Ameren Illinois Flexible Interconnection and DER Orchestration Report
Phase 2

Ameren Illinois
10 Richard Mark Way
Collinsville, IL 62234

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Executive Summary

Phase 2 of Ameren Illinois' flexible interconnection efforts builds off the foundational material developed in Phase 1 but provides a higher degree of focus on specific key questions related to the implementation details of static scheduled and dynamically managed flexible interconnections.

During Phase 2, Ameren Illinois developed an initial approach for both methods, including sample studies to demonstrate the effects of key design questions. The details of the initial approach and results of the studies were presented to a variety of stakeholders with experience and interest in load and DER interconnections in Illinois at an in-person workshop on May 5-6, 2026. The workshop was facilitated by the CHARGED Initiative[1], and they provided facilitation support to maximize the value of stakeholders' time and enhance discussion to make concrete progress on key focus areas.

For both static schedule and dynamic flexible interconnections, the central focus was to avoid triggering thermal overloads on substation components by reducing the operation of new connections during constrained periods (with customer agreement). This could be on a temporary basis during the construction of the upgrade (to decrease the time between applicant approval and energization) or on a permanent basis (to avoid otherwise necessary costs). Substation components were the focus due to two main factors:

- Cost: Substation equipment upgrades are generally very expensive, making them strong candidates to be avoided or deferred using flexibility.
- Data Availability: Substation equipment generally has direct SCADA telemetry, which means historical data (for study purposes) and real-time equipment data (for operational management) are readily available from direct measurements. This removes complex and time-intensive modeling requirements and more reliable operational performance.

Ameren Illinois believes that the additional studies needed to create operating schedules and estimate curtailment could be incorporated within the existing Level 4 DER study process within the Illinois Administrative Code and existing large load addition study processes. Direct telemetry reduces the need for time-series hourly "8760" modeling, instead allowing constraints to be assessed directly from historical SCADA data.[2] Standardizing schedule options to a small number of pre-determined granularity options for customers is also a necessary component, potentially enabling data processing automation to be scripted and system integration and recordkeeping to be easily standardized.

For static scheduled flexible interconnections, Ameren Illinois initially developed four different granularity options to be studied, ranging from two 2-point time-of-day varying options, a four-point option with seasonal variations tailored to Ameren Illinois' territory and load characteristics, and a 24-point option with seasonal variations and six 4-hour time blocks.

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[1] [1] https://chargedinitiative.org/

[2] As the flexible interconnection program matures, Ameren may leverage time series modeling and/or target telemetry investments in constrained locations that would benefit from flexible interconnection.

Table 1: Initial Static Schedule Options

Schedule Option	# of Intervals	Interval Splits	Design Goal
2-Point Solar	2	10 AM – 2 PM, 2 PM – 10 AM	Capture PV+BESS Shifting Performance
2-Point EVCP*	2	11 PM – 7 AM, 7 AM – 11 PM	Align with EV Charging Program Rider Times
4-Point Seasonal	4	June-September, October-November, December-February, March-May	Follow Seasonal Peak Load Variations in Downstate Illinois (e.g., September Peaks)
24-Point Seasonal + Time-of-Day	24	Seasonal + 4-Hour Blocks 10 AM – 2 PM, 2 PM – 6 PM, 6 PM – 10 PM, 10 PM – 2 AM, 2 AM – 6 AM, 6 AM – 10 AM	Maximize utilization across all technology types by capturing meaningful block variations while balancing granularity risk

Key insights from the static schedule study results include:

- For exporting DER, during the sample studies, variations of maximum export capacity (i.e., the volume of additional DER operation that could be accommodated in each interval) were relatively low, indicating that moving from a single static limit to schedule-based limits would not significantly improve DER operation on the studied feeders. It is anticipated that this differentiation would improve on feeders with relatively higher penetrations of DER operating closer to the existing limits.
- For flexible loads, the sample studies identified significant variations between maximum import capacity values, with some off-peak intervals allowing for more than double the amount of available import power (compared to a single static limit based on the highest peak load value). This indicates significant potential for flexible loads or other off-peak loads to connect and operate without triggering thermal capacity limits.

For dynamic flexible interconnection, Ameren Illinois' study process explored the differences in curtailment and the amount of new DER integration enabled by sequential "Last In, First Out" and shared "Pro-Rata" approaches to capacity allocation. This included one option that begins sharing capacity access after traditional firm capacity was exhausted (referred to as "U.S. Style" due cost causer approach common in U.S. jurisdictions) as well as another option that assumes all new resources are operated flexibly regardless of existing capacity (referred to as "Australia Style" due to the preferential access offered to flexible DER regardless of specific local constraints)[3].

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[3] Under existing interconnection rules in Illinois, there is no mechanism to encourage or require participants to consider flexible interconnection until existing firm capacity is exhausted. The "Australia Style" option is considered within the analysis to provide a hypothetical maximum and inform future interconnection policy discussions.

Table 2: Expanded Capacity Allocation Methods

Capacity Allocation Method	Description
Planned Switching Only	Curtailment only during planned switching to enable partial operation. Can be considered independent of participation in normal configuration flexible interconnection or capacity allocation.
Last In, First Out (LIFO)	Earlier applicants and connectors get priority access to capacity, with curtailment occurring in reverse order of approved connection
"U.S. Style" Pure Pro-Rata	Participating projects share capacity proportionally based on size, beginning **after** traditional firm capacity has been exhausted
"Australia-Style" Pure Pro-Rata	Participating projects share capacity proportionally based on size, beginning **before** traditional firm capacity has been exhausted
Pro-Rata Tranches	Capacity is shared proportionally by participants up to a pre-calculated total aggregate DER size limit determined by a specific allowable curtailment magnitude. Subsequent applicants may participate in a second tranche with higher curtailment, convert to "LIFO" allocation, or be withdrawn, depending on design choices.

All the curtailment allocation options studied provided an increase in the "effective" hosting capacity (i.e., the amount of DER that can be interconnected before curtailment reaches uneconomical levels). "Australian Style" Pro-rata provided the highest increase, though "U.S. Style" also provided sizable but smaller increases. Last In, First Out had the most variable performance, with the degree of increased capacity dependent upon the relative size and order of new connections and generally lower than "U.S. Style" Pro-Rata.

Given the existing interconnection structures in Illinois and the study results, Ameren Illinois' initial thought process focused on "U.S. Style" Pro-Rata with participation limited by a 5% curtailment target within the study process. The 5% curtailment target is referred to as a target rather than a limit, as it is a value that planning processes drive toward but may be exceeded under certain circumstances, rather than a hard threshold that cannot be surpassed. This approach adds the largest degree of capacity while still working within existing interconnection constructs. Critically, it also avoids enshrining preferential treatment of certain customers over others (i.e., Last In, First Out) in system planning and operations. The primary downside of this approach is the current lack of a viable means of facilitating cost-prohibitive system upgrades (e.g. substation upgrades). While some means are briefly explored here, larger structural change would be needed to facilitate future upgrades to increase DER hosting capacity.

During the workshop, stakeholders generally supported this approach, although stakeholder preference for a hard curtailment limit or compensation mechanisms for exceeding curtailment targets was clearly stated to support project financing. Stakeholders also emphasized the need for clear communication of the results and data access for securing financing. As this approach fits within the existing process and uses a similar structure to other dynamic flexible interconnection pathways, it was generally expected to be the most viable path in the short-term.

Ameren Illinois' next steps are focused around defining the specific details of implementation and flexible interconnection design offerings. This includes the development of study tools and processes, documentation of technical requirements for participation, rollout of the operational capabilities of the DER Management System, and continued engagement with stakeholders.

Project Overview – Phase 2

During Phase 1 of Ameren Illinois' Flexible Interconnection and DER Orchestration efforts, the initial focus was on exploring the various flexible interconnection methods available and identifying relatively short-term opportunities to improve interconnection outcomes for load and DER customers. Phase 1 also explored more complex static schedule and dynamic flexible interconnection options while explaining key concepts and identifying key questions for further exploration during Phase 2.

Phase 2 explores these key questions in detail, expanding the initial discussion areas into fully developed technical descriptions of potential design options and including a focus on DER Management System (DERMS) considerations. These potential design options will also be evaluated for value and feasibility for both static schedule and dynamic approaches. To enable detailed exploration of feasibility, study methodology, and overall value proposition, Electric Power Engineers (EPE) will also be performing demonstration studies using Ameren Illinois feeder model and substation load profiles, equipment constraints, and interconnection study criteria. Specific elements of the study will be designed based on the technical content developed related to the key questions as well as future implementation considerations. Ultimately, the technical content explored, the study methodology used, and results derived will be used to formulate recommendations for Ameren Illinois' approach and next steps for static schedule and dynamic flexible interconnection. Given early stage of Ameren's DERMS deployment, static schedules will be prioritized for near-term implementation with dynamic flexible interconnection implemented upon the availability of DERMS.

Phase 2 also included engagement with load and DER stakeholders, intended to ensure that static and dynamic design elements were evaluated in a manner that reflected their actual needs and provides an effective pathway to utilization. An in-person workshop was conducted in Ameren Illinois' Collinsville office on May 5-6, 2026, wherein Ameren Illinois presented initial concepts, study results, and potential implementation ideas for stakeholder feedback. This event was facilitated by the CHARGED Initiative[4] and included participation from a broad set of industry stakeholders.

This report is structured to mirror the Phase 2 development path, detailing Ameren Illinois' initial considerations, study approach, and study results, followed by stakeholder feedback. This demonstrates both Ameren Illinois' pre-work on the topic as well as the essential input and perspective from load and DER participants. Potential next steps are then presented based on the culmination of these efforts.

DER & Load Operational Considerations

Ameren has developed this plan with the acknowledgement that different customers and resources have different operational needs, a one size fits all approach is infeasible for flexible interconnection and thus a diverse set of flexible interconnection options are required to meet these needs. Specifically, through stakeholder engagement, Ameren has identified the following nuances across customers and resources:

- **Solar & Solar + Storage:** These resources may be more agnostic to when curtailment occurs as opposed to how much curtailment occurs. Thus, the operators of these resources generally prefer DERMS dynamic

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[4] https://chargedinitiative.org/

flexible interconnections as this approach maximizes the amount of MW and MWh that can be interconnected at a given location.

- **Standalone Storage:** These resources may be more sensitive to when curtailment occurs as they can be participating in day-ahead and real-time energy markets which may serve as the primary revenue source for these resources. DERMS dynamic flexible interconnections may be less preferential as curtailment events could conflict with market opportunities potentially putting revenue at risk. In contrast, while schedules may interconnect less overall MW and MWh, they can provide operational certainty and predictability mitigating risk of lost revenues. However, there may be opportunities for a hybrid approach where standalone storage primarily operates on a schedule with DERMS enabling incremental capacity beyond this schedule.
- **Load:** These resources are generally highly sensitive to when curtailment occurs as they are serving customers & operational needs and thus need certainty and predictability. Like standalone storage, schedules are typically preferred by these customers as they provide firm capacity even if this varies over specific time horizons. However, there have been unique use cases such as public electric vehicle charging that have participated in DERMS dynamic flexible interconnections.

These perspectives and unique needs are considered and incorporated in the concepts and proposals throughout this plan.

Static Scheduled Interconnection Development

Exploration of Key Questions

Key questions identified during Phase 1 for further exploration included[5]:

- Which party proposes the schedule?
- What level of schedule granularity is reasonable?
- What level of schedule customization is reasonable for applicants or distribution system locations?
- What requirements are necessary to ensure compliance with relevant operating schedules?

Beyond these core questions, it is also important to examine additional questions regarding the technical interconnection study process and the ability of static schedules to impact the study criteria, which, when exceeded, result in the need for system upgrades. In practice, there are several discrete interconnection study criteria which are evaluated during the interconnection study process, for these the impacts of an operating schedule can range from effectively zero for some criteria to significant impacts on others. This has important impacts on the overall process design and value proposition for static scheduled connections and hence this aspect is also explored in this section.

Interconnection Criteria Impacted by Scheduled Operation

Interconnection criteria, in this context, refers to the set of system impacts that are studied during the interconnection study process to ensure new DER and load additions can be interconnected safely without negatively impacting reliability or power quality for existing customers. While some criteria are shared for both load and DER, there are variations due to the disparate impacts and performances of the underlying technologies. Below are tables illustrating the interconnection criteria used by Ameren Illinois for DER and load interconnections, with relevant impacts and consideration subsequently explored in more detail.

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[5] For explanations of scheduled connection capabilities and technical concepts, please refer to Ameren Illinois' Flexible Interconnection & DER Orchestration Report – Phase 1.

Table 3: DER Interconnection Study Criteria

Study Criteria	Description	Avoidable With FlexIX?	Relative Cost Impact of FlexIX
Thermal Loading	Avoid exceeding equipment rated thermal capacity	Yes	High
Steady-State Voltage	Maintain voltage within required service ranges	Yes	Low-Medium
Frequent Voltage Variation	Ensure voltage does not vary significantly as a result of expected day-to-day changes in resource operation	No	N/A
Distribution Protection	Ensure fault protection equipment and schemes continue to function as intended	No	N/A
Subtransmission Protection	Ensure subtransmission faults do not result in damage to distribution equipment	No	N/A
Weighted Short Circuit Ratio (WSCR)	Ensure local system strength is adequate to support local system stability	No	N/A
Reverse Power Flow (Regulators)	Ensure voltage regulators expected to experience reverse flow are configured appropriately	Yes	Low

Table 4: Load Connection Study Criteria

Study Criteria	Description	Avoidable With FlexIX?	Relative Cost Impact of FlexIX
Thermal Loading	Avoid exceeding equipment rated thermal capacity	Yes	High
Steady-State Voltage	Maintain voltage within required service ranges	Yes	Low-Medium
Frequent Voltage Variation	Ensure voltage does not vary significantly as a result of expected day-to-day changes in resource operation	No	N/A

Thermal overloads, where they occur because of load or DER interconnection, are a primary value driver for flexible interconnection. They are generally very expensive to resolve using traditional system upgrades can be significantly impacted using a static schedule. Substation transformer and feeder equipment overloads, in particular, are generally very expensive conditions to resolve. Because of both high impact and high cost, avoiding triggering equipment thermal loading limits is likely to be the primary use case for static scheduled connections.

The application of static scheduled interconnections towards subtransmission constraints is another key area of consideration. Projects to resolve subtransmission constraints are generally relatively costly, which would tend to increase the value proposition of static scheduled-based connections for avoiding such upgrades. In practice, however, it is significantly more complex to assess the impact on time-varying schedules on subtransmission constraints. Subtransmission planning incorporates contingency operation as a required element of capacity planning, which is necessary to capture capacity risks that may occur as part of the intended design and operation of the system. Because many different contingency configurations must be assessed, incorporating multiple analysis cases to reflect time-varying schedules is an order of magnitude more complex than similar time-series distribution analysis. Consequently, the engineering labor associated with each schedule interval would currently be expected to scale roughly linearly with the number of time points considered (e.g., a 4-point schedule would require approximately 4 times the level of effort as existing single-point studies). There is potential for future enhancements to data processing automation and integrated model management to reduce the degree of additional labor for schedule-based studies, but such tools and capabilities are expected to be complex to develop and deploy in a manner suited to subtransmission utilization. While these capabilities may evolve over time, they are unlikely to be practical in the short-term. As a result, subtransmission constraints are not recommended for consideration within initial static schedule-based studies.

Other study criteria are not impacted by the applicant's use of scheduled options. In particular:

- Fault current and system protection aspects of the study are generally governed by the equipment nameplate capabilities and its inherent fault response characteristics. Consequently, scheduled operation does not significantly impact fault performance within the timeframes considered.
- Capacitor controls (especially voltage and current-controlled banks) have pre-programmed settings that can be impacted negatively by new load or DER additions regardless of their operating schedule. These impacts are generally minor and may include updating device settings or changing the capacitor control mode.
- Weighted Short Circuit Ratio (WSCR) is based on equipment nameplate information and is not impacted by export controls, which prevents schedule-based approaches from impacting the constraint.
- Within the Distribution protection umbrella, one of the factors considered is reverse power flow through hydraulic reclosers. This is evaluated due to the potential for the hydraulic reclosers' nominal 2 second reclose interval to drift from the nominal timing due to the mechanical nature of the equipment. If the reclose interval shortens, the recloser could open and reclose before the 2 second DER anti-islanding window has fully elapsed. This risk is present regardless of whether the recloser experiences reverse power flow but is significantly increased due to the potential for load and generation to match within the island formed when the recloser opens. Because the risk is not fully mitigated, flexible interconnection is not considered as a solution for the hydraulic recloser protection criteria.

Certain study criteria may be impacted by an applicant's use of schedule option, but not to a degree that is likely to significantly change the overall study results or the resulting cost responsibility. In particular:

- Enabling voltage regulators to support reverse power flow is generally a relatively low-cost upgrade when considered from the lens of large DER projects. Utilizing a schedule to avoid this type of upgrade is also likely to significantly constrain DER operations. Preventing reverse power flow through a line or substation device via flexible interconnection would require that flexible interconnections respond in near-real time to changing loading conditions on the system, which is likely to both significantly increase curtailment and lead to risk of misoperation if system conditions change more quickly than communication/DERMS could respond. This combination makes it unlikely that operating schedules will be desirable for avoiding this type of upgrade.
- Frequent Voltage Variation impact from DER does change with system load, but the voltage change is generally higher during high-load conditions and the difference between peak and minimum load cases is often relatively small. Consequently, attempting to utilize scheduled operations to avoid the resulting upgrades would have relatively narrow applicability and would likely result in significant degrees of production curtailment during high-production periods for DER (particularly solar PV).
- For load connections, motor start voltage change calculations are analogous to Frequent Voltage Variation. Similarly, they have relatively narrow ranges of change across peak and minimum load scenarios and are unlikely to be practical to avoid by using a schedule.

One final category of study criteria within this analysis are those that are impacted to varying degrees by scheduled operation depending on specific circumstances, which primarily includes steady-state voltage violation criteria. The likelihood of voltage violations generally follows the degree of loading, with overvoltage most likely during light load conditions and low voltage most likely during high load conditions. As a result, scheduled operations may be an effective means of mitigation for voltage issues. However, there are some complicating factors that impact the overall viability and value proposition of static schedule-based connections for mitigating voltage issues. First, voltage violation solutions range significantly in cost. In some cases, very low-cost solutions such as phase balancing can resolve voltage violation conditions. In other cases, extensive reconductoring may be necessary. The range of solution costs makes it difficult to generalize the value proposition for avoiding voltage violations. Identifying voltage violations and assessing the impact of schedule-based operation on such violations also require detailed power flow modeling for each time snapshot considered. Given the range of variability in value and the significant increase in study complexity to evaluate voltage violation mitigation using scheduled operation, it is recommended to exclude voltage violations from the initial set of criteria for scheduled evaluation. Over time, as analytical and data processing capabilities advance, evaluating voltage criteria impacts could be incorporated into the evaluation process for schedule-based flexible connections more readily.

