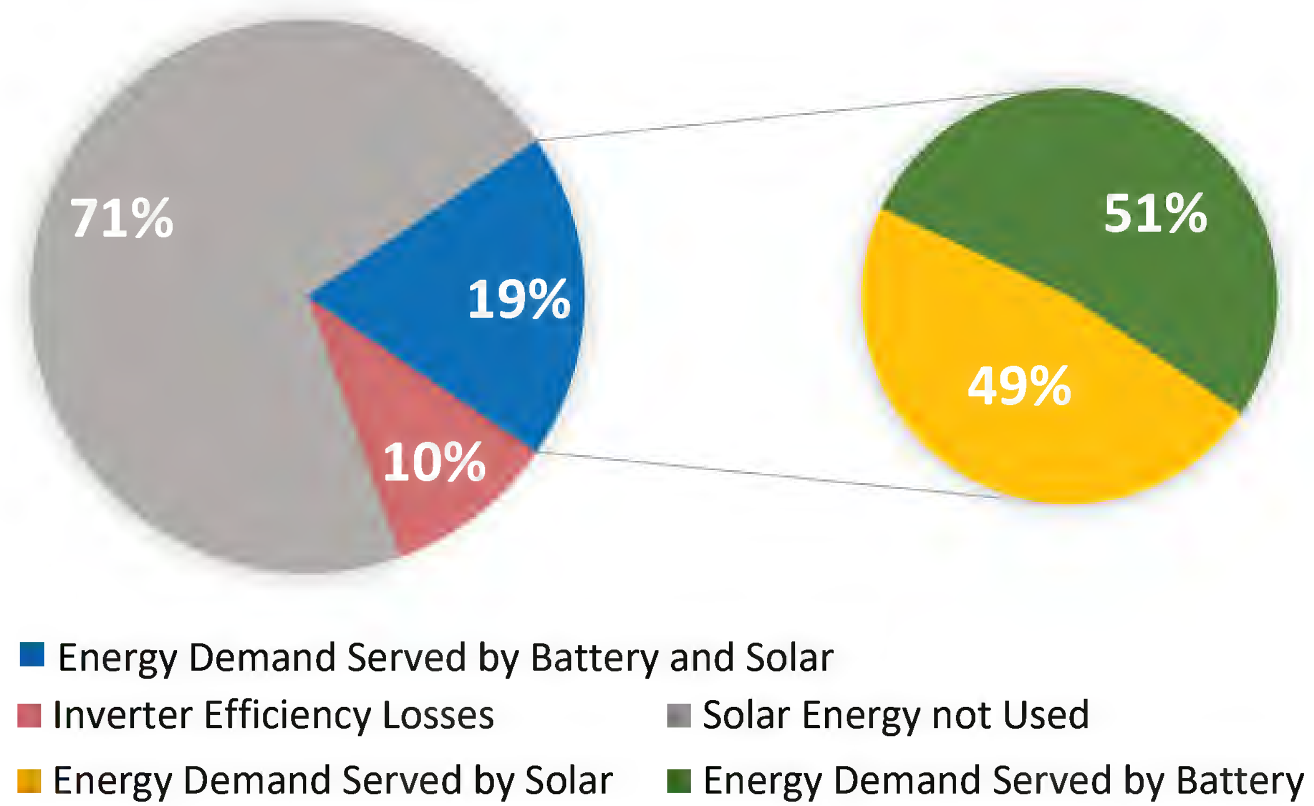
Table 2: Rooftop Solar/In-Home Storage Scenarios

% of Potential Rooftop Solar and In-Home Storage Capacity	Quantity of Solar and Battery Storage				Land Area Required for Utility-Scale Infrastructure (Acres)	Total Capital Cost $(millions)	
	Rooftop Solar (MW)	In-Home Storage (MWh)	Utility-Scale Solar (MW)	Utility-Scale Storage (MWh)		Nominal Cost in 2020	Nominal Cost in 2030
0%	0	0	75	300	293	202	159
50%	6	16	69	284	270	213	165
100%	12	32	63	268	246	224	172

Even assuming every home and business installs solar panels and storage, there is still a large need for utility scale solar generation and storage. In fact, the degree of home and business rooftop solar has a very limited impact on the quantity of utility scale solar required to reliably meet the circuit's energy needs. However, it does reduce the utility-scale infrastructure footprint by almost 50 acres which could be important in land constrained areas like Highland 1103.

