TECHNICAL BRIEF

Procuring Services from Distributed Energy Resources

Part 3 – Distribution Feeder Simulations to Analyze Technical and Market Offer Impacts of DER Grid Services

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FEEDERS AND STUDY METHOD

Application of the proposed electricity market coordination methods described in the previous technical briefs can be validated by performing power flow simulations of sample feeders provided by the utility. This allows measurement of key factors at baseline load levels like overall demand, losses, feeder operating voltages. Then, DER is added to the model in specific volume, size and type of technology to determine the feasibility and impacts of DER providing grid services for both the feeder and for the bulk grid at the T-D interface. This paper briefly describes the feeders and study method used, some example simulation results, and key overall findings. It also describes how observing DER feeder impacts can be used to adjust electricity market offers. Readers can find other simulation examples and findings in the more detailed version of the report.

A selection of feeders is provided by the utility and studied at three load levels (peak, average and minimum), as separate snapshot power flow studies. Power flow magnitudes used were selected from metered time-series data per feeder. These illustrate the power flow exchanged at the T-D interface in baseline conditions. Then, each of the project scenarios are simulated with DER elements added to provide grid services, observing their impact on the grid, using some or all of a set of metrics identified to determine either success of services provided or operating thresholds exceeded.

The utility selected eight (8) feeder models from the York region that represent a variety of total feeder demand, presence of existing small DER, and even a few large DERs that already participate in the wholesale electricity markets. Each of the utility feeders are operated at the 27.6 kV voltage class. In addition, the project scope included study of the IEEE 34-bus test feeder and the IEEE 342-Node secondary network feeder models are included in simulations. This is intended to represent feeder compositions that have other and unique challenges than those found using typical Alectra feeder design and operating conditions. The IEEE 34-bus feeder is operated at 24.9 kV, and the IEEE 342-Node secondary networks model (which itself consists of eight (8) feeders) is run at 13.8 kV, with a 115kV source.

Table 1. *Feeder model characteristics*

FEEDER	PEAK AMPS	AVERAGE AMPS	MIN AMPS	PEAK MW	AVERAGE MW	MIN MW	CONNECTED DER MW
1	434	235	156	19.7	11.2	7.2	0.5
2	451	141	32	20.7	6.8	1.5	2.8
3*	431	228	35	20.8	10.9	1.7	0.4
4	438	157	40	19.9	7.5	1.9	1.1
5	424	157	85	19.0	7.5	4.1	0.25
6*	432	165	82	19.6	7.9	3.9	0.7
7	439	174	76	19.8	8.3	3.6	0.2
8	466	155	77	21.1	7.4	3.7	0.7
9 (IEEE 34)	47	28	19	2.1	1.2	0.8	0.0
10 (IEEE 342)	125	75	50	42.8	25.8	17.2	0.0

**Asterisks indicate feeders that currently host DER that participate in the wholesale electricity markets.*

The impact of DER at the T-D interface is evaluated on the following metrics and conditions.

- Change in total net load with added DER (amps and watts)
- Overall feeder losses
- Maximum and minimum operating voltage
- Success or failure to provide distribution and bulk services
- Challenges with using the DER (feeder operating conditions)
- Changes in power flow under contingencies

Note, any existing DER on the feeders is solar PV and considered non-dispatchable for providing grid services, as they are dependent on weather patterns, so additional DER of another technology is always needed for simulation purposes. The power production of those solar facilities is assumed to be 20% of nameplate capacity at peak load conditions and 100% of capacity for minimum and average load conditions, to capture the full range of possible feeder behaviors at baseline. This is the same reasoning for not including wind power in this list of "dispatchable" generation. This is not to imply solar or wind DER cannot provide grid services, rather this project simply focused on more controllable types of DER technology, per requested scope requirements.