Schedule Granularities

Schedule granularity, for the purposes of this report, refers to the number of time points where the allowable import or export values can be differentiated. More granular schedules have higher numbers of points, with less granular schedules having relatively fewer points. Many different schedule granularities are available and are generally broken out by variations across time-of-day, month, season, or a combination of the three. The UL 3141 standard[6] contemplates high degrees of granularity, up to 288-points, including capabilities for hourly, monthly, hourly plus monthly, or a flex configuration capable of directly incorporating specific start and end dates, time blocks, and variation by weekday and weekend days.

Higher granularity schedules with more time blocks generally allow for higher levels of resource operation relative to lower granularities (all other factors being equal). This is easiest to demonstrate by comparing a seasonal schedule to a more traditional single-point limit for a new load addition. The summer peak season is the most constrained period, so, under the single-limit approach, the available summer capacity sets the limit for the entire year. Under the seasonal approach, capacity is less constrained during the non-summer months, which allows the operating limits to be higher without creating overload conditions. The same effect occurs across different hours and months for both load and DER, albeit with differences in the specific limiting time periods.

While higher granularity schedules tend to increase resource operational capabilities, they also have certain challenges and pitfalls that make it more complex to effectively implement and utilize them. First, studying more time intervals requires more time and effort within the study process itself. The specific extent of additional labor depends on the number of scheduled intervals and the extent to which data processing and power flow software tasks can be automated. In addition, higher granularity schedules can also be more complex for customers to understand, develop, or evaluate for suitability.

Most importantly, high-granularity schedules can provide a false sense of precision and can increase the risk of study errors that result in violations of system constraints and the subsequent need to construct facilities that were intended to be avoided by using the schedule. Year-to-year variations in weather and, consequently, the timing of peak or minimum load can range beyond the established schedule interval boundaries from historical data. This

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[6] UL 3141 is an emerging technical standard for power control systems (PCS) that would operate schedules.

concept is easiest to illustrate with a 12-point monthly schedule with varying import limits for a new load addition. Summer peak loads generally occur in June, July, August, or early September in the Midwest. For a new load with a 12-point monthly schedule connected to a substation that has experienced its peak in August for the last three years, the relative operating limit for the new load would be calculated to be higher in June and July than during the historical August peak period. In future years, however, the actual peak is unlikely to always occur in August. Consequently, the higher operating limits calculated in June and July can result in an unintended overload.

All multi-point schedule granularities carry this risk inherently, though higher granularity schedules have a higher degree of risk because there are more boundary points at which allowable operating limits change. Consider, in an even higher granularity 288-point schedule example with 24 hourly intervals for each month, the relative difference between load at 10 AM and 11 AM in June, and the risk becomes even more clear. Increasing the amount of historical data incorporated into the design can help decrease this risk, but it cannot eliminate it, and it also adds considerably more engineering labor and complexity to the process.

Effectively reducing this risk requires establishing schedule boundaries that encompass the entire period(s) over which expected operational conditions will change in response to specific drivers. This approach, in effect, assembles a set of time intervals into a “block” where conditions are expected to be affected by the same driving conditions. From the previous example, using a “summer” schedule block that covers the full expected summer peak range (e.g., June 1 – Sept 15th) is much less likely to result in unexpected overloads than using individual monthly values. This approach can also be applied to time-varying schedules, particularly to account for known time-varying influences such as solar PV production.

The Limited Generation Profiles[7] being implemented by California investor-owned utilities provide three granularity options[8], one of which specifically incorporates the “block” concept, which was primarily developed and proposed by the Interstate Renewable Energy Council (IREC)[9].

- 24-Hourly LGP: One import/export value for each hour, regardless of month or season
- 18-23-Fixed: Two-time blocks for each month, ranging from 12 AM – 6 PM and 6 PM – 12 AM
- Block: Four seasonal blocks, each with six hourly time-varying blocks
    - Seasons: January-March, April-June, July-September, October-December
    - Hour Ranges: 9 AM – 1 PM, 1 PM – 5 PM, 5 PM – 9 PM, 9 PM – 1 AM, 1 AM – 5 AM, 5 AM – 9 PM

When considering appropriate schedule granularity options for potential future use by Ameren Illinois customers, the following goals were identified to help guide decision-making:

- Minimize the risk of utility investment to correct overload conditions or other criteria violations that could result from errors, inaccuracies, or false precision within the schedule development and study process.

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[7] CPUC Limited Generation Profiles: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/rule-21-interconnection/limited-generation-profiles

[8] Approved LGP Options: https://dps.ny.gov/si-limited-generation-profiles-presentation-september-2024

[9] IREC Blocked LGP Analysis: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/rule21/limited-generation-profiles/2_irec-blocked-lgp-analysis_040723.pdf

- Ensure the schedule can be designed and studied effectively by Ameren Illinois with available data and tools. Consider both short-term implementation and longer-term capabilities with associated future process enhancements.
- Maximize the utilization of existing distribution equipment
- Ensure that the customers can understand, evaluate, and comply with the resulting operating schedule
- Maximize connections for technologies and resources with the most anticipated growth in Illinois, including solar PV, battery energy storage systems (BESS), EV charging, and fleet electrification

The static schedule study evaluated multiple schedule granularities, including several low granularity schedules and a higher-granularity 24-point schedule. Low granularity options are much more likely to be practical to effectively study and incorporate into existing processes in the short-term. In addition, they provide an effective baseline for measuring the additional benefits that can be gained from more complex, labor-intensive high granularity options. Specific time and seasonal boundary points were designed to accommodate specific technology performance windows (e.g., solar PV production) as well as capture general trends and historical load profiles within Ameren Illinois' service territory. The following schedule granularities were selected for initial study:

- 2-Point Time-of-Day, intended to target PV+BESS exports
  - 10 AM – 2 PM, 2 PM – 10 AM
- 2-Point Time-of-Day, intended to target EV and fleet electrification and aligned with Rider EVCP
  - 11 PM to 7 AM, 7 AM to 11 PM
- 4-Point Seasonal, capturing general variations in available capacity within Ameren Illinois' territory
  - June-September, October-November, December-February, March-May
- 24-Point Blocks varying across 4 seasons, each with 6-time blocks
  - June-September, October-November, December-February, March-May
  - Time Blocks: 10 AM – 2 PM, 2 PM -6 PM, 6PM -10 PM, 10 PM – 2 AM, 2 AM - 6 AM, 6 AM – 10 AM

Schedule Customization

When considering the implementation of static scheduled interconnection, there are several important dimensions of customer choice and capabilities to explore. The extent to which customers can customize the schedule granularity and specific import and export values has important consequences on the implementation and assessment of scheduled interconnection options.

<u>Granularity Options:</u>

As discussed previously, there are many different potential ways to split up a year into schedule intervals using a combination of date, month, season, weekday/weekend, and time of day. In practice, for a utility to be able to process and study schedule-based applications at the necessary scale, a reasonable limit on the number of granularity options available to applicants must be established.

During the interconnection process itself, the utility must be able to screen and study the applicant in the prescribed timeframes. In order to process the flexible interconnection application in a similar timeframe as the existing standard study applicants, with added complexities, data processing and automation capabilities will need to be established. Developing such capabilities for specific pre-determined schedule options is much more practical than trying to cover every edge case that customers may wish to pursue.

Pre-determined schedule options are also much more practical from a recordkeeping perspective. Keeping accurate records of how an interconnected resource will perform is essential to both distribution planning activities and subsequent interconnection studies. Developing a standardized set of schedule options that is easy to document and can be translated into a machine-processible format, drastically simplifies this process.

In addition, pre-determined schedule options can simplify customer communications and enable more effective communication of necessary supporting information. A smaller set of specific options can make it easier for customers to understand the available options and determine whether a flexible connection option is viable for them. It also becomes more practical to generate relevant hosting capacity information with corresponding time intervals.

The biggest downside of limiting schedules to a set of pre-determined options is the loss of potential utilization that could theoretically be achieved if each customer was allowed to fully customize their proposed schedule by specifying their specific hours, months, or other time intervals of restricted operation based on their unique capabilities and local grid constraints (e.g., an 8760 hour operating schedule). In practice, allowing for such customization is unlikely to be scalable and results in elevated risk of unanticipated violations in future years due to the boundary point risks described previously.

To ensure successful implementation, maximizing an applicant's operational capabilities must be considered alongside the feasibility of scaled implementation and the risk of unanticipated violations. Pre-defined granularity options provide a reasonable pathway to achieve this and enable future expansion as more operational experience with scheduled interconnections is gained and new study methods and processes are established.

Separation of Import and Export Limits

Another important aspect of customization to explore is the separate consideration of import and export limits for a customer site. Existing UL 3141 documentation prescribes the testing of import limit schedule files and export limit files separately. In theory, this allows for import and export limits within an operating schedule to be defined fully independently, using different schedule granularities and different values within each time interval. For instance, import limits for a customer site could be defined using a seasonal approach, while export limits could be defined using a time-of-day approach.

In practice, allowing for fully separate import and export schedule definitions is likely to create implementation challenges, especially in the short term. Evaluating import and export constraints within the same time intervals during the study process allows for the same input data sets to be used to evaluate or define the operating schedule, significantly reducing the study complexity and associated labor. Allowing separate import and export granularities would require separate data processing efforts for each, increasing the overall complexity and labor. In addition, recordkeeping and formatting would be more complex, as multiple constraints at varying times would have to be tracked.

For initial applicants considering scheduled interconnections, the requirement to use the same schedule granularity for import and export restrictions is unlikely to be a significant barrier. Stand-alone applications for solar PV or load additions will utilize import or export limits, but not both. Energy storage (with or without accompanying PV) may be subjected to both import and export limits, but generally in a coordinated manner that allows for use of the same time intervals and schedule granularity without significant limitation. Over the longer term, as applicants add different technologies or combinations of DER with varying needs and limitations, there may be more value in allowing for separate schedule granularities to be considered.

For initial implementation considerations, applicants should be limited to a single schedule granularity for their operating schedule. Within that granularity, import and export values for each time interval can be defined independently based on system constraints and operating conditions, but the schedule intervals themselves must be the same.

Customer-Specific Versus Utility Location or System-based

While the initial focus of scheduled connections has primarily been for individual customers proposing their own schedules (within defined granularity options), that is not the only approach to consider. There is also the potential for the utility to pre-determine schedules for applicants at the substation, feeder, or even system-wide level.

Customer-specific operating schedules (where import and export limits are defined for the specific customer within each time interval) are the most practical implementation within existing processes and provide the highest degree of customer operating freedom. So long as available granularity options are limited to pre-determined timeframes, customer-specific schedules are feasible to determine and evaluate.

Feeder or substation-level pre-determined schedules have some potential application for specific types of DER, though there are process barriers to implementation that limit the overall viability of this approach when it comes to avoiding triggering system upgrades. In theory, an operating schedule could be determined such that a specific, calculated amount of a specific type of DER (e.g., solar PV) could be accommodated without experiencing production loss in excess of a certain percentage. This approach would allow the existing capacity to be shared between a pool of existing or future applicants, increasing the total amount of DER that could be accommodated by the existing infrastructure. In practice, under the existing "first come, first served" approach to capacity access, applicants would have no incentive to utilize such a schedule unless they would otherwise be required to bear cost for a system upgrade, which reduces the overall magnitude of potential achievable benefit to a level lower than if schedules were able to be customized for each applicant.

System-level operating schedules are not a viable path forward for distribution interconnection, as individual constraints at specific feeders or substations will vary significantly based on existing load profiles, the volume of DER connected, and a host of other factors.

Proposing the Schedule

Key questions for schedule implementation include which party (the applicant or the utility) will propose the use of an operating schedule, select the appropriate granularity, and define the specific operating limits within the operating schedule.

Ideally, the applicant would propose the use of a scheduled interconnection when they submit their application, including the granularity and specific operating limits. Philosophically, this would align most closely with the existing practice, as the customer would provide the specific characteristics of their facility for study by the utility. In practice, there are process and data hurdles that prevent this from being viable in the short term.

From the applicant's perspective, there would be effectively no benefit to choosing to utilize a scheduled interconnection unless they were able to avoid the costs or timeline impacts resulting from a specific grid constraint. Consequently, for applicants to propose schedule use as part of their initial application, they must be able to identify the grid constraints that would result from their application (and the associated costs) with relative certainty prior to submitting their application. Ameren Illinois' hosting capacity map provides useful information about potential grid constraints, but it does not currently provide time-varying or seasonal information that would be needed for the applicant to propose specific operating schedules. Expanding the available information (as part of, for instance, Dynamic Hosting Capacity) could help alleviate this issue, but the additional level of data processing and analysis needed to publish accurate and reliable information for every distribution substation at the granularity needed will be very challenging to implement, especially in the short-term.

Instead of requiring customers to propose using an operating schedule as part of their initial application, another potential approach is to have the utility calculate an operating schedule for the customer if it would allow the customer to avoid triggering the need for a system upgrade. This would enable customers to choose between pursuing the grid upgrade, utilizing the proposed schedule, or withdrawing their application. This approach is much more practical in the short term, as the data processing and analysis needed to generate the schedule would only have to be performed by the utility for specific applicants at specific substations (as opposed to the entire distribution system). It also lessens the analytical burden on the applicant. This does add an extra layer of responsibility to the utility (compared to the existing study process or the applicant-proposed schedule process), as they would have to develop and confirm the suitability of an operating schedule instead of simply assessing whether a specific schedule still triggered the need for an upgrade.

As a whole, the existing Administrative Code Part 466 rules for DER interconnection are relatively amenable to static schedule-based flexible interconnections. Changes to operating profile that do not extend the operating window or increase export capacity are not considered material modifications and can thus be made during the process without requiring the applicant to withdraw.

The Level 2 process (including the Supplemental Review) could, in certain circumstances, accommodate static schedule-based connections. However, the current structure would likely require meaningful refinement before it could reliably support scheduled connections in practice. The Level 2 process includes a revision window after initial screening failure, which would allow for applicants to adopt a utility-proposed schedule (if they choose to do so) to avoid triggering the need for a system upgrade. The timelines for Level 2 analysis, however, are relatively condensed and further integration of additional process steps to propose and study a flexible option would stress both utility and customer timeline obligations significantly.

The Level 4 process, generally intended for larger, more complex interconnections, aligns more closely with the timeline requirements and analytical nature of flexible interconnections. The Level 4 process is segmented into separate studies with opportunities for dialogue and customer engagement between each:

- Feasibility Study: Identifies potential adverse system impacts resulting from the interconnection.
- System Impact Study: Identifies the specific system impacts, including modifications needed to accommodate the interconnection.

- Facilities Study: Identifies detailed upgrade costs and construction timelines for any necessary system modifications needed to accommodate the interconnection.

The separation of potential adverse impacts (within the Feasibility Study) and detailed modeling and results (within the System Impact Study) enables a natural integration of flexible options. Within the feasibility study, Ameren Illinois could identify whether any potential adverse system impacts may be avoidable using flexible options. These options could be communicated to the applicant for their consideration (alongside the traditional upgrade pathway) within the system impact study. If the applicant chooses to have a flexible option evaluated, the system impact study results can present both the traditional upgrade cost as well as the operating schedule needed to avoid triggering the need for the upgrade (or, for dynamic, the anticipated curtailment needed for upgrade avoidance). Once presented with the results, the applicant could select their preferred path forward for detailed cost estimation within the Facilities study.

Within the Level 4 process, there is no explicit window to allow applicants to modify the performance or operating schedule of their resources after the initial application is submitted. However, operating profile changes that do not increase export capacity or extend the operating window are not considered “material modifications” within Part 466.125 of the Admin Code. As a result, such modifications can be considered as part of the Level 4 process without requiring the applicant to withdraw or resubmit. This effectively enables flexibility to be used within the Level 4 process as described above.

For both the Supplemental Review and Level 4 processes, there is an existing provision allowing for the actual cost of conducting the study to be recovered directly from the applicant, which could be used to recover any additional incremental costs from schedule-driven analysis.

So far, DER interconnection has been the primary focus area for the integration of flexibility, but flexible loads are also an important element to consider. In practice, the load connection process is significantly less formalized than its DER counterpart but follows the same general structure. Customers wishing to connect new loads or add significant new load at their existing location will contact Ameren Illinois and provide a load sheet detailing their planned new load(s). From there, load connection with flexible options can follow the same general process flow as the Level 4 study. Where applicable constraints are likely to be triggered, Ameren Illinois can inform the customer of their traditional and flexible options and move forward by studying both the traditional pathway and a flexible option (if desired). When the study is completed, the customer can be presented with a cost estimate which, for loads, may include any applicable revenue considerations.

This process flow also provides an effective pathway for use of flexibility for both temporary and permanent bases. If the customer wishes to bear the cost responsibility for the upgrade but wishes to utilize flexibility to connect more quickly prior to the completion of construction, that can be established using the same process described above without any structural modifications.

Schedule Compliance

As discussed in detail in Ameren Illinois’ previous Flexible Interconnection and DER Orchestration Report, the UL 3141 Power Control System (PCS) standard is a natural starting point as a method for customers to comply with the schedule developed within the interconnection process. Under the current outline version of the standard, hardware can be certified for its ability to accommodate different levels of time granularity, including:

- Hourly: Defines a single day in 24-hour increments that are valid on each day of the year.

- Monthly: Defines 12 specific values by month, which are applied to each day and hour within the given month.
- Hourly+Monthly: Supports monthly, hourly, and schedules up to 24 hourly values and 12 monthly permutations (up to 288 entries).
- Flex: Supports schedules with any combination of start date/time and weekday/weekend designation up to 288 entries.

It is important to note that not all PCS equipment certified to UL 3141 is capable of accommodating all levels of time granularity. Some hardware may only be certified to “Hourly” or “Monthly”, which would not be sufficient to implement certain schedule granularities. Given the different options that may be available to applicants, materials to be provided to customers should communicate the required level of time granularity performance so that suitable hardware can be selected by the applicant.

Another important dimension of compliance is preventing unplanned modifications to the operating schedule used by the hardware to comply with interconnection performance requirements. The current standard outline requires at least one of the following means of restricting access to the adjustment of control settings:

- Software that has password protected access to the adjusting means accessible to qualified personnel only
- Located behind locked doors, accessible only to qualified personnel
- Hardware located in areas requiring a tool for access

Many existing inverter and PCS vendors utilize a vendor-managed password to restrict access and prevent end-customers from modifying the settings after a pre-set period following energization. This approach is relatively robust, as any schedule modifications would require vendor participation, which adds a layer of additional process (and, subsequently, protection) against intentional non-compliance. The standard, however, does not require this, and allows for site deployments to be protected using on-site physical access control means. Such means provide protection against accidental or inadvertent modifications, but do not protect against intentional modifications intended to increase site production by circumventing the required operating schedule.