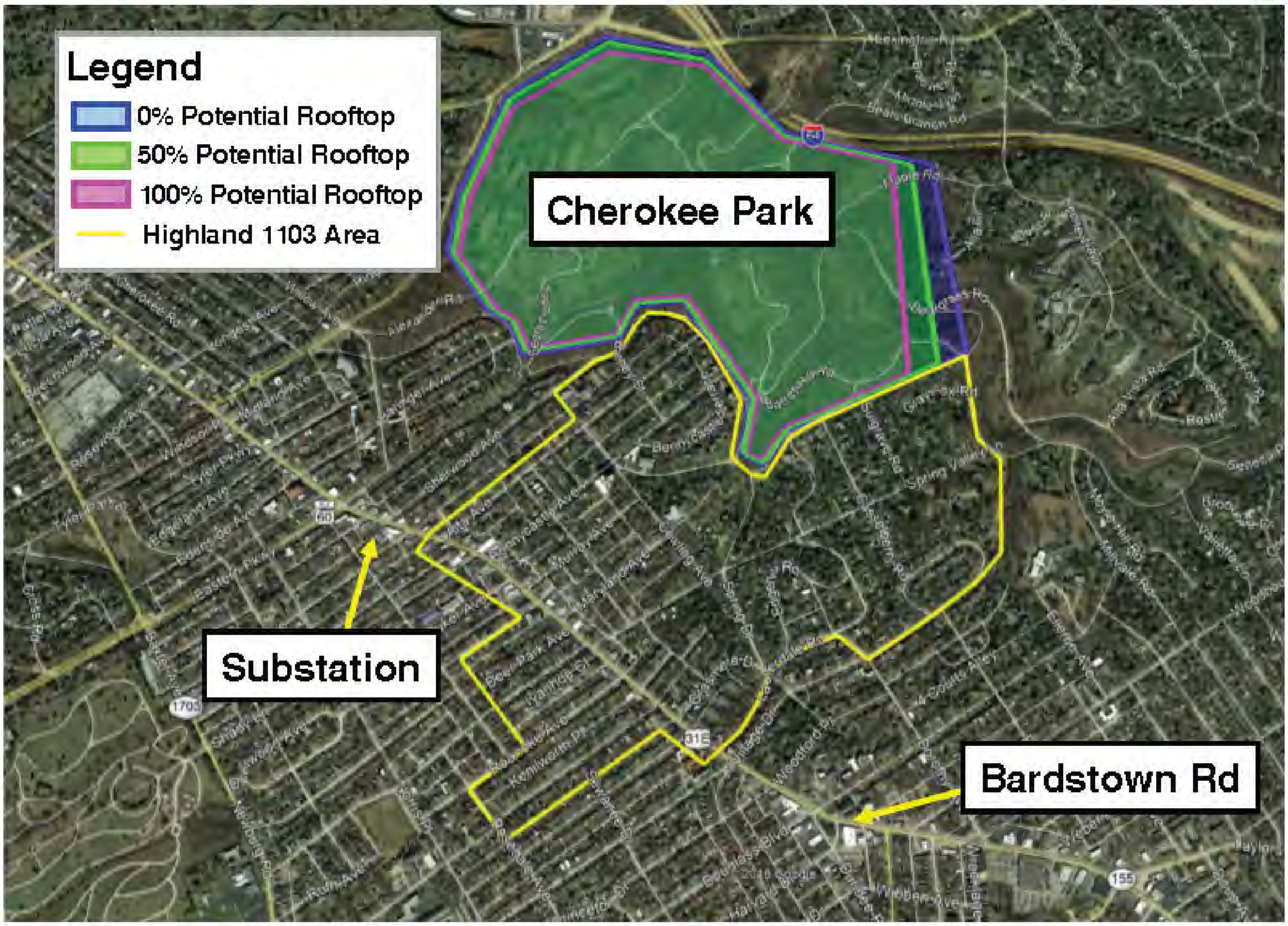
As shown in Table 2, approximately 75 MW of solar generating capacity is required to store sufficient energy to serve load during the winter when nights are longer and clouds are more prevalent. This capacity is approximately eight times larger than Highland 1103's summer peak of around 9 MW. This excess capacity can produce far more energy annually than is required to serve the customers' energy needs. In fact, as shown in Figure 8, approximately 71 percent of the potential solar energy would be unused. Figure 8 also shows that approximately 49 percent of the circuit's electricity would be generated directly by the solar panels with the remainder coming from storage. With so much energy flowing through storage, approximately 10 percent of solar generation would be consumed by inverter losses.