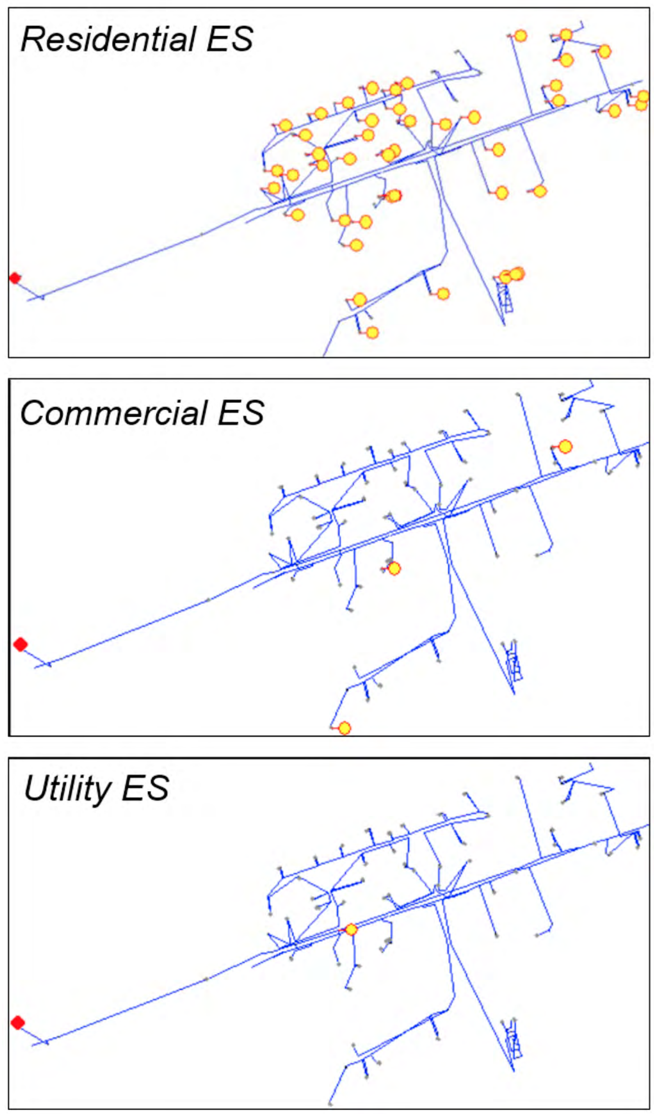

Figure 1. *Sample method of allocating energy storage (ES) on Feeder 1*

When DER elements are added to the feeder, the following types of technology are considered:

- Utility-scale energy storage
- Commercial-scale energy storage
- Residential-scale energy storage
- Utility-scale natural gas generator
- Commercial-scale natural gas generator
- Residential smart thermostats
- Commercial & Industrial Demand Response

Figure 1 illustrates how DER may be allocated across a feeder for these simulations. It shows each of the scales of energy storage (ES) DER. This allocation is similarly applied to other DER technologies. Most images and discussion in the rest of this report will focus on energy storage, but static power flow studies can find very similar results regardless of actual DER technology used, focusing mainly on actual power output.

The current practice at the utility is to develop distribution system upgrade plans for any feeder exceeding 400 Amps total load. Each feeder in this study slightly or moderately exceeds this limit, providing an opportunity for DER to relieve some of the load as a service (in relevant scenarios).

The project simulations assume a few very important things about DER model additions and their capabilities.

- All DER is added downstream of feeder constraints (aka congestion). Varying DER unit sizes and fleet count are added to represent and compare impacts of equivalent amounts of DER.
- DER added for these studies are all controllable to provide desired output as needed.
- For simplicity in modeling DER output magnitudes for different scenarios and grid services, all DER will use a "flexible interconnection agreement" (see detailed report for more information).
- Utility-scale or commercial-scale DER element locations are selected manually, relative to feeder constraint locations and presence of large electric customers.
- An automated allocation method is used for locating residential-scale DER in each feeder model. This targets a percentage of load elements with small demand, spreading the aggregate MW size needed for DER services across those identified sites.

MODELING SAMPLES TO ILLUSTRATE TECHNICAL FINDINGS PER SCENARIO

This section includes notable results from feeder simulations to show the effects of DER for different scenarios. They highlight the technical effects seen on the feeder whenever the agreed upon DER magnitudes have been identified and dispatched.

Scenario 1 – Transmission Energy Dispatch

In the first scenario, a very simple interaction between DER and the wholesale market is investigated. The DER (in this case, energy storage) is dispatched without regard to any distribution constraint, to simply review what the effect of the added DER providing wholesale energy services is on the power exchanged at the T-D interface.

Feeder 1, as shown in Figure 1, has a 19.7 MW peak demand, yet there are very low losses on the feeder (~190 kW), even without any DER added. The addition of large amounts of DER can directly affect overall demand, but the change in losses is not substantial, compared to the total load. For instance, introducing as much as 5 MW of DER only reduced total losses by about 60 kW, at most. Most of the Alectra feeders have similar performance, in terms of the impact on losses. Relative to either the baseline case or significant DER added for grid services, Feeder 1 has just under 1% losses. However, considering the IEEE 34-bus feeder, it only serves 2 MW of demand, but the losses reach up to 0.28 MW, which is about 13.6% compared to peak load. This feeder is longer with some smaller wires and can see over 200 kW reduction in losses (about 70% reduction) when a 1.3 MW DER is added.

These results show that DERs, when dispatched to provide wholesale services, can deliver the scheduled energy plus additional benefits in the form of avoided losses. For most feeders studied, the additional benefits were not material (such as the Feeder 1 example). However, in certain cases with less robust feeder design (such as the IEEE 34-bus test feeder), the benefits were more substantial.