Consequently, hardware certification does not necessarily provide full protection against intentional non-compliance. Telemetry of the impacted resources (e.g., via a site recloser for a large standalone DER) can provide an additional layer of protection, enabling operators to respond effectively if customer non-compliance occurs and results in system issues. For sites without telemetry, limiting site hardware to PCS that use a vendor software password for modification prevention could be considered. This would add an additional layer of requirements and communication with the applicant but would provide additional protection against future non-compliance.

Initial Static Schedule Approach for Study and Stakeholder Engagement:

As discussed above, the Level 4 pathway for DER (and a similarly structured process for flexible loads) provides a highly effective pathway for the integration of flexible options into the interconnection process. Within this process, Ameren Illinois would screen potential thermal overloads of substation transformers and feeder equipment within the substation that could be avoided using static scheduled connections. The applicant could then select whether to consider flexible options and which specific option for further study before ultimately choosing the traditional pathway, their selected flexible pathway, or to withdraw from consideration. Specific static schedule flexible options initially considered for study are illustrated in the following table:

Table 5: Initial Static Schedule Options

Schedule Option	# of Intervals	Interval Splits	Design Goal
2-Point Solar	2	10 AM – 2 PM, 2 PM – 10 AM	Capture PV+BESS Shifting Performance
2-Point EVCP*	2	11 PM – 7 AM, 7 AM – 11 PM	Align with EV Charging Program Rider Times
4-Point Seasonal	4	June-September, October-November, December-February, March-May	Follow Seasonal Peak Load Variations in Downstate Illinois (e.g., September Peaks)
24-Point Seasonal + Time-of-Day	24	Seasonal + 4-Hour Blocks 10 AM – 2 PM, 2 PM – 6 PM, 6 PM – 10 PM, 10 PM – 2 AM, 2 AM – 6 AM, 6 AM – 10 AM	Maximize utilization across all technology types by capturing meaningful block variations while balancing granularity risk

Static Scheduled Interconnections - Study Approach

For the demonstration study for static scheduled interconnection, the study approach focused on evaluating the feasibility of static schedules with relatively few points (which are more likely to be able to be implemented more quickly) as well as the additional value provided by increasing the granularity. This approach was applied to both load and power-injecting DER (e.g., solar PV) with a focus on large resources (1+ MW), which are most likely to be impacted by thermal loading constraints.

Interconnection Criteria Considerations for Study

As explained earlier in the report, many study constraint criteria are not meaningfully impacted by the use of schedule options. The impact of scheduled operation, for the purposes of this study, was only applied to thermal overloads of substation equipment (e.g., transformers and feeder exit equipment), as they are the most practical constraint to avoid using scheduled operation and generally have high upgrade costs.

In practice, however, it is known that considering only the potential positive impact on thermal constraints does not capture the full impact of other interconnection criteria that may constraint interconnection at a specific site. For the purposes of this study, thermal limitations will be considered independently to demonstrate the study process and potential impacts of flexibility on thermal constraints.

Throughout the study, a 0.25 MVA margin was applied between the allowable operation and the summer normal rating of the equipment. This margin was selected to identify the full potential value of flexible options. In practice, this approach may result in substation equipment being loaded very near to the limit, with only a small number of additional residential or small commercial load or DER applications able to be accommodated before the criteria is violated. In a more realistic implementation, additional reserve margin may be necessary to ensure the viability and timeliness of small customer connections and to ensure that existing cost allocation mechanisms for large load and DER can continue to function effectively.

Developing Load Profiles for Use in Scheduled Studies

Load Data Cleanup

The process for cleaning SCADA data was vital to the study process to ensure results would be as accurate as possible. Multiple years of hourly kW and kVAR substation SCADA data were provided for each substation studied. Each set of data was screened for sudden rises and dips to identify switching events or data errors not reflective of anticipated system performance. If data was found to be unreasonable, erroneous data was replaced based on the load trends before and after the period of unsound data to provide a continuous data set for analysis.

Schedule Selection for Study

The following schedule granularities were evaluated within the demonstration study:

- 2-Point Time-of-Day: 10 AM – 2 PM, 2 PM – 10 AM
- 2-Point Time-of-Day: 11 PM to 7 AM, 7 AM to 11 PM
- 4-Point Seasonal: June-September, October-November, December-February, March-May
- 24-Point Blocks varying across 4 seasons, each with 6-time blocks
    - Seasons: June-September, October-November, December-February, March-May
    - Time Blocks: 10 AM – 2 PM, 2 PM -6 PM, 6PM -10 PM, 10 PM – 2 AM, 2 AM - 6 AM, 6 AM – 10 AM

Site Selection for Study

When selecting the substation to be considered within the study, emphasis was placed on identifying a realistic location that could be subjected to future large load and DER growth and could effectively illustrate the flexible interconnection concept. Consequently, the study results are not intended to reflect typical system locations and should not be used to make projections about the overall value of flexible interconnection throughout Ameren Illinois' distribution system.

Preference was given for substations that serve a relatively rural area and are located within five miles of an interstate highway exit with multiple gas stations. Being in a relatively rural area generally means there is land available for potential large solar PV deployment(s). Being close to a large interstate exit increases the likelihood that EV charging corridor development will bring new large DC fast charging loads with the potential for flexible charging.

Because flexible interconnection is intended to avoid triggering higher cost distribution substation system thermal loading constraints, preference was given to substations where the substation transformer has less than 5 MW of remaining load capacity (constrained by thermal loading). Further preference was given to substations that also have less than 5 MW of DER hosting capacity. This helps maximize the demonstration value for using flexible interconnections to avoid triggering system upgrades.

Assessing Customer Impacts of Scheduled Operation

One of the key elements of the study will be to quantify the level of impact of schedule-based restrictions on the resource's ability to operate. The study will consider solar PV and large flexible loads. Once the operational schedule is determined, resource impacts will be identified by quantifying the number and relative timing of constrained intervals (e.g., which hours, months, or seasons) as well as the magnitude of those constraints.

For Solar PV, estimated output profiles for a typical year will be developed from the National Renewable Energy Laboratory (NREL) PVWatts tool. Additional consideration will be given to actual solar PV performance data if existing PV systems with SCADA telemetry are available in the vicinity of the substation selected for study. Because these estimation methods produce realistic operational data, estimated curtailment can be directly calculated by comparing the scheduled operating limits against the production that would otherwise be expected during a specific time interval.

For flexible loads, it is much more challenging to generate realistic operating profiles. Even if narrowing the profile down to just DC fast charging equipment, generating an accurate, representative profile is difficult, as it will depend heavily on the specific location of the facilities and may change significantly as EV adoption increases and fast charging becomes more heavily utilized. As a result, rather than directly estimated load capacity curtailment, the analysis will identify the anticipated periods where power import will be restricted to a value below the maximum. Unlike the solar PV analysis, this approach for loads cannot be directly translated into an overall volume of energy curtailed or lost production. Instead, it would reflect periods where charging or other equipment utilization may need to occur more slowly. When communicating the resulting information, the primary focus will be on information that applicants would need to decide whether static scheduled flexible interconnection is viable for their facility's operational needs.

Static Schedule Study Approach

2-Point Time-of-Day

For 2-Point time-of-day schedules, each year of clean load data was filtered between the defined schedule time-blocks. The maximum and minimum kW demand for each time-block was defined using the hourly load data and then verified to ensure reasonableness. Since both BESS and PV were being studied, export limits were further defined by technology. For PV, only daytime loading periods were considered since PV can only produce when sunlight is available. BESS limits considered each hour of the day since BESS can be dispatched when needed if charged.

Real and reactive power demand data for the dates identified were converted to kVA and then compared to the substation rating to determine system limits. Export limits were defined by the addition of the minimum system load plus the substation rating. Import limits were defined by the difference between the maximum system load and the substation rating. For both the import and export limits, a margin of safety is subtracted from the limits to account for changes in actual load. The initial margin of safety used is 0.25 MVA but can be changed based on utility needs. The results consist of two export limits and two import limits.

4-Point Seasonal

The process to determine limits for the 4-Point seasonal schedules was almost the same as the process for creating the 2-Point time-of-day schedules but instead identified minimum and maximum loading per season. A 0.25 MVA margin of safety was applied to 4-Points limits as well. The results consist of four export limits and four import limits.

24-Point Blocks

The process for determining 24-Point schedules was similar to the processes for the 4-Point and 2-Point schedules but identified the minimum and maximum loading across each season and for each of the six time-blocks. The 0.25 MVA margin of safety was applied to the 24-Point limits, with results consisting of 24 export limits and 24 import limits.

Static Scheduled Interconnections - Study Results Summary

Two substations within Ameren's service area were studied to provide an example of what flexible interconnection limits could look like. Substation A serves primarily small commercial and residential loads near an interstate exit, with rural loading near the end of the circuit with little to no existing generation. Substation B also serves small commercial and residential loading near an interstate in a rural area but has more existing generation than substation A.

The sections below provide summary results for each study. For each table, the lowest import or export limit across all intervals represents the value at which, without schedule options, import or export would be limited throughout the year.

Results for both substations showed similar patterns for both export and import limits. Export limits showed little variation between time-block or season, resulting in little variation in between schedule types in the amount of curtailment for the PV example studies. The small difference in export limits between time-blocks and seasons was due to there being little change in minimum loading that helped to define the limits. Import limits for loads resulted in more variation within each schedule except for the 2-Point schedule geared towards PV+BESS.

PV Data Collection

Standalone PV Data Collection

NREL's PVWATTs[10] tool was used to obtain hourly PV data based on the criteria in the Table 6 below. PVWATTs is a tool developed by NREL to estimate PV production based on location provided by the user and national irradiance data.

Table 6: PVWatts Inputs for Example PV Profile

DC System Size (kW)	1,200
DC to AC Ratio	1.2
AC System Size (kW)	1,000
Module Type	Standard
Array Type	1-Axis Tracking
Array Tilt (deg)	0
Array Azimuth (deg)	180
System Losses (%)	14.08
Inverter Efficiency Rating (%)	96
Ground Coverage Ratio	96

Substation A Static Scheduled Results

Static Schedule Limits

For substation A, hourly load data from 2022, 2024, and 2025 were used along with a substation capacity rating of 6.25 MVA to determine import and export limits according to the processes defined in the Study Approach section.

Table 7 below provides limits for substation A using the 2-Point schedule targeted towards PV and BESS. Both the export and import limits for this schedule saw little difference between the limits for each time block.

Table 7: Substation A Limits for 2-Point Schedule Targeted Towards PV+BESS

Time-Block	PV Export Limits (MVA)	BESS Export Limits (MVA)	Flex Load and BESS Import Limits (MVA)
10AM-2PM	7.14	7.14	2.11
2PM-10AM	7.20	7.03	1.77

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[10] NREL's PVWatts: PVWatts Calculator

Table 8 below provides limits for substation A using the 2-Point schedule targeted towards EV and electric fleets (which aligns with the time periods from Ameren Illinois' Electric Vehicle Charging Program Rider EVCP). While export limits saw little variation (like the other 2-Point schedule), import limits saw a relatively large change between time blocks, with a 1.5 MW difference between time-block limits (an 84% increase relative to the fixed limit).

Table 8: Substation A Limits for 2-Point Schedule Targeted Towards EV and Fleets

Time-Block	PV Export Limits (MVA)	BESS Export Limits (MVA)	Flex Load and BESS Import Limits (MVA)
7AM-11PM	7.15	7.15	1.77
11PM-7AM	7.03	7.03	3.27

Table 9 below provides limits for substation A using the 4-Point seasonal schedule which is geared towards capturing general variations in available capacity throughout the year. Minimum load data did not show much variation across seasons, resulting in little difference between export limits. However, import limits showed much more variation, with summer having the lowest limit and winter having the highest limit.

Table 9: Substation A Limits for 4-Point Seasonal Schedule

Season	PV Export Limits (MVA)	BESS Export Limits (MVA)	Flex Load and BESS Import Limits (MVA)
Mar-May	7.14	7.03	2.46
Jun-Sep	7.19	7.06	1.77
Oct-Nov	7.21	7.15	2.68
Dec-Feb	7.31	7.12	3.33

Table 10 and Table 11 below provide export and import limits for substation A using the 24-Point seasonal time-blocks schedule which is geared towards capturing variations in limits across seasons and four-hour time-blocks. Similarly to the 2-Point and 4-Point schedule limits, the 24-Point schedule export limits showed little variation between limits, with 0.47 MW variation between the highest and lowest periods. Import limits showed much more variation than export limits, with a 2.27 MW difference between the highest and lowest periods.

Table 10: Substation A Export Limits for 24-Point Seasonal Time-Blocks Schedule

Month/ Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	7.16	7.16	7.03	7.03	7.03	7.13	7.13	7.13	7.13	7.15	7.15	7.16
1	7.16	7.16	7.03	7.03	7.03	7.13	7.13	7.13	7.13	7.15	7.15	7.16
2	7.12	7.12	7.03	7.03	7.03	7.06	7.06	7.06	7.06	7.18	7.18	7.12
3	7.12	7.12	7.03	7.03	7.03	7.06	7.06	7.06	7.06	7.18	7.18	7.12
4	7.12	7.12	7.03	7.03	7.03	7.06	7.06	7.06	7.06	7.18	7.18	7.12
5	7.12	7.12	7.03	7.03	7.03	7.06	7.06	7.06	7.06	7.18	7.18	7.12
6	7.31	7.31	7.16	7.16	7.16	7.16	7.16	7.16	7.16	7.26	7.26	7.31
7	7.31	7.31	7.16	7.16	7.16	7.16	7.16	7.16	7.16	7.26	7.26	7.31
8	7.31	7.31	7.16	7.16	7.16	7.16	7.16	7.16	7.16	7.26	7.26	7.31
9	7.31	7.31	7.16	7.16	7.16	7.16	7.16	7.16	7.16	7.26	7.26	7.31
10	7.31	7.31	7.14	7.14	7.14	7.20	7.20	7.20	7.20	7.21	7.21	7.31
11	7.31	7.31	7.14	7.14	7.14	7.20	7.20	7.20	7.20	7.21	7.21	7.31
12	7.31	7.31	7.14	7.14	7.14	7.20	7.20	7.20	7.20	7.21	7.21	7.31
13	7.31	7.31	7.14	7.14	7.14	7.20	7.20	7.20	7.20	7.21	7.21	7.31
14	7.32	7.32	7.20	7.20	7.20	7.35	7.35	7.35	7.35	7.30	7.30	7.32
15	7.32	7.32	7.20	7.20	7.20	7.35	7.35	7.35	7.35	7.30	7.30	7.32
16	7.32	7.32	7.20	7.20	7.20	7.35	7.35	7.35	7.35	7.30	7.30	7.32
17	7.32	7.32	7.20	7.20	7.20	7.35	7.35	7.35	7.35	7.30	7.30	7.32
18	7.50	7.50	7.21	7.21	7.21	7.36	7.36	7.36	7.36	7.41	7.41	7.50
19	7.50	7.50	7.21	7.21	7.21	7.36	7.36	7.36	7.36	7.41	7.41	7.50
20	7.50	7.50	7.21	7.21	7.21	7.36	7.36	7.36	7.36	7.41	7.41	7.50
21	7.50	7.50	7.21	7.21	7.21	7.36	7.36	7.36	7.36	7.41	7.41	7.50
22	7.16	7.16	7.03	7.03	7.03	7.13	7.13	7.13	7.13	7.15	7.15	7.16
23	7.16	7.16	7.03	7.03	7.03	7.13	7.13	7.13	7.13	7.15	7.15	7.16

Table 11: Substation A Import Limits for 24-Point Seasonal Time-Blocks Schedule

Month/ Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	3.57	3.57	3.68	3.68	3.68	2.97	2.97	2.97	2.97	4.03	4.03	3.57
1	3.57	3.57	3.68	3.68	3.68	2.97	2.97	2.97	2.97	4.03	4.03	3.57
2	3.82	3.82	4.00	4.00	4.00	3.66	3.66	3.66	3.66	4.04	4.04	3.82
3	3.82	3.82	4.00	4.00	4.00	3.66	3.66	3.66	3.66	4.04	4.04	3.82
4	3.82	3.82	4.00	4.00	4.00	3.66	3.66	3.66	3.66	4.04	4.04	3.82
5	3.82	3.82	4.00	4.00	4.00	3.66	3.66	3.66	3.66	4.04	4.04	3.82
6	3.53	3.53	3.51	3.51	3.51	2.77	2.77	2.77	2.77	3.89	3.89	3.53
7	3.53	3.53	3.51	3.51	3.51	2.77	2.77	2.77	2.77	3.89	3.89	3.53
8	3.53	3.53	3.51	3.51	3.51	2.77	2.77	2.77	2.77	3.89	3.89	3.53
9	3.53	3.53	3.51	3.51	3.51	2.77	2.77	2.77	2.77	3.89	3.89	3.53
10	3.44	3.44	2.90	2.90	2.90	2.11	2.11	2.11	2.11	3.03	3.03	3.44
11	3.44	3.44	2.90	2.90	2.90	2.11	2.11	2.11	2.11	3.03	3.03	3.44
12	3.44	3.44	2.90	2.90	2.90	2.11	2.11	2.11	2.11	3.03	3.03	3.44
13	3.44	3.44	2.90	2.90	2.90	2.11	2.11	2.11	2.11	3.03	3.03	3.44
14	3.33	3.33	2.46	2.46	2.46	1.77	1.77	1.77	1.77	2.68	2.68	3.33
15	3.33	3.33	2.46	2.46	2.46	1.77	1.77	1.77	1.77	2.68	2.68	3.33
16	3.33	3.33	2.46	2.46	2.46	1.77	1.77	1.77	1.77	2.68	2.68	3.33
17	3.33	3.33	2.46	2.46	2.46	1.77	1.77	1.77	1.77	2.68	2.68	3.33
18	3.35	3.35	2.91	2.91	2.91	1.93	1.93	1.93	1.93	3.20	3.20	3.35
19	3.35	3.35	2.91	2.91	2.91	1.93	1.93	1.93	1.93	3.20	3.20	3.35
20	3.35	3.35	2.91	2.91	2.91	1.93	1.93	1.93	1.93	3.20	3.20	3.35
21	3.35	3.35	2.91	2.91	2.91	1.93	1.93	1.93	1.93	3.20	3.20	3.35
22	3.57	3.57	3.68	3.68	3.68	2.97	2.97	2.97	2.97	4.03	4.03	3.57
23	3.57	3.57	3.68	3.68	3.68	2.97	2.97	2.97	2.97	4.03	4.03	3.57

PV Example Results

Table 12 below provides the results after applying the schedule limits to the annual PV profile obtained from PVWatts at various interconnection sizes. Each row provides the total amount of PV production if a generator of the relevant size is connected, as well as total PV production after curtailment from each schedule and the percent curtailed. Due to minimal differences in export schedule limits across intervals, there is little change in the amount of PV curtailment between schedule options.