Figure 8: Distribution of Solar Energy Production



Because the interest in distributed solar and storage is often described in terms of local economic impact and reduced need for investment in transmission assets, it is important to understand the space requirements associated with isolating Highlands 1103 from the grid. Figure 9 shows the range of geographic space requirements for the three rooftop solar/in-home storage scenarios. The space required for the utility-scale facilities is large, even in the best-case use of rooftop solar/in-home storage. For this particular circuit, the only large vacant land area contiguous to the Highland 1103 circuit is Cherokee Park. LG&E is not recommending using the park in this manner but placing utility scale solar in other areas still impacts land use and would require additional electric lines to connect the facilities to this particular circuit. These costs are not included in this study.

Figure 9: Representative Land Use Required for Utility-Scale Solar and Battery Storage



Cost Comparison of Solar/Storage Cases to Remaining Connected to the Grid

Each of the rooftop solar with in-home storage scenarios in Table 2 were evaluated based on both LG&E's cost of capital (7.58%) as well as the cost of 100% debt financing (4.40%). The study was performed using NREL's cost forecasts for 2020 and 2030, which show continued future declines in both solar and energy storage costs.[14] In this study, the solar and battery storage systems were evaluated in a very favorable light. For example, all assets were assumed to have a useful life of 30 years, fixed operating costs for the solar and battery systems were ignored, and an inflation rate of zero percent was used to estimate nominal solar and battery storage costs in 2020 and 2030 from NREL's forecast. These and other assumptions are optimistic for the solar with storage concept (see "Favorability of Major Assumptions" for further discussion).

[14] NREL expects the costs of solar and battery storage to decline from 2020 to 2030 by 1.6% per year and 2.8% per year, respectively, in real terms.

In order to compare the cost of using 100% solar and storage to serve the electric load on the Highland 1103 circuit, the investments in solar and storage were levelized over 30 years and added to an estimate of the costs of maintaining and operating the existing distribution system that would still be required to serve load. These costs were then compared to a range of possible future costs of continuing to receive energy from the LG&E system. Note that the range of possible future LG&E costs are not predictions of future electricity prices but are meant to capture a range of possible future price paths over the next 30 years for comparing to the solar/storage off-grid cases.

Table 3 shows the levelized cost of electricity of serving the Highland 1103 load for all of the cases evaluated. These costs exclude the costs of operating and maintain the distribution system that would still be required. Not surprisingly, cases with a higher cost of capital have a higher levelized cost of electricity. The cases with rooftop solar and in-home battery storage require less land for utility infrastructure but are more expensive. Finally, the cost of installing the solar and battery systems in 2030 is less expensive than in 2020 due to the forecast of decreasing solar and battery storage costs.