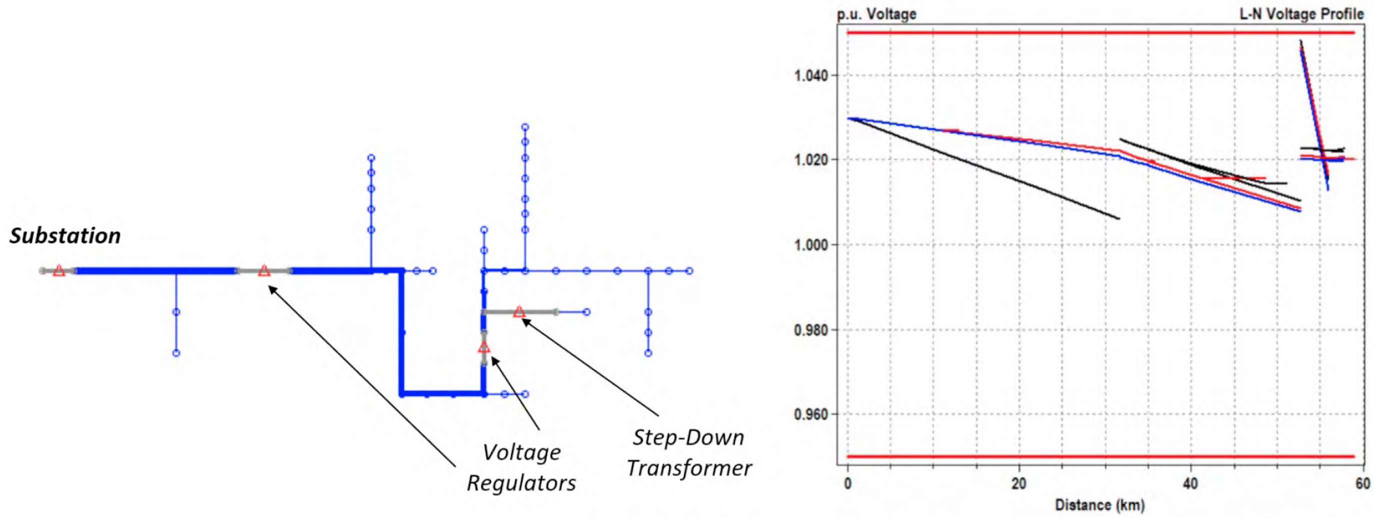

Figure 2. *IEEE 34-bus topography and minimum load voltage profile*

Scenario 2 – Distribution Override

The difference between Scenarios 1 and 2 is that now any direct impact or existing constraint on the distribution system is considered, rather than simply comparing power magnitude changes at the T-D interface. This scenario identifies any additional coordination needed should the DSO determine the need to override resources to prevent DER-induced distribution system constraints. These simulations only reflect a sample of *conditions* that could potentially drive the need for overrides and not the *frequency* of such conditions.

The IEEE 34-bus test feeder experiences voltage challenges in baseline conditions. It contains two sets of voltage regulators to keep operating conditions within limits, even at a much smaller scale of load. The feeder topography is displayed in Figure 2, along with the voltage profile that occurs at minimum feeder demand.

When DER is added to this feeder (1.3 MW) for market participation, at minimum load conditions, each "zone" of the feeder between regulators experiences an overvoltage, if the regulators do not have any adjustment given to their settings. In this use case, the DSO will need to override the DER output to a fraction of total output (0.7 MW) to bring voltages back within acceptable operating ranges. It highlights the need for alignment between the DSO, ISO, and DER in all conditions throughout the year, not simply at peak demand times.

Scenario 3 – Distribution Import-Congestion

This new scenario begins to explore how DER can provide both distribution and bulk grid services, specifically for relieving thermal load congestion. Feeder 8 is used to demonstrate DER for distribution congestion relief. This feeder has two main areas or "pockets" of load with a total load of 21.1 MW, which is about 466 Amps. For the congestion relief studies, the DER must be able to reduce element loading below the planning threshold of 400 Amps. In this case, it's about 17% load reduction required. The study finds that 3.5 MW of DER is needed to achieve that change, for any DER scale (residential, commercial, utility). For perspective, the feeder has 87 residential-scale transformers. If it is assumed these transformers serve between 4 to 10 homes, and half the homes have DER, that would translate to each DER being sized between 8 to 20 kW, which is not realistic compared to currently offered typical sizes between 1 to 5 kW. The feeder element topography and loading are shown in Figure 3, before energy storage is added.

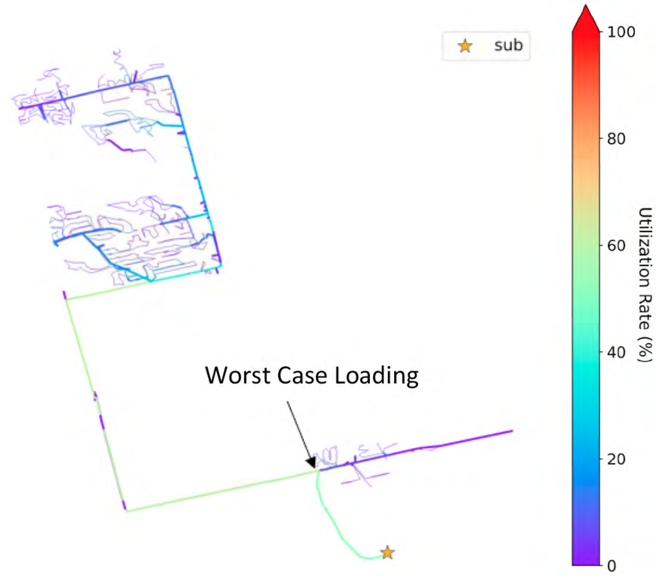

__Figure 3.__ Heat map of feeder 8 displaying feederelement loading

If this magnitude is increased by another 3 MW to provide bulk grid services,[1] commercial-scale storage in some locations on this feeder begin to overload the service transformers. Residential and utility storage can provide bulk grid services without this concern. Utility scale storage further reduces feeder element thermal loading to 70%. Residential storage output when used for bulk grid services increases reverse flow through transformers, but it does not create thermal loading issues. It's unlikely, though, that connecting an aggregate of 6.5 MW of purely residential storage would be feasible for a single feeder. Given the same calculations earlier, but for larger aggregate DER size, this would probably require each DER to be about 15 to 38 kW each.