Table 12: Standalone PV Curtailment from Static Schedule Limits for Substation A

PV Size (MW)	Hypothetical Uncurtailed PV Production (MWh):	Annual PV Production after Curtailment (MWh):			
		2-Point for PV+BESS	2-Point for EV/Fleet	4-Point	24-Point
7.5MW	14,503	14,499 (-0.03%)	14,499 (-0.03%)	14,499 (-0.03%)	14,500 (-0.03%)
8MW	15,470	15,423 (-0.31%)	15,422 (-0.31%)	15,425 (-0.29%)	15,426 (-0.29%)
8.5MW	16,437	16,284 (-0.93%)	16,281 (-0.95%)	16,290 (-0.90%)	16,293 (-0.88%)
9MW	17,404	17,047 (-2.05%)	17,041 (-2.09%)	17,060 (-1.98%)	17,069 (-1.93%)
9.5MW	18,371	17,694 (-3.69%)	17,684 (-3.74%)	17,716 (-3.57%)	17,732 (-3.48%)
10MW	19,338	18,247 (-5.64%)	18,234 (-5.71%)	18,277 (-5.49%)	18,299 (-5.37%)

Load Example Results

The tables below estimate the degree of operation available to a new 3 MVA constant load on substation A and after applying each static schedule. This load size was selected to demonstrate the potential impacts of each operating schedule and the resulting restrictions. Each table provides a 288-point summary view of where the load could potentially see constrained operation during all intervals of the corresponding schedule. Each cell within the table reflects the total magnitude of potential operation (relative to the 3 MVA size, displayed as a percentage) that is restricted during the time interval. For static schedule results, this can be interpreted as “the percentage of the total load size that can be operating during the interval.”

Table 13: Flexible Limits for 3 MVA Load Using 2-Point Schedule for PV+BESS for Substation A

Time Block	Import Limit (MVA)	Total Number of Intervals Per Year	Number of Intervals Constrained
10AM-2PM	2.11	1,460	1,460
2PM-10AM	1.77	7,300	7,300

Table 14: Flexible Load 288-Point Results Using 2-Point Schedule for PV+BESS for Substation A

Month/ Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
1	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
2	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
3	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
4	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
5	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
6	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
7	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
8	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
9	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
10	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
11	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
12	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
13	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
14	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
15	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
16	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
17	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
18	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
19	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
20	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
21	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
22	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
23	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%

Table 15: Flexible Limits for 3 MVA Load Using 2-Point Schedule for EV/Fleets for Substation A

Time Block	Import Limit (MVA)	Total Number of Intervals Per Year	Number of Intervals Constrained
7AM-11PM	1.77	5,840	5,840
11PM-7AM	3.27	2,920	0

Table 16: Flexible Load 288-Point Results Using 2-Point Schedule for EV/Fleets for Substation A

Month/ Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
2	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
5	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
6	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
7	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
8	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
9	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
10	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
11	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
12	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
13	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
14	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
15	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
16	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
17	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
18	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
19	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
20	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
21	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
22	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%	59%
23	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Table 17: Flexible Limits for 3 MVA Load Using 4-Point Schedule for Substation A

Time Block	Import Limit (MVA)	Total Number of Intervals Per Year	Number of Intervals Constrained
Mar-May	2.46	2,208	2,208
Jun-Sep	1.77	2,928	2,928
Oct-Nov	2.68	1,464	1,464
Dec-Feb	3.33	2,160	0

Table 18: Flexible Load 288-Point Results Using 4-Point Schedule for Substation A

Month/ Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
1	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
2	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
3	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
4	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
5	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
6	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
7	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
8	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
9	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
10	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
11	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
12	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
13	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
14	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
15	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
16	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
17	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
18	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
19	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
20	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
21	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
22	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
23	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%

Table 19: Flexible Limits for 3 MVA Load Using 24-Point Schedule for Substation A

Season	Time Block	Import Limit (MVA)	Total Number of Intervals Per Year	Number of Intervals Constrained
Mar-May	2am-6am	4.00	368	0
	6am-10am	3.51	368	0
	10am-2pm	2.90	368	368
	2pm-6pm	2.46	368	368
	6pm-10pm	2.91	368	368
	10pm-2am	3.68	368	0
Jun-Sep	2am-6am	3.66	488	0
	6am-10am	2.77	488	488
	10am-2pm	2.11	488	488
	2pm-6pm	1.77	488	488
	6pm-10pm	1.93	488	488
	10pm-2am	2.97	488	488
Oct-Nov	2am-6am	4.04	244	0
	6am-10am	3.89	244	0
	10am-2pm	3.03	244	0
	2pm-6pm	2.68	244	488
	6pm-10pm	3.20	244	0
	10pm-2am	4.03	244	0
Dec-Feb	2am-6am	3.82	360	0
	6am-10am	3.53	360	0
	10am-2pm	3.44	360	0
	2pm-6pm	3.33	360	0
	6pm-10pm	3.35	360	0
	10pm-2am	3.57	360	0

Table 20: Flexible Load 288-Point Results Using 24-Point Schedule for Substation A

Month/ Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	100%	100%	100%	100%	100%	99%	99%	99%	99%	100%	100%	100%
1	100%	100%	100%	100%	100%	99%	99%	99%	99%	100%	100%	100%
2	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
5	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
6	100%	100%	100%	100%	100%	92%	92%	92%	92%	100%	100%	100%
7	100%	100%	100%	100%	100%	92%	92%	92%	92%	100%	100%	100%
8	100%	100%	100%	100%	100%	92%	92%	92%	92%	100%	100%	100%
9	100%	100%	100%	100%	100%	92%	92%	92%	92%	100%	100%	100%
10	100%	100%	97%	97%	97%	70%	70%	70%	70%	100%	100%	100%
11	100%	100%	97%	97%	97%	70%	70%	70%	70%	100%	100%	100%
12	100%	100%	97%	97%	97%	70%	70%	70%	70%	100%	100%	100%
13	100%	100%	97%	97%	97%	70%	70%	70%	70%	100%	100%	100%
14	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
15	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
16	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
17	100%	100%	82%	82%	82%	59%	59%	59%	59%	89%	89%	100%
18	100%	100%	97%	97%	97%	64%	64%	64%	64%	100%	100%	100%
19	100%	100%	97%	97%	97%	64%	64%	64%	64%	100%	100%	100%
20	100%	100%	97%	97%	97%	64%	64%	64%	64%	100%	100%	100%
21	100%	100%	97%	97%	97%	64%	64%	64%	64%	100%	100%	100%
22	100%	100%	100%	100%	100%	99%	99%	99%	99%	100%	100%	100%
23	100%	100%	100%	100%	100%	99%	99%	99%	99%	100%	100%	100%

Substation B Static Scheduled Results

Static Schedule Limits

For substation B, hourly load data from 2022 and 2023 load were used along with a substation capacity rating of 16.06 MVA to determine import and export limits according to the processes defined in the Study Approach section.

Table 21 provides the export and import limits for substation B using the 2-Point schedule geared towards PV and PV+BESS systems. Similarly to substation A's export and import limits under the same schedule type, the limits for substation B showed little variation between time blocks.

Table 21: Substation B Limits for 2-Point Schedule Targeted Towards PV+BESS

Time-Block	PV Export Limits (MVA)	BESS Export Limits (MVA)	Flex Load and BESS Import Limits (MVA)
10AM-2PM	18.06	18.06	6.73
2PM-10AM	18.02	17.98	6.77

Table 22 summarizes substation B limits using the 2-Point schedule geared towards EVs and electric fleets (aligning with Rider EVCP). Export limits under this schedule resulted in a small difference between limits, but import limits saw about 2.64 MVA difference in limits between the two time-blocks.

Table 22: Substation B Limits for 2-Point Schedule Targeted Towards EV and Fleets

Time-Block	PV Export Limits (MVA)	BESS Export Limits (MVA)	Flex Load and BESS Import Limits (MVA)
7AM-11PM	18.02	18.02	6.77
11PM-7AM	17.98	17.98	9.41

Table 23 provides limits for substation B using a 4-Point seasonal schedule, which similarly to the 4-Point schedule for substation A, saw little variation in export limits but much more variation in import limits.

Table 23: Substation B Limits for 4-Point Seasonal Schedule

Season	PV Export Limits (MVA)	BESS Export Limits (MVA)	Flex Load and BESS Import Limits (MVA)
Mar-May	18.02	17.98	7.88
Jun-Sep	18.54	18.19	6.77
Oct-Nov	18.40	19.41	9.09
Dec-Feb	18.09	18.09	9.64

Table 24 and Table 25 provide the export and import limits for Substation B using heat maps. The export limits resulted in a 1.81 MW difference between the maximum and minimum limits, while import limits resulted in a 4.32 MW difference between the maximum and minimum limits.

Table 24: Substation B Export Limits for 24-Point Seasonal Time-Blocks Schedule

Month/ Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	18.49	18.49	18.03	18.03	18.03	18.37	18.37	18.37	18.37	19.42	19.42	18.49
1	18.49	18.49	18.03	18.03	18.03	18.37	18.37	18.37	18.37	19.42	19.42	18.49
2	18.32	18.32	17.98	17.98	17.98	18.19	18.19	18.19	18.19	19.41	19.41	18.32
3	18.32	18.32	17.98	17.98	17.98	18.19	18.19	18.19	18.19	19.41	19.41	18.32
4	18.32	18.32	17.98	17.98	17.98	18.19	18.19	18.19	18.19	19.41	19.41	18.32
5	18.32	18.32	17.98	17.98	17.98	18.19	18.19	18.19	18.19	19.41	19.41	18.32
6	18.42	18.42	18.07	18.07	18.07	18.36	18.36	18.36	18.36	19.79	19.79	18.42
7	18.42	18.42	18.07	18.07	18.07	18.36	18.36	18.36	18.36	19.79	19.79	18.42
8	18.42	18.42	18.07	18.07	18.07	18.36	18.36	18.36	18.36	19.79	19.79	18.42
9	18.42	18.42	18.07	18.07	18.07	18.36	18.36	18.36	18.36	19.79	19.79	18.42
10	18.09	18.09	18.06	18.06	18.06	18.76	18.76	18.76	18.76	18.40	18.40	18.09
11	18.09	18.09	18.06	18.06	18.06	18.76	18.76	18.76	18.76	18.40	18.40	18.09
12	18.09	18.09	18.06	18.06	18.06	18.76	18.76	18.76	18.76	18.40	18.40	18.09
13	18.09	18.09	18.06	18.06	18.06	18.76	18.76	18.76	18.76	18.40	18.40	18.09
14	18.12	18.12	18.02	18.02	18.02	18.88	18.88	18.88	18.88	18.64	18.64	18.12
15	18.12	18.12	18.02	18.02	18.02	18.88	18.88	18.88	18.88	18.64	18.64	18.12
16	18.12	18.12	18.02	18.02	18.02	18.88	18.88	18.88	18.88	18.64	18.64	18.12
17	18.12	18.12	18.02	18.02	18.02	18.88	18.88	18.88	18.88	18.64	18.64	18.12
18	19.02	19.02	18.51	18.51	18.51	19.14	19.14	19.14	19.14	18.54	18.54	19.02
19	19.02	19.02	18.51	18.51	18.51	19.14	19.14	19.14	19.14	18.54	18.54	19.02
20	19.02	19.02	18.51	18.51	18.51	19.14	19.14	19.14	19.14	18.54	18.54	19.02
21	19.02	19.02	18.51	18.51	18.51	19.14	19.14	19.14	19.14	18.54	18.54	19.02
22	18.49	18.49	18.03	18.03	18.03	18.37	18.37	18.37	18.37	19.42	19.42	18.49
23	18.49	18.49	18.03	18.03	18.03	18.37	18.37	18.37	18.37	19.42	19.42	18.49

Table 25: Substation B Import Limits for 24-Point Seasonal Time-Blocks Schedule

Month/ Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	10.05	10.05	9.38	9.38	9.38	8.25	8.25	8.25	8.25	10.79	10.79	10.05
1	10.05	10.05	9.38	9.38	9.38	8.25	8.25	8.25	8.25	10.79	10.79	10.05
2	10.57	10.57	9.61	9.61	9.61	10.36	10.36	10.36	10.36	11.05	11.05	10.57
3	10.57	10.57	9.61	9.61	9.61	10.36	10.36	10.36	10.36	11.05	11.05	10.57
4	10.57	10.57	9.61	9.61	9.61	10.36	10.36	10.36	10.36	11.05	11.05	10.57
5	10.57	10.57	9.61	9.61	9.61	10.36	10.36	10.36	10.36	11.05	11.05	10.57
6	9.80	9.80	9.61	9.61	9.61	8.91	8.91	8.91	8.91	10.48	10.48	9.80
7	9.80	9.80	9.61	9.61	9.61	8.91	8.91	8.91	8.91	10.48	10.48	9.80
8	9.80	9.80	9.61	9.61	9.61	8.91	8.91	8.91	8.91	10.48	10.48	9.80
9	9.80	9.80	9.61	9.61	9.61	8.91	8.91	8.91	8.91	10.48	10.48	9.80
10	9.96	9.96	8.30	8.30	8.30	6.73	6.73	6.73	6.73	9.50	9.50	9.96
11	9.96	9.96	8.30	8.30	8.30	6.73	6.73	6.73	6.73	9.50	9.50	9.96
12	9.96	9.96	8.30	8.30	8.30	6.73	6.73	6.73	6.73	9.50	9.50	9.96
13	9.96	9.96	8.30	8.30	8.30	6.73	6.73	6.73	6.73	9.50	9.50	9.96
14	9.90	9.90	7.88	7.88	7.88	6.77	6.77	6.77	6.77	9.09	9.09	9.90
15	9.90	9.90	7.88	7.88	7.88	6.77	6.77	6.77	6.77	9.09	9.09	9.90
16	9.90	9.90	7.88	7.88	7.88	6.77	6.77	6.77	6.77	9.09	9.09	9.90
17	9.90	9.90	7.88	7.88	7.88	6.77	6.77	6.77	6.77	9.09	9.09	9.90
18	9.64	9.64	7.93	7.93	7.93	6.91	6.91	6.91	6.91	9.54	9.54	9.64
19	9.64	9.64	7.93	7.93	7.93	6.91	6.91	6.91	6.91	9.54	9.54	9.64
20	9.64	9.64	7.93	7.93	7.93	6.91	6.91	6.91	6.91	9.54	9.54	9.64
21	9.64	9.64	7.93	7.93	7.93	6.91	6.91	6.91	6.91	9.54	9.54	9.64
22	10.05	10.05	9.38	9.38	9.38	8.25	8.25	8.25	8.25	10.79	10.79	10.05
23	10.05	10.05	9.38	9.38	9.38	8.25	8.25	8.25	8.25	10.79	10.79	10.05

PV Example Results

Table 26 summarizes the PV curtailment for Substation B after applying each schedule type to an example PV profile using various sizes. Since the PV schedule limits did not vary significantly between time-blocks and seasons, curtailment did not vary much between schedules.

Table 26: Standalone PV Curtailment from Static Schedule Limits for Substation B

PV Size (MW)	Annual Uncurtailed PV Production (MWh):	Annual PV Production after Curtailment (MWh):			
		2-Point for PV+BESS	2-Point for EV/Fleet	4-Point	24-Point
19.5MW	37,709	47 (-0.12%)	49 (-0.13%)	49 (-0.13%)	46 (-0.12%)
20.5MW	39,642	173 (-0.44%)	177 (-0.45%)	166 (-0.42%)	159 (-0.40%)
21.5MW	41,576	413 (-0.99%)	420 (-1.01%)	372 (-0.89%)	358 (-0.86%)
22.5MW	43,510	815 (-1.87%)	827 (-1.90%)	708 (-1.63%)	681 (-1.57%)
23.5MW	45,444	1406 (-3.09%)	1423 (-3.13%)	1208 (-2.66%)	1157 (-2.55%)
24.5MW	47,377	2161 (-4.56%)	2182 (-4.61%)	1894 (-4.00%)	1812 (-3.82%)
25.5MW	49,311	3043 (-6.17%)	3066 (-6.22%)	2726 (-5.53%)	2620 (-5.31%)

Flexible Load Study Results

Table 27 through Table 34 below estimate the degree of operation available to a new 9 MVA constant load on Substation B after applying each static schedule. This load size was selected to demonstrate the potential impacts of each operating schedule and the resulting restrictions. Each table provides a 288-point summary view of where the load could potentially see constrained operation during all intervals of the corresponding schedule. Each cell within the table reflects the total magnitude of potential operation (relative to the 9 MVA size, displayed as a percentage) that is restricted during the time interval. For static schedule results, this can be interpreted as “the percentage of the total load size that can be operating during the interval.”