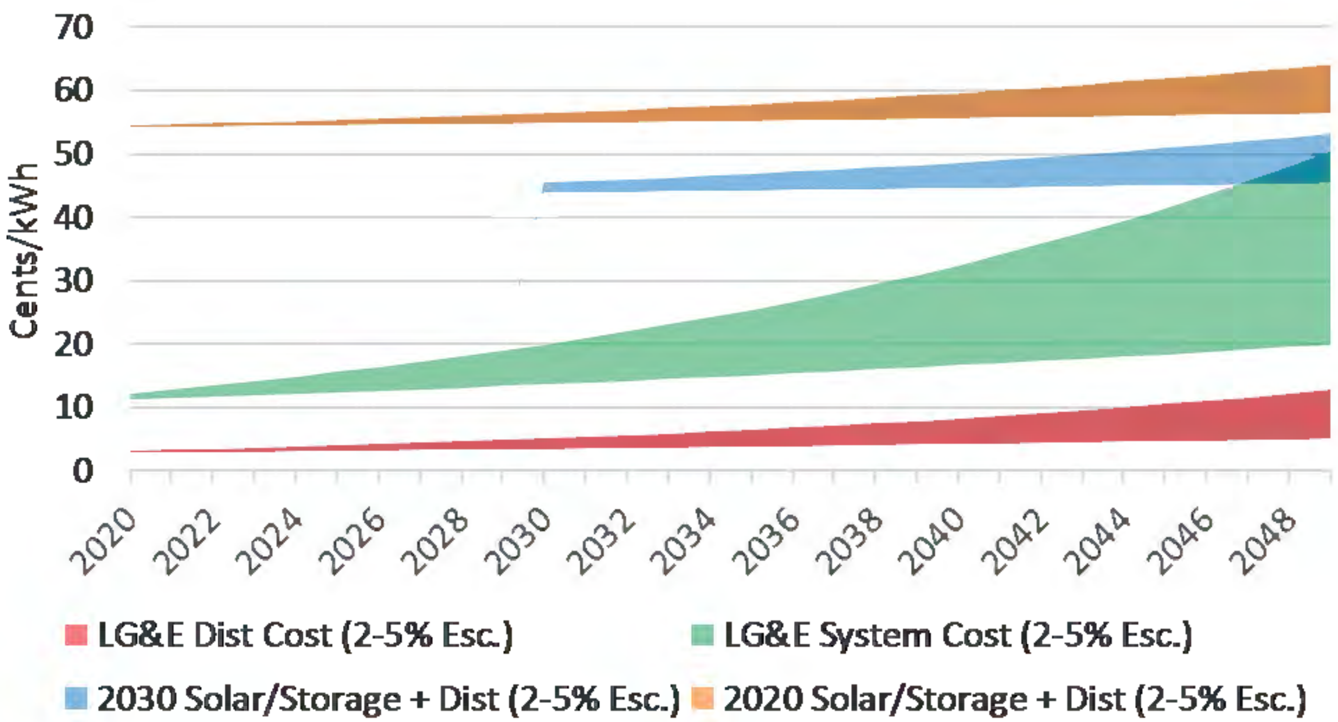
Table 3: Levelized Cost of Electricity excluding Distribution System Costs

Commission Year	Cost of Capital	% of Potential Rooftop Solar and In-Home Storage Capacity	Solar & Battery Storage System Cost Levelized Cost of Energy (cents/kWh)
2020	7.58%	0%	79.2
		50%	83.2
		100%	87.1
	4.40%	0%	51.4
		50%	54.0
		100%	56.6
2030	7.58%	0%	62.2
		50%	64.5
		100%	66.8
	4.40%	0%	40.4
		50%	41.9
		100%	43.3

Adding the cost of maintaining the distribution grid to the best 2020 and 2030 cases from Table 3 allows the comparison to a range of rate paths for staying on the existing LG&E grid. Figure 10 contains a range of rate paths for the LG&E distribution system in red and the entire LG&E system in green.[15] The ranges were created by escalating actual 2017 costs by 2 percent and 5 percent. The total costs for the best 2020 and 2030 cases were created by adding the range of distribution costs to the levelized costs in Table 3. This cost reflects the average cost of electricity for all customers on the Highland 1103 circuit.

[15] LG&E distribution system costs are assumed to grow proportionally with LG&E system costs.