Results of the Feeder 8 study show DER can be placed and sized to provide both distribution and bulk system services. However, using either commercial or residential DER likely requires either a higher volume of each type of electric customer to connect these DER, or some mix of each DER scale to achieve successful participation in bulk grid services. Also, note that this has a specific correlation to appropriate DER sizing limited to an individual feeder rather than aggregated DER across a broader area.

1 The amount of added capacity does not imply the same magnitude is the minimum increment of DER to participate in market services. This was an arbitrary value chosen to illustrate material feeder behavior changes

Scenario 4 – Distribution Operating Reserves

This unique scenario accounts for grid or service provider interruptions. Backup DERs are contracted and ready to provide distribution services, but specific and likely contingencies have to be identified to plan for appropriate location and size of DER to serve the altered grid. Feeder 2 is used to illustrate how multiple technologies could be used to address heavy loading, and that they could act as reserve for each other. The heavily loaded branch is in the middle left of the feeder (circled), where it branches off of the mainline. This influenced the selection of the commercial and utility-scale DER locations to be sure both that branch and the overall feeder can benefit from the supplied power.

DER of all three scales is allocated across the feeder, but utility and commercial DER options are specifically located in the first load pocket area, downstream of the identified constraint. If utility-scale storage is the primary DER intended to provide congestion relief, and it were to have some failure, either the commercial or residential storage fleet are sized sufficiently that they could provide reserve energy to maintain the committed distribution services. Both the commercial and residential storage allocations could reduce the branch and mainline section loading by about 12% to be within limits.

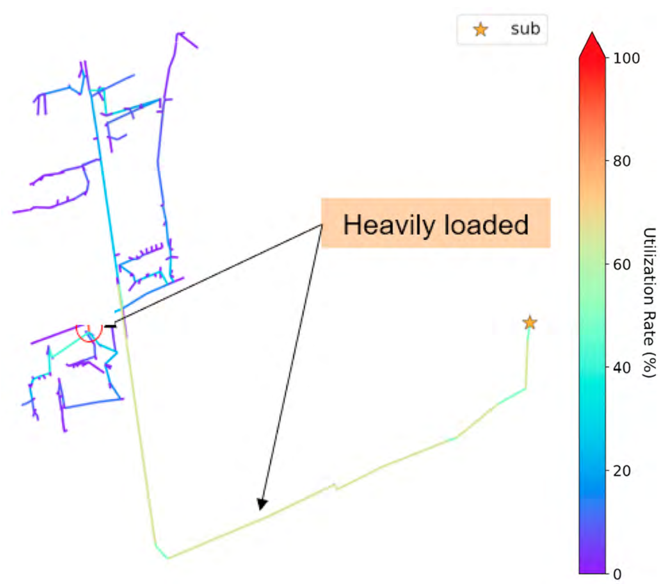

__Figure 4.__ Heat map of feeder 2 displaying feeder element loading

For this feeder, if DER were all expected to increase output by another 3 MW to participate in bulk grid reserves coincident with the distribution constraint, overall feeder loading is reduced further (another 14%) but without creating new thermal or voltage constraints. This shows that purposeful location of DER of any scale can technically provide congestion relief either as the primary or reserve distribution resource, and for some feeders it can also succeed in doing so at the bulk grid level. However, there will be feeder-specific economics and energy output coordination to iron out.

Scenario 5 – Capacity Service

This scenario is an extension of Scenario 3 – Distribution Congestion-Import. The primary difference is that the DER participate in a capacity auction at the bulk grid level, where they bid for and commit capacity to be available at heavy load times of year. This is usually done months in advance of the season of need. This also commits the DER to provide energy offers to wholesale electricity markets in the normal day-ahead and real-time market processes for those periods where the capacity is required.