Table 27: Flexible Limits for 9 MVA Load Using 2-Point Schedule for PV+BESS for Substation B

Time Block	Import Limit (MVA)	Total Number of Intervals Per Year	Number of Intervals Constrained
10AM-2PM	6.73	1,460	1,460
2PM-10AM	6.77	7,300	7,300

Table 28: Flexible Load 288-Point Curtailment using 2-Point Schedule for PV+BESS for Substation B

Month/ Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
1	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
2	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
3	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
4	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
5	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
6	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
7	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
8	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
9	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
10	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%
11	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%
12	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%
13	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%
14	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%	74.8%
15	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
16	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
17	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
18	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
19	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
20	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
21	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
22	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%
23	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%	75.2%

Table 29: Flexible Limits for 9 MVA Load Using 2-Point Schedule for EV/Fleets for Substation B

Time Block	Import Limit (MVA)	Total Number of Intervals Per Year	Number of Intervals Constrained
7AM-11PM	6.77	5,840	5,840
11PM-7AM	9.41	2,920	0

Table 30: Flexible Load 288-Point Curtailment using 2-Point Schedule for EV/Fleets for Substation B

Month/ Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
2	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
5	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
6	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
7	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
8	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
9	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
10	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
11	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
12	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
13	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
14	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
15	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
16	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
17	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
18	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
19	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
20	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
21	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
22	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%
23	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%	75%

Table 31: Flexible Limits for 9 MVA Load Using 4-Point Schedule for Substation B

Time Block	Import Limit (MVA)	Total Number of Intervals Per Year	Number of Intervals Constrained
Mar-May	7.88	2,208	0
Jun-Sep	6.77	2,928	2,928
Oct-Nov	9.09	1,464	1,464
Dec-Feb	9.64	2,160	0

Table 32: Flexible Load 288-Point Curtailment using 4-Point Schedule for Substation B

Month/ Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
1	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
2	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
3	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
4	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
5	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
6	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
7	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
8	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
9	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
10	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
11	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
12	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
13	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
14	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
15	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
16	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
17	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
18	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
19	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
20	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
21	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
22	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
23	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%

Table 33: Flexible Limits for 9 MVA Load Using 24-Point Schedule for Substation B

Season	Time Block	Import Limit (MVA)	Total Number of Intervals Per Year	Number of Intervals Constrained
Mar-May	2am-6am	9.61	368	0
	6am-10am	9.61	368	0
	10am-2pm	8.30	368	368
	2pm-6pm	7.88	368	368
	6pm-10pm	7.93	368	368
	10pm-2am	9.38	368	0
Jun-Sep	2am-6am	10.36	488	0
	6am-10am	8.91	488	488
	10am-2pm	6.73	488	488
	2pm-6pm	6.77	488	488
	6pm-10pm	6.91	488	488
	10pm-2am	8.25	488	488
Oct-Nov	2am-6am	11.05	244	0
	6am-10am	10.48	244	0
	10am-2pm	9.50	244	0
	2pm-6pm	9.09	244	0
	6pm-10pm	9.54	244	0
	10pm-2am	10.79	244	0
Dec-Feb	2am-6am	10.57	360	0
	6am-10am	9.80	360	0
	10am-2pm	9.96	360	0
	2pm-6pm	9.90	360	0
	6pm-10pm	9.64	360	0
	10pm-2am	10.05	360	0

Table 34: Flexible Load 288-Point Curtailment using 24-Point Schedule for Substation B

Month/ Hour	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
0	100%	100%	100%	100%	100%	92%	92%	92%	92%	100%	100%	100%
1	100%	100%	100%	100%	100%	92%	92%	92%	92%	100%	100%	100%
2	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
5	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
6	100%	100%	100%	100%	100%	99%	99%	99%	99%	100%	100%	100%
7	100%	100%	100%	100%	100%	99%	99%	99%	99%	100%	100%	100%
8	100%	100%	100%	100%	100%	99%	99%	99%	99%	100%	100%	100%
9	100%	100%	100%	100%	100%	99%	99%	99%	99%	100%	100%	100%
10	100%	100%	92%	92%	92%	75%	75%	75%	75%	100%	100%	100%
11	100%	100%	92%	92%	92%	75%	75%	75%	75%	100%	100%	100%
12	100%	100%	92%	92%	92%	75%	75%	75%	75%	100%	100%	100%
13	100%	100%	92%	92%	92%	75%	75%	75%	75%	100%	100%	100%
14	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
15	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
16	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
17	100%	100%	88%	88%	88%	75%	75%	75%	75%	100%	100%	100%
18	100%	100%	88%	88%	88%	77%	77%	77%	77%	100%	100%	100%
19	100%	100%	88%	88%	88%	77%	77%	77%	77%	100%	100%	100%
20	100%	100%	88%	88%	88%	77%	77%	77%	77%	100%	100%	100%
21	100%	100%	88%	88%	88%	77%	77%	77%	77%	100%	100%	100%
22	100%	100%	100%	100%	100%	92%	92%	92%	92%	100%	100%	100%
23	100%	100%	100%	100%	100%	92%	92%	92%	92%	100%	100%	100%

Dynamic Flexible Interconnections

Dynamic Flexible interconnection shows significant potential to interconnect new resources more efficiently and with a lower degree of constraint when compared to static schedule-based methods. In practice, however, there are many complicating factors that must be considered to effectively implement dynamic flexible connections while maintaining the reliability of the distribution system. This report will explore key questions related to dynamic flexible interconnection implementation and identify a recommended path forward.

Exploration of Key Questions

Ameren Illinois' Phase 1 Flexible Interconnection and DER Orchestration report explored the foundational elements of dynamic flexible interconnections and identified several key questions to answer as part of the detailed design of flexible options. These key questions, which will be explored in detail in this section, include:

- How will available capacity be allocated amongst participating loads and DER?
- Who will be responsible for determining estimated curtailment?
- What supporting tools or data sharing infrastructure needs to be in place to support this analysis?
- What additional mechanisms, if any, are reasonable to protect applicants against higher-than-expected curtailment?
- How will customer site design and equipment be impacted by communications and control requirements?
- What communications architecture, media, and equipment will be necessary to implement dynamic connections effectively?

In addition to these key questions, eligible interconnection criteria (i.e., those that can be avoided using dynamic flexible interconnections) must also be identified.

Eligible Interconnection Criteria

When it comes to evaluating interconnection criteria under a dynamic flexible interconnection approach, many of the considerations relevant to static scheduled connections are still relevant, and there are also new operational factors that must be accounted for. Commercial utility operational control systems (e.g., ADMS/DERMS) generally do not include the same level of analytical capabilities as planning-focused power flow software. As a result, operational systems are generally concerned with managing thermal loading and steady-state voltage. As a result, these two criteria are the primary potential value drivers for dynamic flexible interconnections.

As with the static scheduled method, thermal overload avoidance is the primary value driver of dynamic flexible interconnection for both load and DER. DERMS vendors have demonstrated capabilities to reduce maximum import and export values in response to system conditions to prevent equipment overloads. From the interconnection study perspective, equipment overloads impacting substation transformers and feeder exit equipment are the easiest to analyze and generally result in the highest-cost modifications. Because direct telemetry exists for the loading on these assets, power flow modeling is generally not necessary to effectively assess the impact of the load or DER on the thermal loading of the assets. SCADA metering for substation assets is available for majority of locations, but gaps are still present. For assets outside of the substation, direct telemetry is not available for most system components, so thermal loading assessment would require time-series power flow analysis to estimate thermal loading throughout the year. Because dynamic flexible interconnections do not have pre-defined operating intervals, an annual hourly study (i.e., 8760 analysis) would be required.

Steady-state voltage violation prevention and mitigation can also be performed by commercially available operational control software. However, operational tools do not attempt to identify the root cause of voltage issues, instead attempting to mitigate them with the available control tools. This presents challenges for dynamic flexible interconnection from a study perspective, as emergent high or low voltage issues may or may not be caused directly by the DER and may or may not be able to be effectively mitigated through DER real or reactive power management. In addition, the same challenges of solution cost variability and the requirement for time-series power flow (expanded to hourly 8760 analysis for dynamic studies) are still present. Combined, these factors make it most challenging to assess the need for voltage mitigation as part of dynamic interconnection studies.

Voltage-related impacts are also highly locational, which may make it difficult to effectively utilize dynamic capacity allocation methods in the intended manner. When a voltage violation condition occurs and multiple dynamically managed DER are on the system, each DER may contribute to the cause or resolution of the condition at different magnitudes based on the specific location of the violation and the DER. The relative ability of each DER to impact the constraint condition (commonly referred to as the “sensitivity”) is independent of the intended capacity allocation strategy. For instance, under a pro-rata allocation method where each DER is intended to be equally curtailed on a percentage basis, modifying DER electrically closer to the voltage violation (i.e., with higher sensitivity) would be much more effective at mitigating the violation than modifying a DER that is electrically further away. Maintaining an equal pro-rata curtailment philosophy, in that context, may significantly constrain the operation of the DER least impactful to the violation. Deviating from the pro-rata philosophy could improve overall operational efficiency and reduce curtailment, but it changes the overall allocation approach. The impact is even more significant for LIFO-style curtailment. If a pure “first out” philosophy is maintained, newer DER with limited capability to impact the voltage violation may be fully curtailed even if other DER connected earlier may have much more influence on the violation (and would, as a result, experience much less curtailment to resolve the violation).

With these complexities considered, it is recommended to initially focus on thermal overloads for substation transformers and feeder equipment within the substation. Limiting the applicability of dynamic flexible interconnections to thermal overloads on this equipment will dramatically improve the feasibility of curtailment analysis and ensure that the intended capacity allocation philosophy can be cleanly implemented and maintained.

Capacity Allocation Options

Three capacity allocation strategies (applicable for both load and generation resources) were previously explored in relative detail within the Phase 1 report (Pages 40-44). Summary tables have been provided below for reference:

Table 35 - Capacity Allocation Options Descriptions

Approach	Description
Pure Pro-Rata	Capacity is allocated proportionally based on the relative size of participant resources and their contributions to the constraint condition.
Pro-Rata Tranches	Capacity is allocated proportionally for participants up to a pre-determined total tranche size (i.e. the total amount of aggregate DER that can participate) at a given location.
Pure Last In, First Out (LIFO)	Capacity is allocated based on the order of interconnection, with earlier connectors having higher priority access and later connectors being curtailed first.

Table 36 - Capacity Allocation Option Benefits and Drawbacks

Approach	Benefits	Drawbacks
Pure Pro-Rata	+ Treats all participants equally + Can provide a pathway to efficient system upgrades when used in combination with other mechanisms	– Potential for early connectors to experience increasing curtailment over time, driving adoption hesitancy – Likely requires development of supporting mechanisms to protect early participants
Pro-Rata Tranches	+ Enables equal capacity allocation among participants (up to a pre-set cap) + Maximizes use of existing infrastructure	– Optimal implementation to maximize existing capacity may require regulatory engagement – Unsubscribed portions of the tranche become more complex to manage in future years
Pure LIFO	+ Fastest approach to implement due to philosophical alignment with existing process + Early adopters have more certainty around future curtailment magnitude	– Creates operational complexity and philosophical concerns by enshrining unequal treatment of customers into operational decisions – Enables relatively fewer resources to connect than pro-rata approaches

While these three philosophies provide a useful overview of the concept, there are additional considerations to explore, particularly with respect to Pro-Rata allocation. Illinois, like many other states, utilizes a "cost causer pays" approach to DER interconnection costs where individual applicants bear costs for system upgrades they would trigger if their project were added. If individual projects do not trigger such upgrades, they bare effectively no cost. As a result, applicants are only likely to be interested in flexible interconnection when existing available capacity has been exhausted, and they would otherwise be responsible for major system upgrades. In such an environment, a Pro-Rata capacity allocation mechanism would only share curtailment access amongst participants after traditional firm capacity has been exhausted. This will be referred to as **"U.S.-Style" Pro-Rata**.

Southern Australia, in contrast, has leaned into flexibility as effectively the new default option (at least for residential solar PV, which dominates the market in terms of total aggregate size). Most new residential solar PV are encouraged to pursue flexible interconnections regardless of the existence or non-existence of local constraints, with flexible connections able to connect to 10kW of solar PV while firm connections are limited to 1.5kW[11]. By encouraging flexibility early, a larger total amount of capacity can be shared across all participants, enabling more PV connections with the same infrastructure. This type of "flexibility first" approach, which effectively shares all existing capacity equally, will be referred to as **"Australian-Style Pro-Rata"**.

There is also a separate potential use case for flexible interconnection that would enable DER to remain operational during planned switching events. For certain construction and maintenance activities, particularly for substation equipment, facilities must be de-energized so work can be performed safely. For instance, upgrading feeder voltage regulators within the substation requires the feeder exit to be de-energized. In such cases, customer facilities normally supported by that equipment are transferred to alternate feeders for the duration of construction, which can span days or weeks (or longer, depending on the activities). When facilities are transferred, sometimes DER are unable to remain connected when they are moved to another feeder. This is particularly true for large DER that are located very close to substations, as the transfer to the new feeder may place their system in an area that is electrically weaker and more susceptible to voltage violations or frequent voltage variations. In such cases, DER may not be able to safely remain connected. Utilizing flexible interconnection during planned switching may allow for the DER to remain energized and producing at a reduced level during such switching events, rather than ceasing generation. Because such events are not part of the normal operating condition, DER not interested in flexible interconnection for cost avoidance may still wish to participate on a "**planned switching only**" basis, separate from other capacity allocation considerations.

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[11] Aus Energy Solar: https://ausenergysolar.com/blog/how-much-solar-can-i-export-to-the-grid-in-australia/

Taken together, this equates to five options for capacity allocation under dynamic flexibility:

Table 37: Expanded Capacity Allocation Options

Capacity Allocation Method	Description
Planned Switching Only	Curtailment only during planned switching to enable partial operation. Can be considered independent of participation in normal configuration flexible interconnection or capacity allocation.
Last In, First Out (LIFO)	Earlier applicants and connectors get priority access to capacity, with curtailment occurring in reverse order of approved connection
"U.S. Style" Pure Pro-Rata	Participating projects share capacity proportionally based on size, beginning **after** traditional firm capacity has been exhausted
"Australia-Style" Pure Pro-Rata	Participating projects share capacity proportionally based on size, beginning **before** traditional firm capacity has been exhausted
Pro-Rata Tranches	Capacity is shared proportionally by participants up to a pre-calculated total aggregate DER size limit determined by a specific allowable curtailment magnitude. Subsequent applicants may participate in a second tranche with higher curtailment, convert to "LIFO" allocation, or be withdrawn, depending on design choices.

Mechanisms to Support Commercial Viability

For flexible interconnection to be a viable option, applicants need to have some means to ensure that their project will remain commercially viable when choosing dynamic flexible interconnection. For Solar PV resources (particularly Community Solar), where the relative value of energy is constant across time, the total amount of annual curtailed energy production and the relative risk of future curtailment is expected to be the primary consideration. For flexible loads, the timing and relative confidence in the availability of capacity to support continued business operations is essential. To support commercial viability, several potential mechanisms within the flexible interconnection offering design can be considered, ranging in cost and complexity from data sharing up to the execution of system upgrades for curtailment relief. Several options will be investigated for their usefulness and applicability to specific capacity allocation methods. These options are separated by time horizon, with "short-term" options being available under existing regulatory constructs and "long-term" options focused on pathways to system upgrades, likely requiring some degree of cost allocation or cost causation philosophical change (particularly for DER).

Short-Term Commercial Viability Support Mechanisms

Short-term mechanisms to support commercial viability are generally those that can be executed in relatively short timeframes as part of the interconnection and study process without major structural changes.

No Support Mechanism

The first approach to consider is the "null" case, where no support mechanisms are utilized. As discussed previously, the lack of any support mechanism may increase financial or operational risk to applicants. This is particularly relevant for both Pure Pro-Rata approaches, as subsequent new connections will tend to increase the degree of curtailment experienced by early connectors. This risk is further heightened if future project costs are lower, enabling later participants to sustain a higher degree of curtailment. In such a case, new projects would continue to connect and increase the total curtailment beyond a point at which earlier connectors would have been economically viable. This increased level of financial risk may make it more difficult for applicants to secure funding or may result in hesitancy to utilize dynamic flexible interconnection.

Utility Data Sharing

One of the principal mechanisms that can be used to help participants assess commercial viability and secure financing is data sharing. Where curtailment estimation is performed by the utility, study results and/or relevant underlying data can be made available to the applicant (or their contracted 3rd party) to perform a detailed review and perform additional analysis that can satisfy financing requirements. For instance, a sensitivity analysis may be used to identify the relative impact of higher or lower load or DER growth on the expected degree of curtailment or the relative impact of year-to-year changes in seasonal weather conditions.

Ideally, the curtailment study results documentation would be constructed in a manner that can fully satisfy a financing party's requirements. Documentation of study methods, data inputs, and underlying assumptions may fulfill this purpose, particularly if other mechanisms are in place to limit curtailment risk or provide an upgrade pathway. Because the underlying data and models may contain protected customer data or information about critical infrastructure, incorporating the necessary performance data directly into the study results is preferable to direct access. If direct access to the underlying system data and power flow model were required, supporting infrastructure for access control, data anonymization, and redaction may be needed to maintain customer privacy and data security of critical infrastructure.

If the applicant (or their approved 3rd party) were to be responsible for performing the curtailment study, this would remove the utility's responsibility and role in risk management, theoretically migrating the risk to the applicant. In practice, however, non-utility experts cannot perform such studies without access to the same types of data used by the utility. For utility-driven studies, only the individual location of the applicant needs to be studied and the data potentially shared. This significantly reduces the scale of data processes and data sharing when compared to Dynamic Hosting Capacity, which would require analysis and data availability for the entire distribution system.

Pro-Rata Curtailment Cap or Design Target

Under Pure Pro-Rata implementations, one of the primary risks to participants is that subsequent dynamic flexible interconnections will tend to increase the extent of curtailment and operational restriction for all existing dynamic flexible interconnection resources already operating on a given feeder or substation. This makes it difficult for applicants to effectively assess their future curtailment risk. One method to mitigate this risk is to limit participation within Pure Pro-Rata schemes at specific locations whenever a new applicant would cause estimated curtailment to exceed a pre-set threshold.

In practice, this is very similar to the Pro-Rata Tranche approach, but it does not require the specific total size of participating resources to be known or limited in advance. This may be advantageous in areas where existing interest in interconnection is not yet sufficient to fill the entire tranche size. It is also advantageous because it allows for a higher degree of year-over-year changes without having to update and re-publicize allowable tranche sizes. The downside of this approach is that each new participant must be studied for its impact on operational curtailment, whereas the Pro-Rata Tranche approach only requires this study to be performed once or periodically updated as necessary.

When considering this style of mechanism, using precise language in descriptions, study documents, and interconnection agreements is essential. One potential approach is a “soft” limit, where a curtailment target is set within the study process. This target value is compared against the total estimated curtailment when a new applicant is studied and beyond which new applicants cannot participate within the Pro-Rata curtailment sharing. Under this approach, there is no explicit guarantee that, within an individual year, participant curtailment does not exceed the target. Rather, participant risk is limited by a structural backstop within the study process. This approach is used within Commonwealth Edison’s dynamic flexible interconnection construct[12]. Precedent within Illinois and the lack of rate impact make it practical to implement this type of mechanism in the short-term.

Alternatively, a “hard” curtailment cap could be considered, beyond which utility corrective action or compensation would be required. Under this type of construct, the curtailment cap would be explicitly specified within the study results and the interconnection agreement. This minimizes the risk to participants by providing relatively firm performance expectations, but it shifts the risk to the utility (and, subsequently, other non-participant customers) if system conditions were to change and local load were to noticeably decrease. Limited Generation Profiles (LGPs) in California[13] use this approach, allowing the utilities to change or reduce export capacity if changing system conditions make it necessary to maintain reliability and providing a pathway to recover any upgrade costs needed through rates to restore the customer’s original LGP. Compensation for curtailed production beyond a specified cap (explored in more detail below within the Long-Term Mechanisms) can also be considered. It is expected that any rate-funded pathway for curtailment relief within dynamic flexible interconnection would require regulatory engagement and Commission approval.