Figure 10: Total Solar/Battery Storage Cost versus LG&E System Cost



As shown in Figure 10, the cost of isolating the Highland 1103 circuit from the grid and serving its electricity requirements with solar and battery storage is 2.5 to 3.5 times greater in 2030 than the LG&E system. Assuming LG&E's rates were to escalate at 5 percent annually, then it is possible that a solar and battery storage system installed in 2030 might be less expensive by the late 2040s. It should be noted that since 1990, LG&E average electricity rates have increased at an average rate of about 2.1 percent meaning that future rates would have to escalate at more than twice the historical rate in order for the solar and storage system to be even plausibly economical. The study also shows that with both solar generation and battery storage costs forecasted to decline, waiting as long as possible to make such investments would increase the probability of being economical compared to the LG&E system rates.

Favorability of Major Assumptions

In preparing the financial analysis for this study, a number of the operational and technology performance parameters were assumed to be favorable toward reducing the cost of using 100% solar generation and energy storage to serve Highland 1103. For example:

- The financial results presented assumed all panels, inverters, and batteries perform perfectly for 30 years. Based on what we know today, inverters and batteries are likely to have much shorter lives.
- The solar panels and battery storage were sized to exactly match 2017 actual load. Some contingency would need to be built in order to address load uncertainty and random equipment failure.
- No land cost was assumed for the utility scale solar generation and battery storage.

While recognizing that there would be incremental costs associated with addressing these issues in an actual project design, these items are also more uncertain and subject to change over time. Because the purpose of this case study was to evaluate the local solar generation and storage concept at a high-level, the Company did not want to distract from the study's fundamental purpose by explicitly trying to incorporate costs to address these issues.

Potential Issues Identified in Preparing this Case Study

As stated at the outset, this case study is a high-level analysis of the technology and financial implications associated with serving the load on a single LG&E distribution circuit. One of the benefits of preparing such a study is that it identified a number of issues and questions that a more detailed study would certainly need to address should such a project ever be considered in the future. Like this study, the questions and issues identified below are not meant to be exhaustive.

1. This study assumed that all roof-top solar and in-home storage was built overnight. In the real world, that would not occur so provisions (technical and financial) would need to be made to address changes (both increases and decreases) in the quantity of roof-top solar and in-home storage over time.

2. It was assumed that load (energy and shape) would be rather stable over 20 years. Provisions (technology and financial) would need to be put in place among the customers on the circuit to deal with material changes in load and load shape that would impact asset utilization and possibly cost recovery and future asset investment. Because the costs of this off-grid system are for all practical purposes fixed, changes in energy usage would not materially impact costs but could result in over- or under-collection of fixed costs. For example, unless load is forecasted to grow (say due to increased market penetration of electric vehicles or converting from natural gas to electric space heating), the economics of energy efficiency may not reduce overall costs but instead only shift fixed costs to other customers on the circuit depending on rate design.

3. Once such a system is created, the ability to undo it in the future may be limited or very expensive, so exit costs should be considered.

4. It was assumed for purposes of this study that all assets are owned and financed by LG&E but that may not have to be the case, particularly for roof-top solar and in-home storage. Some legal and regulatory issues would have to be addressed in this new type of system.

5. Because all assets were assumed to be owned and financed by LG&E there was no need to address compensation to individuals who invest their own funds in rooftop solar and in-house storage. However, in reality, it is highly likely that individual homeowners and business would invest their own funds and would seek compensation for contributions to supporting the circuit's load.

Conclusion

The declining cost of solar generation and projections of future cost declines for battery storage along with increasing focus on CO_2 emissions have raised the interest of both customers and utilities identifying opportunities to deploy these technologies. To date, the vast majority of applications of these technologies have focused on applications that still require connection to the national power grid, a grid that today relies heavily on fossil fuel resources to reliably meet customers' real time electricity needs. This study was a valuable exercise in identifying and evaluating the numerous technological, economic, land use, and transitional challenges that must be met in the future in order to scale solar and storage to the levels required to meet a sizable proportion of the nation's electricity needs.

__The report was prepared by staff from the following departments at LG&E and KU Energy: Electrical Engineering & Planning, Technology Research & Analysis, Generation Planning, and Sales Analysis & Forecasting.__