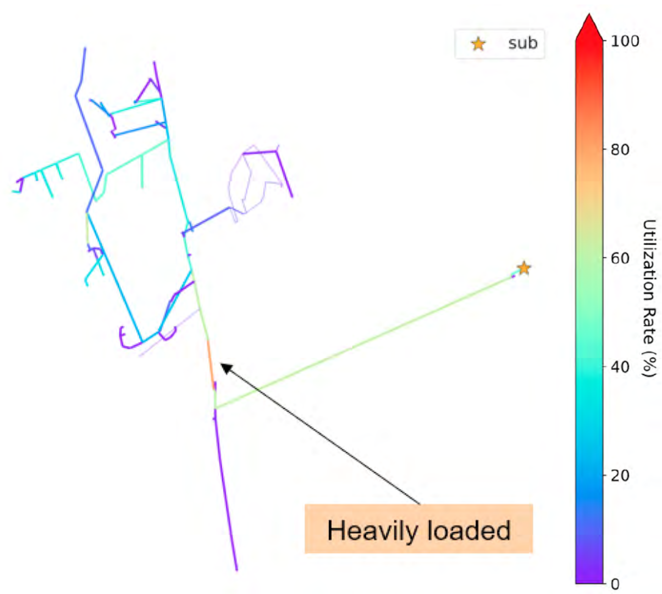

Figure 5. *Heat map of feeder 3 displaying feeder element loading*

From a simulation perspective, the results of these arrangements are highly similar to the results evaluated in Scenario 3. The challenge is identifying specific feeders and DER allocations that will accommodate the committed energy without creating feeder constraints. Feeder 3 was evaluated to consider each of the three scales of energy storage evaluated. Commercial and utility scale storage each can provide distribution capacity and bulk grid capacity without causing constraints. However, the substantial addition of power output from residential-scale storage causes nearly a 20% overload of related feeder elements (e.g., service transformers and nearby distribution lines) when providing both services. Advanced analysis of this feeder would be needed to identify this potential conflict and only commit capacity to the bulk grid if the appropriate scale of DER is added and utilized for capacity. This demonstrates that generally there needs to be either a balance of DER dispatch relative to local load demand, or simply a recognition that it is not reasonable to assume residential DER can always provide substantial energy to the wholesale electricity market if required to successfully provide both distribution and bulk grid services at the single-feeder level.

WHOLESALE MARKET OFFERS FOR DISTRIBUTED ENERGY RESOURCES PROVIDING GRID SERVICES

The participation of Distributed Energy Resources (DERs) in wholesale electricity markets is a developing field with growing interest due to drivers like FERC Order 2222, European initiatives, and Ontario's DER Market Vision and Design Project. Understanding the structure of how DERs issue wholesale market offers is crucial for future participants and market operators alike, accounting for the unique characteristics of DERs. For example, distribution losses and distribution congestion changes caused by the dispatch of DERs in the wholesale market will differ between feeders and impact the economic selection of these resources in a way that does not impact similar technologies on the transmission system participating in wholesale markets. Likewise, the ability for DERs to form heterogenous aggregation consisting of multiple technologies that form as one to the market operator is unique and differentiates a DER aggregator participant from those on the transmission system.

This section briefly outlines the generic format of offers that DERs should provide to the ISO for wholesale market participation. It then focuses on the impact of distribution system losses on DER dispatch for wholesale services which was found to have the greatest unique influence on offer determination and selection of DERs in wholesale markets. Distribution congestions may also be affected by DER dispatch, depending on the distribution system's topology and other factors, but aren't considered in this study.

DER Market Offer Structure

The structure of DERs offers for wholesale markets includes data for the intended market products. This information comprises the offer represented by monotonically increasing price/quantity pairs expressed in [MW, $/MWh]. Depending on the coordination framework (Total DSO or Dual Participation), the ISO receives offers from either the DSO or a DER/DER Aggregator. Also, based on the desired participation model (e.g., electric storage resource, variable generation, conventional generator, or demand response), DERs may need to submit additional parameters. These participation models review technology characteristics but don't necessarily require specific individual DER technologies. Most regions compliant to FERC Order 2222 in the United States allow DERs to choose the participation model that aligns best with their characteristics and strategy from multiple valid options.

Each participant's registered resource type determines the offer parameters they must submit to represent physical and economic factors. Multiple resource types are available, offering flexibility to participating DERs through various registration options. Examples of offer parameters are energy offers, ramp rates, etc. Depending on the chosen participation model, the participant (DER or DSO) must determine parameters that best represent the operating characteristics of the aggregated DERs in the offer. Aggregating parameters can encompass various approaches, such as adding them together (for example, individual energy offers could be combined as separate segments of a multi-segment offer) or employing alternative techniques. In general, these will be dependent on factors such as the types of technology, operating costs, offer strategy etc.

Distribution Losses and Potential Impact on DER Offers to the Wholesale Market

Distribution losses refer to energy lost due to the electrical resistance of distribution lines. The unique characteristic of DERs in wholesale markets, compared to transmission-connected technologies, is their impact on distribution losses will depend on where they are located on the distribution system. The impact of DERs on distribution congestion also is another unique characteristic that can affect market offers of DERs. However, this was not analyzed in the distribution feeders in this study. Understanding how DER dispatch affects distribution losses helps determine efficient schedules in the ISO's wholesale market. DERs that can reduce distribution system losses by delivering close to loads can be more economically attractive to transmission resources or DERs further than loads, all else held equal. Previous research looked at incorporating distribution losses into distribution-level LMPs (DLMPs), which are not currently utilized in the Ontario market or elsewhere.

An alternative solution involves capturing distribution losses in market offers through various methods. One approach is adjusting the offer price based on historical contribution to distribution losses which may include offline distribution system modeling. Another involves including distribution losses as a separate component in the market offer, requiring accurate measurement and forecasting.