Under a “hard” cap construct, it is important to note that dynamic flexible interconnections would inherently be limited to those whose estimated curtailment is lower than the mitigation threshold by a sufficient margin. Without

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[12] ComEd DERMS Workshop – Hybrid Curtailment Approach Implementation: https://www.comed.com/cdn/assets/v3/assets/blt3ebb3fed6084be2a/bltcf678da93a461af2/68f8d27f4f91f1730457a9f5/ComEd_DERMS_and_Flexible_Interconnection_Workshop_2_-_Session_2_-_Pro-Rata_&_System_Constraints_&_DERMS_Prioritization.pdf?branch=prod_alias

[13] PG&E Limited Generation Profiles, SCE LGPs

such limits, the potential for required utility investments to support new interconnections quickly becomes a reality, effectively shifting interconnection cost responsibility directly from the applicant to utility customers. Depending on where and how these limits are set, this may discourage projects that would be economically viable for interconnection. Outlier years with significantly higher curtailment than would typically be expected are of specific interest, as they would require mitigation under the contractual mechanism even if such conditions are not likely to reoccur.

Hybrid approaches may also be considered. For instance, a "soft" curtailment study target threshold could be set within the study process, while a relatively higher "hard" cap could be established beyond which upgrades or compensation may be triggered.

Long-Term Commercial Viability Support Mechanisms

In contrast to the short-term mechanisms discussed previously, long-term mechanisms generally require structural change or new cost recovery approval. This includes exploring new pathways for system upgrades to expand available traditional capacity and relieve curtailment.

Participant-Funded Upgrade Pathway (Cost-Sharing)

Participant-funded interconnection cost sharing structures have been a focus of significant interest and development in recent years as a means of more efficiently allocating upgrade costs across applicants and addressing the "first mover" problem[14]. State-level efforts such as New York's Cost Sharing 2.0[15] Market-Initiated Upgrades provide one leading example of the concept. One of the major challenges within such frameworks is that cost-sharing participants usually must wait until a sufficient level of interest and participation is established before the system upgrade construction will occur and they can connect and operate their facilities.

Combining dynamic flexible interconnection with reactive, participant-funded cost sharing approaches can eliminate this delay by allowing some facilities to connect and operate while subsequent applications for cost-sharing participation are submitted and the upgrade is constructed. This effectively utilizes dynamic flexible interconnection as an "opportunistic" bridge-to-wires, providing a pathway to curtailment-relieving upgrades while also improving interconnection speed. Flexible interconnection participants that do not participate in the cost share mechanism could remain connected, but cost-share participants effectively move ahead of such customers for access to available capacity (though this does create a new version of the "free rider" problem).

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[14] The "first mover" problem generally refers to system upgrade costs that are too high for an individual applicant to bear themselves, but which would be economically viable if the costs were spread across all subsequent interconnection applicants. As a result, the upgrade does not occur, the applicant withdraws, and subsequent queued applicants also withdraw, as they would be subjected to the same cost after earlier queued applicants withdraw.

[15] Cost Sharing 2.0 Summary (PSEG Long Island): https://www.psegliny.com/aboutpseglongisland/ratesandtariffs/sgip/-/media/B63F65D2682E4669844F4D18965612E6.ashx

Implementing participant-funded upgrade cost sharing pathways is a significant undertaking that is likely to require regulatory engagement and modifications to existing rules, tariffs, and practices. Dynamic flexible interconnection is not integral to the functioning of such mechanisms, instead acting primarily as an added benefit. Therefore, if this mechanism is pursued as a means of providing a pathway to curtailment relief, it may be most effectively developed separately from dynamic flexible interconnection and appropriately coordinated.

Utility-Funded Upgrade Pathway (Capacity Planning)

In addition to process design elements and participant funding, there are also support mechanisms that place some degree of cost responsibility on the utility. In Illinois, as in many other U.S. jurisdictions, utility-funded investments intended to benefit a specific DER interconnection project have historically not been supported or recoverable through rates except where specifically authorized. Despite this, there is growing interest in updating treatment of DER-related upgrades, cost allocation, and cost recovery to reflect the anticipated high-DER environment. Potential utility-funded mechanisms to facilitate dynamic flexible interconnection and provide curtailment protection to applicants will be considered here to further inform such conversations.

One potential mechanism is to incorporate DER hosting capacity and curtailment outcomes directly into distribution system capacity planning processes. This approach has been most widely applied in Australia, with South Australia Power Networks implementing export tariffs[16] beginning in 2025, with the corresponding revenue applied to investments intended to increase DER hosting capacity and relieve curtailment experienced by customers participating in their Dynamic Operating Envelope interconnection mechanism (a type of dynamic flexible interconnection).

This approach (with or without the associate export tariff construct) effectively enshrines DER capacity and curtailment management into the set of planning criteria that utilities consider when identifying and prioritizing capital investments. Notably, it does not provide direct assurance to specific customers that curtailment will not exceed a pre-set threshold. Rather, the extent of customer curtailment under the Dynamic Operating Envelope approach and the resulting customer experience becomes the utility's responsibility to manage. DER capacity and curtailment relief investments, in this context, are likely to resemble existing reliability planning and investment approaches where prioritization is based on a blend of highly-impacted outliers (analogous to Customers Exceeding Reliability Targets), specific constrained feeders (analogous to Worst Performing Circuits), and overall system needs and cost-effectiveness (analogous to general SAIFI/SAIDI improvements).

The major upside of this approach is the ability for utilities to more effectively engage in investments to improve DER hosting capacity and operating capabilities. In effect, it treats DER interconnection as a key function of the distribution system, rather than something that the system tolerates. This change in philosophy allows for more holistic and proactive approaches to investments that can better meet the full set of system needs. It also does not come with specific contractual requirements or investment triggers, reducing the overall risk of inefficient utility spending.

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[16] South Australia Power Networks, Export Tariffs: https://www.sapowernetworks.com.au/your-power/billing/tariffs-we-charge-to-distribute-your-electricity/export-tariff/

Compensation for Curtailed Production

Another potential protection mechanism that incorporates utility spending is direct compensation for curtailed production. This approach has been used extensively within the United Kingdom at the transmission level as well as within UK Power Networks' DERMS-based implementation of Flexible Connections. Under their Flexible Connection construct for addressing thermal constraints, participating curtailable customers can have their load or generation curtailed up to a defined annual curtailment limit without any compensation being required. Once a customer has been curtailed up to that limit, any additional curtailment is compensated at a pre-determined published set price[17] on a $/kWh basis.

This type of approach can be incorporated under the curtailment cap approach described previously, providing strong customer protection but comes with risk of additional costs to non-participant customers. Because there are cost consequences to curtailment beyond the cap, curtailment compensation mechanisms must be paired with a utility pathway to system upgrades to ensure economically advantageous system upgrades occur instead of excessive curtailment-related payments.

Assessing Customer Impacts of Dynamic Operational Limits

Identifying the extent of operational limits and any resulting capacity curtailment is a critical step within the dynamic flexible interconnection analysis process. To estimate these impacts, the maximum grid capacity will need to be estimated for each time interval using historical data. This maximum allowable operation profile can then be compared with the resources' operational profiles to determine the extent of curtailment or operational limits. The specific resource operating profiles and resulting restrictions on customer operational capabilities will vary by technology type and utilization.

Just as with static schedules, this assessment can either be performed by the customer (or their appointed representative) prior to the submission of the interconnection application or by the utility as part of the interconnection study process. Each approach has benefits, drawbacks, and feasibility considerations that must be evaluated when considering dynamic flexible interconnection implementation.

Utility Estimation of Operational Limit Impacts

Because the operational limits for dynamic flexible resources are derived from distribution system capacity constraints, the utility is a natural option to determine the limits because they have access to all data and models necessary to identify potentially constrained intervals. This does create a few noteworthy challenges. First, because the utility is conducting the analysis, the accuracy and trustworthiness of the study results become critically important, since it will materially impact the project's commercial viability and the ability of the resulting project to secure financing. This creates a higher degree of risk for the applicant, relative to the existing traditional process, because higher-than-expected curtailment will not become apparent until after the project is already constructed.

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[17] UK Power Networks DERMS Products and Operational Implementation: https://d1lf1oz5vvdb9r.cloudfront.net/app/uploads/2025/05/UK-Power-Networks-DERMS-Access-products-and-their-operational-implementation-Guide-May-2025.pdf

Mechanisms such as utility assumption disclosure and data sharing (within the study results or separately) may help to offset this risk by enabling 3rd party assessment for financing purposes.

The second challenge of a utility-based approach is that the utility is not best positioned to estimate the production or operational characteristics of the applicant's facilities. Utilities can develop estimates of varying accuracy and applicability, but ultimately the applicant is most knowledgeable about their proposed resources and is most motivated to develop an accurate operational profile. Applicants could be asked to provide one or more operating profiles for study during the interconnection process, which would allow for sophisticated applicants to see a more realistic, tailored set of results. This is particularly noteworthy for load customers where individual characteristics are a key consideration.

Under any of the Pro-Rata approaches, setting a curtailment limit via "soft" study targets, "hard" cap implementation, or a tranche-based allocation somewhat simplifies the execution of curtailment estimation. In effect, this condenses the parameters of the curtailment assessment into a single utility-driven initial study to determine the appropriate tranche size expected to result in a specific curtailment threshold. Supporting analysis must still be performed to ensure that other interconnection criteria not eligible for avoidance through dynamic management can support the full resource size.

Size-based studies are much less influenced by the uncertainty of new connections than pure Pro-Rata approaches, but the growth of small-scale loads or DER can have complex impacts. Over time, load growth would tend to reduce the relative curtailment experienced by DER flexible interconnection participants. In contrast, new interconnections of small DER must be considered as part of the design of such schemes. If new larger projects are being connected to avoid triggering high-cost upgrades, then new unmanaged connections of even small DER would potentially trigger the need for the upgrade. With interconnection costs for Level 1 DER applicants capped at $200 by the Administrative Code, the continued small interconnections could lead to the cost of the relieving upgrade to be recovered through rates. This risk exists today under the current process, but the introduction of dynamic flexible interconnection makes it more likely that new connectors will connect to the "edge" where such upgrades become necessary to support new unmanaged connections.

Alternatives to rate recovery of such upgrades do exist, though they come with their own complexities and downsides. A portion of DER hosting capacity could be reserved for smaller DER moving through the Level 1 or Level 2 Expedited processes. While this does provide some runway for additional small DER connections, it does not solve the structural problem once the reserved capacity is exhausted. It also creates the need for complex new administrative processes to calculate and track reserved capacity across the system while barring projects that would otherwise connect and use that capacity.

Another alternative is to include smaller DER within the dynamic flexible interconnection scheme (up to the appropriate total size cutoff). This also does not solve the problem, though it makes better use of the system than reserved capacity in the meantime. Level 1 customers have no incentive to agree to such schemes under the $200 cap rules, which means implementation would likely require regulatory engagement. Additionally, establishing communications and managing larger numbers of small systems requires its own approach for operational and communications systems that would need to be considered. Ultimately, longer-term consideration of how costs from system upgrades for DER-based constraints are recovered is likely needed.

Customer Assessment of Operational Limit Impacts

Rather than relying on the utility to perform the analysis, the applicant (or an Ameren trusted 3rd party consultant) could perform the analysis for the project. This is primarily applicable to LIFO or Pure Pro-Rata without a curtailment limit. From the utility perspective, having customers perform their own analysis reduces the scope of the dynamic interconnection process to effectively the same level as within the existing process. It also reduces the potential need for supporting curtailment protection mechanisms by removing the utility's analysis as an element of securing financing or estimating future financial performance. From the applicant's perspective, this gives the applicant greater control over the analytical process and results, which may make it easier to secure financing using the results, at the cost of having to perform (or contract a firm to perform) the analysis.

For this approach to be viable, the customer would need to have access to the relevant utility system data to successfully execute the analysis with sufficient rigor to secure financing. Depending on the specific implementation of dynamic flexible interconnection and the study criteria eligible for the process, this may require significantly more data than is currently available to applicants, including:

- Hourly, Annual historical Load Profiles for the Impacted Feeder and Substation
- Feeder and Substation Equipment Ratings and One-Line Diagrams
- Feeder and Substation Load and DER Growth Forecasts (with time-varying profiles, if available)
- Size and Operational Characteristics of Existing and Queued DER and Load Additions
- Feeder and Substation Power Flow Model Files

Providing applicants with access to the level of utility system data required for this approach would necessitate a robust set of protective measures. These would likely include, but not be limited to, executed NDAs, defined data handling and retention policies, restrictions on downstream sharing, and potentially regulatory oversight to ensure that sensitive grid and operational information is adequately protected throughout the process.

Communications and Management Design Considerations

Dynamic flexible interconnection requires communications to be established with customer equipment so that appropriate operating limits can be communicated and performance can be monitored. Ideally, this is accomplished by communicating across a single interface point between utility and customer systems. Because dynamic management is used to preserve reliability in lieu of otherwise necessary system upgrades, maintaining communication and ensuring appropriate behavior during loss-of-communication scenarios is essential.

Generally, there are three primary approaches to establishing communications between utility and customer systems (illustrated and explored within Australia's Dynamic Operating Envelopes Working Group for IEEE 2030.5 communications[18]): site gateways, 3rd party cloud communications, and DER native communication support.

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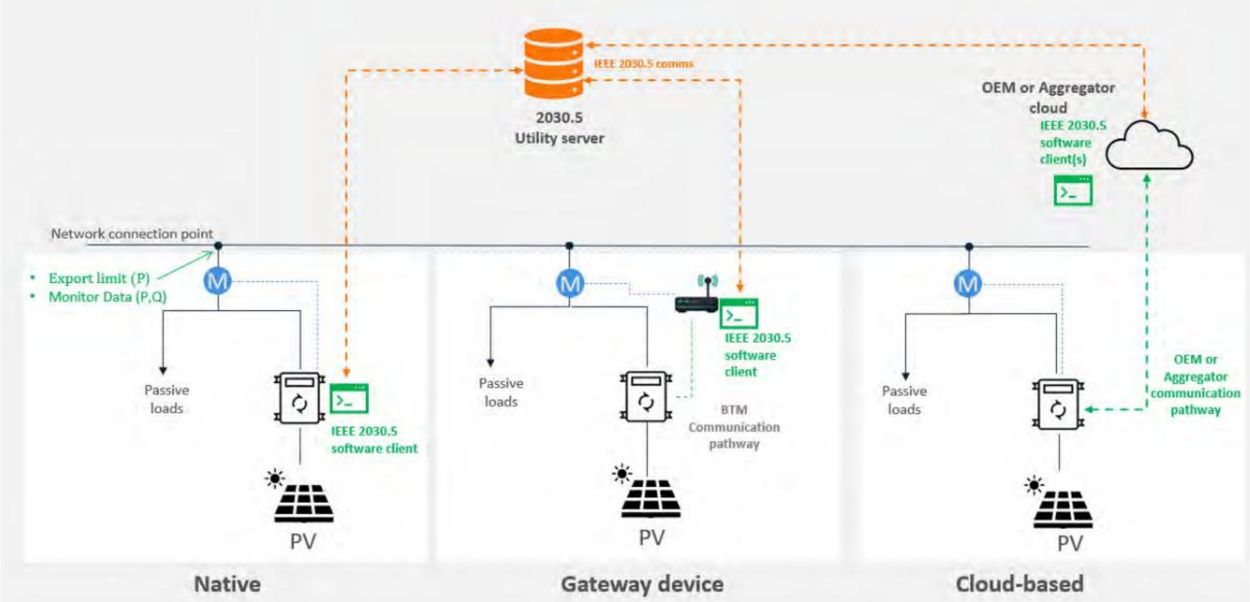
[18] Australia Distributed Energy Integration Program Dynamic Operating Envelope Working Group Outcomes Report – March 2022 - https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf

Figure 1: Australia 2030.5 Communications Methods



Site Gateway

In concept, a site gateway is a class of hardware solutions deployed at the customer site to establish communications back to the utility's head-end systems. Specific product terminology can be tricky, as there are several product types that may or may not include provisions for utility communications and the management of import/export limit setpoints (e.g., power plant controller, power control system).

In some instances, the site gateway is installed and maintained by the utility. PPL Electric's DER Management Device[19] provides one such example, as it interfaces directly with the customer's inverter(s) and communicates back to utility head-end systems.

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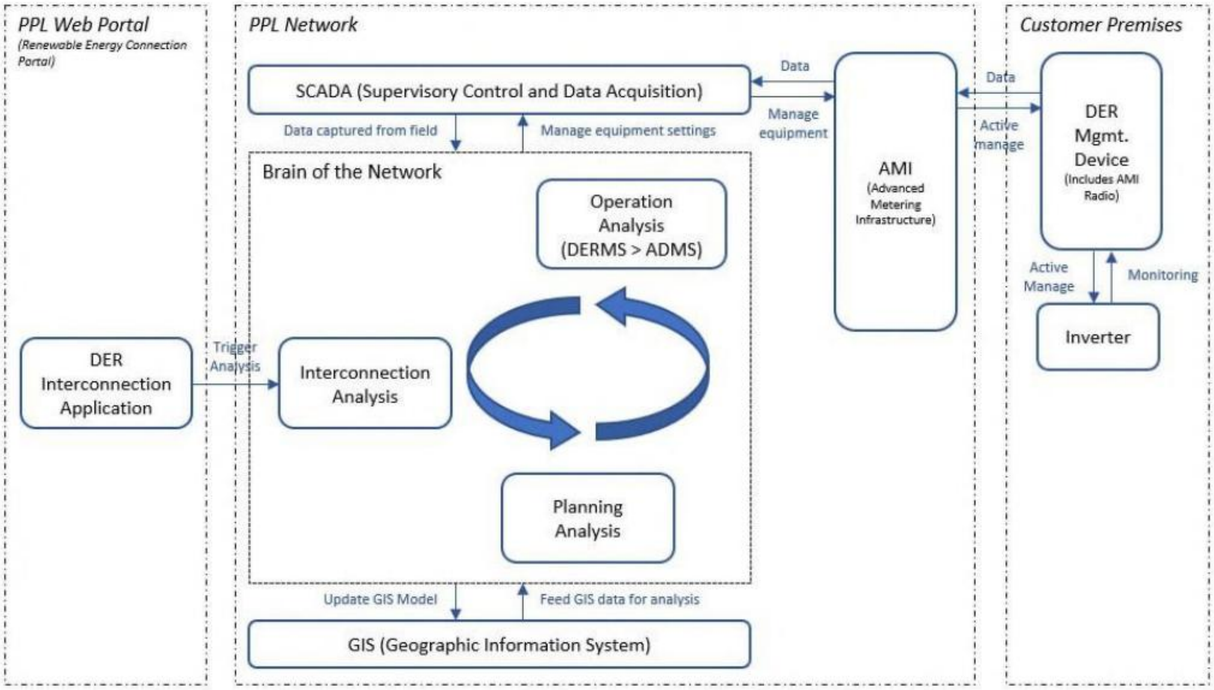
[19] PPL Second DER Management Plan (Pg. 92): https://www.puc.pa.gov/pcdocs/1830626.pdf

Figure 2: PPL Electric DER Management Device (AMI Version)



Customer-provided hardware can be used as a site gateway, either directly via IEEE 2030.5 communications or to establish a connection point for a utility SCADA connection.

For the purposes of dynamic flexible interconnection, the most salient functionality is the requirement for an on-site mechanism that establishes the communication link back to the utility head-end. Gateways can also provide other functions including scheduling functions and the establishment of fallback behavior during loss of communications events. The functionality within the gateway device and the communications medium to connect to the utility head-end are key elements of the design and deployment strategy.

Third Party Cloud

Establishing communications via third party cloud communications infrastructure (i.e., aggregator or original equipment manufacturer [OEM] systems) is another potential pathway. Often, OEMs will establish communications with end-use equipment for warranty, data reporting, firmware updates, or other purposes. Because communication is already established between the OEM and the endpoint, it is possible to establish communications between the endpoint and the utility head-end by coordinating through the OEM's platform. Using this approach, communications can be established to many different sites without requiring new on-site hardware.

Depending on the specific implementation, there are some challenges to this approach. First, vendor interfaces for data access and management may come with vendor costs for access as well as software integration costs. In addition, it may be more challenging to ensure the appropriate fallback behavior if loss-of-communications behavior would otherwise have been managed using an on-site gateway. Cybersecurity and communications reliability are also key considerations and depend heavily on the details of the planned integration.

Native IEEE 2030.5 Support

Some OEMs include direct IEEE 2030.5 communications capabilities as part of the on-site hardware, either built into the inverter itself or via a controller. Enphase's IQ Gateway[20] is one example, coordinating the behavior of microinverters and able to establish communications to a 2030.5 head-end.

When native support is provided, communications can be established directly via public internet using the VPN-style design enabled by 2030.5. This has cost and scalability advantages, especially when communicating with many smaller systems (as is common in Australia). The primary drawbacks are the lack of visibility into potential problems for troubleshooting and the costs to stand up and manage the 2030.5 infrastructure.

Design Considerations

When evaluating the various design options, there are several important dimensions to consider:

- Communications Reliability: the relative frequency of communications failure, impacting data availability and triggering loss-of-communications fallback limits
- Cost: the initial deployment cost and ongoing maintenance costs associated with maintaining communications
- Responsibility: which party (the utility or the customer) is responsible for procuring or providing the communications link necessary to execute dynamic management
- Cybersecurity: ensuring that communications to customer equipment does not create vulnerabilities within utility systems

In theory, having flexible interconnection participants responsible for their own communications to the utility head-end may be ideal because it reduces cost and performance responsibility from the utility. This allows individual sites to make their own decisions about the level of communications reliability they need and how they secure it. There are, however, some practical challenges that would need to be overcome. First, enabling 3rd party systems to connect to utility infrastructure over public internet (or via 3rd cloud-based means) comes with inherent cybersecurity concerns that must be satisfactorily addressed. The lack of visibility and troubleshooting capability also makes it paramount that loss-of-communications performance can be verified and cemented for long-term operation. This approach also requires the deployment of new centralized utility communications platforms (e.g., 2030.5 servers).

If communications are the utility's responsibility (as has primarily been the case for North American pilots and deployments to date), cost and reliability become the most salient aspects of decision-making, though there may still be cybersecurity questions to answer. This tension can be most easily illustrated by considering the differences between using cellular and fiber-based media for DER communications.

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[20] Enphase IQ Gateway Data Sheet: https://enphase.com/en-lac/download/iq-gateway-data-sheet

Cellular has a relatively lower upfront cost, with ongoing data costs varying across vendors, data volume, and infrastructure rights (e.g., private LTE). Communications performance with cellular networks can also be heavily dependent on location and coverage, which may be difficult to assess ahead-of-time (during, for instance, the interconnection study process).

Fiber, on the other hand, can have sizable up-front costs (on a per mile basis) to reach the DER site from the substation, as well as additional backhaul costs to get from the substation to the utility head-end (unless backhaul fiber is already available). While the up-front cost may be much higher, the performance is also generally faster and more reliable.

Given Ameren Illinois' initial focus on using flexible interconnection to avoid triggering thermal overloads of costly substation equipment, the initial design considerations will focus primarily on establishing secure communications to individual large load and DER sites to establish flexible interconnection capabilities. For such sites, on-site gateways with Ameren communications can establish communications and effectively manage the site, including fallback performance requirements during loss-of-communications. Over time, approaches such as IEEE 2030.5 may be considered for their scalability and versatility. Ultimately, communication pathways for flexible interconnections will rely on the communication architecture design and implementation of DERMS, with cybersecurity decisions playing a significant role in the pathways leveraged between the utility's DERMS gateways and customer DER sites.

Customer Site Design Impacts

For dynamic flexible interconnection, many of the same considerations from static scheduled connections still apply, but with the additional complexity of providing a communications interface to the utility. For sites with multiple inverters or flexible loads, this means establishing some means of communicating with each piece of equipment and coordinating the overall operation of the site to remain within allowable import/export limits. Three design options, each with different architectures, are provided below[21]:

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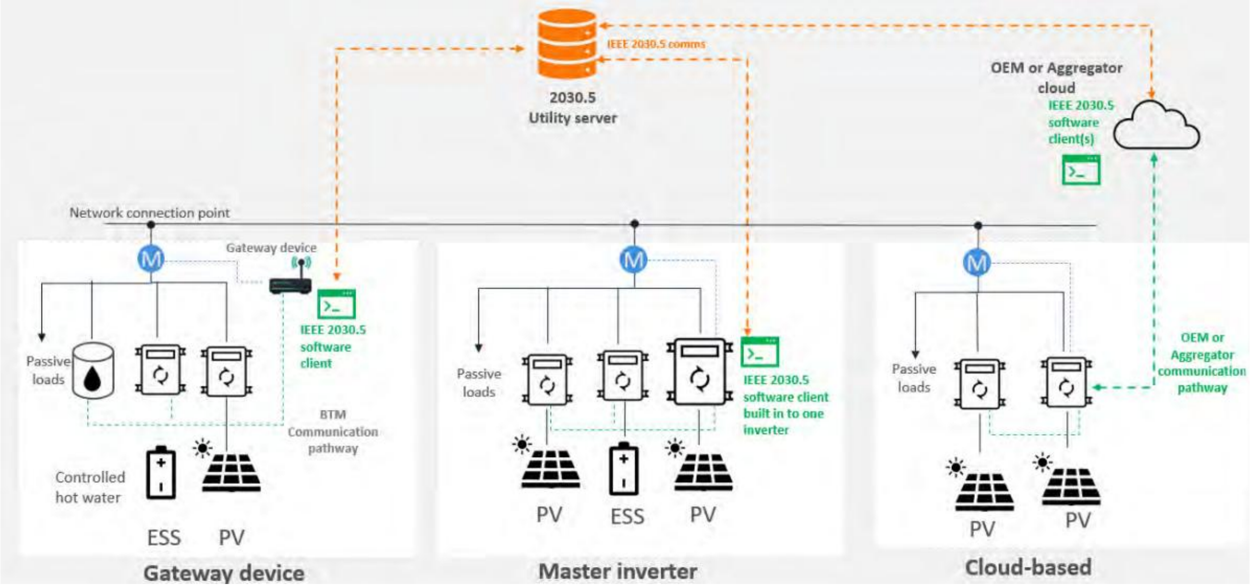
[21] Australia Distributed Energy Integration Program Dynamic Operating Envelope Working Group Outcomes Report – March 2022 - https://arena.gov.au/assets/2022/03/dynamic-operating-envelope-working-group-outcomes-report.pdf

Figure 3: Australia 2030.5 Site Design Options



Power Control Systems (PCS) certified under the current UL 3141 standard can also serve as the communications point if designed to do so (see Gateway Device illustration above). This is ideal, as the PCS can provide a single communications interface to the utility while managing the performance of the connected resources using whichever protocols are used by the customer's equipment. Other gateway options, including utility-provided gateways, may also serve this function, though it does complicate site networking if non-standard protocols are used.

Depending on the protocol, certain inverters or flexible load equipment may be configured to be networked together with one inverter acting as the "master" and coordinating the behavior of the site in aggregate. This has many of the same advantages as the certified PCS described above (and many BESS inverters are certified for PCS capabilities) without requiring separate hardware. It also allows customer-side communications to use non-standard protocols while still meeting utility communications requirements.

Finally, rather than establishing physical communications across all inverters, a cloud-based approach could be used. This approach would primarily be considered when using aggregator or OEM cloud communications architecture where all applicable equipment at a particular site is virtually aggregated and the total result communicated to the utility. This approach relies on software-based coordination, which is more difficult to verify after initial commissioning and may be more subject to future changes or errors than on-site, hard-wired approaches.

While certified PCS equipment (either as a stand-alone controller or as part of the equipment design) is preferable, there is also the potential for custom, non-certified hardware to be used. SEL's Real-Time Automation Controller (RTAC)[22] that is relatively common and may already be in-use by some customers for their own communications and control purposes. Non-certified hardware, if allowed, would generally require significantly more strenuous site testing to ensure appropriate and timely response to dynamically changing import/export limits. This is particularly

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[22] SEL RTAC: https://selinc.com/products/RTAC/

relevant for the loss-of-communications fallback behavior, which is an essential component of ensuring safe and reliable operation under dynamic management.

In addition, the custom nature of the hardware would also make it more difficult to protect against future unintended modifications. Mechanisms such as vendor software locks are not available, and the customer (by definition) has the ability to re-program the device. The establishment of communications seems like it would help mitigate this issue but, in practice, the information provided by the device may be erroneous or not reflective of all equipment in operation under the dynamic scheme at the site. Loss-of-communication fallback behavior is also an important factor, as the loss of communications to the equipment would cease operational reporting as well. Given the additional risks with such hardware, additional protective measures and redundant telemetry may be necessary to ensure ongoing compliance with import/export limits.

Study Design Approach

Structurally, the dynamic flexible interconnection studies are performed in a manner very similar to the static scheduled studies described previously. The major difference is that operational limits are calculated and compared to the resource(s)' operating profile for each hour (rather than having the operational limits determined across all schedule intervals then re-imposed).

Operational Profile Development

For solar PV facilities, production profiles can be estimated using publicly available tools such as NREL's PVWatts tool to get a "typical" production year estimate. Where available, historical production data from other solar PV systems in the area may also provide reasonable estimates of production profiles for new resources. Where combined PV and BESS are used within existing import capacity limits, BESS operation would not be considered within the study.

For flexible loads, operating profiles are much more variable than those for solar, as each customer's specific equipment, location, and operational needs will impact the load profile in different ways. As a result, quantifying actual frequency, duration, and magnitude of capacity limitations starting from full, continuous, unconstrained operation provides the clearest look at potential operational impacts.

Dynamic Flexible Interconnection - Study Results

Substation A Dynamic Study Results

LIFO PV Curtailment

Table 38 and Table 39 below provide summaries of PV curtailment using the LIFO method under two scenarios using differing aggregates of PV. Each table provides the aggregate amount of PV connected in increments of 0.5 MW, starting with the minimum amount that can be connected before causing a thermal violation due to reverse flow. The second PV added causes the first substation thermal violation and is curtailed enough to clear the violation plus a margin 0.25 MVA (which would be added in case of unexpected load variation). Each increment of PV is added is curtailed until there is no longer a thermal violation plus the margin of safety.

The first scenario studied a total of 9 MW of PV, and the second scenario studied 10.5 MW of PV. Under a total of 9 MW, the total production for the final 0.5 MW increment added is curtailed at 9.64%, but under 10.5 MW, the final 0.5 MW increment is curtailed significantly higher at 30.56%. The seasonal breakdown under both scenarios shows most curtailment occurs during the spring and summer seasons.

Table 38: Dynamic PV Curtailment using LIFO with 9 MW of PV on Substation A

PV	PV Size (MW)	Total PV Production (MWh)	Curtailment (MWh)	% Curtailment	Seasonal Curtailment (MWh)			
					Mar-May	Jun-Sep	Oct-Nov	Dec-Feb
1	7.0	13536	0	0%	0	0	0	0
2	0.5	967	0.16	0.02%	0.16	0	0	0
3	0.5	967	14.51	1.50%	14.51	0	0	0
4	0.5	967	50.42	5.21%	50.3	0.12	0	0
5	0.5	967	93.2	9.64%	87.04	6.12	0	0.04
Total	9.0	17404	158.29	0.91%	152.01	6.24	0	0.04

Table 39: Dynamic PV Curtailment using LIFO with 10.5 MW of PV on Substation A

PV	PV Size (MW)	Total PV Production (MWh)	Curtailment (MWh)	% Curtailment	Seasonal Curtailment (MWh)			
					Mar-May	Jun-Sep	Oct-Nov	Dec-Feb
1	7.0	13536	0	0%	0	0	0	0
2	2.0	3868	158.29	4.09%	152.01	6.24	0	0
3	0.5	967	147.31	15.24%	119.54	25.95	0.56	1.26
4	0.5	967	213.77	22.11%	142.46	62.17	3.89	5.25
5	0.5	967	295.47	30.56%	161.54	112.46	9.95	11.52
Total	10.5	20305	814.85	4.01%	575.55	206.82	14.40	18.07

“Australia” Pro-rata PV Curtailment

Table 40 summarizes PV curtailment using the “Australia” pro-rata method for substation A. **Error! Reference source not found.** shows results with an aggregate of 7.5 MW of PV and Table 40 shows the results using an aggregate of 10.5 MW. Under the Australia pro-rata method, each PV connected is curtailed evenly according to its nameplate to total PV ratio. When there is a substation thermal violation, each PV is curtailed regardless of if interconnecting that increment PV is the cause of the substation thermal violation. Compared to LIFO, more PV can be connected to the substation under Australia pro-rata before the total maximum curtailment for a single PV system reaches a certain threshold such as 5%.

Table 40: Dynamic PV Curtailment using “Australia” Pro-rata with 10.5 MW of PV on Substation A

PV	Size (MW)	Annual PV Production (MWh)	Curtailment (MWh)	% Curtailment	Seasonal			
					Mar-May	Jun-Sep	Oct-Nov	Dec-Feb
1	7	13536	543	4.01%	384	138	10	12
2	0.5	967	39	4.01%	27	10	1	1
3	0.5	967	39	4.01%	27	10	1	1
4	0.5	967	39	4.01%	27	10	1	1
5	0.5	967	39	4.01%	27	10	1	1
6	0.5	967	39	4.01%	27	10	1	1
7	0.5	967	39	4.01%	27	10	1	1
8	0.5	967	39	4.01%	27	10	1	1
Total:	10.5	20305	815	4.01%	576	207	14	18

“US” Pro-rata PV Curtailment

Table 41 provides a summary of using the U.S. pro-rata on substation A for a total of 8 MW of PV and 10.5 MW of PV. Similarly to LIFO, the U.S. pro-rata method only curtails PV connected after a substation thermal violation is detected. However, similarly to the Australia pro-rata method, the U.S. pro-rata curtails PV evenly according to their nameplate size compared to the total amount of PV that is being curtailed. Under the U.S. pro-rata methodology, more PV can be connected to the substation before total curtailment for a single PV reaches a defined threshold, but not as much as the Australia pro-rata method.

Table 41: Dynamic PV Curtailment using "U.S." Pro-rata with 10.5 MW of PV on Substation A

PV	Size (MW)	Annual PV Production (MWh)	Curtailment (MWh)	% Curtailment	Seasonal			
					Mar-May	Jun-Sep	Oct-Nov	Dec-Feb
1	7	13536	0	0.000%	0	0	0	0
2	0.5	967	116	12.039%	82	30	2	3
3	0.5	967	116	12.039%	82	30	2	3
4	0.5	967	116	12.039%	82	30	2	3
5	0.5	967	116	12.039%	82	30	2	3
6	0.5	967	116	12.039%	82	30	2	3
7	0.5	967	116	12.039%	82	30	2	3
8	0.5	967	116	12.039%	82	30	2	3
Total:	10.5	20305	815	4.013%	576	207	14	18

Tranches for PV using “Australia” Pro-rata Curtailment

Table 42 provides a summary of the amount of PV that can be connected under each tranche using the Australia pro-rata method for PV curtailment. Each row in the table represents a separate scenario where the tranche defines the maximum amount of PV curtailment allowed per PV system and the aggregate of PV systems. For example, if the tranche is 5%, the maximum amount of PV that can be connected is 10.81 MW.

Table 42: PV Curtailment Tranches using Australia Pro-rata on Substation A

Tranche Curtailment %	PV Size (MW)	Annual PV Production (MWh)	Curtailment (MWh)	Seasonal Curtailment (MWh)			
				Mar-May	Jun-Sep	Oct-Nov	Dec-Feb
1.0%	9.07	17537	175	167	8	0	0
2.5%	9.92	19181	479	389	81	4	5
5.0%	10.81	20906	1045	682	305	28	29
7.5%	11.51	22250	1669	938	583	79	68
10.0%	12.15	23490	2349	1187	897	147	118

Tranches for PV using "US" Pro-rata Curtailment

Table 43 provides results for tranches using the U.S. pro-rata style on substation A. The first 7 MW do not contribute to the substation thermal violation and are not included in curtailment. Under this method, the 5% tranche maxes out at about 9.21 MW of PV before there is curtailment due to substation thermal violations. The Australia pro-rata method allows an additional 1.6 MW of PV to connected before any PV is curtailed.

Table 43: PV Curtailment Tranches using U.S. Pro-rata on Substation A

Tranche Curtailment %	PV Size (MW)	Annual PV Production (MWh)	Curtailment (MWh)	Seasonal Curtailment (MWh)			
				Mar-May	Jun-Sep	Oct-Nov	Dec-Feb
-	7	13536	0	0	0	0	0
1.00%	1.097	2121	21.2	21	0	0	0
2.50%	1.576	3048	76.13	76	1	0	0
5.00%	2.213	4279	213.97	200	14	0	0
7.50%	2.734	5287	396.31	335	56	2	3
10.00%	3.178	6146	614.24	470	128	6	10

Flexible Load Connection Curtailment Study

Table 44: Flexible Load Intervals Constrained Using Dynamic for Substation A

Total Number of Intervals Per Year	Number of Intervals Constrained
8,760	426

Table 45: 288-Point Results for Dynamic Flex Load Management for Substation A

Month/ Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
2	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
5	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
6	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
7	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
8	100%	100%	100%	100%	100%	99.9%	100%	99.9%	100%	100%	100%	100%
9	100%	100%	100%	100%	100%	99.0%	99.7%	99.7%	100%	100%	100%	100%
10	100%	100%	100%	100%	100%	98.4%	98.6%	98.7%	99.6%	100%	100%	100%
11	100%	100%	100%	100%	100%	97.6%	97.2%	97.8%	99.3%	100%	100%	100%
12	100%	100%	100%	100%	99.9%	96.1%	95.9%	96.1%	98.9%	100%	100%	100%
13	100%	100%	100%	100%	99.7%	95.2%	93.7%	94.4%	97.9%	99.8%	100%	100%
14	100%	100%	100%	100%	99.6%	94.1%	91.9%	93.4%	97.2%	99.6%	100%	100%
15	100%	100%	100%	100%	99.5%	93.2%	89.8%	92.2%	96.8%	99.5%	100%	100%
16	100%	100%	100%	100%	99.4%	92.9%	89.4%	93.0%	97.4%	99.9%	100%	100%
17	100%	100%	100%	100%	99.9%	93.9%	92.3%	96.2%	98.8%	100%	100%	100%
18	100%	100%	100%	100%	100%	96.1%	95.5%	98.3%	99.6%	100%	100%	100%
19	100%	100%	100%	100%	100%	97.4%	98.1%	99.2%	99.9%	100%	100%	100%
20	100%	100%	100%	100%	100%	99.0%	99.5%	100.0%	100%	100%	100%	100%
21	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
22	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
23	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Substation B Dynamic Study Results

LIFO PV Curtailment
Summarized below in Table 46 and

Table 47 are the results of dynamically managing PV on substation B using the LIFO curtailment method. Each table provides results based on an aggregate of PV for two different scenarios where PV is added in increments of 0.5 MW. The first 19 MW of PV on substation B does not cause a substation thermal violation and therefore is not curtailed under LIFO.