This section explores how distribution losses may be considered through offline analysis, using sensitivity factors to update market offers submitted by DERs. Definitions for several sensitivity factors are provided, and illustrative cases are discussed.

Distribution Delivery Factor (DDF): The distribution delivery factor shows how much power is going to reach the Transmission-Distribution (T-D) interface (reference bus) if additional power is injected at distribution bus i.

$$\mathrm{DDF}_i = \frac{\Delta Energy\ delivered\ to\ T{-}D\ interface}{\Delta Energy\ injected\ at\ dist.location\ i}$$

If the DER creates an energy value at the T-D interface greater than its production, DDF will be greater than 1 to reflect the positive impact to reduce feeder losses. If the DER adds losses to the feeder compared to the injection coming from the T-D interface, DDF will be less than 1.

Distribution Loss Adjustment Factor (DLAF): This is a factor by which the incremental cost of power production of a given DER is multiplied to take into account the distribution losses, defined as the inverse of the distribution delivery factor:

$$\mathrm{DLAF}_i = \frac{1}{DDFi}$$

Adjusted Offer (AO): The adjusted offer is determined by multiplying the original offer (OOi) by the Distribution Loss Adjustment Factor (DLAFi). This enables the offer to account for the economic impact of distribution losses (assuming transmission losses are considered in IESO's MRP market clearing platform and priced through locational prices, there is no need to consider transmission losses in the offer). If a DER is able to reduce distribution losses more effectively (i.e., DLAF is less than 1), relative to its nameplate injection of power and an equal withdrawal at the transmission/distribution interface, it gets an adjusted offer (reduced price offer) because it gives that DER more of a chance to be cleared. Conversely, if the DER increases distribution losses, the offer is raised as it will cost more to dispatch the resource.

$$AO_i = OO_i * DLAF_i$$

For demonstrating how loss adjusted DER offers can be calculated and understanding the impact on market clearing, the study considered a 9-bus feeder with five DERs connected at various locations with offers as shown in Figure 6. The calculation of loss adjusted offers from DERs based on sensitivity factors are shown in Table 2, and the aggregated DER offers using the adjusted offers are shown in Figure 7.

In the example, most of the DERs are contributing to a reduction in the distribution losses (as understood from DDF and balanced at the interface). The DER use an adjusted offer as this offer is more reflective of its cost relative to other resources (e.g., DER 2 can have the effect of providing 0.525 MW when injecting 0.5). If the DER is somewhere that it actually increases losses compared to the interface, it has an increased offer price to reflect this added cost (e.g., DER 4 has the effect of providing only 1.15 MW when injecting 1.2 MW, because it is on a lossy part of the feeder).

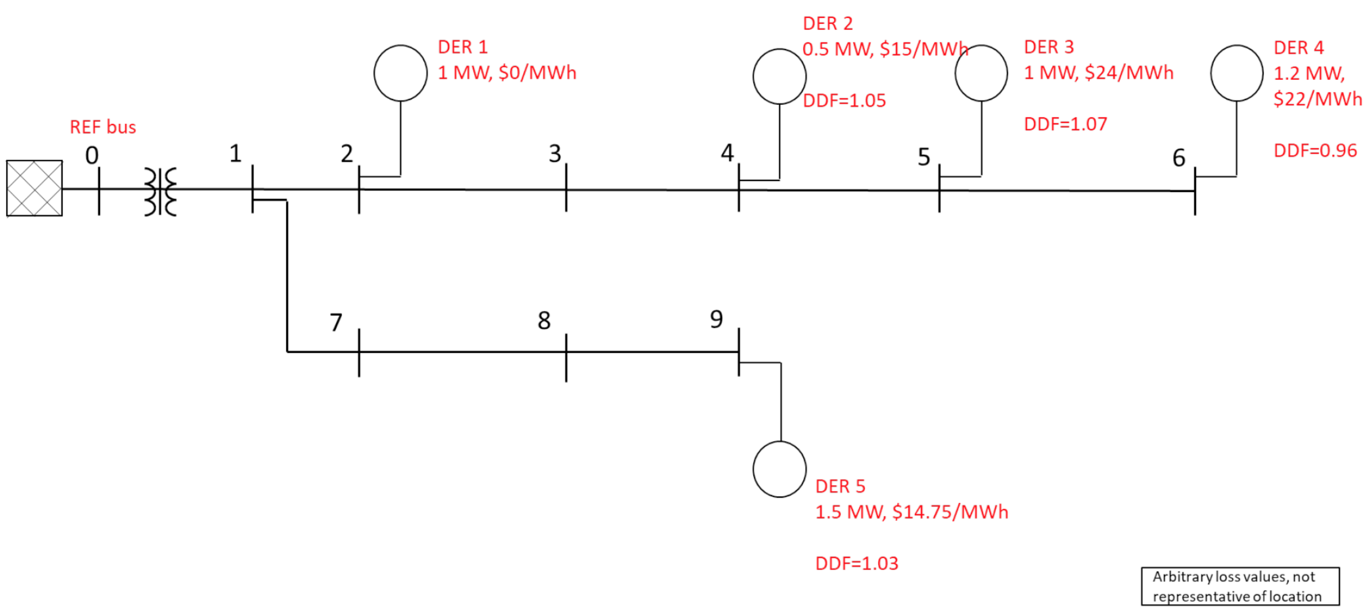

Figure 6. *Nine-bus test feeder with DER details*

Table 2. *Loss adjusted offer calculations*

DER (BUS)	DDF_1	DISTRIBUTIO LOSS ADJUSTMENT FACTOR $DLAF_i\left(\frac{1}{DDF_i}\right)$	ORIGINAL OFFER $/MWh	ADJUSTED OFFER (AO_1) ORIGINAL OFFER (OOD_1)* $DLAF_i$ ($/MWh)
DER 1 (Bus-2)	1	1	0	0
DER 1 (Bus-4)	1.05	0.952	15	14.28
DER 1 (Bus-5)	1.07	0.935	24	22.43
DER 1 (Bus-6)	0.96	1.042	22	22.92
DER 1 (Bus-9)	1.03	0.971	14.75	14.32

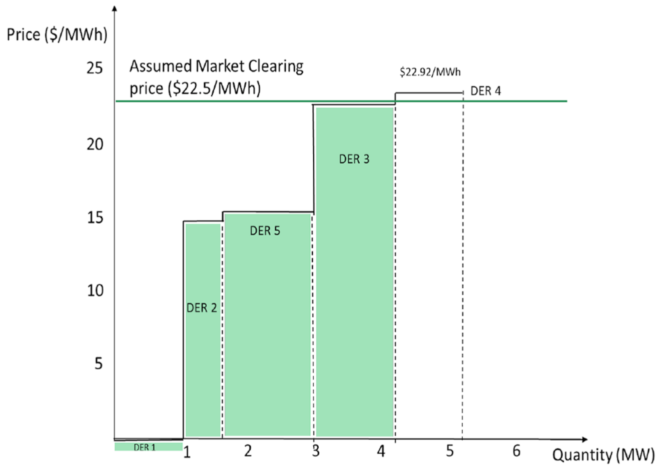

Figure 7. *One single offer with multiple price-quantity pairs provided by DER/DERA or DSO*

KEY TAKEAWAYS

This technical brief, the third and final document of a companion series, documents the power flow simulation efforts taken to illustrate the technical grid impacts witnessed when using DER for grid services, as described in the previous two briefs. This brief does not intend to draw absolute conclusions about the market coordination methods developed, as the results are specific only to the provided sample feeder circuits to analyze.

Simulating feeders with DER providing both distribution and bulk grid services highlights that many of Alectra's feeders have similar behaviors, but it also shows that DER location and size cannot be unlimited, even in a robustly built distribution system. Table 2 shows overall simulation results at peak load conditions, with DER size needed for congestion relief, losses impact, potential need for DSO override, and other observations.

Alectra Feeder Observations

The Alectra feeders all behave similarly, due to a few characteristics such as feeder cable and equipment design, operating voltage class, and the moderate feeder loading planning threshold.

- Throughout all simulations of the eight Alectra feeders, very few of them exhibited troublesome voltage conditions.
- The thermal congestion constraint was most often on the main or backbone line of the feeder between the substation and the first major loading section(s) of the feeder.
- In many cases, all three scales of energy storage DER could be used for both distribution congestion relief and market participation without issue, technically. However, there will be feeder-specific economics and energy coordination to address that may limit the capability of DER to provide both services, especially smaller-scale DER.
- The most common limitation was an overload when applying a large volume of residential storage relative to the service equipment connecting them to the feeder. Some feeders do not have this issue based on higher volume of residential electric customers allowing for smaller individual DER sizes, but achieving both distribution and bulk grid services when a feeder has fewer residential customers would require individual DER sizes to be unreasonable.
- Most often, the losses witnessed on the feeder were at or below 0.5 MW, or less than 3% relative to peak load. The robust design of the selected Alectra feeders results in small changes to losses from DER providing services.

Table 3. *Overall feeder simulation results*

FEEDER	PEAK MW	DER MW FOR DX RELIEF	PRE DER LOSSES	LOSSES CHANGE (REDUCTION)	OVERRIDE NEEDED?	NOTES
1	19.7	2.0	189 kW	Up to 62 kW	Yes	Residential DER, sized for congestion relief and market participation, cause feeder element overloads at average and min load.
2	20.7	2.5	508 kW	Up to 216 kW	Possible	Reverse power flow through the T-D interface at min load if DER produces at full nameplate. No overloads or voltage issues, though.
3	20.8	1.5 to 2.0	248 kW	Up to 127 kW	Yes	Residential DER, (congestion and market sizes) cause overloads at average and min load. Also, reverse power flow through T-D interface.
4	19.9	1.7 to 2.4	239 kW	Up to 99 kW	Yes	Residential DER, (congestion and market sizes) cause overloads at average and min load. Also, reverse power flow through T-D interface.
5	19.0	1.5	584 kW	Up to 201 kW	Yes	Residential DER, (congestion and market sizes) cause some overloads at average and min load. Also some notable undervoltage to correct.
6*	99 kW	Yes	82	19.6	Yes	Residential and commercial DER could substantially overload feeder elements, nearly 200%, when sized for market participation. Also, reverse power flow through T-D interface.
7	19.0	1.5	584 kW	Up to 201 kW	Yes	Residential DER, (congestion and market sizes) cause some overloads at average and min load. Also some notable undervoltage to correct.
8	19.6	2.0	434 kW	Up to 140 kW	Yes	Some notable undervoltage to correct. Potential for commercial DER to overload feeder elements in market participation size.
9 (IEEE 34-Bus)	19.8	2.0	799 kW	Up to 315 kW	Yes	Overvoltage in min load, undervoltage at peak. Voltage regulators already handling excessive conditions. DER can exacerbate high voltage.
10 (IEEE 341-Bus)	21.1	3.5	693 kW	Up to 329 kW	Yes	Min load, DER can cause reverse flow, must be prevented.