Table 46: Dynamic PV Curtailment using LIFO with 21.5 MW of PV on Substation B

PV	PV Size (MW)	Total PV Production (MWh)	Curtailment (MWh)	% Curtailment	Seasonal Curtailment (MWh)			
					Mar-May	Jun-Sep	Oct-Nov	Dec-Feb
1	19	36742	0	0%	0	0	0	0
2	0.5	967	1.28	0.13%	1.28	0	0	0
3	0.5	967	7.69	0.80%	7.69	0	0	0
4	0.5	967	22.36	2.31%	22.36	0	0	0
5	0.5	967	37.14	3.84%	37.14	0	0	0
6	0.5	967	51.71	5.35%	51.65	0.06	0	0
Total	21.5	41576	120.18	0.29%	120.12	0.06	0	0

Table 47: Dynamic PV Curtailment using LIFO with 27.5 MW of PV on Substation B

PV	PV Size (MW)	Total PV Production (MWh)	Curtailment (MWh)	% Curtailment	Seasonal Curtailment (MWh)			
					Mar-May	Jun-Sep	Oct-Nov	Dec-Feb
1	19	36742	0	0%	0	0	0	0
2	6.5	12570	1283.18	10.21%	987.84	285.59	3.3	6.44
3	0.5	966.89	272.8	28.21%	153.6	108.02	5.17	6.01
4	0.5	966.89	302.75	31.31%	159.01	127.74	8.01	8
5	0.5	966.89	336.06	34.76%	163.57	150.08	10.47	11.93
6	0.5	966.89	372.16	38.49%	169.47	174.6	13.39	14.7
Total	27.5	53179	2566.95	4.83%	1633.5	846.03	40.34	47.08

“Australia” Pro-rata PV Curtailment

Below in Table 48 is the summary of PV curtailment using the Australia pro-rata method on substation B. Similarly to the seasonal result for substation A, seasonal curtailment results for substation B show most curtailment occurring in the spring and summer.

Table 48: Dynamic PV Curtailment using “Australia” Pro-rata with 27.5 MW of PV on Substation B

PV	Size (MW)	Annual PV Production (MWh)	Curtailment (MWh)	% Curtailment	Seasonal			
					Mar-May	Jun-Sep	Oct-Nov	Dec-Feb
1	19	36742	1774	4.827%	1129	585	28	33
2	0.5	967	47	4.827%	30	15	1	1
3	0.5	967	47	4.827%	30	15	1	1
4	0.5	967	47	4.827%	30	15	1	1
5	0.5	967	47	4.827%	30	15	1	1
6	0.5	967	47	4.827%	30	15	1	1
7	0.5	967	47	4.827%	30	15	1	1
8	0.5	967	47	4.827%	30	15	1	1
9	0.5	967	47	4.827%	30	15	1	1
10	0.5	967	47	4.827%	30	15	1	1
11	0.5	967	47	4.827%	30	15	1	1
12	0.5	967	47	4.827%	30	15	1	1
13	0.5	967	47	4.827%	30	15	1	1
14	0.5	967	47	4.827%	30	15	1	1
15	0.5	967	47	4.827%	30	15	1	1
16	0.5	967	47	4.827%	30	15	1	1
17	0.5	967	47	4.827%	30	15	1	1
18	0.5	967	47	4.827%	30	15	1	1
Total:	27.5	53179	2567	4.827%	1634	846	40	47

"US" Pro-rata PV Curtailment

The tables below provide results for dynamic PV curtailment using the U.S. pro-rata method for substation B. Under this method the first 19 MW do not cause a substation thermal violation and therefore are not curtailed. Under this method only about 23 MW of PV can be connected until an individual PV is curtailed at about 5% of its production, compared to the Australia pro-rata method where 27.5 MW of PV can be connected before any individual PV is curtailed about 5% of its production.

Table 49: Dynamic PV Curtailment using "U.S." Pro-rata with 23 MW of PV on Substation B

PV	Size (MW)	Annual PV Production (MWh)	Curtailment (MWh)	% Curtailment	Seasonal			
					Mar-May	Jun-Sep	Oct-Nov	Dec-Feb
1	19	36742	0	0.000%	0.00	0	0	0
2	0.5	967	151	16%	96	50	2	3
3	0.5	967	151	16%	96	50	2	3
4	0.5	967	151	16%	96	50	2	3
5	0.5	967	151	16%	96	50	2	3
6	0.5	967	151	16%	96	50	2	3
7	0.5	967	151	16%	96	50	2	3
8	0.5	967	151	16%	96	50	2	3
9	0.5	967	151	16%	96	50	2	3
10	0.5	967	151	16%	96	50	2	3
11	0.5	967	151	16%	96	50	2	3
12	0.5	967	151	16%	96	50	2	3
13	0.5	967	151	16%	96	50	2	3
14	0.5	967	151	16%	96	50	2	3
15	0.5	967	151	16%	96	50	2	3
16	0.5	967	151	16%	96	50	2	3
17	0.5	967	151	16%	96	50	2	3
18	0.5	967	151	16%	96	50	2	3
Total:	27.5	53179	2567	4.827%	1634	846	40	47

<u>Tranches for PV under "Australia" Pro-rata Curtailment</u>

Table 50 below provides the summary of the amount of PV that can be connected under each tranche using the Australia pro-rata method on substation B. Results show about 27.63 MW of PV can be connected under Australia pro-rata without being curtailed more than 5%.

Table 50: PV Curtailment Tranches using Australia Pro-rata on Substation B

Tranche Curtailment %	PV Size	Annual PV Production (MWh)	Curtailment (MWh)	Curtailment Seasonal			
				Curtailment Mar-May	Curtailment Jun-Sep	Curtailment Oct-Nov	Curtailment Dec-Feb
1.00%	23.255	44970	450	410	40	0	0
2.50%	25.387	49093	1227	955	264	3	5
5.00%	27.631	53432	2671	1679	896	45	52
7.50%	29.394	56841	4263	2315	1657	150	141
10.00%	31.008	59962	5996	2943	2490	304	259

<u>Tranches for PV under "US" Pro-rata Curtailment</u>

The table below provides a summary of the amount of PV that can be connected in each tranche using the U.S. pro-rata method for substation B. Under this method the first 19 MW are not curtailed because it does not cause substation thermal violations.

Table 51: PV Curtailment Tranches using U.S. Pro-rata on Substation B

Tranche Curtailment %	PV Size (MW)	Annual PV Production (MWh)	Curtailment (MWh)	Dynamic Limit Curtailment Seasonal			
				Curtailment Mar-May	Curtailment Jun-Sep	Curtailment Oct-Nov	Curtailment Dec-Feb
-	19	36742	0	0	0	0	0
1.00%	1.439	2782	27.81	27.81	0	0	0
2.50%	2.51	4854	121.35	121.28	0.07	0	0
5.00%	4.009	7752	1134.07	358.9	28.7	0	0
7.50%	5.287	10224	766.79	653.21	112.43	0.23	0.92
10.00%	6.414	12403	1240.37	962.57	269.25	2.86	5.69

Flexible Load Curtailment Study

Table 52: Flexible Load Intervals Constrained Using Dynamic for Substation B

Total Number of Intervals Per Year	Number of Intervals Constrained
8,760	113

Table 53: 288-Point Results for Dynamic Flex Load Management for Substation B

Month/ Hour	1	2	3	4	5	6	7	8	9	10	11	12
0	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
1	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
2	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
3	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
4	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
5	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
6	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
7	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
8	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
9	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
10	100%	100%	100%	100%	100%	100%	100%	99.90%	100%	100%	100%	100%
11	100%	100%	100%	100%	100%	100%	99.98%	99.59%	100%	100%	100%	100%
12	100%	100%	100%	100%	100%	100%	99.66%	99.27%	100%	100%	100%	100%
13	100%	100%	100%	100%	100%	100%	99.20%	98.71%	99.98%	100%	100%	100%
14	100%	100%	100%	100%	100%	100%	98.81%	98.31%	99.86%	100%	100%	100%
15	100%	100%	100%	100%	100%	100%	98.60%	98.00%	99.75%	100%	100%	100%
16	100%	100%	100%	100%	100%	100%	98.47%	97.66%	99.61%	100%	100%	100%
17	100%	100%	100%	100%	100%	99.95%	98.40%	97.62%	99.61%	100%	100%	100%
18	100%	100%	100%	100%	100%	100.0%	98.68%	97.89%	99.79%	100%	100%	100%
19	100%	100%	100%	100%	100%	100.0%	99.25%	98.56%	99.88%	100%	100%	100%
20	100%	100%	100%	100%	100%	100.0%	99.62%	99.19%	99.99%	100%	100%	100%
21	100%	100%	100%	100%	100%	100%	99.85%	99.72%	100%	100%	100%	100%
22	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
23	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Operational Considerations for Dynamic Flexible Interconnections

While this report has primarily explored the planning, regulatory, and equipment aspects of dynamic flexible interconnection, it is also essential to consider how realistic operational challenges and the divergence from study assumptions will impact day-to-day execution.

Capacity Allocation for Differing Operating Characteristics

Each of the capacity allocation methods works most effectively when the connecting resources are of similar type and operate in a similar manner. Two solar PV facilities, for instance, can be effectively managed using any of the three approaches. If a BESS is added to one of the two facilities, this is also still manageable, so long as BESS is used for import/export limitations and the pro-rata limits are applied to export capacity rather than nameplate capacity. Challenges begin to arise when attempting to apply these capacity allocation methods to resources with different operating characteristics. The specific impacts depend on how curtailment allocation is approach operationally.

One potential approach is to allocate operating capacity in each time interval regardless of the actual operation of the resources. This approach ensures that overload conditions do not occur, but results in artificially reserved capacity that could otherwise be used. Another approach is to only trigger capacity allocation when overload conditions would otherwise occur in practice. This approach is much less restrictive but requires taking a reactive approach to criteria violations that can increase the potential risk to equipment if load or generation conditions change quickly.

This is easiest to illustrate by considering two large flexible loads whose load profiles are inverses of each other. Consider an office building which offers daytime EV charging to its workers and a warehouse that has electrified its forklifts, which recharge overnight. When capacity is pre-allocated, under either pro-rata approach, available capacity for each interval will be split between the two customers, even though only one of the customers will ever be utilizing that capacity at a given time. This artificially limits the ability of each customer to charge. A LIFO approach for pre-reserved capacity would make this problem even worse, restricting access for the lower-priority customer to an even higher extent than under pro-rata (assuming equivalent size).

A reactive approach, reducing operating capacity only when a criteria violation is triggered, would avoid some of the inefficient reservation of capacity, but creates its significant operational risk. Assuming both customers can use more capacity than is available (and, hence, have connected via flexible interconnection), even under a reactive approach, operating restrictions would be necessary on a regular basis. When executed, these operational restrictions have the same inefficiencies described under the pre-allocation approach above, albeit occurring relatively less often.

Customer resource performance can change quickly, which can cause equipment ratings to be exceeded until the reactive operational limits can be put in place. This would be expected to be a relatively common occurrence, as the limits would only be applied in response to identified violations. Intentionally allowing equipment overloads on a regular basis is not a sustainable strategy. Even with mechanisms intended to reduce this risk, such as short-term forecasting and additional operational capacity reserve margin, can only reduce the frequency and do not fully remove the structural risk. The specific approach and capacity management decision-making will depend on the DERMS configuration and optimization capabilities.

Responding to Site Non-Compliance After Energization

Identifying and responding to non-compliance is an important aspect to consider within utility operations when dynamic flexible interconnections are enabled. In theory, the presence of communications allows for performance monitoring to ensure ongoing compliance with import/export limits and any other applicable site requirements. However, there are complicating factors. For one, changes within the import/export limiting controller (particularly for non-certified hardware) may also compromise communications or blind the monitoring to one or more of the component resources at the site (i.e., one of the ten total inverters at a particular site). Additionally, loss of communications will disable the direct monitoring capabilities, so detection and assurance of intended operation during such conditions cannot be achieved via the same communications link.

For large stand-alone sites, establishing SCADA monitoring at the revenue meter or an on-site recloser can provide redundant visibility for Operations. Because of the changing nature of the dynamic setpoints, it is more complex to set alarms to alert operators if current dynamic limits are exceeded. In practice, however, visibility of the load on the substation equipment (and any related alarms) does provide a means to identify and respond to issues that may result from non-compliance during critical operating windows. This monitoring, combined with redundant site telemetry and documentation of dynamic operating requirements provides all the tools needed to identify and respond to equipment thermal overload conditions.

There is also a potential pathway to identify non-compliance outside critical windows by reviewing the direct monitoring and redundant SCADA data to flag discrepancies or violations of the dynamic limit. This works for stand-alone sites (e.g., Community Solar) where the whole site is operating under the constraint but is more challenging if new resources are connected under a managed structure at an existing customer with on-site load (e.g., a large retail store adding EV charging in the parking lot). In such cases, redundant telemetry at the meter may be available, but the operation of the managed resources will be embedded within total site usage. In addition, meter data may be backhauled through AMI and may not be directly integrated with SCADA, making it more difficult to detect. In such cases, when an overload condition is identified and dynamically managed resources are connected on the feeder, it may require additional investigative steps to identify the root cause.

Stakeholder Feedback

Ameren Illinois sincerely appreciates the high level of engagement and feedback that participants shared during the workshop. The facilitation support provided by the CHARGED Initiative was also a key element of the success of the workshop, providing clear structure and feedback channels that helped maximize constructive dialogue on complex, technical topics. The perspectives and recommendations shared during the workshop will be incorporated to help shape Ameren Illinois' pathways to implementing flexible interconnection mechanisms.

Prior to the workshop process, Ameren Illinois developed an initial approach to static and dynamic flexible interconnection. This was intended to give participants something concrete to react to and to maximize the value of in-person time to discuss critical elements. There were several areas where stakeholder feedback was broadly supportive of the initial approach, including:

- Enabling both static and dynamic pathways
- Enabling static connections on a relatively shorter timeline than dynamic pathways
- Enabling both temporary "bridge-to-wires" and long-term cost avoidance use cases for both static and dynamic
- Using existing platforms and regulatory structures (interconnection agreement, Powerclerk portal, etc.)
- Using the level 4 process and keeping to existing level 4 timelines for static schedule-based and dynamic flexible interconnection
- Maintaining schedules on an ongoing basis without unexpected changes
- Use of a pro-rata approach with a target curtailment limiting mechanism at 5% of total annual theoretical production, beginning after traditional capacity firm capacity is exhausted
- Documenting operating schedule or dynamic requirements within formal documents (e.g., the interconnection agreement) with formal customer approval
- Continuing to expand opportunities to voltage and subtransmission criteria as capabilities are established and processes mature

Many of the discussions within the workshop yielded recommended enhancements for future flexible interconnection policy. These include:

- Including a weekday and weekend differentiated option for static schedules for loads. Both customer and feeder load profiles are often significantly different on weekends, potentially increasing available capacity and the likelihood of utilization
- General preferences for higher scheduled granularities (e.g., 24-points or more) due to their potential to increase available operating capacity and account for changing conditions
- Providing a pathway for static scheduled connections to convert to dynamically managed connections once dynamic offerings become available
- Incorporating static scheduled and dynamic connection information into future hosting capacity map refinements
- Providing clarity on the specific communications channels to be used for dynamic management, as it relates to upfront cost and ongoing communications reliability. In particular, high per-mile costs from fiber and potential cellular coverage issues were identified as being key to adoption decisions
- Coordinating the information provided to participants to support participant financing needs

- Clearly documenting how existing queues and queued applicants will be impacted by flexible interconnection offering rollouts
- Establishing clear, publicly available technical requirements to facilitate customer site design

While the overall tone was positive and progress-focused, there were a few areas where stakeholder requests or ideas diverged from Ameren Illinois' perspective. This included:

- Hard curtailment caps and contractual curtailment compensation mechanisms were discussed as a means of improving the ability to finance projects. Ameren Illinois does not believe that such mechanisms can be implemented without increasing costs to other Ameren Illinois customers or larger structural regulatory and cost recovery changes.
- Increasing customization for static schedule options was discussed as a way of improving the willingness of load customers to accept flexible interconnections. This included recommendations for full customization as well as schedule carve-outs for holidays that may impact certain types of customers' operating profiles. For static schedule options to be studied and implemented effectively at scale within the existing prescribed timelines, Ameren Illinois believes it is essential to establish standardized schedule granularities to enable automated data processing and maintain accurate records and integrations across impacted software platforms.

Next Steps

After concluding the flexible interconnection investigation efforts and stakeholder engagement within Phase 2, there are important benefits available to both load and DER customers from enabling access to schedule-based interconnections and dynamic management. To enable the implementation of these options, the following activities are anticipated:

- Finalize schedule options, considering participant feedback.
- Finalize and document static schedule and dynamic study methodologies, assumptions, and data sources.
- Develop data processing automations for static and dynamic studies to enable timely, efficient study completion.
- Develop technical requirements for applicant participation in scheduled and dynamic flexible interconnections.
- Facilitate internal change management efforts to implement new processes and inform impacted Ameren Illinois teams.
- Continue DERMS rollout efforts as a vehicle for enabling dynamic flexible interconnections.
- Identify appropriate avenues for ongoing stakeholder engagement for formal implementation plans.
- Identify low-risk vehicles to test site hardware and operational capabilities for static schedule and dynamic flexible options through pilot projects or as part of temporary “bridge-to-wires”