In comparison to typical distribution feeder operations in the industry, and primarily in North America, these feeders are much more robust and resistant to negative impacts that can be seen with large swings in load and voltage. It is reasonable to assume that the same methods applied to this study would produce more notable changes to other, less robust feeders, such as those that taper down wire sizes toward the farthest ends from the substation, which would accumulate impedance and possibly promote greater voltage changes and losses impacts from DER. Also, any feeders with notable existing DER that is non-dispatchable likely needs to be evaluated with a slightly different perspective than feeders with relatively no existing non-dispatchable (solar) DER, to capture the nuances of how much solar energy can offset load demand along with its variable power output nature.

IEEE Test Feeder Observations

The IEEE 34-bus feeder is inherently challenged with maintaining appropriate voltage. It is very lightly loaded, but it is also very long. It has voltage regulators to address voltage drops, but introducing DER only has positive effects if connected in locations where the reduction of load is truly needed. Also, DER of any notable size can produce overvoltages because of the low load demand, even at peak. The scale of losses on this feeder was much higher at 14%, despite only being 0.3 MW. DER had a substantial impact on reducing losses by over 30%, resulting in about 9% total losses. This kind of feeder in the industry would significantly benefit from DER services, from the perspective of loss reduction, and the location of DER would be more notably impactful on market offer adjustments than the sampled Alectra feeders.

The IEEE 342-Node secondary network feeder introduced a completely different operating paradigm. Some of the same methods of applying DER allocations were used, but this still posed challenges in power flow conditions. Radial feeders are able to deal with some amount of equal or reverse power flow from DER, but secondary network feeders with complex network protectors trip open if power flows in reverse, as a way to preserve the network in case one of the multiple primary voltage feeders has a fault. This challenges the allowed DER sizes, meaning anything close to or in excess of load demand will pose a risk to the intended design and operation of networks.

Using Feeder Conditions to Adjust Market Offers

The key findings from incorporation of distribution losses into DER offers are as follows:

- Considering distribution losses can lead to modification of the energy offer seen by the ISO, accounting for cost changes resulting from the resources impact on distribution losses (positive or negative).
- Power injection from DERs in wholesale markets typically reduces distribution losses. However, the relative effect on distribution losses in the evaluated feeders is relatively low. Other distribution feeders may experience more notable impacts on loss magnitudes and adjusted offer amounts.
- Distribution losses have a small effect on adjusted DER market offers in this study. Nonetheless, even this slight change in losses can impact which DERs are cleared in the wholesale market. The significance of incorporating distribution losses in DER offers may increase with higher DER penetration levels and especially with two-way power flow.
- Robust feeder design and operation, such as large capacity wires and inter-feeder tie switches, lead to minor changes in losses and DER offer adjustments. However, other distribution topologies, especially longer, radial feeders, and proximity of DERs to major load centers (such as the IEEE 34-bus test feeder), may experience larger impacts on distribution losses. These topologies may have a more significant effect on loss-adjusted offers, justifying the consideration of distribution losses when comparing offers from distribution-connected DERs to transmission-connected market participants.

General Analysis

The results shown in this paper focused on peak loading conditions to highlight if the simulated DER can provide congestion relief. However, in some feeders, increasing DER production to provide bulk grid services is either not feasible due to the DER scale/volume or it would create some unintended distribution feeder constraints, especially at minimum feeder load, and even at peak load. Results from simulation of the other two load demand levels are provided in a more comprehensive version of this report, and they sometimes show that the DER can create thermal or voltage issues if producing energy at the same nameplate rating used at peak load. A flexible interconnection agreement is critical to ensure that the DSO has permission to override whenever either operating framework calls for more energy than would be appropriate for distribution operations. This is needed alongside a strong coordination framework between the DSO, ISO, and each DER, regardless of operating framework.

It is also important to note these studies only employ snapshot power flow analysis and do not consider the evolution of metrics with time-series conditions. Most images and discussion in this report focus on energy storage, but static power flow studies can find very similar results regardless of actual DER technology used, focusing mainly on actual power output. Time-series studies would illustrate some of the nuances of DER technology types, cumulative impact on losses, total DER energy production and standby times, and other important aspects to consider for long-term use of DER for grid services.

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